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Arizona Corporation Commission
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EXHIBIT

TEP-9

ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	)	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. E-01933A-07-0402

TUCSON ELECTRIC POWER COMPANY

REBUTTAL TESTIMONY AND EXHIBITS

VOLUME 1 OF 2

April 1, 2008

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
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Rebuttal Testimony of

James S. Pignatelli

on Behalf of

Tucson Electric Power Company

April 1, 2008

Executive Summary of the Rebuttal Testimony of James S. Pignatelli

Mr. Pignatelli is the Chairman of the Board, President and Chief Executive Officer of Tucson Electric Power Company ("TEP" or the "Company"). Mr. Pignatelli's Rebuttal Testimony addresses the following matters:

Commission Staff and Intervenors have ignored prior Commission decisions and disregarded clear evidence of rising costs in recommending a rate decrease for TEP without any consideration for the impact such rates would have on the Company's financial standing. The unreasonably low rates proposed by Commission Staff and Intervenors would threaten TEP's financial health and force it to scale back plans for much-needed system expansion and improvements .

Commission Staff and Intervenors oppose the Company's proposed Termination Cost Regulatory Asset ("TCRA"). The TCRA provides a regulatory alternative to the damages or other remedies a court would award in response to a breach of contract claim stemming from the denial of TEP's right to charge market-based generation rates beginning in 2009. Mr. Pignatelli introduces the testimony of The Honorable Thomas A. Zlaket, retired Chief Justice of the Arizona Supreme Court, who has presented his expert opinion that the 1999 Settlement Agreement is a valid contract, the Commission is a party to the contract, TEP could be awarded of damages or equitable relief for a breach of the contract and a court would likely find that TEP is entitled to charge market rates for generation service in 2009.

Responses to several issues raised by Commission Staff and Intervenors, including:

1. **The cost of Springerville Unit 1.** Mr. Pignatelli states that Commission Staff and Intervenors have disregarded prior Commission orders establishing that a reasonable market rate should be used to recover the cost of this unit.

2. **Depreciation expenses.** Mr. Pignatelli states that Commission Staff and Intervenors would unfairly penalize TEP for complying with accounting requirements and would undo the effects of the 1999 Settlement Agreement without recognizing the costs imposed on the Company.

3. **SO_2 credits.** Mr. Pignatelli states that TEP should retain the proceeds from the sale of sulfur dioxide ("SO_2") credits because customers were not asked to fund the emissions control improvements that made those credits available.

4. **Capital structure and return on equity.** Mr. Pignatelli defends TEP's proposed use of a pro-forma capital structure and proposes that the Company be granted a return on equity on par with that recently approved for use by another Arizona electric utility.

5. **Luna Energy Facility.** Mr. Pignatelli rejects the cost-based recovery proposed by Commission Staff and Intervenors and maintains that TEP should be treated similarly to another Arizona electric utility, which employs a non-cost based recovery for certain generating assets.

6. **Performance Enhancement Plan.** Mr. Pignatelli defends full recovery of the Company's incentive pay plan as beneficial to both customers and

shareholders. He offers a compromise that 50 percent officer incentive pay be funded by shareholders and non-officer pay be funded by ratepayers.

7. FERC OATT. Mr. Pignatelli explains TEP's legal obligation to employ FERC's Open Access Transmission Tariff ("OATT") and again seeks parity with another Arizona electric utility, which recovers its FERC OATT costs from customers.

Q. Please state your name and position with Tucson Electric Power Company ("TEP").

A. My name is James S. Pignatelli. I am Chief Executive Officer, President and Chairman of the Board of Directors of TEP. I hold the same positions with UniSource Energy Corporation, TEP's parent company.

Q. Mr. Pignatelli, have you reviewed the direct testimony of the Commission Staff and Intervenors filed in this proceeding?

A. Yes, I have.

Q. What is the purpose of your Rebuttal Testimony?

A. My Rebuttal Testimony provides a general response to the rate recommendations offered in the direct testimony of Commission Staff as well in testimony from RUCO and AECC (to whom I will refer as the "Intervenors"). Other TEP witnesses address in greater detail our specific rebuttal and corrections to the direct testimony of the Commission Staff and Intervenors.

To support inclusion of the Transition Cost Recovery Asset ("TCRA") in a cost-of-service rate methodology, I introduce the testimony of The Honorable Thomas A. Zlaket, Retired Chief Justice of the Arizona Supreme Court, who testifies to his opinion that (i) the 1999 Settlement Agreement is a valid contract; (ii) the Commission is a party to the 1999 Settlement Agreement; (iii) TEP's remedies for a breach of the 1999 Settlement Agreement by the Commission or other parties include damages and equitable relief; and (iv) based upon extrinsic evidence and the 1999 Settlement Agreement, TEP is entitled to charge the market based rates for generation service.

I also introduce the Rebuttal Testimony of Alan D. Felsenthal, CPA of Huron Consulting Group, who testifies that (i) TEP appropriately discontinued application of FAS 71 in

1999 and cannot reapply the provisions of FAS 71 at this time; (ii) TEP correctly changed its depreciation accounting pursuant to the requirements of Generally Accepted Accounting Principles ("GAAP"); (iii) the Company has complied with FAS No. 143; and (iv) asset retirement costs were returned to customers through the stranded cost provisions of the 1999 Settlement Agreement.

Q. What is your general response to the direct testimony of Commission Staff and Intervenors?

A. The positions offered by Commission Staff and Intervenors in this case abandon the principle of "just and reasonable rates". Instead, they appear to be a results-oriented attempt to build a case for unreasonably low rates. A review of the recommendations proposed by the Commission Staff and Intervenor witnesses reveals a pattern of disregard for (i) the provisions of prior Commission orders; and (ii) the consistent resolution and treatment of rate-related issues.

The Commission Staff and Intervenor recommendations would decrease TEP's base rates from their existing levels. These recommendations are particularly egregious because the Company has been under a rate freeze since 1999 and it is undisputed that TEP's current base rates are lower than they were in 1994.

I cannot believe that anyone who reviews this case with an eye toward authorizing just and reasonable base rates will conclude that any rate decrease is warranted. On the contrary, under each of the rate methodologies presented by TEP in this proceeding, a significant base rate increase is fully supported by the evidence.

Finally, while I strongly disagree with much of what Commission Staff has recommended, especially regarding base rates, I do want to point out that TEP and the Staff agree that the Commission should approve a purchase power and fuel adjustment

clause for the Company if TEP is returned to cost-of-service ratemaking. The Commission has approved such clauses for other Arizona utilities, and the same protections afforded the customers of those companies should be in place for TEP's customers.

Q. Mr. Pignatelli, what is the basis for your belief that Commission Staff and Intervenors have recommended unreasonably low rates?

A. The recommended rate decreases ignore important Commission Orders, penalize the Company for following the requirements of the Financial Accounting Standards Board ("FASB"), penalize the Company for following the requirements of the Federal Energy Regulatory Commission ("FERC"), discriminate against TEP by disregarding the Commission's treatment of other similarly situated Arizona utilities and advocate that the Commission – and therefore, the State of Arizona – ignore its contractual obligations under the 1999 Settlement Agreement.

TEP's rebuttal testimony provides specific examples of these aberrations and their impact on the revenue requirement recommendations of the Commission Staff and Intervenors. In particular, I will point out several instances where, if the appropriate treatment had been applied by Commission Staff and the Intervenors, their recommendations would lead to positive rate increases in this case.

Q. Are you concerned that Commission Staff may recommend further rate reductions?

A. Yes, I am. The direct testimony of Mr. Radigan suggests that the Commission Staff is preparing to do just that in its surrebuttal testimony regarding TEP's FERC-approved Open Access Transmission Tariff ("OATT"). It appears Commission Staff will

recommend that TEP should be penalized for following FERC requirements and prior Commission orders that directly address this issue. As all parties are well aware, the FERC Order 888 requires TEP to charge OATT rates for transmission service. And, the Commission similarly ordered TEP to charge rates for transmission and ancillary services based on the OATT in Decision No. 62103 as stated in Section 4.4 of the 1999 Settlement Agreement. I believe that if the Commission Staff does take such an extreme position, then it will be further distracting the Commission from making a determination of just and reasonable rates.

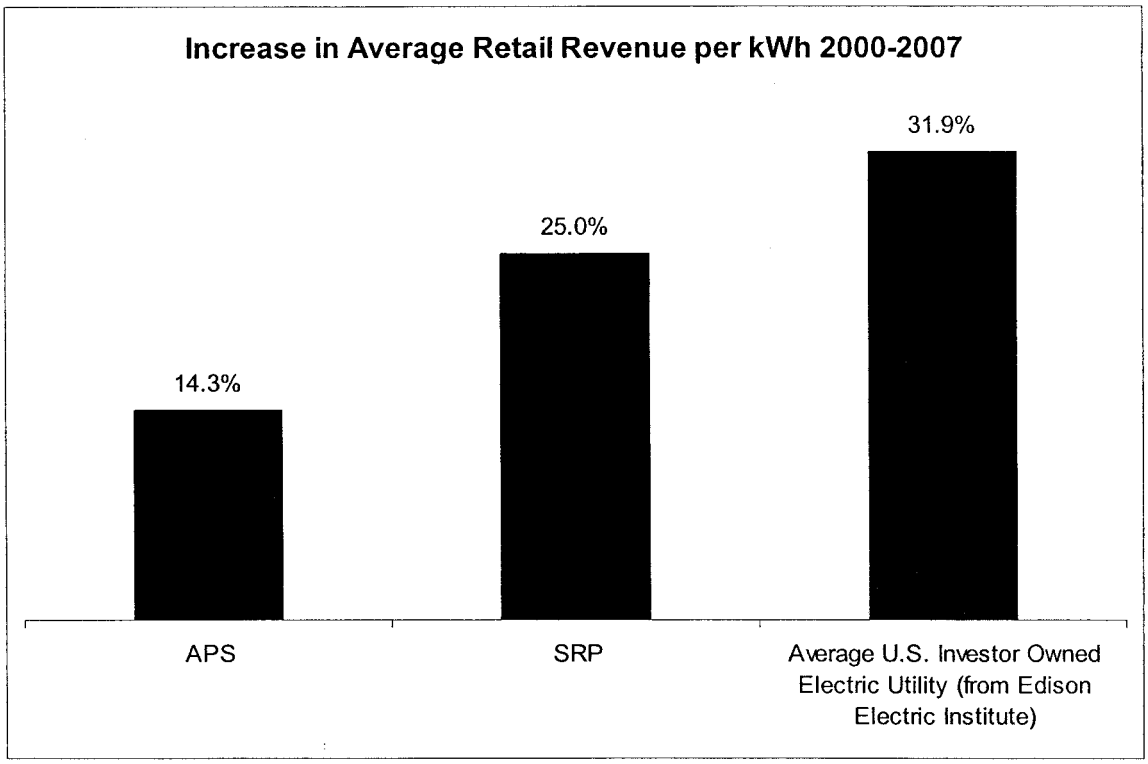
Q. Mr. Pignatelli, what would be the impact on the Company if the recommendations of the Commission Staff and Intervenors are adopted by the Commission?

A. The impact would be devastating to TEP, its customers, its employees and its shareholders.

To fully appreciate my answer, you have to put the past 10 years in perspective. It has been a constant challenge to maintain the high level of safe and reliable service that has been the trademark of TEP. As I pointed out in my direct testimony, the costs of raw materials, natural gas, wages and benefits, and other business needs have skyrocketed during the period that our rates have been frozen. Our system maintenance costs have risen, and we face an increasing need for significant capital investments to meet our customers' growing energy demands. The Company endured these pressures with the understanding that, under the 1999 Settlement Agreement, it would be entitled to charge full market-based rates for generation service in 2009. After investing more than $700 million in capital improvements over the past five years, the Company is preparing to nearly double that spending – to $1.4 billion – from 2008 through 2012. These much-needed improvements have been timed to take advantage of an anticipated increase in revenues after this year.

If TEP is not allowed to charge a market rate for generation or if significant rate relief does not occur, then these plans will have to be scaled back, operating expenses will have to be further reduced and the reliability of TEP's service will undoubtedly suffer. The Company's credit ratings for its unsecured debt, which are currently rated as speculative or below investment grade by Standard and Poor's and Fitch Ratings, Inc., could face further reductions due to weaker financial indicators. This would drive up TEP's borrowing costs at the very time that a lack of adequate cash flow would force the Company to make heavier use of debt to fund its most dire capital needs. A rate reduction would serve only to exacerbate these problems, further eroding the significant value that TEP customers derive from the reliability of their service.

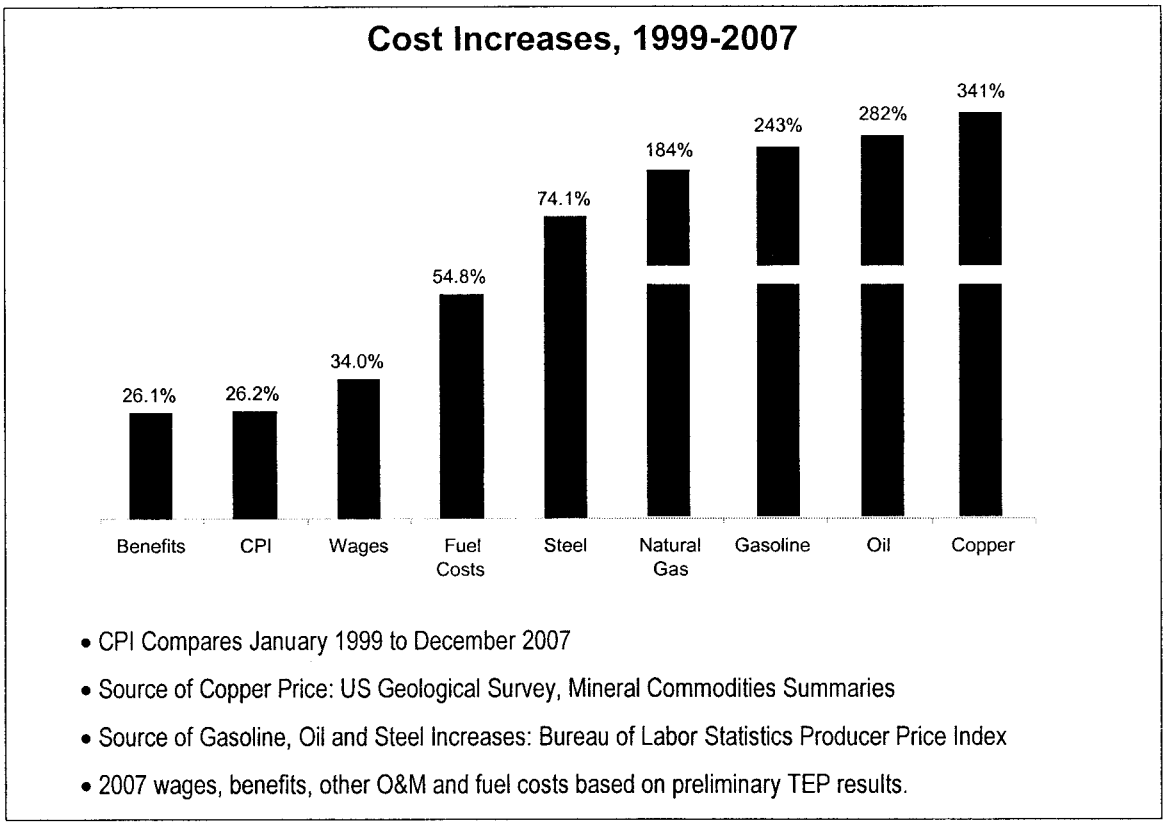
I think it is informative to look at the rate relief that Arizona's two other major electric utilities received from 2000 through 2007:



While TEP's rates have been frozen, the average retail rates charged by Arizona Public Service ("APS") increased 14 percent. The rates charged by Salt River Project ("SRP") increased 25 percent during that period, while the average U.S. investor-owned electric utility increased rates nearly 32 percent. TEP's residential rates, meanwhile, were 11 percent lower than those of APS and 2 percent lower than those of SRP at the end of 2007. If TEP does not receive adequate rate relief, this disparity is set to increase even further. APS has recently sought an additional 8 percent increase, while SRP's Board of Directors recently approved an average 3.9 percent rate increase that will take effect May 1.

Q. Has TEP faced similar cost increases to those experienced by APS and SRP?

A. Yes. While I cannot speak to specific expenses incurred by APS and SRP, all three utilities have faced rising market costs for wages and benefits, fuel, materials and other business needs since the 1999 Settlement Agreement was signed, as is generally shown in the following table:



In light of these rising costs, and the rate increases granted to other electric utilities to address them, I do not see how anyone could conclude that a reduction of TEP's long-frozen base rates would be either just or reasonable.

Q. How might a decision to accept the recommendations of Commission Staff and Intervenors be received by the financial and investment communities?

A. A decision to rescind the 1999 Settlement Agreement without any compensation to the Company – as the Commission Staff and Intervenors have recommended – would likely lead potential investors or lenders to view any authorization or commitment by the Commission or other agency of the State of Arizona to be illusory. Such disregard for a prior contractual commitment would serve to discourage investors or lenders from doing business with TEP and other Arizona utilities or companies, thus hampering the state's

economic development. These concerns are not imaginary and have been raised with me during my meetings with banks, financial analysts and institutional investors.

Q. Have the Commission Staff and Intervenors performed an analysis of the financial impact of their recommendations on TEP?

A. No such analysis was included in their testimony. I do not know how the Commission Staff and Intervenors could evaluate the reasonableness of their recommendations without undertaking an analysis of the financial impact of their proposals.

However, we have performed an analysis of the financial impact of the Commission Staff and Intervenor proposals. Based upon our analysis, adoption of their proposed rates would result in a violation of the financial covenants contained in TEP's Credit Agreement. This would prevent TEP from making additional borrowings on its revolving credit facility, and a default arising from this agreement would trigger cross-defaults in the Company's other debt agreements and long-term purchased power and gas contracts, causing numerous financial and operational concerns. This would lead to higher financing costs, crippling the Company's ability to achieve and sustain solid financial health.

Q: Please address the Commission Staff's and Intervenors' response to the market and hybrid methodologies proposed by the Company.

A. Commission Staff and Intervenors essentially ignored those options, choosing to make exclusive use of a cost-of-service method in calculating the Company's rates. In so doing, they completely disregard TEP's contractual right under the 1999 Settlement Agreement to charge a market-based rate for generated power. As I discuss more fully in my direct testimony, the market methodology employs the MGC to calculate TEP's generation rate. The proposed hybrid methodology would exclude some generating assets from the

Company's rate base, thus increasing the share of generation costs to be recovered through the proposed PPFAC. I believe the Commission would benefit from a continued discussion of these alternatives. They represent the Company's earnest efforts to resolve disagreements about the effect of the 1999 Settlement Agreement – disagreements that may yet find their way to a court of law.

Q: Mr. Pignatelli, please address your criticism of the Commission Staff's and Intervenors' recommendations regarding the 1999 Settlement Agreement and the Termination Cost Regulatory Asset ("TCRA").

As I understand the positions of the Commission Staff and Intervenors, they believe that TEP's rates should be determined based on a cost-of-service methodology without including any amount for the TCRA. The TCRA is a proposed regulatory alternative to the damages or other remedies a court could award in response to a breach of contract claim stemming from the denial of TEP's right to charge MGC-based generation rates beginning 2009.

The Commission Staff's and Intervenors' position apparently is based on their argument that TEP either has no such contractual rights or will not have suffered any harm under the 1999 Settlement Agreement if it is denied the use of MGC-based generation rates in 2009.

TEP, Commission Staff and Intervenors have filed various pleadings in this consolidated proceeding outlining their respective legal and factual analyses of the validity, terms and conditions, rights and obligations and remedies under the 1999 Settlement Agreement. TEP has made it clear that it believes that the 1999 Settlement Agreement is a valid contract; that the Commission is a party to that contract; that it is entitled to charge generation service based upon the MGC beginning January 1, 2009; and that if it is not allowed to do so, and if an acceptable amendment to the 1999 Settlement Agreement is

not reached, it would file a breach of contract action seeking damages or specific damages in court.

Upon review of the filings and testimony in this proceeding, it became clear that Commission Staff, RUCO and AECC were mixing administrative and regulatory principles (used at the Commission) with the legal doctrines and case law that a court would employ in a breach of contract action. I believe that this may have led these parties to underestimate the risks of such a lawsuit to their constituencies and the benefit of the TCRA as a regulatory settlement tool in the event that a cost-of-service rate making methodology is preferred by the Commission in this case.

Accordingly, TEP retained The Honorable Thomas A. Zlaket, retired Chief Justice of the Arizona Supreme Court, and requested that he review filings of the parties and related information to provide his opinion on (i) whether the 1999 Settlement Agreement is a valid contract; (ii) whether the Commission is a party to the 1999 Settlement Agreement; (iii) what remedies a court would award TEP for a breach of the 1999 Settlement Agreement by the Commission or other parties; and (iv) whether, pursuant to the 1999 Settlement Agreement, TEP is entitled to charge market based rates for generation service in 2009. Chief Justice Zlaket's testimony is being filed with the Company's rebuttal testimony, and he will be a witness at the hearing scheduled in this proceeding. His testimony is the only third-party expert legal analysis of the 1999 contract that has been presented to the Commission.

In summary, Chief Justice Zlaket's conclusions are that:

(i) the 1999 Settlement Agreement is a binding contract on its parties;

(ii) the Commission is a party to that contract;

(iii) Damages (or restitution) are the remedies available for a breach of the contract; and

(iv) Based on the language of the 1999 Settlement Agreement, and supporting extrinsic evidence, TEP should be permitted to charge market-based rates for generation service.

He also concludes that even without finding a binding contract, an Arizona court would likely allow a remedy to TEP based on a claim of detrimental reliance.

While Chief Justice Zlaket's conclusions are not binding upon the parties, they are the best evidence before the Commission of the merits of TEP's claims and the need for a TCRA to avoid a lawsuit in the event that TEP's generation rates are to be determined by a cost-of-service rate methodology.

Q. Has TEP filed an estimate of its damages?

A. Yes, it has. I recognize that there are different ways that damages can be calculated. I also realize that a court may calculate damages differently than the parties to the 1999 Settlement Agreement may stipulate to in a regulatory proceeding such as this case.

One way would be to determine the difference between the cost basis and market value of TEP's generation assets. This approach would be based on TEP's need to "acquire" generation assets to serve its customers. TEP's previous generation assets were removed from regulation in 1999 and would have to be reacquired. Reacquisition would be at market prices – as it would with any other acquisition of assets. Using this method, TEP's damages are estimated at $1.9 billion. This would put TEP in the same position it would have been if the contract had not been breached.

In the Company's direct testimony, TEP witnesses present an amount of damages based upon the utilization of a TCRA. Simply stated, the TCRA is calculated using the revenue deficiency that TEP proved in the 2004 Rate Review and adding a carrying cost to that amount through December 31, 2008. Using this calculation the damage amount is $921 million. If TEP calculated the TCRA based upon the revenue deficiencies submitted in the 2004 Rate Review by Commission Staff and RUCO, the corresponding TCRA amounts would be $535 million and $241 million, respectively. As reflected in our filing in this case, the Company is willing to reduce its requested TCRA from $921 million to $788 million if TEP is allowed to retain the revenues collected from the extension of the Fixed CTC.

Q. Do you plan to rebut all of the objectionable adjustments proposed by Commission Staff and Intervenors?

A. I am not addressing all of the objections that we have with the Commission Staff and Intervenor direct testimony. I will leave that task to other TEP witnesses. However, I want to call attention to a few items that demonstrate disregard for prior Commission decisions, inconsistent treatment of TEP and other Arizona electric utilities and indifference to the state of Arizona's economic well-being.

Q. Please respond to the Commission Staff's and Intervenors' recommendations regarding the ratemaking treatment for the cost of Springerville Unit 1.

A. Commission Staff and the Intervenors each disregard the obligation made clear by prior Commission decisions that, for ratemaking purposes, the cost for Springerville Unit 1 should be based on market value.

For example, Commission Staff recommends that Springerville Unit 1 costs be set at the rate of $15 per kW-month. This is not the current market value of Springerville Unit 1.

This is the derived 1989 market value that was used in 1989 for Springerville Unit 1 costs. See Decision No. 56659. However, in Decision No. 56659 the Commission did not set $15 per KW-month as the cost to be used for Springerville Unit 1 in perpetuity. Rather, in that case, the Commission stated that the cost of Springerville Unit 1 should be recovered based on its current market value -- which, at the time, was determined to be $15 per kW month. Two years later in Decision No. 57586, the Commission reiterated that for ratemaking purposes the market price for Springerville Unit 1 should be used. The Commission stated:

> In future rate cases the Commission shall determine the appropriate level of the Century demand charge based on reasonable market prices, but in no event will the rate be lower than the rate allowed in Decision No. 56659, or $15 per kW/month. (Finding of Fact 10.q.; emphasis added)

Both Decision 56659 and 57586 establish that current market rates are to be used to recover Springerville Unit 1 costs. As such, they are compelling reasons to utilize the market rate – currently $29.72 per kW-month – for Springerville Unit 1 in this case.

The only rationale offered by Commission Staff for using the $15 per kW fixed monthly rate, is that "there is no compelling need at this time to revise the $15 per kW fixed monthly rate" and that "the fixed monthly rate should remain at $15 per kW, as established in Decision No. 56659 and used in prior TEP rate cases." Compliance with prior Commission Decisions seems to me to be a "compelling need" to abandon a below market rate for a current market rate. I note that Commission Staff's position on this issue in this case contradicts the position that it took in the 2004 Rate Review. In the 2004 Rate Review, Commission Staff recommended that the amount of $20 per kW-month be used to determine the cost of Springerville Unit 1. Now, Commission Staff shifts to the lower amount of $15 per kW-month, without any rationale.

The $15 per kW-month amount proposed by Commission Staff even falls short of TEP's test-year-recorded costs associated with Springerville Unit 1. The current cost of this lease when properly calculated to include all elements is $26.34 per kW-month (as explained in the Rebuttal Testimony of Ms. Karen Kissinger).

AECC and RUCO argue that the actual cost of the lease should be used to determine Springerville Unit 1 costs. As I previously pointed out, the Commission made it clear that current market rates should be used. AECC' s and RUCO's arguments fail for the same reason that Commission Staff's position must be rejected.

Using TEP's originally filed market rate of $25.67 for Springerville Unit 1 – which was based on a Springerville Unit 3 contract – will increase Commission Staff's revenue requirement by $44.4 million on an ACC jurisdictional basis. Using the current market rate of $29.72 as proposed by TEP witness Mr. Hutchens in his rebuttal testimony would increase staff's revenue requirement by $61.3 million on an ACC jurisdictional basis.

Q. Do the Commission Staff and Intervenor positions regarding Springerville Unit 1 reflect a troubling trend and an inappropriate regulatory outcome?

A. Yes. As I have indicated, in this case there appears to be a pattern of selectively switching back and forth on approaches for resolving the same issue and choosing the solution that will produce the lowest current rate.

In 1988, when the cost for Springerville Unit 1 exceeded market levels, the Commission adopted a market-based recovery for the unit. In 1991, the Commission reiterated that market rates were to be used in future ratemaking proceedings to recover Springerville Unit 1 costs. As a result and upon reliance of the Commission orders, TEP reduced the unit's capitalized lease cost, writing down the asset on its books. Now that market rates

for the same asset are higher than the written-down book costs, the Commission Staff and Intervenors are recommending that the lower costs be reflected in rates. This approach ignores the clear Commission directive that market prices are to be used to recover costs for Springerville Unit 1 and exacerbates the problem by adopting a calculation that reflects a lower cost resulting from the prior write-down of the asset.

This "heads I win, tails you lose" approach does not produce just and reasonable rates. Regulatory certainty is imperative to utilities, capital markets and customers. It is especially critical in areas like Tucson, where the escalating demand for power is increasing the need for substantial capital expenditures. If regulatory uncertainty is an added risk that must be allocated when TEP goes to market to acquire financing for its operations, including capital expenditures, that risk will require a premium in the form of additional financing costs.

Q. Mr. Pignatelli, have you observed other instances of this approach in the positions of the Commission Staff and Intervenors?

A. The most egregious application of this approach is in the underling issue of this case: the transition to electric competition. In 1999, when it was believed that market prices for generation service in 2009 would be below cost, Commission Staff and Interveners encouraged the Commission to force TEP to transition to electric competition. But now that we are on the cusp of 2009 and it is clear that market prices for generation service will be higher than cost, the same parties argue that the 1999 Settlement Agreement should be ignored and TEP prevented from charging market prices. In so arguing, the parties ignore the fact that the cost-of-service based rates that they are proposing will be calculated on costs that have been reduced, at the expense of the shareholder, in prior periods to reflect market values in the 1990s.

TEP shareholders wrote off $360 million in Springerville generation costs in the early 1990s and then $450 million under this contract because the regulatory determination at those times was that cost was higher than market. These write-offs are equivalent to more than 50 percent of TEP's $1.6 billion of Net Utility Plant In Service at the end of 2006. Now that these diminished capital costs (reduced further by $104.4 million on an ACC jurisdictional basis in the Commission Staff recommendation for cost of removal and depreciation rate changes) are well under market, the Commission Staff and Interveners recommend that rates revert to being cost-of-service based. The Company and its shareholders will lose every time under this "heads I win, tails you lose" approach, and the long-term interests of customers will be sacrificed. Again, that is not just and reasonable.

Q. Please address the position of Commission Staff regarding the effects of FAS 71 accounting.

A. The Commission Staff would penalize TEP for complying with the requirements of FAS 71. Commission Staff proposes to adjust accumulated depreciation to reinstate depreciation expense at the depreciation rates in effect in 1999, notwithstanding that TEP adjusted such rates several times since then to reflect changes in depreciation lives and to eliminate the cost of removal component of depreciation rates upon adoption of FAS 143 in 2003. Because TEP's generation was no longer rate-regulated at the time of such depreciation changes, FAS 71 did not apply and Generally Accepted Accounting Procedures ("GAAP") required depreciation adjustments based on updated depreciation factors.

Commission Staff also has chosen to ignore that the stranded cost calculation – the basis for the Competitive Transition Charge ("CTC") used for the 1999 Settlement Agreement – already incorporated the cost of removal amount for non-legal retirement obligations.

This historical depreciation reserve for the cost of removal reduced TEP's stranded costs and has already benefited customers through a reduction of the Fixed CTC. Nonetheless, Commission Staff has proposed that the cost of removal amount for non-legal obligations be used to reduce rate base. This would return the same monies twice to the customers at a significant and unjustified cost to the Company.

Commission Staff's depreciation-related adjustments are not appropriate and penalize the Company for complying with FAS 71 and FAS 143. They also reflect a one-sided effort to undo the effects of the 1999 Settlement Agreement without recognizing the costs it imposed on the Company. If the Commission wishes to unwind the agreement, it cannot simply undo developments that increase costs for customers without compensating TEP and its shareholders for the expenses incurred in living up to its terms.

TEP is presenting the testimony of Alan D. Felsenthal, who is a Certified Public Accountant and managing director of Huron Consulting Group. Mr. Felsenthal has concluded that that as a result of the 1999 Settlement Agreement, TEP could no longer apply FAS 71 to the generation segment of its business, and that Commission Staff's accumulated depreciation adjustments to reinstate cost of removal and ignore required depreciation rate changes are without basis. Mr. Felsenthal's expert testimony refutes the assertions of Commission witness Ralph Smith, who does not believe that TEP should have discontinued FAS 71 accounting as a result of the 1999 Settlement Agreement. I note that Commission Staff witness John Antonuk agrees that TEP appropriately discontinued FAS 71 accounting, directly contradicting Mr. Smith and thereby further undermining the Commission Staff's position on this issue. This issue will be addressed in further detail in the rebuttal testimony of Mr. Felsenthal and TEP witness Ms. Karen Kissinger.

It also is important to understand that if the Commission Staff's accumulated depreciation adjustments for depreciation rate changes and cost of removal are accepted, TEP would have to write off $159 million. This would reduce TEP's equity by approximately 17 percent, negatively impacting its financial ratios and hindering its ability to finance under the Commission's orders. No consideration of this consequence was made by Commission Staff witness Smith.

Rejecting the Commission Staff's accumulated depreciation adjustments for depreciation rate changes and cost of removal will increase its revenue requirement by $ 13.7 million on an ACC-jurisdictional basis.

Q. Please respond to the proposed treatment of the proceeds of the sales of sulfur dioxide (SO2) allowance credits.

A. Commission Staff proposes that all proceeds from the sale of SO2 allowance credits be transferred to TEP's customers. This ignores the fact that the vast majority of the credits were generated from upgraded pollution control equipment that was installed at the Springerville Generating Station and paid for by Tri-State Electric Cooperative. TEP customers were not asked to pay for these improvements, and consequently, they should not be the recipients of the proceeds. Commission Staff has offered no justification for its recommendation to take all of the gains away from TEP and bestow them on the customers.

If the Company's requested treatment of gains on the sale of SO_2 allowances is followed, the Commission Staff's revenue requirement will increase by $8.3 million on an ACC jurisdictional basis.

Q. Please address the Commission Staff's and Intervenors' recommendations on TEP's capital structure and return on equity.

A TEP has calculated its rates using a pro forma capital structure of 45 percent equity. Commission Staff rejects TEP's proposed equity ratio of 45 percent and recommends that TEP's actual equity ratio of 40 percent be used. However, Commission Staff provides no explanation of or support for why it believes it is more appropriate to use TEP's actual 2006 capital structure. The Commission and Commission Staff have previously supported the use of a pro forma equity ratio to encourage a higher equity ratio and to improve a utility's financial stability. In TEP's 2004 Rate Review, Commission Staff supported use of a pro forma equity ratio of 40 percent for TEP. In Decision No. 70111 (November 27, 2007), the Commission approved the use of a pro forma equity ratio in setting rates for UNS Gas, TEP's sister company.

TEP has significantly improved its financial condition since the Company's last general rate case in 1994. As recently as October 30, 2007, the Commission, in Decision No. 69946, recognized TEP's financial progress:

> In the last 15 years, TEP has been able to increase its equity position substantially, and has demonstrated the financial expertise and management integrity to make positive financial decisions. (Page 9, lines 12-14)

Still, TEP's equity ratio is below the industry average. TEP is continuing to improve its equity ratio. For example, TEP's equity ratio, as calculated for Commission ratemaking purposes, was 41 percent as of December 31, 2007, compared with 40 percent as of December 31, 2006. That improvement is due to an increase in common stock equity through the retention of earnings.

Rates should be set with, at a minimum, the average equity anticipated over the period the rates are in effect. TEP will be increasing its equity as it reinvests its earnings in new plant and equipment. A 45 percent equity ratio will help the Company continue to make gradual improvements in its capital structure and position TEP to access the capital markets on more favorable terms. TEP witness Mr. Larson will address this issue in more detail in his rebuttal testimony.

I further believe that Commission Staff's return on equity recommendation is too low. TEP has demonstrated that the appropriate return on equity level should not be less than 10.75 percent on the pro forma 45-percent equity ratio. Commission Staff's recommendation of 10.25 percent substantially understates the realistic return required for TEP's equity. I note that the Commission recently approved a return on equity of 10.75 percent for APS. See Decision No. 69663. I see no reason why TEP's return on equity should be set lower than that of APS. TEP witness Mr. Hadaway will address this issue in more detail in his testimony. If the Commission adopts the Company's proposed pro forma capital structure and weighted average cost of capital and applies this to Commission Staff's proposed rate base, then the Staff's revenue requirement will increase by $6.1 million on an ACC jurisdictional basis.

Q. Please address the Commission Staff's and Intervenors' recommendations regarding the treatment of the Luna Energy Facility.

A. TEP acquired a one-third interest in the then-unfinished Luna Energy Facility (also referred to as the "Luna plant") in November 2004. The 570-MW combined cycle natural gas-fired plant has been in commercial operation since April 2006. The Luna plant is not in the Company's rate base, and TEP has not proposed any such inclusion in this proceeding. Rather, as detailed in my Direct Testimony, TEP is requesting that the cost of this facility be recovered through a demand charge of $7 per kW-month, a significant

discount to the current market price for gas fired generation of $10.66 per kW-month. TEP is willing to commit to this discounted value for the plant's life if the requested rate treatment is approved. Commission Staff and the Intervenors, however, are recommending that the Luna plant be forced into TEP's rate base at its original cost to TEP.

Once again, Commission Staff and intervenors are seeking to deny TEP the same treatment recently granted to APS and its sister company, Pinnacle West Energy Corporation ("PWEC"). In Decision No. 67744, the Commission approved use of a non-cost based valuation for PWEC assets. This rate was based on the value of the remaining term of a Track B contract between APS and PWEC. In so doing, the Commission adhered to the precedent set in Decisions Nos. 55659 and 57586, which authorized use of a market rate for such assets. Our request in this case seeks nothing more than comparable treatment.

The cost-based treatment proposed by Commission Staff and Intervenors also fails to recognize other fixed costs that were covered by the proposed demand charge, such as the fixed O&M expense that is included in the Luna plant's Long-Term Service Agreement with General Electric. If the Luna plant is to receive cost-based treatment, then these costs must be included.

I should note that TEP is not obliged to accept cost-based recovery for the Luna plant. The Company's shareholders took on the risk of this investment, and their interests may be better served by the sale of TEP's stake in the Luna plant if acceptable rate treatment is not approved in this case. The current replacement cost of the Luna plant is approximately 3 to 4 times more than the amount Commission Staff is proposing.

Q. Please address the treatment of the TEP employee Performance Enhancement Plan ("PEP").

A. Commission Staff and RUCO have recommended the removal of 50 percent of the normalized level of expense related to PEP. Both parties contend that shareholders should bear half the burden of funding this program because it rewards employees for achievements that serve shareholders' interests, including, as RUCO's testimony notes, "financial performance and cost containment goals."

This analysis is shortsighted on several counts. First, it fails to recognize that TEP customers directly benefit from all of the Company's PEP goals. Maintaining appropriate earnings allows TEP to finance its debt at reasonable rates, reducing the interest expense passed along to customers. Similarly, the Company's cost-containment efforts ultimately result in lower rates for customers.

Moreover, there is no evidence to suggest that PEP bonuses lift our employees' total compensation above a level that would be considered just and reasonable. If the PEP amounts were simply included in our employees' salaries as direct compensation, there would be no question that the entire amount should be recoverable through rates. So by placing a portion of our employees' wages at risk, PEP actually makes it possible to reduce our compensation below a just and reasonable level if performance goals are not reached.

I realize that the position taken by Commission Staff and RUCO toward our PEP program reflects the Commission's recent decisions regarding incentive pay programs at other utilities, including UNS Gas. But this approach, if continued, would serve to discourage the use of performance-based pay at TEP as well as at other utilities. I believe customers are well-served by such programs, as they encourage the pursuit of goals that

ultimately serve the interests of customers and shareholders alike. Our employees take pride in these achievements, and our customers clearly benefit by awarding a portion of our reasonable compensation expenses through the PEP program.

I believe our entire normalized PEP expense should be allowed. However, if the Commission is inclined to reduce this expense in pursuit of lower rates, I would propose allowing 100 percent of PEP expense for most of our employees but excluding 50 percent of the expense associated with payments made to corporate officers, as discussed in the rebuttal testimony of TEP Witness Ms. Sabers. If the Commission adopts this alternative adjustment, then the Commission Staff's revenue requirement will increase by $2.3 million on an ACC jurisdictional basis.

Q. Please address the testimony of Commission Staff witness Radigan regarding the Company's use of the FERC's Open Access Transmission Tariff ("OATT").

A. Mr. Radigan's testimony suggests that TEP should not be allowed to pass along FERC's OATT for transmission service. Although his testimony defers full discussion of this proposal until the Commission Staff's Surrebuttal (which in itself is procedurally inappropriate), Mr. Radigan contends that TEP will have no need for its proposed Transmission Cost Adjustment (TCA) to recover the FERC OATT if the Commission adopts Commission Staff's recommendation to restore TEP's exclusive right to serve retail customers in its service territory.

Under the Federal Power Act and pursuant to the order issued by FERC in Docket No. OA96-140, TEP is obligated to charge the rate on file with FERC in a non-discriminatory manner to any entity using TEP's transmission system, including itself and any affiliate of TEP. Any deviation without prior approval from FERC would violate both TEP's tariff and federal law. Once FERC approves an entity's OATT, that entity has to charge the

rate regardless of whether the entity or the transmission customer are located in a region that is vertically integrated or has a market approach.

Therefore, TEP is required to charge the OATT rate, and Commission Staff has not provided any evidence or testimony to indicate how TEP could legally deviate from charging any entity this federally approved, cost-based rate. Moreover, as I have previously indicated, the Commission ordered TEP to charge rates for transmission and ancillary services based on the OATT in Decision No. 62103 as stated in Section 4.4 of the 1999 Settlement Agreement.

This is another issue where Commission Staff is apparently penalizing the Company for following regulatory requirements and is proposing to treat TEP differently than APS. APS, which enjoys the same de facto exclusivity in its service territory as is proposed for TEP, employs a Commission-approved "TCA" to recover its FERC OATT costs from customers. Like APS, TEP also operates under FERC rules that prevent it from enjoying preferential access to its company-owned transmission assets relative to the access provided to other firm wholesale customers. Mr. Radigan is asking the Commission to disregard these clear-line requirements in service to the Commission Staff's pursuit of unreasonably low rates, which apparently will proceed unabated into rebuttal testimony without regard for equity or the financial impact on the company.

Q. Mr. Pignatelli, does this conclude your Rebuttal Testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-0402

Rebuttal Testimony of

Thomas A. Zlaket

on Behalf of

Tucson Electric Power Company

April 1, 2008

Executive Summary of the Testimony of Thomas A. Zlaket

Justice Zlaket is the retired Chief Justice of the Arizona Supreme Court. Justice Zlaket's testimony presents his expert opinion on several issues raised regarding the 1999 Settlement Agreement.

Justice Zlaket provides his opinion as to the viability and likely outcome of a court action for breach of contract on the following issues:

1. Is the 1999 Settlement Agreement a binding contract on its parties?
2 Is the Commission a party to the 1999 Settlement Agreement?
3. What remedies are available to TEP in the event of a breach of the 1999 Settlement Agreement?
4. What happens on January 1, 2009 under the 1999 Settlement Agreement?

Justice Zlaket concludes that a suit for breach of contract would likely survive a Motion for Summary Judgment and/or a Motion for Directed Verdict or Judgment at trial. He further provides his opinion that there is a reasonable likelihood an Arizona court would find that:

1. The 1999 Settlement Agreement is a binding contract on its parties.
2. The Commission is a party to that contract.
3. Damages (or restitution) are the remedies available for a breach of the contract.
4. Based on the language of the 1999 Settlement Agreement, and supporting extrinsic evidence, TEP should be permitted to charge market based rates for generation service.

Justice Zlaket also concludes that even without finding a binding contract, an Arizona court would likely allow a remedy to TEP based on a quasi-contractual of detrimental reliance on the terms and conditions of the 1999 Settlement Agreement.

Q. Please state your name and business affiliation.

A. My name is Thomas A. Zlaket. I am the manager of Thomas A. Zlaket, P.L.L.C. My business address is 310 South Williams Boulevard, Suite 170, Tucson, Arizona.

Q. Please summarize your education and business experience.

A. I received my undergraduate degree from the University of Notre Dame in Political Science in 1962. I was awarded an L.L.B from the University of Arizona in 1965. I obtained a Masters of Laws in Judicial Process from the University of Virginia in 2001.

I have practiced law in the State of Arizona since 1965, with the exception of 10 years when I was on the bench. I have also been admitted to practice law in the U.S. District Court, District of Arizona, U.S. Court of Appeals for the Ninth Circuit and the State of California.

From 1965 to 1992, I practiced law with several firms in Southern Arizona. In 1992, I was appointed as a Justice of the Arizona Supreme Court. In 1996, I was appointed Vice Chief Justice of the Arizona Supreme Court. From 1997 to 2002, I served as the Chief Justice of the Arizona Supreme Court. Upon my retirement from the Arizona Supreme Court, I returned to the private practice of law.

I am a past President of the State Bar of Arizona and the Tucson Chapter of the American Board of Trial Advocates. I am a Life Fellow of the Arizona Bar Foundation and a Fellow of the American Bar Foundation. I was a faculty member of the Arizona College of Trial Advocacy from its inception in the mid-1980s until approximately 2002. I have also taught at the Hastings College of Trial Advocacy and the National Institute of Trial Advocacy. I currently serve as an Adjunct Professor of Law at the University of Arizona College of Law. I am also a Fellow of the American College of Trial Lawyers.

My curriculum vitae is provided as Exhibit 1 to my testimony.

Q. Justice Zlaket, on whose behalf are you testifying in this proceeding?

A. My testimony is being presented by Tucson Electric Power Company ("TEP").

Q. Please summarize your testimony?

A. I was asked to review a number of documents, including the Amended Settlement Agreement entered into by TEP, the Arizona Residential Consumer Office ("RUCO"), members of the Arizonans for Electric Choice and Competition ("AECC"), and Arizona Community Action Association ("ACAA"), as approved by the Arizona Corporation Commission (the "Commission"),[1] and provide my opinion as to the viability and likely outcome of an action for breach of contract action on the following issues:

1. Is the 1999 Settlement Agreement a binding contract on its parties?
2. Is the Commission a party to the 1999 Settlement Agreement?
3. What remedies are available to TEP in the event of a breach of the 1999 Settlement Agreement?
4. What happens on January 1, 2009 under the 1999 Settlement Agreement?

I have concluded that a suit for breach of contract would likely survive a Motion for Summary Judgment and/or a Motion for Directed Verdict or Judgment at trial. In my opinion, there is also a reasonable likelihood an Arizona court would find that:

1. The 1999 Settlement Agreement is a binding contract on its parties.
2. The Commission is a party to that contract.
3. Damages (or restitution) are the remedies available for a breach of the contract.

[1] I will refer to this as the "1999 Settlement Agreement" or as the "contract".

4. Based on the language of the 1999 Settlement Agreement, and supporting extrinsic evidence, TEP should be permitted to charge market based rates for generation service.

I also conclude that even without finding a binding contract, an Arizona court would likely allow a remedy to TEP based on a claim by TEP for detrimental reliance on the terms and conditions of the 1999 Settlement Agreement.

I was not asked to render an opinion concerning whether a breach of contract has occurred, or to calculate an amount of damages. The resolution of those issues would necessarily be fact-dependent, requiring an evidentiary hearing. It would also depend upon what, if any, actions the Commission and other parties to the contract take in this or related proceedings.

Q. What information did you analyze in connection with your review?

A. In connection with my review I analyzed the 1999 Settlement Agreement, filings (including but not limited to legal briefs) submitted to the Commission, Commission Orders, and relevant judicial decisions, laws and rules. I also relied upon my experience as an attorney and Justice of the Arizona Supreme Court in reaching my conclusions and opinions. A list of the Commission filings and Orders that I reviewed is provided as Exhibit 2 to my Testimony.

Q. Justice Zlaket, are you satisfied that you have reviewed sufficient information upon which to base the opinions in your Testimony?

A. Yes, I am.

Q. Did TEP indicate to you directly or indirectly a preferred outcome to your review?

A. No, it did not. TEP was clear that it wanted my unbiased opinions on these issues. If TEP had made any such overtures, I would have declined this engagement.

Q. Please explain your opinion that an Arizona court would conclude that the 1999 Settlement Agreement is a binding contract on its parties.

A. The 1999 Settlement Agreement has all of the characteristics of, and meets the legal requirements for, a valid written contract. In the 1999 Settlement Agreement and Decision No. 62103, I find sufficient assent among the parties, adequate consideration, and a description of rights and obligations to conclude that a binding contract exists.

Section 13.3 of the 1999 Settlement Agreement conditioned the effective date of the contract upon approval by the Commission. That approval was granted in Decision No. 62103 (November 30, 1999). There is nothing in the materials that I have reviewed nor is there anything else of which I am aware that has rescinded or voided the contract. In my opinion the contract is binding on TEP, RUCO, AECC, ACAA and the Commission.

Q. Was the 1999 Settlement Agreement amended subsequent to its approval by the Commission?

A. Yes, it was amended several times. Decision No. 62103 required several minor amendments. These are reflected in the Amended Settlement Agreement. Decision No. 65154 (September 10, 2002) (the "Track A order") effectively amended the contract to waive the mandatory obligation that TEP divest its generation assets. Decision No. 65743 (March 14, 2003) (the "Track B order") addressed the power solicitation process. Decision No. 65751 (March 20, 2003) amended the contract to revise the methodology for determining the Market Generation Credit. Most recently, Decision No. 69568 (May 21, 2007) amended the contract to permit TEP to continue to collect amounts for the

Fixed CTC after the collection of $450 million, subject to potential refund, credit or set off.

I am not persuaded by the arguments of some that Track A voided, rescinded or rendered moot certain of the remaining provisions of the 1999 Settlement Agreement. Individually and collectively the foregoing Decisions and their related amendments did not rescind or void the contract in my opinion.

Q. Please explain your opinion that an Arizona court would conclude that the Commission is a party to the 1999 Settlement Agreement.

A. The Commission became a party to the contract when it approved the 1999 Settlement Agreement in Decision No. 62103.

Section 13.3 of the 1999 Settlement Agreement expressly offered the Commission to become a party by approving the contract. The Commission accepted that offer by approving the 1999 Settlement Agreement. Although the Commission required the parties to modify some aspects of the 1999 Settlement Agreement, it did not reject or seek to modify the language in Section 13.3. The Commission's action in approving the 1999 Settlement Agreement constitutes its acceptance of the offer to join the contract as a party.

Q. Justice Zlaket, can the Commission legally be a party to the 1999 Settlement Agreement?

A. Yes, it can be and it is a party to the 1999 Settlement Agreement.

In Arizona, a government agency, such as the Commission, can enter into a contract that binds its future members, if it is made in good faith, except when the contract is for

personal or professional services for the members. The 1999 Settlement Agreement does not involve personal or professional services for the members and there is no evidence that it was entered into in anything other than good faith.

The Arizona Court of Appeal's decision in *U.S. West Communications, Inc. v. Arizona Corporation Commission*, 185 Ariz. 277, 280-81, 915 P.2d 1232, 1235-36 (App. 1996) ("*U.S. West*") is instructive. In that case, U.S. West alleged that the Commission violated the terms of a settlement agreement the two parties had entered into concerning rate making treatment related to the sale of its directory service operation. The Court of Appeals required the Commission to adhere to the terms of the settlement agreement it had entered into with U.S. West.

I also find helpful a Court of Appeals case, *Arizona Consumers Council v. Arizona Corporation Commission*, 200 Ariz. 85, 94 ¶ 37, 22 P.3d 905, 914 (App. 2001), *de-published* 201 Ariz. 379, 36 P.3d 57 (2001). In that case, the Arizona Consumers Council challenged the Commission's order approving Arizona Public Service Company's ("APS") 1999 Settlement Agreement. The APS 1999 Settlement Agreement addressed many of the same issues as in the (TEP) 1999 Settlement Agreement. The Commission was also a party to the APS 1999 Settlement Agreement. The Arizona Consumers Council argued that the order was unlawful because it sought to contract away the Commission's ratemaking authority. The Court disagreed, and found that the Commission "clearly and unmistakably has the authority to enter into rate contracts, including those specifying rates for a definite period of time, where it believes it necessary to fulfill its ratemaking function." *Id.*

The Commission, having properly entered into the 1999 Settlement Agreement, is bound by the terms and conditions of the contract along with RUCO, AECC, ACAA and TEP.

Q. Please explain your opinion that an Arizona court would conclude that TEP's remedies in the event of a breach of the 1999 Settlement Agreement include damages and restitution.

A. The most common remedy awarded by a court for a breach of contract is damages. In establishing the measure of damages, the basic assumption is that the aggrieved party is entitled to full compensation for its actual loss. Contract damages are typically based upon the injured party's expectation interest. However, depending on the circumstances and specific facts, the injured party could recoup its reliance damages and/or restitution damages. A court may even award specific performance of the contract in limited circumstances.

"Expectation damages" are intended to give a party the benefit of its bargain by awarding the sum of money that will, to the extent possible, put the party in as good a position as it would have been had the *contract been performed*, including lost profits and, in some circumstance, expenditures by the non-breaching party that were wasted as a result of the breach. *See A.R.A. MFG. Co. v. Pierce*, 86 Ariz. 136, 141, 341 P.2d 928, 932 (1959); Restatement (Second) of Contracts ("Restatement"), § 347, cmt. a; *see also* Restatement § 344 and cmt. a thereto.

"Reliance damages" are an alternative to expectation damages. Reliance damages are the losses caused by reliance on the contract and are intended to put the non-breaching party in as good a position as if the *contract had not been made.* Through reliance damages, the injured party has a right to damages based on its reliance interest, including expenditures made in preparation for performance, less any loss that the party in breach can prove with reasonable certainty the injured party would have suffered had the contract been performed. *See* Restatement § 349

"Restitution damages" are an alternative remedy for a breach of contract and seek to restore the non-breaching party to its pre-contractual status quo. Restitution is typically aimed at depriving the breaching party of unjust enrichment or improper gains resulting from the breach. *See* Restatement § 373 and cmt. a thereto. This recovery is often, but not always, associated with the idea that the contract being breached can be rescinded. *See* Dobbs on Remedies (2d ed. 1993), Sec. 12.1(1). Moreover, courts using restitution as a remedy for breach have shaped the damage award in a calculation that roughly approximates reliance damages. *See, e.g., Glendale Fed. Bank, F.S.B. v. United States*, 239 F.3d 1374, 1380 (Fed. Cir. 2001). This expanded view of restitution is intended to restore the non-breaching party to the position it would have been in had there never been a contract to breach. *See Glendale Fed. Bank*, 239 F.3d at 1380.

Even if it is determined that parties are discharged from their obligations under a contract due to such doctrines as frustration of purpose or impracticability/impossibility, courts may award restitution to one of the parties to avoid injustice. *See* Restatement § 377. However, in such cases, courts have not necessarily limited the injured plaintiff to the benefits bestowed on the defendant (e.g., restitution). Instead, some courts have been willing to go beyond the traditional definition of restitution and find benefits in cases involving breaches of governmental contracts, or to otherwise expand the traditional definition of restitution to fairly compensate a party for its performance under a contract. *See, e.g. Far West Fed. Bank, S.B. v. Office of Thrift Supervision*, 119 F.3d 1358, 1367 (9th Cir. 1997); *Landmark Land Co. v. Federal Deposit Ins. Corp.*, 256 F.3d 1365, 1372-73 (Fed. Cir. 2001).

Finally, a court may award "specific performance" of the contract in appropriate circumstances. This would require the parties to perform their rights and obligations

under the terms of the contract. This equitable remedy is typically awarded if monetary damages are inadequate and depends on the uniqueness of subject of the contract.

Q. Is TEP obligated to attempt to mitigate the amount of its damages if it believes the contract is breached?

A. Yes, it does have an obligation to mitigate its damages. I think that a court would conclude that it has repeatedly attempted to do so. Beginning in 2005, TEP has filed a series of pleadings with the Commission seeking to engage the parties to the contract in a confirmation or modification of the 1999 Settlement Agreement. At this point, RUCO and the AECC have argued against TEP charging market based rates in 2009. The Commission has yet to address the matter.

Q. Justice Zlaket, would TEP be entitled to a damage award even if the 1999 Settlement Agreement is deemed not to be a valid contract?

A. Yes, even if the 1999 Settlement Agreement is deemed not to be a valid contract a court would likely award TEP damages on quasi-contractual grounds. Such relief may be determined by the costs incurred in reliance on the relationship.

Also, in the event that a court would determine that the contract is not enforceable due to "frustration of purpose" or one of the other contract-based defenses to enforcement of the 1999 Settlement Agreement, then the Restatement § 377 provides that TEP "is entitled to restitution of any benefit that [it] has conferred on the other party by way of part performance or reliance."

Courts have been willing to fashion a restitution remedy that fairly compensates the non-breaching party for its performance in cases involving breach of contract claims against the government. *See, e.g., United States v. Winstar Corp.,* 518 U.S. 839 (1996).

Moreover, it appears that the same justifications that allowed courts to use reliance damages as a fall-back measure of damages for breach should apply as an alternative measure of restitution if the 1999 Settlement Agreement is found unenforceable by reason of frustration of purpose or similar doctrine.

Q. Please explain your opinion that through extrinsic evidence an Arizona court would find that TEP should be permitted to charge market based rates for generation service.

A. The 1999 Settlement Agreement provides that the Fixed CTC will terminate upon collection of the $450 million stranded cost amount (as amended by Decision No. 69568), and the Floating CTC and the rate increase freeze will terminate on December 31, 2008. There is no express termination date for the utilization of the Market Generation Credit ("MGC") and the Adder. Consequently, TEP would charge the MGC amount plus the Adder for generation service beginning January 1, 2009. Moreover, these two items were to be combined on the customer's bill and would reflect the generation rate that would be replaced if the customer obtained competitive generation service from another provider – that is, it was the generation rate that competitors had to beat.

There is no express language, however, that details how TEP should charge for generation service beginning on January 1, 2009. Accordingly, a court could find that the 1999 Settlement Agreement is ambiguous on this point. In such circumstances, Arizona courts will look to extrinsic evidence to determine how generation rates should be determined beginning January 1, 2009.

Q. Is there language in the 1999 Settlement Agreement that provides insight into the intent of the parties to the contract?

A. Yes, there is. The 1999 Settlement Agreement contains numerous statements that support the conclusion that the contract was intended to transition TEP from a non-competitive monopoly provider for all electric services to a competitive provider of certain services, including generation. For example, the Recitals to the contract repeatedly refer to the relationship between the 1999 Settlement Agreement and the implementation of Competitive Retail Access. The 1999 Settlement Agreement further states that in the event the provisions of the contract and the Electric Competition Rules conflict, the 1999 Settlement Agreement prevails.

The contract also provides for the implementation of a "competition transition charge", market generation credit, the unbundling of rates, rate reductions and the modification of TEP's certificates of convenience and necessity in order to permit Competitive Retail Access.

These provisions in the contract, together with the extrinsic evidence, would support a finding that the parties intended TEP to begin charging market based rates for generation service as of January 1, 2009.

Q. Please summarize the extrinsic evidence that supports your opinion that TEP is entitled to charge market based rates for generation service beginning January 1, 2009.

A. Extrinsic evidence is used to clarify a written agreement. Extrinsic evidence can include parties' words or conduct prior to, contemporaneous with, or subsequent to the execution of a written agreement. The filings that the parties submitted to the Commission outline

significant and compelling extrinsic evidence in support of TEP charging market rates for generation service beginning January 1, 2009.

For example, the Commission repeatedly stated that the Electric Competition Rules, the 1999 Settlement Agreement and related orders were designed and intended to transition electric utilities such as TEP to a competitive marketplace for certain services, including generation. These statements and the conduct of the parties, considered with the language of the 1999 Settlement Agreement, lead to the conclusion that TEP may be entitled to charge market rates for generation service beginning January 1, 2009.

A summary of the Commission Orders and related information I reviewed and considered as extrinsic evidence, which has also been put forth by the parties in this and other proceedings, is provided in Attachment 3 to my testimony.

Q. Please explain your opinion that even if an Arizona court would conclude that the 1999 Settlement Agreement is not a binding contract on its parties, TEP would be entitled to damages pursuant to the doctrine of detrimental reliance.

A. TEP has acted in good faith reliance upon the terms of the 1999 Settlement Agreement to its financial detriment. Most notably, TEP has refrained from seeking rate relief that would be effective prior to January 1, 2009, as required by the contract. I believe that constitutes performance for which TEP is entitled to be compensated.

In June 2004, TEP, RUCO, AECC and Commission Staff filed their respective financial analyses with the Commission. TEP concluded that it was experiencing a deficiency. Absent the rate increase freeze provision of the 1999 Settlement Agreement, TEP would have (previously) or immediately thereafter filed a request for a rate increase. However, based upon the 1999 Settlement Agreement's rate increase freeze provision, TEP did not

file any such rate increase request and its rates have not been increased. This set of facts fits within the definition of a claim for detrimental reliance by TEP.

Therefore, even if a court found that the 1999 Settlement Agreement is not a binding contract, TEP would be entitled to its reliance damages, as I previously discussed.

Q. Justice Zlaket, during the course of your review did you form an opinion on any other principles through which a court could resolve a breach of contract claim brought by TEP?

A. Yes, I did. I believe that a court would apply the doctrine of estoppel to prevent the Commission from repudiating the 1999 Settlement Agreement, or TEP's rights under the contract. Estoppel is an equitable remedy that is imposed to prevent a party from acting contrary to positions it has taken and upon which others have relied.

The Commission approved the 1999 Settlement Agreement in Decision No. 62103. That contract has been subsequently amended several times. In the *Arizona Consumers Council* case I previously cited, the Commission argued in support of the binding nature of its settlement agreements. If, in a breach of contract action brought by TEP, the Commission were to attempt to now argue that the 1999 Settlement Agreement is not valid, I believe a court would apply the doctrine of estoppel to preclude the Commission from taking a position inconsistent from prior promises and/or actions.

Also, the extrinsic evidence that I have reviewed establishes that the Commission not only approved the 1999 Settlement Agreement but that it still requires the parties to be bound by the terms and conditions of the contract, as amended.

The Commission cannot pick and chose the provisions of the contract that it seeks to enforce against TEP and ignore the others. It cannot impose the rate increase freeze but ignore TEP's right to charge market based rates in 2009. Again, if the Commission attempted to act in a contrary manner regarding the effectiveness or interpretation of the 1999 Settlement Agreement, I believe a court would apply the doctrine of equitable or promissory estoppel to prevent the Commission from taking a position inconsistent with its prior promises and/or actions.

Estoppel against the State is applied only in limited circumstances when the government's wrongful conduct threatens to work a serious injustice and the public interest will not be unduly damaged. I believe that a court would find estoppel appropriate in this case.

Q. Justice Zlaket, do you have any concluding remarks.

A. Yes, I do. Settlement agreements are a common and valuable tool in resolving issues, sometimes even the most complex issues, between parties. The integrity of such contracts must be upheld by the parties who enter into them. In my opinion, the 1999 Settlement Agreement is a binding contract that should be honored by its parties. If there is a claim of breach, then the parties should try to resolve the conflict among themselves. If that is unsuccessful, then a breach of contract action in court is an appropriate means for resolving the dispute. In my testimony I have presented my opinion on how a court would rule on the matters identified.

Q. Does that conclude your testimony?

A. Yes, it does.

EXHIBIT

TAZ-1

Exhibit TAZ-1

CURRICULUM VITAE

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University of Virginia, Charlottesville, Virginia.
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- All Arizona state courts, September 25, 1965
- United States District Court, District of Arizona, July 27, 1967
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- All California state courts, May 7, 1976

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- Judge Pro Tem, Superior Court of the State of Arizona, Pima County, Arizona, 1983 to 1992.
- Associate Justice, Arizona Supreme Court, 1992 - 1996
- Vice Chief Justice, Arizona Supreme Court, 1996 - 1997
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- Estes, Browning, Maud & Zlaket
  Estes, Browning & Zlaket
  Estes & Zlaket
  177 North Church Avenue
  Tucson, Arizona 85701
  1970 - 1973
  (Partner)

- Slutes, Estes, Zlaket, Sakrison & Wasley
  Slutes, Zlaket, Sakrison & Wasley
  Slutes, Browning Zlaket & Sakrison
  33 North Stone Avenue
  Tucson, Arizona 85701
  1973 - 1982
  (Partner)

- Zlaket & Zlaket, P.C.
  2701 East Speedway Boulevard, Suite 200
  Tucson, Arizona 85716
  1982 - 1992
  (Shareholder)

- Law Offices of Thomas A. Zlaket, P.L.L.C.
  310 South Williams Boulevard, Suite 170
  Tucson, Arizona 85711-4446
  5/1/02 – present
  (Managing Member)

Professional Memberships:

State Bar of Arizona, 1965 to present:

- Board of Governors, 1980 - 90

President, 1988-89
President-Elect, 1987-88
First Vice President, 1986-87
Second Vice President, 1985-86

- Professionalism Task Force, 2003 – 06

- Injury and Wrongful Death Litigation Advisory Commission, 1990-92

- Committee on Professionalism, 1988 - 92

- Disciplinary Probable Cause Panelist, 1986-87

- Committee on Criminal Rules Revision, circa 1974-76

- Certified Specialist, Injury and Wrongful Death Litigation, 1991-92

Pima County Bar Association, 1965 to present:
Board of Directors, 1969 - 70; and 1980 - 90

- Civil Practice Committee, 1985 - 90

- Medical - Legal Committee, 1980 - 85
(Chairman, circa 1984 - 85)

- Courthouse Committee, 1975 - 80

- Medical - Legal Screening Panel, 1968 - 75

State Bar of California, 1976 to present.

Maricopa County Bar Association, 1992 - 2003.

Fellow, American College of Trial Lawyers, 1982 - present
- Arizona State Chairman, 1991 - 92

Life Fellow, American Bar Foundation.

National Conference of Chief Justices, 1997 - 2002.
- Board of Directors, 1998 - 2001

Founding Fellow, Arizona Bar Foundation.

American Bar Association, 1966 - present.

- Arizona Delegate, ABA House of Delegates, 1990 - 92

American Board of Trial Advocates, 1972 - present

- National Executive Committee, 1982 - 85
- President, Tucson Chapter, 1981
- Secretary/Treasurer, Tucson Chapter, 1980

Defense Research Institute, 1970 - 82

- Arizona State Chairman, circa 1975 - 78

Tucson Defense Bar Association, 1970 - 82

- President, circa 1977 - 78

American Trial Lawyers Association, 1972 - 91

Arizona Trial Lawyers Association, 1985 - 91

American Judicature Society, circa 1968 - 80; 1992 - present

National Panel of Arbitrators, American Arbitration Association, circa 1975 – 91

Arizona Capital Representation Project Board of Directors, 2003 – present

Federal Civil Justice Reform Act Advisory Committee for the District of Arizona, 1991 - 95

Arizona Supreme Court Commission on the Courts, 1988 - 90

Arizona Governor's Task Force on Medical Liability Insurance Premiums, 1989 - 90

Arizona Supreme Court Committee on Medical Malpractice Rules of Procedure, 1989 - 92

Chairman, Arizona Supreme Court Committee on Civil Discovery Abuse, Cost & Delay, 1990 - 92

Chairman, Arizona Supreme Court Commission on Technology, 1992 - 97

Arizona College of Trial Advocacy Executive Committee, 1986 - 2002

Teaching Faculty, Arizona College of Trial Advocacy (State Bar of Arizona), 1986 - 2002

Teaching Faculty, National Institute of Trial Advocacy, Western Session, San Diego, California, 1988

Teaching Faculty, Hastings College of Trial Advocacy, San Francisco, California, circa 1978 - 80

Teaching Faculty, Pima County Bar Association Trial Advocacy Program, 1989 - 90

Lecturer-in-Law, University of Arizona College of Law, 1967 – 78.

Adjunct Professor of Law, James E. Rogers College of Law at the University of Arizona, 2003 - present

National Board of Directors, The Justice Management Institute, 2003 - present

Lecturer at numerous continuing legal education seminars in Arizona and around the United States from 1970 to the present, primarily on the subjects of ethics and professionalism, civil litigation, and discovery abuse.

Chairman, Attorneys' Planning and Program Committee for the Arizona Judicial Conference, 1990

Board of Directors, Arizona Capital Representation Project, 2003 – present.

University of Arizona Law College Association, 1975 - present.

- Board of Directors, 1990 – present

University of Arizona James E. Rogers Law School Board of Visitors, 2001 - present

Arizona Law Review Association, 1986 - present

Co-chair, National Conference on Public Trust and Confidence in the Justice System, Washington, D.C., May, 1999

Phi Delta Phi Legal Fraternity

- President, Pattee Inn, 1964 – 65

Student Bar Board of Governors, University of Arizona College of Law, 1963

Honors and Awards:

2006 Public Service Award, Arizona Center for Law in the Public Interest

Thomas A. Zlaket Professionalism in Teaching Endowment, University of Arizona James E. Rogers College of Law, 2003

Honorary Doctor of Law Degree, University of Arizona, 2002

Distinguished Alumnus Award, University of Arizona James E. Rogers College of Law, 2002

Distinguished Service Award, Pima County Volunteer Lawyers Program, 2002

2001 National Center for State Courts' Reardon Award

State Bar of Arizona James A. Walsh Distinguished Jurist Award, June 15, 2001

American Judges Association 2000 Chief Justice Richard W. Holmes Award of Merit

State Bar of Arizona Award of Special Merit, June 16, 2000

University of Arizona Distinguished Citizen Award, February 21, 1998

American Board of Trial Advocates Civil Justice Award, April 1, 1992

Member of the Year Award, State Bar of Arizona, June 1991

Outstanding Graduate Award, University of Arizona College of Law, 1989

Arizona Supreme Court Certificate of Appreciation for Service on Board of Governors, 1988

State Bar of Arizona Award for Contribution to Continuing Legal Education, 1988

City of Tucson Copper Certificate for Service on Magistrate Selection Commission, 1982

Listed in three editions of "The Best Lawyers in America" before going on the bench in 1992, and again beginning with the 2007 edition.

Listed among Top Attorneys in Arizona 2007 by Super Lawyers Publishing.

Martindale-Hubbell AV rating

Arizona Law Review, 1963 - 65
- Editor-in-Chief, 1964 - 65
- Editorial Staff, 1963 - 64

National Moot Court Team, University of Arizona College of Law, 1964 - 65
- Regional Finalists, Albuquerque, New Mexico, 1965

Individual Moot Court Champion, University of Arizona College of Law, 1962 - 63, 1963 - 64, and 1964 - 65

Tucson Title Insurance Award, University of Arizona College of Law, 1965

Udall on Evidence Award, University of Arizona College of Law, 1965

AmJur Awards in Trust and Corporations, University of Arizona College of Law, 1964 – 65

Other Associations and Activities:

Member, Tucson Airport Authority, 2003 – present
Board of Directors, 2007 - present

Member, D-M 50, 2003 – present

Chair, Tucson Unified School District No. 1 Bond Oversight Committee, 2004 – 2006
Member, 2006 - 07

Arizona Board of Trustees, The Nature Conservancy, 2004 - present

Board of Directors, Tucson Country Club, 2005 – present
President, 2007- present

Tucson Conquistadores (Life Member) 1977 - present
- Board of Directors, 1981 - 84
- President, 1983 – 84

Arizona Academy, 1988 - present.
- Delegate, Arizona Town Hall on Civil Justice, 1988

City of Tucson Magistrate Selection Commission, 1997 - 82

Big Brothers of Tucson Board of Directors, circa 1970 - 75

St. Joseph's Hospital Community Advisory Committee, circa 1975 - 80

Exchange Club of Downtown Tucson, circa 1970 - 80

"Off the Record" Debate Society
- Board of Directors, 1991 - 93

Member, The Breakfast Club (of Tucson), 2004 - present

Articles:

Casenote, 6 Arizona Law Review 156, "Second Mortgagee May Not Acquire Title to Mortgaged Property as Against First Mortgagee Through a Tax Deed — Moore vs. Crisp (Okla. 1963)."

President's Message, "Reviving Professionalism," Arizona Attorney, September 1988

President's Message, "God Bless Madison Avenue," Arizona Attorney, October 1988

President's Message, "Dispute Prevention," Arizona Attorney, November 1988

President's Message, "Paper Wars," Arizona Attorney, December 1998

President's Message, "A Town Hall View of Lawyers and Justice," Arizona Attorney, January 1989

President's Message, "Out of the Frying Pan . . .," Arizona Attorney, February 1989. (Republished in the ALI-ABA CLE Review, Vol. No. 6, March 10, 1989.)

President's Message, "A Learned Profession?," Arizona Attorney, March 1989

President's Message, "Don't Worry, Be Happy?," Arizona Attorney, April 1989

President's Message, "Letters... We get Letters," Arizona Attorney, May 1989

President's Message, "So Long, It's Been Good to Know You ...," Arizona Attorney, June 1989

"Encouraging Litigators to be Lawyers: Arizona's New Civil Rules", 25 Arizona State L. J. 1 (1993).

"Should Lawyers Be Required to Tell the Truth?" (unpublished) Masters Thesis, U of Virginia (2000)

(Rev. 12/13/07)

EXHIBIT

TAZ-2

Exhibit TAZ-2

Commission Filings and Decisions

1999 Settlement Documents
Docket Nos. E-10933A-98-0471,
E-01933A-97-0772, RE-00000C-94-0165

Decision No. 62103 - 1999 Settlement Agreement	11/30/99
Amended Settlement Agreement	12/01/99
Brief – TEP	08/30/99
Brief - Commission Staff	08/30/99
Brief - Cyprus Climax Metals, Inc., Asarco, Incorporated and Arizonans for Electric Choice and Competition ("AECC")	08/30/99
Brief - The Residential Utility Consumer Office ("RUCO")	08/30/99

Amend Decision No. 62103
Docket No. E-01933A-05-0650

Commission Docket Summary Report	
TEP's Motion to Amend Decision No. 62103 and Direct Testimony of James S. Pignatelli	09/12/05
Staff's Response to TEP's Motion to Amend Decision No. 62103	10/12/05
Direct Testimony of James S. Pignatelli – TEP	08/18/06
Rebuttal Testimony of James S. Pignatelli – TEP	01/29/07
Direct Testimony of MaryLee Diaz Cortez (and Memorandum of Law) – RUCO	01/08/07
Summary of Direct Testimony of Kevin Higgins (and Memorandum of Law) – AECC	01/08/07
Direct Testimony of Michael Ileo – ACC Staff	01/08/07
Surrebuttal Testimony of Kevin Higgins – AECC	02/08/07
Surrebuttal Testimony of Michael Ileo – ACC Staff	02/08/07

2004 Rate Review Documents
Docket No. E-01933A-04-0408

TEP's Notice of Filing	06/01/04
Direct Testimony of James S. Pignatelli – TEP	06/01/04
Summary of Schedules	06/01/04
TEP's Supplemental Notice of Filing	09/15/04
Supplemental Testimony of James S. Pignatelli - TEP	09/15/04
Direct Testimony of Steven J. Glaser – TEP	09/15/04
Direct Testimony of Karen G. Kissinger – TEP	09/15/04
Direct Testimony of Michael J. DeConcini – TEP	09/15/04
Direct Testimony of Kevin P. Larson – TEP	09/15/04
Direct Testimony of James J. Dorf - Commission Staff	06/24/05
Direct Testimony of Jeff Schlegel - Southwest Energy Efficiency Project and Western Resource Advocates, Inc.	06/24/05
Direct Testimony of Kevin C. Higgins – AECC	06/24/05
Direct Testimony of Marylee Diaz-Cortez – RUCO	06/25/05
Direct Testimony of William A. Rigsby – RUCO	06/25/05
Direct Testimony of Timothy J. Coley – RUCO	06/25/05
Notice of Errata re Direct Testimony of Kevin C. Higgins - AECC	07/01/05

2007 TEP Rate Case Documents
Docket No. T-01933A-07-0402 et al.

Direct Testimony of James S. Pignatelli	07/02/08
Unredacted Direct Testimony of John Antonuk – Staff Witness	02/29/08

Decisions/Rules

Article 16 – Retail Electric Competition (R14-2-1601 – R14-2-1618)

Decision No. 65154 – Track A	09/10/02
Decision No. 65743 – Track B	03/14/03
Decision No. 65751 – MGC Order	03/20/03
Decision No. 61973 – APS 1999 Settlement Agreement	10/06/99
Decision No. 59943 – Electric Competition Rules	11/26/96
Decision No. 60977 – Stranded Costs	6/22/98
Decision No. 61969 – Electric Competition	9/29/99

EXHIBIT

TAZ-3

Exhibit TAZ-3

Summary of Extrinsic Evidence to the 1999 Settlement Agreement

A.R.S Sec. 40-202.B.

A.R.S Sec. 40-202.B. declares that it is the public policy of the State of Arizona that a competitive market shall exist in the sale of electric generation service. I believe a court would take judicial notice of this statement as a backdrop for the interpretation of the 1999 Settlement Agreement.

Decision No. 62103 (November 21, 1999).

Decision No. 62103 and filings made pursuant to that Commission Order evidence the fact that the contract served to transition TEP into competition and market based rates in 2009. In Decision No. 62103 the Commission addressed the application of the MGC to rates, the inter-relationship between the fixed and floating CTC and market prices and the operation of the "adder" all in relation to rates to be charged by TEP. For example, in Decision No. 62103, the Commission states the purpose of the 1999 Settlement Agreement is to "[h]ave full generation competition as soon as possible" and concluded that the contract "satisfies the[se] objectives." Decision No. 62103 at 17. The Commission further stated in Decision No. 62103 that it "supports competition in the generation market because of increased benefits to customers".

Decision No. 62103 also repeatedly refers to the transition period created by the 1999 Settlement Agreement. By way of example, the Commission stated "[w]e believe that the Settlement will result in an orderly process that will result in small rate reductions during the transition period to a competitive generation market." *Id.;* (emphasis added). Further, the Commission found that the "Settlement will permit competition in a timely

and efficient manner and insure all customers benefit during the transition period." *Id.* at 20 (emphasis added).

Tariffs.

Pursuant to Decision No. 62103, TEP also filed tariffs with the Commission regarding rates to be charged customers. Direct Access Residential Schedule No. 1 provided the unbundled rates for the elements of service, including a generation component that references the MGC.

TEP Schedule MGC-1 states that there are two purposes to the MGC. First, to "establish a price to which TEP's energy customers can compare to the prices of competitors." Second, as part of the calculation of the floating CTC.

Commission Orders

Decision No. 59943 (December 26, 1996).

The Commission stated in this Order related to the Electric Competition Rules that the "Rules as drafted set forth a framework for the introduction of competition into the electric services market in Arizona." (Appendix B, Page 38).

Decision No. 60977 (June 22, 1998).

The Commission stated in this order, related to Stranded Costs, that its primary objectives included the implementation of "full generation competition as soon as possible" and "to minimize the duration of the transition period consistent with other objectives." The Commission further stated that "it is the Commission's intent that individual stranded costs proceedings occur as quickly as possible in order to provide an opportunity for full generation competition as soon as possible" and "at the same time, the Affected Utilities will need to continue to tighten their belts in order to bring their

costs down to the market by the end of the transition period. After the Affected Utilities have collected the expenses associated with their appropriate regulatory assets, all customers remaining on the standard offer should receive a reduction in their overall rates."

Decision No. 61969 (September 29, 1999).

In this Order, the Commission stated that "both aggregated and non-aggregated competitive generation services should remain classified as Competitive Services" and that "the current phase-in schedule is not unreasonable and will allow the Affected Utilities to continue their current course of preparation for the commencement of full competition."

Decision No. 65154 (September 10, 2002).

This Commission Order is referred to as the Track A Order. The Commission stated "we must take further action to regulate the transition to competition." The Commission waived the requirement that APS and TEP divest its generation assets and stated, "we believe that in this way we can encourage a phase-in to competition." Referring to the Track B proceeding the Commission stated that it "will encourage a phase-in to competition".

Decision No. 65743 (March 14, 2003).

This Commission Order is referred to as the Track B Order which addressed a competitive bidding process for procuring generation. The Commission restated that it is "the Commission's goal [to] encourage[e] the development of a vibrant wholesale generation market in Arizona".

Decision No. 65751 (March 20, 2003).

In this Commission Order, issued subsequent to the Track A and Track B orders, indices used to calculate the MGC were changed as the index originally relied upon was no longer published. This Commission action confirmed the continued force and effect of the 1999 Settlement Agreement.

Testimony of the Parties.

During my review of the information I also came across references to testimony from representatives of parties to the contract that would be considered as extrinsic evidence. For example, TEP's CEO, Mr. James S. Pignatelli testified, that the 1999 Settlement Agreement provided a framework for transition to competition in generation. RUCO Executive Director, Mr. Greg Patterson, also stated that a major benefit of the Settlement Agreement was removing generation from rate of return regulation. Other relevant statements by the parties regarding the 1999 Settlement Agreement could also be considered as extrinsic evidence.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-0402

Rebuttal Testimony of

Alan Felsenthal

on Behalf of

Tucson Electric Power Company

April 1, 2008

Executive Summary of the Rebuttal Testimony of Alan D. Felsenthal

Alan Felsenthal is a managing director at Huron Consulting Group and is expert in the application of accounting principles to regulated utilities.

Mr. Felsenthal details the requirements of FAS 71, Accounting for the Effects of Certain Types of Regulation. In particular, FAS 71 governs the accounting and financial reporting of entities whose revenues are based on their costs, including its cost of capital, considering the economic effects of the traditional ratemaking process. Entities subject to FAS 71 may recognize costs and income in periods different than entities whose revenues are not cost based.

After the 1999 Settlement Agreement was approved, the generating assets and operations of TEP no longer qualified for FAS 71, and TEP properly discontinued the application of FAS 71. Nothing in the intervening period, including Track A (which eliminated the requirement that TEP divest its generating assets) or the 2003 rate review provided a basis for TEP returning to FAS 71 for its generating assets.

ACC Staff contends that TEP should have continued to collect depreciation expense in its base rates throughout the rate freeze period at levels determined in its previous rate case. TEP was no longer under FAS 71, because the link between rates and expenses of its generating assets had been severed by the transition to competition. Thus, changes to depreciation expense resulting from periodic reviews of the lives and experience of generating assets were reflected in TEP's financial statements as required under GAAP for enterprises in general. There was no regulatory basis to alter this required accounting.

In 2003, FAS 143 became effective. This pronouncement changed the accounting for the costs incurred to retire assets. In particular, only the liabilities associated with legally binding asset retirement obligations were to be recognized. Under the previous accounting, TEP had been charging additional depreciation expense each year to factor in an estimated cost of removal to build up a cost of removal to fund the eventual retirement obligation. Once FAS 143 was applied, this prior treatment was no longer acceptable under GAAP. ACC Staff believes that upon adoption of FAS 143, TEP should have reclassified the previous non-legal cost of removal amounts to a regulatory liability. However, TEP's generating assets did not qualify for FAS 71 and, accordingly, it was required to remove its accumulated cost of removal amounts from the reserve for accumulated depreciation. This was a non-cash event. TEP was precluded from recognizing a regulatory liability because only enterprises that apply FAS 71 can record regulatory liabilities and TEP was not subject to FAS 71. Furthermore, TEP's accumulated cost of removal was considered in the determination of the Fixed CTC and ratepayers had already benefited from the accumulated cost of removal amounts.

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Exhibits

Exhibit AF-1 Curriculum Vitae of Alan D. Felsenthal

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Alan Felsenthal. My business address is 550 West Van Buren Street, Chicago, Illinois 60607.

Q. Please state your occupation and work experience.

A. I am a managing director at Huron Consulting Group (Huron). Huron provides a variety of accounting, tax and consulting services to various industry sectors. My focus is on the regulated industry sector, primarily electric and gas utilities.

Upon graduation from the University of Illinois in 1971, I was hired by Arthur Andersen & Co, where I was an auditor, focusing on audits of financial statements of rate regulated entities. I supervised audits of financial statements on which the Firm issued audit opinions that were filed with Securities and Exchange Commission, Federal Communications Commission, Federal Energy Regulatory Commission and various state commissions. Arthur Andersen also consulted on a significant number of utility rate cases and I helped develop testimony for myself and others on a variety of issues, including CWIP in rate base, phase-in plans, projected test years, lead-lag studies, cost allocation and income tax normalization. The testimony was filed in Illinois, Indiana, Florida, Michigan, Minnesota, New Mexico, Texas, Nevada and Wisconsin. I have testified before the Florida Public Service Commission and the Illinois Commerce Commission. I joined PricewaterhouseCoopers in 2002 and continued performing audits and rate work for regulated entities. My curriculum vitae is attached as Exhibit AF-1.

Q. Have you dealt with the unique accounting, tax and financial reporting issues encountered by rate regulated enterprises?

A. Throughout my career, I have focused on utility accounting, income tax and regulatory issues, primarily as a result of auditing regulated enterprises. The unique accounting standards applicable to rate regulated entities embodied in Financial Accounting Standard ("FAS") 71, FAS 90, FAS 92, FAS 101 and various Emerging Issues Task Force ("EITF") issues all need to be understood so that auditors can determine if the accounting has been applied appropriately. During my career, I have seen the issuance of these standards and have consulted with utilities as to how they should be applied. At both Arthur Andersen and PwC, I worked with the technical industry accounting and auditing leadership to communicate and consult on utility accounting and audit matters.

Q. Have you provided training on the application of GAAP to rate regulated enterprises?

A. Yes. At Arthur Andersen and PwC (and now at Huron), I have developed and presented utility accounting seminars focusing on the unique aspects of the regulatory process and the resulting accounting consequences of the process on the application of Generally Accepted Accounting Principles (GAAP). I have presented seminars on an open registration basis, as well as delivered training on an in-house basis. Seminar participants have included utility company and regulatory commission staff accountants, utility rate departments and internal auditors, tax accountants and others. I have also conducted these seminars in-house for the Federal Energy Regulatory Commission, several state commissions, and have presented at various Edison Electric Institute and American Gas Association ratemaking and accounting seminars. Personnel from various state regulatory commissions have attended the open registration sessions.

Q. What is the purpose of your rebuttal testimony?

A. I have been asked to review the accounting basis for the adjustments proposed by the Arizona Corporation Commission Staff ("Staff") to accumulated depreciation and the cost of removal for generating assets.

Q. What documents have you read in connection with this proceeding?

A. I have read the Arizona Corporation Commission Decision No. 62103, the 1999 Settlement Agreement and the related briefs, testimony and transcripts. I have reviewed the Track A and Track B proceedings of the Corporation. I have read certain testimony and proceedings in connection with the 2004 Rate Review of TEP (Docket No. E-01933-04-0408). I have read the financial statements of the Company and its Parent. I have read certain of the testimony and filings in this proceeding.

Q. Have you read the Direct Testimony filed by the Staff?

A. Yes I have. In addition, I have reviewed the deposition transcripts of Ralph Smith and John Antonuk.

Q. Please provide your general assessment of such Direct Testimony.

A. The Staff analysis disregards the accounting implications of an important event—the 1999 Settlement Agreement and the related Decision No. 62103 which deregulated TEP's generation segment. TEP discontinued the application of FAS 71 as a result of the 1999 Settlement Agreement, which included several rate decreases, a 9-year rate freeze, the opening of the service territory to competition, and the expectation upon expiration of the rate freeze, TEP's generation rates would be market based, not cost based. The 1999 Settlement Agreement specifically noted that some assets of TEP distribution would continue to be regulated while generation would operate in the competitive market. Staff

has proposed a number of adjustments that are not appropriate in light of TEP's discontinuance of FAS 71 in 1999.

Staff proposes to adjust accumulated depreciation to reinstate depreciation expense at the depreciation rates in effect in 1999, notwithstanding that TEP adjusted such rates several times since then to reflect changes in depreciation lives and to remove the cost of removal component of depreciation rates upon adoption of FAS 143 in 2003. Because TEP's generation rates were no longer cost based at the time of such depreciation changes, FAS 71 did not apply and GAAP required depreciation adjustments based on these updated depreciation factors.

Staff has also chosen to ignore that the 1999 stranded cost calculation (in particular, the amounts amortized and collected through the Competitive Transition Charge) included the cost of removal amount for non-legal retirement obligations. This factor reduced the CTC amount and has effectively been returned to ratepayers via a reduction of the CTC. Nonetheless, Staff has proposed that the cost of removal amount for non-legal obligations be used to reduce rate base. This would return the same monies twice.

In my opinion, the Staff's adjustments are not appropriate from a ratemaking perspective and inconsistent with the accounting literature as it should be applied given the facts in this proceeding.

Q. Can you please summarize your rebuttal testimony?

A. My rebuttal testimony will address TEP's accounting in the following areas:

- The 1999 decision to discontinue application of FAS 71 for the generation segment of its business.

- The decision to not return to FAS 71 accounting for the generation segment of its business.
- TEP's accounting for depreciation rate changes and why Staff's adjustment to reinstate accumulated depreciation to reduce rate base is inappropriate.
- TEP's accounting for the adoption of FAS 143 and why Staff's adjustment to reinstate cost of removal in accumulated depreciation for non legal asset retirement obligations is inappropriate.

II. APPLICATION OF FAS 71 TO TEP'S GENERATION ASSETS.

A. Background On FAS 71.

Q. Why is an understanding of FAS 71 important in this case?

A. Staff witnesses have proposed a number of adjustments to the Company's requested revenue requirement that are inappropriate for an entity that is not under the accounting requirements of FAS 71. Accordingly, it is important to understand what the accounting ramifications are for entities that follow FAS 71 and what it takes for a Company to be able to apply the accounting standards of FAS 71.

Once it is clear that TEP no longer can apply FAS 71 to the generation segment of its business, Staff's accumulated depreciation adjustments for depreciation rate changes and including a cost of removal factor in the depreciation rate calculation are without basis. These adjustments would only be considered for cost-based regulated enterprises that are able to apply the accounting requirements of FAS 71.

Q. What is FAS 71?

A. FAS 71, Accounting for the Effects of Certain Types of Regulation, was issued by the FASB in 1982. The Statement is the principal accounting guidance for rate regulated entities and addresses the unique accounting for entities where there is a linkage between rates or tariffs charged to its customers and the company's costs. A rate regulated enterprise's costs are defined to include the costs of capital, both debt and equity.

Under FAS 71, utilities are required to defer incurred costs that non-regulated entities would charge to expense if, as a result of the regulatory process, it is probable that such costs will be recovered in future charges to ratepayers. Additionally, rate regulated entities are required to record regulatory liabilities when it becomes probable that a regulator will require the refund of revenues previously charged to ratepayers.

Q. What are the requirements for applying FAS 71?

A. The Summary of FAS 71 contains this succinct guidance:

> "In general, the type of regulation covered by this Statement permits rates (prices) to be set at levels intended to recover the estimated costs of providing regulated services or products, including the cost of capital (interest costs and a provision for earnings on shareholders' investments)."

Paragraph 5 of FAS 71 provides the specific scope requirements. Entities with regulated operations that meet all of the following criteria are required to apply FAS 71 to the general purpose-external financial statements of its regulated operations.

> "a. The entity's rates for regulated services or products provided to its ratepayers are established by, or are subject to, approval by an independent, third-party regulator or by

its own governing board empowered by statute or contract to establish rates that bind ratepayers.

b. The regulated rates are designed to recover the specific entity's costs of providing the regulated services or products.

c. In view of the demand for the regulated services or products and the level of competition, direct and indirect, it is reasonable to assume that rates set at levels that will recover the entity's costs can be charged to and collected from ratepayers. This criterion requires consideration of anticipated changes in levels of demand or competition during the recovery period for any capitalized costs."

Again, an entity's costs include capital costs.

Q. Must all of an entity's operations meet the above criteria for the entity to apply FAS 71?

A. No. If a portion of an entity's operations are regulated and qualify for FAS 71 application, FAS 71 should be applied to that portion

Q. Generally, which types of entities follow the accounting under FAS 71?

A. Historically, rate regulated electric, gas, telephone and water utilities followed the accounting requirements of FAS 71. Unlike competitive entities, where the rates/prices charged for products or services are based on competition, rate regulated entities typically set the rates they charge their customers based on their costs, as determined in a rate case in which test year operating and capital costs were presented to a regulator, with a revenue requirement based on costs ultimately ordered. Utilities typically have exclusive right to- and were required to provide service in their certificated area in exchange for the

Commission's oversight of a number of operational and financial factors, such as determining the rates that could be charged to customers. The economic effects of regulation were considered unique by the FASB when they considered the accounting that eventually resulted in FAS 71.

Said another way, because rate regulated utilities were permitted to charge revenue based on costs, their financial statements should recognize the direct linkage between costs and revenues. And, if a regulator permitted recovery (revenue) of a cost in different accounting period than when the cost was incurred, that cost should be deferred on the balance sheet (rather than expensed in the income statement) and amortized to the income statement in the period in which the revenues to recover that cost are being reflected. This accounting matches the costs (expenses) and revenues (based on those costs).

Q. Can you provide a simple example of how FAS 71 is applied?

A. Yes. Assume a tornado occurs in 2006 resulting in considerable damage at two entities. One entity is a rate regulated utility the other is a maker of orange juice. Both entities spend $10 million performing a variety of maintenance activities to repair the damage caused by the tornado. Under GAAP, both entities would record $10 million of maintenance expense in 2006 as both companies incurred $10 million of maintenance costs in the period.

The orange juice maker presumably would not be able to pass along the $10 million maintenance expense in the price of orange juice because orange juice prices are set by the competitive orange juice market where there is no direct correlation between costs and future revenues. Thus, that company would likely report that its net income in 2006 is lower than expected due to the tornado.

The utility company would likely seek recovery of this cost from its regulator. Precedent would play an important role in determining whether rate actions of the regulator would permit future rate recovery of the storm costs. If the utility concluded that recovery of the $10 million was probable (i.e., likely), it would reduce the $10 million of maintenance expense and record a regulatory asset. The regulatory asset would then be charged to expense (amortized) in the period that the regulator permitted recovery through rates. So if the regulator permitted recovery of the $10 million unusual maintenance at the rate of $2.5 million per year beginning in 2008, the utility would amortize $2.5 million of the regulatory asset each year as maintenance expense to match the $2.5 million of additional revenues granted to recover that cost.

Q. In your example, the utility does not report an expense in its 2006 income statement like the orange juice company, but defers that cost on its balance sheet and amortizes that cost to the income statement in the periods it is being recovered in regulated rates. Is that because of cost-based rate regulation?

A. Yes. FAS 71 states:

> "This Statement may require that a cost be accounted for in a different manner from that required by another authoritative pronouncement. In that case, this Statement is to be followed because it reflects the economic effects of the rate-making process—effects not considered in other authoritative pronouncements. All other provisions of that other authoritative pronouncement apply to the regulated enterprise."

Unless the ratemaking process provides a linkage between costs and revenues creating an economic effect, GAAP as applicable to enterprises in general should be applied.

Q. Are there other examples you can cite on how FAS 71 is applied?

A. Utilities with automatic fuel adjustment clauses defer actual fuel expense as regulatory assets or liabilities so that the fuel expense in the income statement reflects the fuel expense collected through current rates and the amount to be collected in future months through operation of the fuel clause deferred until the period in which it is passed through to customers.

In addition, under FAS 71 utilities capitalize as a part of plant the cost of equity and debt used to finance construction—the Allowance for Funds Used During Construction. In contrast, non-regulated companies would capitalize only interest costs in accordance with FAS 34, Capitalization of Interest Cost.

Q. When it was issued, did most rate regulated electric, gas, telephone and water utilities follow FAS 71?

A. Yes.

Q. Is it necessary for a utility to recover all its operating costs and earn the allowed rate of return in each year to apply FAS 71?

A. No. The ratemaking process does not guarantee cost recovery, including the return on investment. The ratemaking process provides the opportunity for a utility to recover its costs and earn a reasonable return. The important linkage is that rates be designed to recover all of the utility's costs, including capital costs.

B. TEP's Decision to Discontinue Application of FAS 71 on Generation Assets in 1999.

Q. Prior to the 1999 Settlement Agreement, did TEP apply FAS 71?

A. Yes. Prior to the Settlement Agreement, rates charged to TEP's customers were based on its costs as determined in a rate case. The revenue requirement was established to permit TEP the opportunity to recover its costs, including a reasonable return. The revenue requirement was determined for the total regulated entity consisting of generation, transmission and distribution.

Q. Does TEP continue to apply FAS 71 to its generation segment?

A. No. TEP discontinued application of FAS 71 for its generation segment in 1999. However, it continues to apply FAS 71 to its transmission and distribution segments.

Q. What happened in 1999?

A. In 1999, the ACC issued a Decision adopting a settlement agreement that provided evidence that the generation assets of TEP were to transition from cost based to market based rates. Competition was encouraged. Customers were able to choose to purchase their electricity from other generators, they no longer were required to purchase from TEP (TEP remained the regulated monopoly provider of transmission and distribution electricity). After a rate decline, tariffs were unbundled and frozen until December 31, 2008. Based on these and other factors, the Company concluded and its auditors agreed that generation rates were no longer cost based and FAS 71 could no longer be applied to the generation segment.

Q. Did the FASB provide guidance on when to discontinue application of FAS 71?

A. Yes. Issued in 1988, FAS 101 governs the accounting that entities who were applying FAS 71 should follow when the entity is no longer able to meet the scope requirements necessary to apply FAS 71. While FAS 101 does not provide "bright lines" for determining when to discontinue applying FAS 71, it contains the following examples of causes that should be considered.

> "4. Failure of an enterprise's operations to continue to meet the criteria in paragraph 5 of Statement 71 can result from different causes. Examples include the following:
>
> a. Deregulation
>
> b. A change in the regulator's approach to setting rates from cost-based rate making to another form of regulation
>
> c. Increasing competition that limits the enterprise's ability to sell utility services or products at rates that will recover costs
>
> d. Regulatory actions resulting from resistance to rate increases that limit the enterprise's ability to sell utility services or products at rates that will recover costs if the enterprise is unable to obtain (or chooses not to seek) relief from prior regulatory actions through appeals to the regulator or the courts."

Q. Was any additional accounting guidance issued to help decide when to cease applying FAS 71?

A. Yes. In 1997 the Emerging Issue Task Force reached a consensus on EITF 97-4, Deregulation of the Pricing of Electricity - Issues Related to the Application of FASB Statements No. 71 and No. 101. This EITF addressed issues concerning when FAS 71

should be discontinued and how FAS 101 should be adopted in jurisdictions where electric utility restructuring was occurring with transition to a competitive generation market.

The scope of EITF 97-4 was limited to a specific circumstance in which deregulatory legislation has been passed and a final rate order issued.

The issues addressed in EITF 97-4 appear to parallel the situation that TEP was facing with its generation assets in Arizona. EITF 97-4 concluded:

> "The first issue in EITF Issue 97-4 addresses when an enterprise should stop applying Statement 71 to the separable portion of its business whose product or service pricing is being deregulated. However, this issue was limited to situations in which final legislation is passed or a rate order is issued that has the effect of transitioning from cost-based to market-based rates. In such situations, the issue is when Statement 71 should be discontinued -- at the beginning or the end of the transition period? The EITF concluded that when deregulatory legislation or a rate order is issued that contains sufficient detail to reasonably determine how the transition plan will affect the separable portion of the business, FAS 71 should be discontinued for that separable portion. Thus, FAS 71 should be discontinued at the beginning (not the end) of the transition period."

Q. Did TEP meet the criteria in EITF 97-4 to discontinue application of FAS 71?

A. Yes, once it became probable that the deregulation legislative and/or regulatory changes would occur and the effects were known in sufficient detail to be reasonably estimated, FAS 71 was discontinued and FAS 101 was adopted. The Commission's Retail Electric

Competition Rules had been adopted, state legislation had been passed which supported electric competition as the policy of the State of Arizona and Decision No. 62103 approving the 1999 Settlement Agreement had been received.

Q. Did ACC Staff witness Antonuk indicate that he agreed with the decision for TEP to discontinue applying FAS 71?

A. Yes. Mr. Antonuk said on page 63 of his deposition that he consulted with or relied upon CPA Dennis Kalbarczyk on accounting matters. With respect to the decision for TEP to discontinue applying FAS 71 he stated: "...we certainly reached the agreement that it was appropriate at that time."

Q. Have you reviewed Staff witness Ralph Smith's deposition testimony on TEP's decision to discontinue the application of FAS 71 to its generation assets after the 1999 Settlement Agreement?

A. Yes. He said that he found the decision to be questionable.

Q. Do you agree with Mr. Smith's characterization?

A. No I do not. In my opinion, given the requirements of the accounting literature and the changes in the regulatory regime occasioned by the Settlement Agreement, the discontinuation of FAS 71 was absolutely required.

Q. Were the Commission and Staff informed that TEP would discontinue the application of FAS 71?

A. Yes. For example, in the hearing on the 1999 Settlement Agreement, Ms Kissinger's pre-filed testimony stated at line 24 of page 3, "Once the Arizona Corporation Commission approves the Settlement Agreement, the Company will have a specific cost recovery plan for its assets and determinable deregulation plan. *This means at that point in time the*

Company will need to cease accounting for its generation assets in accordance with FAS 71(emphasis added)."

Q. Did TEP disclose its policy with respect to the application of FAS 71 in its published financial statements and in statements filed with the ACC?

A Yes it did. Annually, it indicates in its footnotes the following disclosure:

> "Upon approval by the ACC of a settlement agreement (Settlement Agreement) in November 1999, TEP discontinued application of FAS 71 for its generation operations. TEP continues to apply FAS 71 to its cost-based rate regulated operations, which include the transmission and distribution portions of its business."

Furthermore, in Mr. Pignatelli's direct testimony in the 1999 Settlement Agreement, he indicates on page 9 "When the Commission approves the Agreement, TEP will be required to stop accounting for its generation operations using FAS 71." Also, please see the reference to Ms. Kissinger's testimony in the Settlement Agreement referred to above

Q. Did the Settlement Agreement provide for the divestiture of generation assets?

A. Yes.

Q. Were the generation assets divested?

A. No. In the "Track A" docket, the Commission rescinded the mandatory obligation to divest generation assets in accordance with the timing and plan contemplated by the 1999 Settlement Agreement and indicated that any such divestiture in the future would require Commission approval.

Q. As a result of Track A and the development in the industry should TEP have returned to FAS 71 for its generating assets?

A. No.

Q. Upon what is your opinion based?

A. The Track A order did not provide new rates designed to allow TEP an opportunity to recover the costs, including the costs of capital, of generation. TEP was still under a rate freeze with no opportunity to even seek cost based rates until after December 31, 2008. Nor did the ACC find that the frozen rates in place were sufficient to allow TEP that opportunity. Without this linkage it would be inappropriate to return to accounting for generation operations under FAS 71.

Q. Did Track A indicate that generation would return to rate regulation?

A. No. The ACC declined to make changes in the direct access provisions of the Retail Electric Competition Rules for example (page 26). In its Findings of Fact the ACC concluded:

> "46. It is incumbent on all parties to work together in such a manner that will allow competition and its expected benefits to develop in whatever timeframe is needed to make it successful..."

Finally, the ACC did not order a return to cost based rates, a condition of applying FAS 71. All of these factors would have been important in reaching my professional accounting judgment that a return to FAS 71 was not appropriate.

Q. Is the expectation of a continued path to competition consistent with previous ACC orders?

A. Yes. Track A recognized the need to allow some flexibility in implementing competition while continuing to provide binding regulatory stability. In its discussion of the Track A Decision to not require generation asset divestiture, the Commission stated on page 23:

> "This determination is consistent with our planned transition to competition and as we said in Decision No. 61973,...'the Commission must be able to make rule changes/other future modifications that become necessary over time.' (Decision No. 61973 at p. 9) As we also said in Decision No. 61973, it is 'not the Commission's intent to undermine the benefits that parties have bargained for.'(Id.) Recognizing this, it is incumbent upon all parties to work together in a manner that will allow competition and its expected benefits to develop in whatever timeframe is needed to make it successful, while ensuring that the citizens of Arizona have safe, reliable and fairly priced electric power. Accordingly, we will modify Decision Nos. 61973 and 62103 to stay the asset transfer provisions as outlined above."

I am not a lawyer and I am not making a legal judgment. I am applying the judgment of a professional accountant in determining the appropriate accounting treatment for TEP's generating assets after Track A.

Q. Are you aware that APS made a different decision in regards to generating assets and the application of FAS 71?

A. Yes. I have reviewed the financial statements of APS and note that they went back on FAS 71 for the year ended December 31, 2002.

Q. What bearing does APS' decision have on your opinion that TEP should not have reapplied FAS 71 to its generation segment?

A. I have not studied APS' situation in detail, but have read Ms. Kissinger's Rebuttal Testimony where she points out differences between the situation of APS and TEP. There are clearly differences between the regulatory schemes of the two companies. The APS Settlement Agreement provided a recovery mechanism for purchased power and fuel costs related to provider of last resort and standard offer customers. TEP does not have a similar recovery mechanism. APS' rate freeze expired in relative short order (July 1, 2004) while TEP's rate freeze extended through December 31, 2008. In APS' rate case, they were permitted to include generating assets in rate base at cost.

In particular, the 9-year rate freeze, whereby TEP would not be able to adjust its rates until December 31, 2008 at the earliest raises doubt about the linkage between costs and revenues required to follow FAS 71. The Track A order did not change this basic fact.

Q. Are you aware of Staff witness Ralph Smith's position on Track A and FAS 71?

A. Yes. Mr. Smith opined that the decision to suspend divestiture of generation in Track A should have lead TEP to conclude that its generation assets had returned to rate regulation and that FAS 71 should be applied. As outlined above, I do not find that Track A facts would allow TEP to meet the requirements of FAS 71. The ACC indicated that it was still on a path to retail competition. For these reasons, I must respectfully disagree with Mr. Smith.

III. TEP'S DEPRECIATION RATE CHANGES

A. Depreciation Changes for Entities that do not Apply FAS 71.

Q. How does the fact that TEP was no longer on FAS 71 affect the ability to adjust depreciation rates?

A. Once the linkage between costs and revenues is severed, TEP is required to follow GAAP as applicable to non-regulated enterprises for the generation segment of its business.

Q. In a market-based and not cost-based regulatory environment, what impact would Commission review and approval of depreciation rates have on TEP's deregulated generation assets?

A. Absolutely none. Accordingly, it is TEP's position that such review and approval was no longer necessary once generation assets became deregulated. It is TEP's position that such Commission review and approval of depreciation rates is only applicable to its distribution assets.

The economic effects of rate regulation discussed as the basis for FAS 71 no longer exist. Rates charged customers were no longer cost based.

Q. How is depreciation expense computed for assets in the competitive as opposed to the regulatory regime?

A. Depreciation expense under GAAP allocates the investment in plant and equipment to expense in a systematic and rational manner over the economic life of the asset. Non-regulated entities establish depreciation lives and rates in accordance with this GAAP definition.

Without the cause and effect relationship of costs and revenues (the economic effect of regulation) there is no basis to consider the ratemaking process in this calculation of depreciation expense for generation assets.

Q. Under GAAP is depreciation expense routinely reviewed?

A. Yes. It is common for companies to perform periodic reviews of the facts and circumstances forming the basis for annual depreciation charges. As the factors on which depreciation charges are based change (for example the economic life of an individual asset or asset class needs to be extended or shortened as a result of changes in technology or obsolescence), depreciation rates are adjusted accordingly.

Q. Did TEP change its generation related depreciation rates after the Settlement Agreement?

A. Yes as more fully explained in Ms. Kissinger's rebuttal testimony, from time to time TEP changed its depreciation rates in periods after the Settlement Agreement.

Q. Did TEP accrue AFUDC on its generating assets under construction after the Settlement Agreement?

A. Based on my review of its financial statements and discussions with the Company it did not accrue AFUDC after 1999 when it went off FAS 71 for its generation segment.

Q. Did TEP file a general rate case in 2004?

A. Yes. Although rates were not permitted to rise until after December 31, 2008 under the Settlement Agreement, TEP had been ordered to file a general rate case so that ACC could determine if a rate decrease was justified.

Q. What was the test year for the 2004 general rate case?

A. The test year was the year ended December 31, 2003 and the record showed a revenue deficiency. This confirms that the rates applicable to TEP's generation assets were not cost based.

Q. In the 2004 general rate case, were depreciation rate changes included in the Company's filing?

A. It is my understanding that depreciation expense in that filing was based on certain depreciation rates that had been revised since the Settlement Agreement.

B. <u>Staff's 2004 Audit of TEP's General Rate Case Information did not Result in Depreciation Expense Adjustments.</u>

Q. Did Staff audit the test year filing of TEP for the 2004 filing?

A. Yes. The Chief Accountant for Staff, James Dorf filed testimony as to the work performed by Staff.

Q. Were any adjustments proposed by Staff related to these depreciation rate changes?

A. No. While Staff included a number of recommended adjustments to the test year, none related to the depreciation rate changes for revisions to estimated useful asset lives.

Q. In this proceeding, Staff witness Ralph Smith has called this audit a cursory review. Is that borne out by your review of the record?

A. No. While I was not involved in the 2004 proceeding and have not reviewed Staff's work, Mr. Smith's observation is not consistent with the record. Mr. Dorf reported in his filed testimony that the Staff had performed a regulatory audit. He describes on page 7-8 of his filed testimony the procedures followed by Staff:

"Q. What audit and review procedures did Staff perform?

A. Staff performed a regulatory audit of the Company's filing and records. The regulatory audit consisted of examining and testing financial information, accounting records, and other supporting documentation and verifying that the accounting principles applied were in accordance with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA").

Staff conducted a complete review of each of the Company's proposed adjustments and the basic underlying financial data. Staff also conducted interviews of Company witnesses and performed substantive audit procedures at the Company's administrative offices. Staff's procedures included reviewing numerous discovery responses in assessing the efficacy of the information provided by TEP.

Staff also utilized an outside consultant, Overland Consulting, to provide Staff members specialized electric utility audit training and audit program development. Overland Consulting also reviewed Staff's testimony."

Based on the record, this does not appear to be a cursory review.

Q. Do you have any reason to believe that the Commission would not have accepted the depreciation rate changes adopted by the Company since 2000?

A. No. The Company had performed an analysis of the service lives of its assets and determined that lives for certain assets needed to be extended. To the extent that the life

extensions were supportable by evidence, the Commission would likely have accepted the adjusted depreciation rates.

In Mr. Smith's deposition, he so much as said that the component of the depreciation rate change attributable to extending property lives most likely would not have been challenged.

Q. Staff proposes to adjust accumulated depreciation based on a calculation of what accumulated depreciation would have been had not the depreciation rates changed. Do you agree with this approach?

A. No. This approach assumes that there was no fundamental change in the regulation of generation, when in fact, there was a clear intent to change from cost based to market based regulation. To apply 20-20 hindsight today, and assume that TEP's generation assets continued to be cost based regulated, even after the Settlement Agreement, is inappropriate.

The 2004 general rate case shows that in spite of proposing numerous adjustments to the test year (with which TEP does not concur) Staff concluded that TEP had a revenue deficiency. And this was without considering any adjustments to accumulated depreciation and the related depreciation expense that Staff is now proposing. The more recent test year 2006 shows again that TEP was not recovering its costs, including a reasonable return.

In addition, if 20-20 hindsight were applied, additional amounts of AFUDC would have to be factored into the rate base and depreciation expense calculations.

IV. TEP'S TREATMENT OF GENERATION RELATED COST OF REMOVAL UNDER FAS 143

A. Background on FAS 143.

Q. Was a new accounting provision effective in 2003?

A. Yes. FAS 143, Accounting for Asset Retirement Obligations, was effective January 1, 2003.

Q. Briefly, what did FAS 143 require?

A. FAS 143 required an entity to determine if it has a legal obligation to remove, dispose, or remediate an asset. If a legal obligation exists, the fair value of the legal obligation is to be recorded as an asset retirement obligation (ARO) with a corresponding retirement cost asset recorded as well The entity would then depreciate the ARO asset and accrete and the ARO liability so that when the retirement cost is paid, the ARO asset would have been fully depreciated and the ARO liability would have increased to the amount of the obligation. Both depreciation expense and accretion costs are recorded on the income statement over time to recognize the estimated costs of legally removing the obligation in the periods that the related asset is being depreciated.

Although not applicable to TEP, the most obvious example of an ARO for a utility is the cost associated with decommissioning a nuclear plant. FAS 143 requires entities with nuclear facilities to estimate the eventual costs to decommission and record that obligation (liability) in the financial statements. The liability is recorded at its fair value and accreted to full value over time. An offsetting ARO asset is initially recorded (and depreciated) as the plant costs should reflect the total costs of the facilities, both the initial construction

costs as well as the estimated costs that will be necessary to decommission the facility at the end of its useful life.

Prior to the issuance of FAS 143, regulated and other entities followed a variety of practices for removal costs. Most regulated entities accrued the estimated removal costs by increases to depreciation expense over the lives of the related assets to build up a liability (generally recorded in accumulated depreciation) that would be relieved when the monies were spent in removal efforts.

Q. Was the building up of a removal cost liability similar in concept to the treatment of salvage value considerations when depreciating an asset?

A. The concept is similar. Under GAAP, it is clear that depreciation is the process of allocating the cost of the asset, less any estimated salvage values, over the estimated lives of the asset in a systematic and rational manner. Cost of removal was treated as "negative salvage" and considered in the depreciation calculation.

FAS 143 did not alter the accounting for salvage values.

Q. What was TEP's policy with respect to removal costs prior to FAS 143?

A. TEP, and most regulated utilities, had estimated the cost associated with removing and dismantling its fixed assets and included a cost of removal component in depreciation expense to build up to the balance to pay the eventual cost to remove or dismantle. By including a cost of removal factor in depreciation expense, the customer who is benefitting from the property, plant and equipment pays for the total plant costs—the original cost of construction plus the estimated cost of removal. Under this approach, the build up of annual cost of removal charges was included in accumulated depreciation.

Q. What was the effect on TEP of the adoption of FAS 143?

A. TEP had minor amounts of legal asset retirement obligations as defined in FAS 143. However, in FAS 143, the FASB concluded that the practice of including a cost of removal factor in depreciation charges for non-legal retirement obligations was no longer appropriate under GAAP. Thus, upon adoption, entities could no longer accrue a cost of removal factor for non-legal obligations in its depreciation rates and cost of removal obligations included in accumulated depreciation would be reversed.

As described previously, utilities routinely included a cost of removal (negative salvage) factor in depreciation rates and did not make the distinction between legal and non-legal retirement obligations. Under GAAP, with the adoption of FAS 143, regulated utilities could no longer accrue a cost of removal factor in depreciation expense and removed any non-legal cost of removal from accumulated depreciation. The only exception to this practice was for cost based rate-regulated entities who follow FAS 71 and whose regulator permitted rate recovery of cost of removal in depreciation rates. In such circumstances, the additional depreciation component for non-legal cost of removal could continue as revenues were permitted to recover these additional costs and the financial statements would reflect the economic effects of regulation. For regulated entities that are also SEC registrants, the cost of removal component included in accumulated depreciation was reclassified as a regulatory liability.

Upon adoption of FAS 143, TEP analyzed its generation assets and determined that the non-legal cost of removal balance recorded in accumulated depreciation was greater than the Asset Retirement Obligation (for legal obligations) computed in accordance with FAS 143. TEP removed the non-legal cost of removal balance from its generation asset books and records. According to their financial statement disclosure at the time of adoption, the net effect of adopting FAS 143 was to increase after tax income in 2003 by approximately

$68 million. Further, after adoption, annual depreciation expense was estimated to decrease by approximately $6 million as a result of removing the non-legal cost of removal component from the depreciation calculation.

Q. Was this treatment in accordance with GAAP?

A. Yes.

Q. Why didn't TEP simply reclassify the non-legal cost of removal amount included in accumulated depreciation to a regulatory liability?

A. This treatment was only available to entities that were able to apply FAS 71 and TEP's generation assets were no longer under FAS 71.

Q. Why didn't TEP continue to include a factor in its annual depreciation charges applicable to generation assets to account for the non-legal cost of removal associated with removing or dismantling property, plant and equipment?

A. This practice was no longer permitted for entities in general and would only be permitted for entities that were able to apply FAS 71. TEP's generation assets were no longer under FAS 71.

Q. Was this a cash windfall for TEP?

A. No. These amounts are non-cash entries and did not provide any additional cash to TEP.

Q. What did Staff propose in 2004 and in the current filing with respect to FAS 143?

A. For TEP's generation assets, Staff proposed in 2004 to reverse the effects of TEP's entries by creating a regulatory liability equal to the difference between the cost of removal as computed prior to the adoption of FAS 143 (including both legal and non-legal retirement costs) and the Asset Retirement Obligations recognized under FAS 143 (legally required

retirement costs only). [See 2004 Rate Review Testimony of James Dorf, page 11 at line 13] Additionally, Staff proposed to increase depreciation expense by $6 million to continue to charge cost of removal in depreciation expense. [*Id.*, page 23 beginning at line 20]

In the current filing, Mr. Smith likewise proposes that TEP create a regulatory liability for non-legal cost of removal amounts and proposes an increase in depreciation expense to continue to charge for cost of removal in depreciation expense.

Q What support did Staff offer for its adjustment?

A. Staff offered two reasons. First Staff argued these expenses had been collected from customers in rates and therefore should be considered a regulatory liability. Second, Staff noted that in the APS rate case the Commission had not adopted FAS 143 for regulatory purposes. The arguments made by Staff in 2004 are identical to the arguments made in this proceeding by Mr. Smith.

Q. Do you agree with these reasons?

A. No. Let me take the second one first. Ms. Kissinger has discussed the differences between APS and TEP. APS had a rate case and readopted FAS 71. TEP did not have rates linked to the costs of its generation. The re-adoption of FAS 71 for TEP was not warranted under the circumstances at the time. Because TEP was not under FAS 71, under GAAP it could not have implemented Staff's recommendations.

Q. Turning to the Staff's first argument, does the collection of the cost of removal through depreciation prior to the rate freeze justify the creation of a regulatory liability?

A. No. Under GAAP, once FAS 143 was adopted, non-regulated entities could not continue to include a cost of removal component for non-legal retirement costs in its financial statements. The only entities that could continue to have cost of removal for non-legal ARO's on its books after adoption of FAS 143 were regulated entities under FAS 71.

After the Settlement Agreement, TEP's generation rates were no longer linked or correlated to its costs and FAS 71 was discontinued. Accordingly, the fact that generation depreciation expense pre-Settlement Agreement included cost of removal in the rates has no meaning to the case at hand.

Q. Did the FERC adopt the provisions of FAS 143?

A. Yes. The FERC issued Order 631 on this issue on April 9, 1993.

Q. Can you summarize this FERC Order?

A. Yes. The FERC basically adopted the requirements of FAS 143 and amended the USOA to include accounts for Asset Retirement Obligations. For non-legal ARO's, the FERC concluded that such amounts can remain on the books of regulated enterprises to the extent that they represent estimated amounts included in the revenues collected from ratepayers to be used to fund actual cost of removal expenditures. The FERC concluded that such amounts need not be reclassified as regulatory liabilities.

It is important to note that the FERC Uniform System of Accounts has adopted the FASB "probable" of recovery or refund definition of what is required to record regulatory assets

and liabilities. Entities that are not subject to cost based regulation generally cannot meet this definition and do not record regulatory assets and regulatory liabilities.

Q. What is the definition of Stranded Costs under the ACC Rules?

A. The ACC's Retail Electric Competition Rules, Section R14-2-1601 defines Stranded Costs as:

> "A. the verifiable net difference between:
>
> i.. The net original cost of all the prudent jurisdictional assets and obligations necessary to furnish electricity (such as generating plants, purchased power contracts, fuel contracts, and regulatory assets), acquired or entered into prior to December 26, 1996, under Traditional Regulation of Affected Utilities; and
>
> ii. the market value of those assets and obligations directly attributable to the introduction of competition under this Article."

Q. What does the term net original cost mean in the definition above?

A. Net original cost generally means original cost less accumulated depreciation.

Q. Were generation related cost of removal costs included in accumulated depreciation at the time of stranded cost determination?

A. Yes. The cost of removal was a component of accumulated depreciation as of the date of the 1999 Settlement Agreement.

Q. What does this mean in terms of the quantification of TEP's CTC regulatory assets?

A. This means that the CTC regulatory asset of $450 million would have been approximately $107 million higher absent the cost of removal component of accumulated depreciation. This was the estimated balance of the cost of removal component included in accumulated depreciation when the stranded cost determination was made.

Stated another way, were it not for the $107 million cost of removal amount, the amount to be recovered by the Fixed CTC would have been $557 million, not $450 million. Ratepayers have had their Fixed CTC charges reduced by the $107 million cost of removal amount.

Q. If the CTC considered generation related cost of removal, why do the Staff and intervenors want to include this amount in generation related accumulated depreciation in this proceeding?

A. There may be some confusion on their part with this adjustment. The accumulated depreciation related to cost of removal accumulated prior to the Settlement Agreement has already been considered and, in effect, was returned to ratepayers through the CTC recovery period, which will end soon. To consider this amount again as a component of the net book value determination of generation assets gives consideration to the same amount twice. The same dollars should not be considered twice—which is what would happen if accumulated depreciation is reduced for the accumulated cost of removal.

Q. What did the 1999 Settlement Agreement indicate in regards to the stranded cost determination?

A. Section 13.1 of the Settlement Agreement states:

> "Neither the Parties nor the Commission shall take any action that would diminish the recovery of TEP's stranded costs or regulatory

> assets provided for herein. In entering into this Settlement Agreement, TEP has relied upon the Commission's irrevocable promise to permit recovery of TEP's stranded costs and regulatory assets as provided herein. Such irrevocable promise by the Commission shall be evidenced by the issuance of the Commission's Approval Order, shall survive the expiration of the Settlement Agreement and shall be specifically enforceable against this and any future Commission." In my opinion, the irrevocable nature of the stranded cost determination means just that—the promise cannot be revoked."

Mr. Smith would like the Commission to ignore this prior promise. He wants to reinstate on TEP's books the non-legal cost of removal amount for generation assets to be used to benefit ratepayers a ***second*** time. This would not be fair or equitable to TEP.

Q. Does Decision No. 62103 address the stranded cost determination and whether it is subject to future changes?

A. Yes, it indicates clearly that these amounts will not be revisited. It states on page 12, lines 6 to 8:

> "We want to make it clear that the Commission does not intend to revisit the stranded cost portion of the Agreement. It is also not the Commission's intent to undermine the benefits that parties have bargained for."

Q. Does Mr. Smith heed this information related to his cost of removal adjustment?

A. No. He is apparently unaware that the issue cannot be revisited as cost of removal is inherently a component of the stranded cost determination which took place prior to the

Settlement Agreement. His position is contrary to the 1999 Settlement Agreement and Decision No. 62103.

Q. What is your opinion of Mr. Smith's attempt to recalculate the depreciation rates post adoption to FAS 143 based on the generation rates pre Settlement Agreement?

A. I think it is inappropriate and based on the flawed notion that generation depreciation rates charged for 2003 to now were somehow cost based. The record shows that in 2004 TEP was not recovering its costs and it also shows that for the more recent test year 2006 TEP was not recovering its costs. Mr. Smith ignores that these accumulated depreciation rate changes he recommends would be accompanied by increased depreciation expense for these periods and would have created an even greater gap between costs and required revenues.

Q. In this proceeding TEP has proposed setting rates for generation based alternative methods (cost of service, hybrid and market methods). Staff has proposed setting rates for generation on cost of service. Does this mean that TEP should "do over" its decision to go off FAS 71 for 1999-2008?

A. No. If the Commission were to return to traditional ratemaking practice and order generation rates be set on a cost-based method, TEP would evaluate whether the requirements of paragraph 5 of FAS 71 would be met and potentially reapply FAS 71. However, this would not change the prior conclusion that going off FAS 71 was required.

In my opinion it would be a mistake to treat the last decade or so as a "mulligan." All parties acted in good faith to negotiate the 1999 settlement agreement. TEP has abided by the terms of the agreement including a 9 year rate freeze. Revisiting each decision made by TEP when it acted (as it said it would) under the presumption that generation was deregulated would create chaos.

Q. What should the regulatory accounting treatment be if generation is brought under cost of service regulation?

A. The generation assets should be brought over at their fair market value. This is the price that TEP would have to pay to acquire such assets from a third party. Another straightforward approach would be to bring the assets over at their depreciated original cost when the new rates become effective. If this alternative approach were used, there should also be recognition of the estimated under earnings during the rate freeze period. If the Commission wishes to return to traditional regulatory practices such as accruing AFUDC or including cost of removal in depreciation rates such adjustments should be applied prospectively.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT

AF-1

Exhibit AF-1

CURRICULUM VITAE
ALAN D. FELSENTHAL

EDUCATIONAL BACKGROUND

June, 1971	B.S. in Accounting University of Illinois Champaign, Illinois
May, 1972	Certified Public Accountant

EMPLOYMENT

2008-	Managing Director-Utilities Industry Huron Consulting Group
2002-2007	Managing Director—Utilities Industry PricewaterhouseCoopers LLP
1985-2002	Principal in Utilities and Telecommunications Practice, Arthur Andersen LLP, Chicago
1976-1985	Manager in Utilities and Telecommunications Practice, Arthur Andersen LLP, Chicago
1971-1976	Staff and Senior Accountant, Arthur Andersen LLP, Utilities and Telecommunications Division, Chicago

TESTIMONY EXPERIENCE

Testified before the Illinois Commerce Commission on behalf of Town Gas Company of Illinois, 1985. Accounting witness covering cost of service issues.

Testified before the Illinois Commerce Commission on behalf of Town Gas Company of Illinois, 1986. Generic hearing regarding high gas costs.

Testified before the Florida Public Service Commission on behalf of Central Telephone Company of Florida. Testimony addressed projected test year, a computer model we developed to simplify forecast procedures and propriety of including pension asset in rate base.

Submitted an expert report and testified in an appeal by Yellow Cab Company versus the City of Chicago, (2000). Topic dealt with the adequacy of taxicab lease rates. Yellow Cab was appealing the lease rates they were permitted to charge lessees. The model developed

by the City of Chicago to set lease rates was based on traditional utility ratemaking principles. Was hired by the City of Chicago to review Yellow Cab's appeal compared to traditional ratemaking principles and submit a report. Yellow Cab appealed the decision and a hearing before a judge resulted.

REGULATORY CONSULTING EXPERIENCE

Synopsis—Throughout the late 1970's, the 1980's, 1990's and 2000's assisted Andersen and PwC partners in the preparation of regulatory testimony covering a variety of accounting issues. Much of this testimony involved income tax accounting issues related to flow-through versus normalization or investment tax credit. Also developed testimony on CWIP in rate base and working capital (lead-lag technique), appropriateness of allocation of service company costs to regulated entities and capital structure issues.

Provided assistance on rate case testimony for the following companies:

- Iowa-Illinois Gas and Electric Company
- The Peoples Gas Light and Coke Company
- Nisource, Inc.
- Southern Bell Telephone Company
- Indiana Bell Telephone Company
- Iowa Power
- Iowa Electric
- Ameritech Corporation
- Central Illinois Light Company
- Tampa Electric Company
- Public Service Company of New Mexico
- Reliant Energy
- Tampa Electric
- Central Telephone Company of Florida
- Central Telephone Company of Texas
- Central Telephone Company of Nevada
- Integrys Energy Group, Inc.

Provided regulatory consulting for the Panama Canal Company. Tariffs charged to transit the Panama Canal were based on a cost of service approach. Assisted the Panama Canal Company in determining test year costs. Tariffs were established based on these costs.

FINANCIAL CONSULTING EXPERIENCE

Assisted two Chinese utility companies in registration filings to have their shares traded on the New York Stock Exchange. Huaneng Power International and Shandong Huaneng Power Company were the first two Chinese utilities to list on the NYSE. Process involved working with attorneys, company personnel and the Securities and Exchange Commission to file the equivalent of a Form S-1.

Assisted a number of companies in the preparation, review and filing of Registration Statements with the SEC to raise debt and equity capital.

Consulted with an electric transmission company on whether costs charged to generation companies based on specific costs are in accordance with the costs permitted by the Federal Energy Regulatory Commission.

Consulted with Ameritech Corporation on a number of projects involving cost allocations and compliance with the Federal Communications Commission separations rules.

FINANCIAL AUDIT EXPERIENCE

- Allegheny Energy
- Ameritech Corporation
- Ameritech Cellular
- Ameritech New Media
- Louisville Gas and Electric Company
- Iowa-Illinois Gas and Electric Company
- Centel Corporation
- Constellation Energy
- Nicor, Inc.
- Peoples Energy
- Nisource
- Focal Communications
- Utilities, Inc.
- Chicago Skyway
- United Airlines

LECTURES AND SEMINARS

Speaker at Edison Electric Institute/American Gas Association Intermediate and Advanced Accounting Seminar 1996-2008. Speech on Income Tax Accounting in a Regulated Environment.

Speaker at Power Plan Associates annual conference (2006, 2004, 2002) on recent accounting, regulatory and SEC matters affecting utilities.

Developed and conducted Utilities Industry Basic Accounting and Ratemaking Seminar. This two-day seminar is conducted each year for Andersen, PwC and Huron personnel assigned to utility audits or projects. In addition, the seminar is periodically offered on an open-registration basis for utility company personnel as well as offered and conducted for specific utility companies at their training sites.

Developed and conducted Utility Income Taxes-Accounting and Ratemaking Issues. This two-and-a-half day seminar is conducted each year for Andersen, PwC and Huron personnel assigned to utility audits or income tax projects. In addition, the seminar is

conducted annually on an open-registration basis for utility company personnel as well as offered and conducted for specific utility companies at their training sites.

Developed and conducted Rate Case Experience Seminar. This week long seminar is conducted each year on an open-registration basis for utility company personnel as well as offered and conducted for specific utility companies at their training sites.

Specific examples of special training conducts for utility companies/regulators are as follows:

- Nicor
- Peoples Energy
- Sempra Energy
- Centerpoint
- Nisource
- Cleco Corporation
- Consolidated Edison
- Duke Energy
- Tucson Electric Power
- Portland General
- Pepco Holdings, Inc.
- Ameritech Corporation
- Louisville Gas and Electric
- American Water Works
- Tampa Electric
- Natural Gas Pipeline Company of America
- Transco Pipeline
- Federal Energy Regulatory Commission
- Oklahoma Commission
- Arkansas Commission
- Illinois Commerce Commission
- Sprint Corporation
- American Electric Power
- Consumers Power Company
- Arizona Public Service Company
- Qwest
- Northwest Pipeline
- SBC
- Alaska Regulatory Commission
- Xcel Energy
- Exelon Corporation
- PG&E Corporation

PROFESSIONAL ASSOCIATIONS

American Institute of Certified Public Accountants

Illinois CPA Society

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-0402

Rebuttal Testimony of

Karen G. Kissinger

on Behalf of

Tucson Electric Power Company

April 1, 2008

Executive Summary of the Rebuttal Testimony of Karen G. Kissinger

Ms. Kissinger is the Vice President, Controller and Chief Compliance Officer for UniSource Energy Corporation ("UniSource Energy"). She is also Vice President, Controller and Chief Compliance Officer of Tucson Electric Power Company ("TEP" or "Company"). Ms. Kissinger's Rebuttal Testimony addresses the following matters:

1. **Accounting Under FAS 71.** The Commission was notified on several occasions that the Company would discontinue applying FAS 71 to its generation operations upon signing the 1999 Settlement Agreement. No events since that time would enable the Company to return to accounting for its generation under FAS 71, even though Arizona Public Service did re-adopt FAS 71 after the Track A order was issued. There are significant differences between the two companies' settlement agreements that provided APS significantly greater assurances as to the recovery of its costs as early as 2002. TEP does not have similar conditions in its settlement agreement. The fact that TEP was not eligible to follow FAS 71 given the provisions of its settlement agreement has given rise to many of the differences questioned by the Staff and intervenors in the present case. Because the Company's accounting resulted from the 1999 Settlement Agreement, it is inappropriate to penalize the Company for its accounting during the period of the 1999 Settlement Agreement simply because the Commission does not like the results. Whether the Company is able to once again follow FAS 71 for its generation operations as a result of resolution of this case is unclear; it will depend on how the rates are designed and whether the Company's service territory remains open to competition.

2. **Rate Base Issues.**

   a. **Impact of FAS 143**: The adoption of FAS 143 in January of 2003 had different financial statement implications for TEP than it would have for a company allowed to follow FAS 71 for its generation assets. Because the Company was precluded from establishing a regulatory liability for amounts formerly included in the reserve for accumulated depreciation for cost of removal of generation assets, the amount was recognized in income in 2003. Such amount is not refundable to customers as it was included, as a benefit to customers, in the determination of stranded cost in 1999. No cost of removal amounts have been accrued as a part of generation depreciation expense since 2002 as a result of FAS 143. Only companies eligible to follow FAS 71 may accrue cost of removal as an element of depreciation expense.

   b. **Depreciation Recorded by the Company**: In addition to no longer accruing cost of removal as an element of depreciation expense, the Company made other changes to depreciation rates. The Company added new generation assets which had no depreciation rates previously authorized by the ACC. The Company also extended the lives of some of

its generation assets, based on new information regarding the economic useful lives of these assets. The changes made were the same changes the Company would have made under cost-based regulation. Such depreciation rates were and are just and reasonable. The Company did not seek Commission authorization of such changes. Such authorization was irrelevant because our generation rates were to be competitive and market-based, not cost-based. The linkage of costs and revenues was no longer applicable to generation.

c. **Inclusion of Springerville Unit 1 in Rates**: Springerville Unit 1 generation costs have been recovered in rates through a market-based purchased power arrangement since 1989. Because the initial market-based rate was below cost, the Company recorded losses of $185 million in the 1990s, reducing the financial statement cost of this asset. Now that market rates are higher, parties in this docket want to recover the costs of Springerville Unit 1 based on this lower financial statement value that resulted from the earlier disallowances. This logic is circular at best. The cash costs of operation of Springerville Unit 1 are higher than reflected in the Company's financial records and significantly higher than acknowledged by the parties to this case.

3. **Rate Base Adjustments.** The Company proposes an adjustment to amend its initial filing by adding in plant in service not previously recognized as in service. It also adjusts its calculations for deferred income taxes and accumulated deferred income taxes to more accurately reflect elements of the case. In addition, the Company challenges the appropriateness and/or calculations of various adjustments proposed by Staff and RUCO: Implementation Cost Regulatory Asset (ICRA); Fuel Inventory as a Component of Working Capital; Accumulated Depreciation and Accumulated Deferred Income Taxes for Cost of Removal and Depreciation Changes; Other ADIT and Deferred Credit Adjustments; Luna as Rate Base; and Plant Held for Future Use.

4. **Operating Income Adjustments.** The Company has updated its adjustment for property taxes based on more current information available. In addition, the Company challenges the appropriateness and/or calculations of various adjustments proposed by Staff and RUCO: FAS 143 Cost of Removal Increase to Current Depreciation Rates; Amortization of the ICRA; Property Taxes; and Gain on Land Sales.

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Exhibits

Exhibit KGK-2 2007 Depreciation Study (Generation with Net Salvage)

Exhibit KGK-3 Support for Company Proposed Adjustments

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Karen G. Kissinger and my business address is 4350 East Irvington Road, Tucson, Arizona, 85714.

Q. Are you the same Karen G. Kissinger that previously submitted Direct Testimony on behalf of Tucson Electric Power Company ("TEP" or "Company") in this Docket?

A. Yes.

Q. Have you reviewed the Direct Testimonies filed by the Arizona Corporation Commission Staff ("Staff") and RUCO?

A. Yes I have.

Q. Have you also reviewed the transcripts of the depositions of Mr. Ralph Smith, which took place on March 10, 2008, and Mr. John Antonuk, which took place on March 13, 2008?

A. Yes, I have.

Q. Please provide your general assessment of such Direct Testimony.

A. There appear to be a number of points of confusion as to what happened during the years leading up to the 1999 Settlement and in the years subsequent to the issuance of the order and why certain things were done. A number of these issues relate to accounting facts and circumstances. In that regard, I believe my role is to provide the applicable history for certain transactions and describe the related impacts. Secondly, there are specific adjustments posed by Staff and RUCO witnesses with which I disagree, and certain computational amounts with which I disagree.

Q. Please summarize your rebuttal testimony.

A. I consider my testimony to consist of three primary parts. First, the parties disregard efforts which took place in this state to deregulate electric generation in the late 1990s. They further disregard disclosures related thereto made by the Company. In this testimony, I remind the parties of some of those items.

There seems to be a presumption that the Company should have known in the past that the ACC would decide in 2008 to return TEP to full traditional cost of service rate making and require calculations of amounts as if we had never been transitioning to a competitive market. There was no request for tracking differences between GAAP and ratemaking in the 1999 Settlement Agreement and no concern expressed that perhaps the Company's belief that going off of FAS 71 for generation was inappropriate. There was no indication in the 2004 rate review that the depreciable lives were inappropriate, and no one questioned the depreciation changes disclosed, except for the adoption of FAS143. It is information in their hands today telling them what we should have done over the last nine years; information the Company obviously could not have had at the time. While hindsight provides a nice roadmap, the expectation that TEP should have had foresight that its generation would be re-regulated in 2008 is unreasonable.

Second, there seems to be minimal understanding of the history of Springerville Unit 1 as it relates to its early rate treatment and the ensuing write-offs to a market value below cost. To then in 2008 say that recovery should be based on financial statement cost, when that financial statement cost is a written-down value based on previous market valuations is circular and unfair to say the least. Recovery for Springerville Unit 1 should at a minimum cover the cash cost to TEP to own and operate Springerville Unit 1 at the present time, including the full value of lease payments being paid.

Third, there are adjustments made that I address. Some of the adjustments are late filed adjustments posed by TEP that I explain. These include additions to utility plant in service, and changes to the calculations of deferred income taxes and property taxes. Other adjustments are proposed by Staff and RUCO. For these adjustments, I disagree in whole or in part with various aspects of the calculations and explain the nature of my disagreement.

II. ACCOUNTING UNDER FAS 71.

Q. Did the Company inform the ACC that approving and adopting the 1999 Settlement Agreement would result in TEP discontinuing the application of FAS 71 to its generation operations?

A. Yes. During the 1999 settlement proceedings, TEP repeatedly disclosed that it believed that it had to discontinue application of FAS 71 in the event that the settlement agreement was approved. For example, Mr. Pignatelli discussed this in his direct testimony (at page 9) in the 1999 proceedings. I made the same point in my rebuttal testimony at pages 3 and 5. That point is reiterated in the Company's Post-hearing Brief, at pages 11 and 12: "Upon approval of this order, TEP will be required to immediately go off FAS 71 for accounting purposes and will be required to immediately write down generation assets under FAS 121. Once this occurs, there is no going back."

Q. Was this the first time the ACC had been informed that signing agreements to deregulate the generating assets at Arizona utilities would result in the utilities no longer qualifying to account for their generation assets in accordance with FAS 71?

A. No. This was not new information at all. As a part of opening up the service territories to competition, the ACC held meetings of various Stranded Cost Working Groups. The ACC Staff, with input from affected constituents participating in the Working Groups, then

rendered reports regarding many aspects of deregulating generation assets. Both the Accounting, Financing and Tax Committee Report, dated July 15, 1997 at pages 1-4 and the Report to the Arizona Corporation Commission dated September 30, 1997 at pages 53-59 discuss the potential that deregulation would result in the affected utilities no longer being able to apply FAS 71.

Q. When you were cross examined as a part of the process to approve the 1999 Settlement, were you asked questions as to the implications of going off of FAS 71, or how that might impact the Company?

A. I have recently reviewed the transcript of my cross examination in that case and the only questions related to FAS 71 had to do with the interplay of FAS 71 and the calculation of stranded costs. I also noted that both I and the individuals (including Staff) cross-examining me referred to the signing of the Settlement Agreement as "deregulating generation."

Q. Did anyone who cross-examined you suggest that you should be tracking differences between what you would be recording "on" or "off" FAS 71 in a tracking account, or in some other way?

A. No.

Q. **Did any party who cross-examined you in that case indicate in such cross examination that it might be inappropriate for the Company to discontinue accounting for its generation operations under FAS 71 at that time?**

A. No.

Q. Did ACC Staff witness Antonuk indicate that he agreed with the decision for TEP to discontinue applying FAS 71?

A. Yes. While not an accountant himself, Mr. Antonuk said that he relied upon or consulted with CPA Dennis Kalbarczyk on accounting matters. On page 63 of his deposition, Mr. Antonuk states: "...we certainly reached the agreement that it was appropriate at that time."

Q. ACC Staff witness Smith indicated in his deposition that he believed TEP's decision to go off FAS 71 was "questionable". He also expressed that he is confused as to why APS went back on FAS 71 for generation and TEP did not. Can you help provide perspective on this situation?

A. Yes. I will provide some data points for this through review of public disclosures and also analysis of the Settlement Agreements for APS and TEP.

Q. Are you familiar with the timing of APS going off FAS 71 for generation assets?

A. Yes, APS went off FAS 71 for generation assets in the third quarter of 1999, as disclosed in their Form 10-Q for the quarter ended September 30, 1999. The timing of going off FAS 71 was driven by the guidance of Emerging Issues Task Force Issue 97-4, as shown in the following excerpt:

> "5. Regulatory Accounting
>
> For the regulated operations, APS prepares its financial statements in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements. During 1997, the Emerging Issues Task Force (EITF) of the Financial Accounting

Standards Board (FASB) issued EITF 97-4. EITF 97-4 requires that SFAS No. 71 be discontinued no later than when legislation is passed or a rate order is issued that contains sufficient detail to determine its effect on the portion of the business being deregulated.

In September 1999, the Settlement Agreement with the ACC was approved (see Note 6 for a discussion of the agreement), and, as a result, APS has discontinued the application of SFAS No. 71 for its generation operations. This meant that regulatory assets, unless reestablished as recoverable through ongoing regulated cash flows, were eliminated and the generation assets were tested for impairment. APS determined that the generation assets were not impaired. A regulatory disallowance, which removed $234 million pretax ($183 million net present value) from ongoing regulatory cash flows, was recorded as a net reduction of regulatory assets. This reduction ($140 million after income taxes or $1.65 per basic share and $1.64 per diluted share) was reported as an extraordinary charge on the income statement."

Q. Is this consistent with the timing of when TEP went off FAS 71 for its generation assets?

A. Yes. TEP's Settlement Agreement was finalized in the fourth quarter of 1999 and accordingly, TEP went off FAS 71 in the fourth quarter of 1999 as disclosed in TEP's Annual Report on Form 10-K for the year ended December 31, 1999. This is consistent with the requirements set forth in EITF 97-4, FAS 71 and FAS 101.

Q. Did APS go back on FAS 71?

A. Yes.

Q. Subsequent to the issuance of the Settlement Agreements above, the ACC issued the Track A Order (ACC Decision No. 65154). Please describe the major impact of the Track A Order.

A. The major impact of the Track A Order was that the ACC reversed the mandatory requirement contained in the Settlement Agreements to transfer generation assets to an unrelated third party or a separate corporate affiliate. The Track A Order did not forbid future transfers of generation assets, but any future asset would require Commission approval. Page 23 lines 7 through 13 states:

> "Therefore, we find that the public interest requires that the divestiture requirement found in AAC R14-2-1615(A) and our extensions of that requirement until January 1, 2003, found in Decision Nos. 61973 and 62103, must be modified in the following manner: TEP is granted a waiver of AAC R14-2-1615(A); APS is granted a waiver of AAC R14-1615(A); and both companies are hereby directed to cancel any plans to divest interests in any generating assets. Should either company wish to pursue the divestiture outlined in R14-2-1615(A) in the future, they should file applications to that effect for Commission consideration."

Q. Was the Track A Order cited as a primary reason why APS reapplied FAS 71 for its generation assets in 2002?

A. APS went back on FAS 71 in the third quarter of 2002, as disclosed in their Form 10-Q for the quarter ended September 30, 2002. The primary reason that APS cites regarding this

decision to go back on FAS 71 is the fact that under the Track A Order APS would not be able to transfer its generation assets out of APS:

> "19. Regulatory Accounting
>
> APS is regulated by the ACC and the FERC. The accompanying condensed consolidated financial statements reflect the ratemaking policies of these commissions. For regulated operations, we prepare our financial statements in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements. EITF 97-4 requires that SFAS No. 71 be discontinued no later than when legislation is passed or a rate order is used that contains sufficient detail to determine its effect on the portion of the business being deregulated. In 1999, we discontinued the application of SFAS No. 71 for APS' generation operations due to the 1999 Settlement Agreement with the ACC. See Note 5 for a discussion of the 1999 Settlement Agreement. In the Track A order, the ACC determined that APS would not be able to transfer its generation assets as provided for in the 1999 Settlement Agreement (see Note 5). Accordingly, we now consider APS generation to be cost-based, rate-regulated and subject to the requirements of SFAS No. 71."

Q. Were both TEP and APS impacted by the Track A Order?

A. Yes.

Q. Did TEP also re-adopt FAS 71 when the Track A Order was issued?

A. No.

Q. Can you explain why APS and TEP were not consistent in their determinations as to whether FAS 71 should apply to the generation operations once the Track A Order was issued?

A. While I am not privy to the thought process of APS in their determination that FAS 71 became appropriate for their generation operations, I can identify certain key differences between the facts and circumstances surrounding TEP and APS Settlement Agreements which may be factors in the differing approaches. I would consider these factors to be material differences between the circumstances of the two companies. Please see the table below:

Description	TEP Order 62103	APS Order 61973
Settlement Agreement Date	June 9, 1999	May 14, 1999
Rate Freeze Period	Through December 31, 2008	Through July 1, 2004
System Open to Competitive Retail Access	January 1, 2001	January 1, 2001
Adjustment Clause for POLR and Standard Offer	No	Yes (page 12, lines 20-27)
Effective Date of Adjustment Clause	N/A	July 1, 2004
Commission Filing after Settlement Agreement	June 1, 2004 only for purposes of rate decrease	June 30, 2003 for rate case

My main overall observations on this comparison are: 1) APS' period of rate freeze was much shorter in duration than TEP's, and 2) APS Settlement Agreement provided for an adjustment clause to insulate APS from purchased power cost fluctuation to provide service to POLR (Provider of Last Resort) and Standard Offer customers while TEP had

no such adjustment clause. APS was therefore in a much better position to claim that its generation costs would be recovered in regulated rates, and thus to potentially revert to FAS 71.

Q. Does APS cite any other key factors in their 10-Q for the quarter ended September 30, 2002 related to their regulatory situation?

A. Yes. They also cite the proposed Track B proceedings which would only require competitive procurement of electricity for that portion of their needs which could not be supplied by its own resources. Also, APS disclosure makes it clear that their intent in their financing application filed with ACC on September 16, 2002 was that they want to bring APS generation and Pinnacle West Energy assets under a "common financial and regulatory regime".

Q. What else does APS mention?

A. Per the 10-Q, "APS stated that it did not intend or desire to foreclose the possibility that it would acquire all or part of the Pinnacle West Energy Assets or that it may propose that the Pinnacle West Energy Assets be included in APS' rate base or afforded cost-of-service regulatory treatment to the extent the Pinnacle West Energy Assets are used by APS customers. APS stated that these issues would be appropriate topics in APS' 2003 general rate case and noted that the Track an Order specifically stated that the ACC would not pre-judge the eventual rate treatment of the Pinnacle West Energy Assets."

Q. What do you observe related to this statement?

A. It appears, based on my reading, that APS' intent was to get generation assets re-established in rate base in the 2003 rate case they were required to file. This intent is consistent with their disclosure that they are now going back on FAS 71 for their

generation segment. This was less than a year from when APS would seek recovery of these generation assets in rate base.

Q. How does this compare to TEP's position in late 2002?

A. TEP still had to comply with a rate freeze for an additional six years. This placed TEP in a position with no guarantee of recovery of generation related costs. Furthermore, since no adjustment clause was included in TEP's Settlement Agreement, TEP still considered its generation segment to be deregulated. Further, as of today, TEP still has no regulatory pricing mechanism that provides for recovery of its generation costs on a cost of service basis.

Q. On page 68 of his deposition, Staff Witness Smith says that as long as TEP has net income, it has recovered its depreciation expense, implying that all costs have been recovered in such a situation. Is he correct?

A. Not necessarily. In the context of FAS 71, return on investment is a cost as defined in FAS 71 and indeed it is included in the ACC's "cost of service" computation. During the 2000-2008 period TEP did not have rates for generation designed to recover its actual costs of service for generation including a reasonable return on investment. The rate freeze following a rate decline in 1999 was designed to have generating assets operate in the competitive market (Decision No. 62103, page 4).

Q. Have parties to this current case indicated a desire for the Company to begin accounting for its generation operations pursuant to FAS 71 again?

A. If my understanding of the testimony of Staff and RUCO is correct, both parties believe it would be appropriate for that to happen.

Q. Do you think a possible result of this case is that TEP will re-adopt FAS 71 for generation operations?

A. It is possible, but I can't say that I know whether it is probable. The Staff and intervenors call for a return to cost of service ratemaking for purposes of setting rates. If rates are so calculated as a result of this case, that would address one of the three requirements of FAS 71. As stated in my direct testimony in this case, there are three requirements in FAS 71:

- an independent regulator sets rates;
- the regulator sets the rates to recover specific costs of providing service; and
- the service territory lacks competitive pressures to reduce rates below the rates set by the regulator.

We will have to make the decision at the time of the order based upon a review with our independent auditors of all of the facts and circumstances in existence. FAS 101 provides specific guidelines on how and when to stop applying FAS 71. Unfortunately, there is no similar guideline on what circumstances are required, what specific actions to take, or when to start applying FAS 71 again. We believe that the cost-of-service case could provide the first two elements that would allow the Company to begin recording transactions in its generation operations following FAS 71; however, there are several issues that the Company and its auditors would need to evaluate:

- Will the Commission explicitly declare that either deregulation continues or that it is dead?
- Will the service territory be open to competition and in what form?
- How will the Commission treat generation in its ratemaking?
- How will fuel and purchased power costs be recovered?
- What is the timing and form of recovery of the TCRA?
- Will there be another extended Rate Freeze? Extended rate freezes may imply rates are not set to recover specific costs of service.

- What adjustments will the Commission make to the cost of service case?

Q. Do Staff's witnesses comment on whether the Company's service territory is open to competition upon the completion of this case?

A. Yes. Commission Staff Witness Antonuk makes the statement "Staff concludes that TEP's Certificate of Convenience and Necessity should be regarded as exclusive." I cannot tell if he thinks we ought to act like the Company has its exclusive CC&N back, or whether he is recommending that TEP formally receive such exclusivity. Moreover, Staff Witness Radigan, in his rate design testimony (at page 12), states that "The Company is completely regulated, and in this case, Staff is proposing that the commission recognize TEP as an exclusive provider." That fact could be important in the determination as to whether TEP goes back on FAS 71 as a result of this case.

Q. How does the conclusion that TEP appropriately discontinued applying FAS 71 to its generation segment in 1999 and remains off to this day affect this proceeding?

A. FAS 71 requires accounting for the effects of regulation. Because our rates our no longer cost based, we discontinued applying FAS 71 and had to follow GAAP as it pertains to enterprises in general. We were no longer able to record regulatory assets and regulatory liabilities. I cover these effects in Section III of my rebuttal testimony.

III. RATE BASE ISSUES.

A. Impact of FAS 143.

Q. When did the Company adopt FAS 143 for financial accounting purposes?

A. The Company adopted FAS 143 in January of 2003.

Q. **Did the Company have a choice in adopting FAS 143 for financial statement purposes?**

A. All Companies had to adopt the standard by no later than the annual financial statement periods beginning after June 15, 2002. Earlier adoption was permitted.

Q. What about for reporting pursuant to the FERC Uniform System of Accounts?

A. In 2003 the FERC adopted FAS 143 as a part of its Uniform System of Accounts. The ACC rules require utilities under their jurisdiction to follow the FERC Uniform System of Accounts. See A.A.C. R14-2-212.G.2. Thus, the ACC's own rule required TEP to adopt FAS 143 because it is now part of the FERC Uniform System of Accounts. Filing for approval by the ACC for TEP to adopt FAS 143 would have been superfluous.

Q. Did the Company disclose its adoption of FAS 143 to the Commission?

A. Yes. The documents that the Company files with the ACC showing financial results for 2003 reflected such adoption as income. Also, on page 3 in my testimony filed in the 2004 Rate Review (Docket No. E-01933-04-0408), I noted that the Company had adopted FAS 143 at the beginning of 2003 and that the ramifications of such adoption would have been different had we still met the criteria to apply FAS 71 to TEP generation operations.

Q. What was the key impact on public utilities of adopting FAS 143?

A. Public utilities in many states for years had been recovering through depreciation rates an estimated cost for final removal of productive assets. The utilities and their commissions recognized that assets would eventually be removed from service, and the cost to remove those assets should be charged to the parties receiving the benefit of those assets. FAS 143 established that liabilities should be recorded only for those amounts which were legally binding asset removal obligations. All other removals should be recognized as expense at the time the removal actually occurred. No amounts were allowed to continue to be reported as a part of depreciation in GAAP financial statements.

Q. What generally happened to amounts collected through rates for the "non-legally binding" removal obligations?

A. Utilities that met the requirements to follow FAS 71 in their GAAP financial statements removed the amounts from accumulated depreciation and established regulatory liabilities for the amounts. Utilities not meeting the requirements of FAS 71 were required to recognize such amounts in income. When retirement would occur in the future, the entire amounts spent would have to be recognized as expense in their income statements. TEP fell in that latter category for its generation assets. It fell into the former category for its transmission and distribution assets.

Q. Both Staff and RUCO witnesses have asserted that the amounts recognized in income for the generation assets should be established as a regulatory liability by the Company. Do you agree with that assertion?

A. No. That result would ignore the underlying facts. Prior to 2003, all amounts collected for cost of removal less salvage were recorded in accumulated depreciation. The Company calculated its estimate of stranded costs in 1998 and provided them to ACC staff. In such calculations, the Company compared its estimated future cash flows to be

received from market-based rates for its generation assets (both leased and owned) to the recorded net book value of such generation assets, both leased and owned. The difference between those two numbers was TEP's estimate of stranded costs. The book value in the comparison was the net book value of the assets (both leased and owned) as of December 31, 1997. At that time, TEP had $107 million in net cost of removal recorded in accumulated depreciation for its generation assets. Had that amount not been recorded in accumulated depreciation, the net book value of the Company's generation assets would have been $107 million greater, as that cost of removal reduced the net book value of the assets recorded in 1997. That would have meant, in turn, that the amount of stranded cost calculated would have been $107 million greater, if there were no offset for costs of removal. The calculation of the stranded cost amount is discussed in greater detail in the testimony of Mr. Grant. In effect, the regulatory asset for stranded cost has already been reduced by the Staff's proposed regulatory liability.

Said another way, the Fixed CTC calculation would have been $557 million were it not for the consideration of the $107 million cost of removal, which reduced the net Fixed CTC to $450 million. In effect, there was a regulatory asset of $557 million that ratepayers would pay offset by a regulatory liability that would be refunded to ratepayers of $107 million. The net $450 million was presented as a net regulatory asset in our financial statements.

Q. So what are the implications of the fact that the removal cost obligation reduced the book value of the generation assets?

A. The $107 million amount of cost of removal has already been returned to the customers. To set up a regulatory liability as proposed by Staff would benefit the customer twice for the same cost.

Q. What about post 1997?

A. The Company continued to accrue cost of removal for generation assets through 2002, then reversed those amounts at the beginning of 2003. So, there is no cost of removal for generation assets recorded as an element of expense for periods subsequent to 1997.

Q. Is the Company open to accruing cost of removal as an element of expense again?

A. The answer is yes, assuming the various elements of the overall rate order support the Company again being able to adopt FAS 71 for its generation assets. Without adopting FAS 71, the Company would be unable to record the cost of removal as an element of depreciation.

Q. What happens if the ACC would have the Company accrue cost of removal for generation assets for periods subsequent to 1997 but prior to 2009?

A. Since no amounts were actually recorded by the Company for such years, the amount determined to be appropriate for such years should be added together with the other elements of expense not recovered which are reflected in the TCRA calculation. In other words, any amount calculated would have to be additive to the TCRA balance already computed. The totality of the Company's revenue forgone during the rate freeze should be viewed together, not in isolated parts. If TEP is to return to cost-of-service ratemaking for generation operations, the ratemaking should consider the totality of the events that transpired during the period of transition to deregulation, including such factors as the fact that the Company had no fuel and purchased power clause during such period, the level of capital expenditures for generation required to be expended during the period, and other factors related to operations.

Q. If the Company is told to develop amounts for years post 1997, what facts should be considered?

A. I do not believe that the calculation of cost of removal for years post 1997 should be based on the depreciation rates in the 1996 Settlement Agreement. The amounts calculated should be based on the depreciation rates actually used by the Company during those years. The removal rates of 17% for steam production and 11% for other production would likely still be appropriate. I have no evidence to the contrary for the removal rates. Assuming that no adjustment is made to depreciation expense or rates for periods prior to 2009, a new schedule of depreciation rates, based on the Company's currently proposed depreciation rates, but increased to include the removal rates stated above, appears in Exhibit KGK – 2, attached to this rebuttal testimony. This Exhibit is more fully discussed later in my testimony.

B. <u>Depreciation Recorded by the Company.</u>

Q. Does Mr. Smith bring up any ACC depreciation guidance in his testimony?

A. Yes. In his testimony at page 36, Mr. Smith quotes from the Settlement Agreement in TEP's 1995 rate case (approved by Decision No. 59594 (March 29, 1996) ("1996 Rate Settlement") that "TEP's depreciation rates may be changed from time to time in accordance with results of depreciation studies performed by TEP with such changes to thereafter become effective upon Staff's approval. The Commission shall not be bound to adopt for ratemaking purposes any changes in depreciation rates made pursuant to this provision."

Q. What are your concerns about this reference?

A. It cannot and should not apply upon the subsequent adoption of the 1999 Settlement Agreement. The quoted language refers to making depreciation changes – which may or

may not be later adopted for ratemaking. If the changes are not for ratemaking, by default the changes must be for financial accounting purposes only. At the time of the 1996 Rate Settlement, the Company could still meet the requirements to follow FAS 71 for its generation assets. This meant that the Company could still calculate and report in its GAAP financial statements depreciation expense as approved by its commission. Once the settlement agreement was signed, the Company could no longer follow FAS 71 for its generation assets, and had to make depreciation changes as any un-regulated company would. With all due respect to the Commission, it cannot set GAAP for deregulated generation assets. GAAP is set by the Financial Accounting Standards Board, and amplified for publicly traded companies by rules of the Securities and Exchange Commission.

Q. During the period since the depreciation study approved in the 1996 Rate Settlement, what kind of generation depreciation changes did the Company make, besides adopting FAS 143?

A. Two different kinds of depreciation changes were made:

Group A: New Assets

The Company added peaking gas turbines for which there would have been no depreciation rates in place from the 1996 depreciation study. These units were installed at DeMoss Petrie and North Loop in 2002. In 2006, a jointly owned base load gas turbine was added at Luna. Quite simply, there have never been "commission approved" depreciation rates for such assets.

Group B: Change in Lives

The lives of steam generating stations were extended in 2002, 2004 and 2005 for assets at Sundt, Springerville and San Juan generating stations. In the second quarter of 2002, TEP changed its depreciation rates to reflect twenty-year life extensions for gas-fired steam production units at its Sundt Generating Station and fifteen-year life extensions for

gas-fired internal combustion turbines. During 2004, TEP engaged an independent third party to review the economic estimated useful lives of its owned generating assets in Springerville. Based on that information, combined with plant life information provided by the operators and participants of the joint generating plants in which TEP participates, new depreciation rates reflecting service life extensions ranging from 11 to 22 years were implemented in July for Springerville owned generation. Finally, during the second quarter of 2005, a study requested by the participants in the San Juan Generating Station was completed that indicated an economic useful life changed from previous estimates. As a result, new depreciation rates reflecting an extension of the estimated useful life of 20 years were implemented April 1, 2005 for San Juan generation assets.

Q. **Before 1999, if you added new classes of generation assets between rate cases, how were they accounted for?**

A. If we added a new class of assets, we would begin depreciating them based on engineering estimates as to useful lives. At the next rate case, we would provide the economic useful life information to the person performing the depreciation study, and that individual would perform an analysis. The study would either confirm or modify the original presumption. The original depreciation recorded by the Company would be followed by the Company until the Commission issued a rate order changing it. Historically, the Commission has adopted the concept of remaining life depreciation rates, which means that differences in estimating lives and net salvage are spread prospectively, not retroactively adjusted.

Q. So what would that lead you to believe for the DeMoss Petri, Luna and North Loop assets you describe in group A?

A. There is no difference between how TEP determined the useful life and began depreciating them from when TEP was under FAS 71, except for no longer accruing cost of removal.

Q. How would TEP have accounted, before 1999, for the changes you describe as Group B, where you changed existing useful lives?

A. We would have developed the new information that led to a different economic life, but would not have implemented the depreciation change until affirmed by the ACC in a rate order.

Q. Did you communicate the changes in depreciable lives to the ACC?

A. The changes are reflected in the annual filings we make with the ACC each year. The annual reports for 2002 through 2006 had the Company's Form 10-K for each year attached. In those Forms 10-K, the depreciation changes are disclosed on the following pages:

- 2002 10-K: Page K-82
- 2003 10-K: Page K-102
- 2004 10-K: Page K-114
- 2005 10-K: Page K-124
- 2006 10-K: Page K-120

More specifically, in my testimony in the 2004 Rate Review docket, footnote 1 on page 43, I identified that we had made depreciation changes and would make them again in the future, if we obtained data that indicated a change was appropriate and our auditors concurred in such changes.

Q. In the testimony of the Staff and intervenors in the 2004 Rate Review, did anyone suggest that the Company had recorded too little depreciation expense in the test year because you had lengthened the useful lives of certain assets?

A. No. The only depreciation issue raised was that Staff and RUCO felt the $112 million gain recorded on adopting FAS 143 should be reversed.

Q. What seems strange to you about the claims now that the depreciation life changes were inappropriate?

A. Two things seem strange to me. First, the changes we made were exactly the same kind of changes we would have sought to make in rate cases, if we had been having rate cases. They were life extensions – something I do not recall a commission turning down in a depreciation study. Life extensions typically reduce depreciation expenses, and thus generally result in a lower revenue requirement.

Second, since we were in a rate freeze and were expecting competition for generation at the end of the freeze, we were not expecting a return to regulatory accounting for generation. There seems to be a presumption that the Company should have known in the past that the ACC would decide in 2008 to return TEP to full traditional cost-of-service rate making and require calculations of amounts as if we had never been transitioning to a competitive market. There was no request for tracking differences between GAAP and ratemaking in the 1999 Settlement Agreement. Nor was concern expressed in response to the Company's repeated, clear statements in the 1999 proceedings that it would be going off of FAS 71 for generation. There was no indication in the 2004 rate review that the depreciable lives were inappropriate, and no one questioned the depreciation changes disclosed, except for the adoption of FAS143. It is information in their hands today telling them what we should have done over the last nine years; information the Company obviously could not have had at the time. While

hindsight provides a nice roadmap, the expectation that TEP should have had foresight that its generation would be re-regulated in 2008 is unreasonable. Moreover, the Commission has not yet determined whether to re-regulate TEP's generation and the disputed questions about the meaning and effect of the 1999 Settlement Agreement have not yet been resolved.

C. Inclusion of Springerville Unit 1 in Rates: History of Springerville Unit 1 Accounting.

Q. There seems to be some confusion among the parties as to the history of the accounting for the Company's lease of Springerville Unit 1. Please provide a brief overview.

A. Springerville Unit 1 generation costs have been recovered in rates through a market-based purchased power arrangement since 1989. Because the initial market-based rate was below cost, the Company recorded losses of $185 million in the 1990s, reducing the financial statement cost of this asset. Now that market rates are higher, parties in this docket want to recover the costs of Springerville Unit 1 based on this lower financial statement value that resulted from the earlier disallowances. This logic is circular at best. The cash costs of operation of Springerville Unit 1 are higher than reflected in the Company's financial records and significantly higher than acknowledged by the parties to this case.

Q. Please provide the history in more detail.

A. Tucson Electric Power began taking power from Springerville Unit 1 during the 1980s under a purchased power agreement with Alamito Company, a former affiliate of TEP. Because of the related party nature of the transaction, in a 1989 rate order the Commission set rate recovery for this purchased power agreement based on a

comparative arm's length purchased power agreement, which reduced the Company's recovery to $15/kw/mo, as discussed in the rebuttal testimony of Mr. Hutchens. Because the Company's costs under the purchased power arrangement were in excess of $15/kw/mo, the Company recorded a loss (an expense) of approximately $178 million, which represented the net present value of the loss that would be incurred over the anticipated life of the purchased power agreement. This calculation assumed the Company never recovered more than the initial $15/kw/mo, as there was no way to know whether future market rates would be higher than $15/kw/mo.

Q. Does TEP continue to take power from Springerville Unit 1 through a power purchase agreement?

A. No. During the financial restructuring of TEP in 1992, TEP assumed the Springerville Unit 1 lease as a direct obligation. TEP became the direct lessee, and there was no more purchased power arrangement. TEP recorded an additional $7 million of loss for Springerville Unit 1 lease costs, because TEP's obligations under the lease were now for the full life of the lease agreement, not just for the term of the purchased power agreement. Therefore, the basis on which TEP is recording depreciation of this asset, then and now, is $185 million less than the amount would have been without a disallowance.

Q. So do you believe the costs currently reflected in the Company's income statement for 2006 represent the cost to the Company for the lease of that asset?

A. No. The Company's actual cash cost of the Springerville Unit 1 lease is the amount of lease payments made over time, plus the costs of the leasehold improvements installed by the Company over time, together with the associated operating and maintenance costs and property taxes. Because the $15/kw/mo initial allowed recovery included the allocable costs of the Springerville coal handling facilities, the cost of Springerville Unit

1 also includes 50% of the costs associated with the lease and operation of the Springerville Coal handling facilities in addition to the leasehold improvements related to Springerville Unit 1. Therefore, the costs of Springerville Unit 1 as represented by Ms. Diaz Cortez are inaccurate.

Q. Can you quantify the costs of operating Springerville Unit 1?

A. Yes. The table below summarizes the costs. Following the table, I will then describe the amounts included in the table.

Springerville Unit 1 Operating Costs	Annual Dollar Amount ($000s)
(A) Springerville Unit 1 Lease Payments	$ 81,066
(B) Half of non-fuel Coal Handling Facilities Lease	5,652
(C) Depreciation on Leasehold Improvements	7,265
(J) Depreciation on Unit 1 Delayed Plant	161
(D) Operating & Maintenance Expense per General Ledger	23,103
(E) Property Tax Expense	5,890
(J) Property Tax on Unit 1 Delayed Plant	106
(F) Levelized Overhaul Expense Reduction	(2,410)
Total Operating Costs	$120,833
Additions to Rate Base	12/31/06 Balances ($000s)
(G) Leasehold Improvements for Unit 1	$92,524
(J) Unit 1 Delayed Plant	4,386
(H) Less Accumulated Depreciation on Leasehold	(30,368)

Improvements	
(J) Less Accumulated Depreciation Unit 1 Delayed Plant	(132)
(I) Less ADIT for Springerville Unit 1 Leasehold Improvements	(7,939)
(J) Less ADIT for Unit 1 Delayed Plant	(77)
Total Increase to Rate Base	$58,394

Q. Please explain the costs included in the preceding table.

A. (A) represents the annual average lease payment due on Springerville Unit 1 for the period 2009-2014. The year 2014 represents the end of the lease term. The actual lease payments vary by year in this period from $30 million to $151 million, so the table reflects the average amount per year. If the Commission wants Springerville Unit 1 to be considered a "FAS 71" asset as a result of this rate case, its cost recovery would have to be based on the costs to be incurred for the time period the rates would be effective. These costs are known and measurable. The average annual Springerville Unit 1 lease payment for the period 1992 through 2014 is $69,521,000.

(B) reflects one half of the non-fuel related levelized lease cost for the Springerville Coal Handling Facilities. TEP replaced this item in the test year filing with a market-based purchased power cost.

(C) reflects the annualized depreciation expense for the leasehold improvements related to the leases, using end of test year plant balances. TEP replaced this item in the test year filing with a market-based purchased power cost.

(D) reflects actual test year operating and maintenance expenses for Springerville Unit 1. TEP replaced this item in the test year filing with a market-based purchased power cost.

(E) reflects the annualized property tax expense for Springerville Unit 1, computed on the same basis as the Company's updated property tax adjustment. TEP replaced this item in the test year filing with a market-based purchased power cost.

(F) reflects an overhaul levelization amount using the same methodology as used for developing the adjustment for the remaining generation units. Since we remove Unit 1 costs from cost of service to substitute the market rate, no overhaul levelization amount was previously computed for Springerville Unit 1. The test year maintenance expense number in (D) included $4.6 million of major overhaul costs, which are reduced to the $2.2 million normal levelized amount.

(G) represents the capitalized leasehold improvements which are removed from rate base when we substitute the market-based purchased power basis for Unit 1.

(H) represents the accumulated depreciation associated with the removed capitalized leasehold improvements which we eliminate from rate base when we substitute the market-based purchased power basis for Springerville Unit 1.

(I) represents the ADIT for Springerville Unit 1 leasehold improvements and half the coal handling facilities leasehold improvements.

(J) represents additional costs identified in the Delayed Plant Unitization Adjustment described at Section IV B of this testimony which relate to Springerville Unit 1.

Q How do the Springerville Unit 1 costs described above compare with Mr. Smith's proposed recovery approach?

A. Mr. Smith proposes TEP recover Springerville Unit 1 generation costs at $15/kw/mo. Applied to our estimated output, he has included $68,400,000 as shown on Smith's Schedule C-1. Thus, Mr. Smith's approach allows slightly more than half of the Springerville Unit 1 operating costs. When a return on the rate base additions are included, the gap between the amounts proposed by Mr. Smith and our total Springerville Unit 1 costs widens even more. Recovery for Springerville Unit 1 should at a minimum

cover the cash cost to TEP to own and operate Springerville Unit 1 at the present time, including the full value of lease payments being paid.

Q. Did Mr. Smith mention that he believes that there is an alternative recovery path for Springerville Unit 1?

A. Yes. On page 51 of his direct testimony Mr. Smith indicates that an alternative might be to treat Springerville Unit 1 as a capital lease for ratemaking purposes. Ratemaking would be simpler for TEP if it could treat capital leases for GAAP as capital leases for ratemaking. TEP has a few leases, and fewer adjustments would be required in that event.

Q. **Are there any problems with Mr. Smith's alternative?**

A. Yes. ARS 40-302(E) appears to preclude that option. This statute states in part:

> "E. The Commission may not authorize the capitalization of the corporate franchise... nor shall any ... lease be capitalized...."

For this reason, TEP has requested recovery of its capital leases other than Springerville Unit 1 since 1990 on the basis of levelized lease payments, believing that is the intent of the statute. Such filings have been accepted by the Commission as appropriate ratemaking. For ratemaking, we have used this method since we entered into the leases other than Springerville Unit 1. Springerville Unit 1, in contrast, has consistently been recognized in ratemaking as a market-based purchased power agreement by the Commission.

Q. Do you have any other comments about RUCO's proposed adjustment to deny the use of the traditional capacity allowance approach to recovering the cost of Springerville Unit 1?

A. Yes. In our initial filing, to reflect the capacity allowance adjustment, we removed the end-of-test year balance of leasehold improvements at Springerville Unit 1 and an allocable portion of Springerville Coal Handling Facilities. We also separately removed the related accumulated deferred incomes taxes associated with both as part of our ADIT adjustment. In connection with its proposed rejection of the capacity allowance approach, RUCO added back to rate base the same amount of plant in service ($92 million) and accumulated depreciation ($30 million) that we had previously removed. Additionally, RUCO added back $1,764,000 of accumulated deferred income taxes that relate to the portion of the Springerville Coal Handling Facilities allocable to Unit 1. They failed, however, to also add back the ADIT associated with Unit 1 leasehold improvements. An additional $6,174,863 of ADIT should have been added back as part of the RUCO adjustment.

IV. RATE BASE ADJUSTMENTS.

A. Implementation Cost Regulatory Asset ("ICRA").

Q. On Pages 23 to 28 of his testimony, ACC Witness Ralph C. Smith, proposes to reduce the Implementation Cost Regulatory Asset ("ICRA") from $47,455,224 to $14,214,843, resulting in decrease to rate base of $33,242,381. RUCO Witness Ms. Diaz Cortez makes a similar adjustment on pages 12-13 of her testimony. Do you agree with their adjustment?

A. No.

Q. Which ICRA regulatory assets does he disallow?

A Mr. Smith and Ms. Diaz Cortez are proposing to eliminate the TEP ICRA amounts related to the San Juan Coal Contract Amendment, the Sundt Coal Contract Termination and Financing Costs – Generation.

Q. What is Mr. Smith's basis for disallowing these costs from the ICRA?

A. Mr. Smith states that "As a general matter, TEP should not be allowed to set up new regulatory assets for costs that the Company expensed in prior years and in instances where TEP had neither requested, nor received Commission approval for deferral" (Smith Direct, page 24, lines 3-5) .

Q. Do you agree with his conclusion regarding the disallowed costs?

A. No, on several fronts. First, if TEP generation assets return to cost based regulation as a result of this proceeding, ratepayers will directly benefit from reduced expenses as a result of incurring these costs. Second, Commission pre-approval of the recording of regulatory assets is not a requirement for cost recovery in a future rate proceeding as Mr. Smith states. Third, it is not uncommon for items expensed in an earlier period to become regulatory assets in a later period under appropriate circumstances. I will address each of these in detail below.

Q. Can you please explain what the 1999 Settlement Agreement provided for in the way of ICRA?

A. Yes. Section 4.6 of the 1999 Settlement Agreement states "TEP shall defer for future recovery its cost to implement Competitive Retail Access. The Commission shall authorize TEP to recover its reasonable and prudently incurred Competitive Retail Access implementation costs as a plant cost and/or deferred debit subject to review in the TEP June 1, 2004 filing (as discussed in section 5.2 below)".

This language is quite specific and clear that Competitive Retail Access costs can be deferred and recovered. There is no requirement whatsoever to obtain specific additional approvals for such costs in order for them to be recovered.

Q. Are the requested items allowable as regulatory assets?

A. Yes. Clearly the Deferred Direct Access Costs, Deferred Divestiture Costs and Deferred GenCo Separation Costs qualify as costs incurred to implement Competitive Retail Access and, as previously described in my testimony, each is recoverable under the ICRA. But for the 1999 Settlement Agreement, TEP would not have incurred those costs. The remaining items are appropriate generation-related regulatory assets and recoverable in this proceeding in connection with a return to cost-based regulation for the generation segment of our business.

Q. Do these items benefit ratepayers if TEP's generation assets become rate regulated as a result of this proceeding?

A. Yes.

Q. How do the San Juan Coal Contract Amendment and the Sundt Coal Contract Termination fees benefit ratepayers?

A. The San Juan Coal Contract Amendment and the Sundt Coal Contract Termination fees were costs incurred to lower TEP's overall fuel costs. As this proceeding is reestablishing a PPFAC, the ratepayers will benefit from these costs through lower coal costs included in the PPFAC, or through lower base rates, depending upon how the PPFAC is ultimately structured. To allow the ratepayers to enjoy the benefit of lower fuel costs without consideration of the one-time costs to realize these benefits is unfair.

Q. How should the Financing Costs – Generation be handled?

A. These costs have a similar fact pattern to the coal contract costs. Because TEP's generation assets may now become rate regulated once again, the interest component of the overall return is lower as the result of TEP incurring these generation-related debt costs. There is a disconnect if the ratepayers enjoy the lower interest costs without consideration of the financing costs which generated these benefits. Permitting recovery of the one-time cost incurred to lower ongoing interest costs is very common and another example of an equitable arrangement. Ratepayers receive benefits (lower interest expense) but the cost to achieve the lower interest expense should also be borne by the ratepayer. To do otherwise requires shareholders to pay for costs while the ratepayers receive benefits of reduced costs—a totally unfair result.

Q. Do you agree with Mr. Smith's contention that TEP failed to request regulatory asset treatment for such costs and such amounts had not been recorded as regulatory assets and therefore they should be denied recovery in this proceeding?

A. No. As I summarize above, TEP's generation assets from 1999 until now have not been subject to FAS 71. The 1999 Settlement Agreement explicitly approved recovery of prudently incurred costs to implement retail access and TEP recorded regulatory assets for Deferred Direct Access Costs, Deferred Divestiture Costs and Deferred GenCo Separation Costs under the Settlement Agreement. Mr. Smith does not take exception to these amounts.

A similar standard should govern the recovery of other prudently incurred costs that benefit ratepayers. There is no contention by anyone that these costs were not prudent, and disallowing them now on the basis of not having received prior approval is unfair and unreasonable. There were sound reasons why we did not seek permission to defer these

costs at the time and why such amounts have not previously been recorded as regulatory assets.

Q. What portion of FAS 71 provides guidance on whether or not you can record regulatory assets?

A. Paragraph 9 of FAS 71 which states:

> "Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An enterprise shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:
>
> a. It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes.
>
> b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost."

Q. What was your conclusion at the time these costs were incurred?

A. First, because the generation segment of our business was competitive and effectively deregulated, Commission approval to defer such costs was not necessary. Second, because the generation portion of our business was deregulated and competitive and off SFAS No. 71, TEP could not record regulatory assets for these costs as we could not demonstrate that future recovery of these amounts was probable.

Q. What is the basis for now treating these amounts as regulatory assets?

A. The overarching theme of Staff and RUCO's case in this proceeding is the premise that generation rates will become rate regulated as a result of this proceeding. Furthermore, a PPFAC will be established as a result of this proceeding. Under this premise, TEP is requesting these amounts be recovered in rates, that recovery is probable and then TEP can establish such amounts as regulatory assets. The fact that these costs were incurred in prior years is irrelevant.

Q. Can you elaborate on why TEP was not required to request deferral of these amounts from the Commission when they were incurred?

A. Yes. The generation rates were no longer cost-based rates regulated by the Commission at the time these costs were incurred. Our generation rates were to be competitive and market-based, not cost-based. The linkage of costs and revenues was no longer applicable to our generation segment. As such, Commission approval of amounts was not required nor was it relevant. However, if the Commission decides to re-regulate generation, it should recognize these items as regulatory assets, as they will benefit customers upon a return to cost-based regulation.

Q. Why could you not demonstrate that recovery of these incurred costs was probable and record them as regulatory assets?

A. The probability threshold in FAS 71 requires more than a 50.01% likelihood. The "probable" standard for recording regulatory assets is "likely to occur." Our generation assets were no longer under traditional cost based regulation. There was no longer a linkage between costs and revenues and there was no recovery mechanism available for us to be able to demonstrate we could recover these costs. We concluded, however, that if we were ever to return to cost based regulation with a mechanism to recover these

specific costs, we could record a regulatory asset when recovery met the probable standard.

Q. Could you have recorded a regulatory asset for these items on your regulatory books in accordance with the Uniform System of Accounts?

A. No. The FERC Uniform System of Accounts has adopted the GAAP definition of probable for recording regulatory assets. FERC Order 552 provides the basis for recording regulatory assets in the Uniform System of Accounts.

Q. Mr. Smith suggests that TEP should have sought prior Commission approval to establish these costs as regulatory assets. Do you agree?

A. No. As previously stated, with the Settlement Agreement, our generation was de-regulated and subjected to competition. Given that our generation segment was subject to a competitive market, there was no reason to seek Commission approval at the time to defer costs because there was no mechanism to recover these costs through market based rates.

Q. If the Commission had approved an order to set up regulatory assets for these items would TEP have recorded regulatory assets for GAAP?

A. No. To record a regulatory asset the asset recovery must be probable. A Commission order that does not provide evidence that costs are probable of recovery does not provide sufficient basis to record a regulatory asset even for operations that apply FAS 71. As we did not apply FAS 71 to generation operations, we cold not record a regulatory asset even if it were "probable" of recovery.

Q. Is Mr. Smith's assertion that because you did not record a regulatory asset at the time you cannot recover that cost in this proceeding logical?

A. No. In fact, it is quite illogical and unfair to TEP. Staff's position effectively penalizes TEP for adhering to the letter and the intent of the 1999 Settlement Agreement. We had discontinued the application of FAS 71 and thus were not permitted to record regulatory assets. Only entities that meet the requirements of FAS 71 can record regulatory assets. Even if we had not discontinued application of FAS 71, in order to record a regulatory asset, we have to demonstrate that recovery is "likely to occur." We could not do that at the time because there was no recovery mechanism due to deregulation. This is illogical and, if adopted, would prevent recovery of any cost incurred during a rate freeze or period of deregulation where evidence supporting the initial probability determination could not be justified.

Q. Would an accounting order from the Commission have been justification to record a regulatory asset?

A. Likely not. An accounting order is just that—permission to defer a cost until a later proceeding where that cost could be reviewed in detail. As the Commission is aware, just because a cost is deferred in one period does not mean that it will be permitted recovery in a future period. The best evidence of probability of recovery is a rate order or tracker permitting recovery of the specific cost. Recovery of a similar cost, recovery by a neighboring utility and the amount of the cost all enter into the probability determination. An accounting order by itself is typically not sufficient to meet the probability standard.

Q. Can you cite in the accounting literature where a cost was initially deemed not to be a regulatory asset and in later periods was determined to be a regulatory asset?

A. Yes. This exact fact pattern is set forth in Emerging Issues Task Force Issue 93-04, Accounting for Regulatory Assets." The EITF states:

"With respect to the broader issue, the Task Force also reached a consensus that a cost that does not meet the asset recognition criteria in paragraph 9 of Statement 71 at the date the cost is incurred should be recognized as a regulatory asset when it does meet those criteria at a later date."

The fact that TEP is now before the Commission under a potential rate regulation scenario (as proposed by Staff) where the PPFAC is being reestablished and generation rates are subject to rate regulation, creates a fact pattern where TEP believes it is appropriate to request deferral of the cost for ratemaking from the Commission. Under Mr. Smith's theory, this EITF would not have been required because the fact pattern included therein could not have occurred.

Q. When will you record the regulatory asset on your books?

A. Assuming all of the fact patterns in this case are resolved such that the Company once again qualifies to account for its generation assets pursuant to FAS 71, when the Commission provides sufficient evidence to enable TEP to meet the criteria above of paragraph 9, and will book a regulatory asset at that time. This is precisely in accordance with the provisions of EITF Issue 93-04 above.

Q. In addition to your testimony explaining why the ICRA adjustment proposed by Staff and RUCO are not appropriate, do you have any other comments on the proposed adjustment?

A. Yes. There are differing financial statement and income tax treatments for the items that comprise the ICRA, thereby giving rise to deferred income tax reserves. Any adjustment to the deferred balances requested for recovery also necessitates an adjustment to the related deferred income tax reserves. As part of Staff's proposed $33 million adjustment

to remove certain ICRA components, Mr. Smith correspondingly adjusted accumulated deferred income taxes by $8.4 million. RUCO also proposed reducing ICRA by the same $33 million, but failed to make any corresponding adjustment to the related deferred income taxes.

B. <u>Delayed Plant Unitization Adjustment.</u>

Q. Please explain the Delayed Plant Unitization Adjustment.

A. As we gathered the information to respond to data requests received from the Staff and RUCO in late 2007, we discovered that a portion of the charges to a construction work order for the Common Facilities at Springerville were already in service, but continued to reside in Construction Work in Progress on the Company's balance sheet. Approximately $4.5 million went into service during 2005 and $4.3 million went into service during 2006. As a result, we recorded an adjusting journal entry in December 2007 to transfer $8.77 million from CWIP to Plant in Service. Additionally, all related capitalized interest that had been accrued after the actual in-service date was removed, and depreciation from the in-service date through the end of 2007 was added to the depreciation reserve, with corresponding changes to ADIT and property tax expense.

Q. How does this adjustment affect your rate case filing?

A. The $8.77 million plant addition applies to Springerville Unit 1 Common Facilities and Unit 2 Common Facilities. For ratemaking purposes, however, the net plant investment in Springerville Unit 1 is removed as part of the fixed cost rate adjustment addressed in the testimony of Company witness Mr. Hutchens. Accordingly, only one-half, or $4.38 million, of the $8.77 million should be added to the plant in service component of rate base. Additionally, accumulated depreciation should be increased by $131,960 and ADIT

increased by $77,369. Supporting workpapers for this adjustment are included at Exhibit KGK – 3 Support for Company Proposed Adjustments.

The Delayed Plant Unitization adjustment also affects depreciation and property tax amounts requested in the cost of service in the initial rate case filing. The correcting accounting adjustment affects test year recorded depreciation expense and property taxes, however, because both are annualized for ratemaking, the amounts required to be reflected in this rate case differ from the adjustment recorded for the Company's financial statements. The effect of adding $4.38 million to plant in service increases the Company's pro forma adjustment to annualize depreciation, based on end-of-test year plant and the applicable 3.67% depreciation rate contained in Dr. Kateregga's study, by $160,966. Similarly, the adjustment to annualize property tax expense, based on end-of-test year plant, the applicable tax assessment ratio, and the most current known property tax rates, calls for an increase of $106,358.

Q. Is there anything else with respect to this adjustment that we should note?

A. Yes. This adjustment includes only half the costs of this plant addition. This plant addition is applicable on a 50/50 basis to Springerville Units 1 and 2. At Section III. C of my testimony I have included the Unit 1 impacts of this adjustment which would be necessary to consider if Springerville Unit 1 is recovered on a cost-of-service basis.

C. **Company-Proposed Adjustments to Deferred Income Taxes.**

Q. Do you have any proposed adjustments to the income tax amounts contained in the Company's initial filing?

A. Yes. I am amending the adjustments initially filed by the Company for both Deferred Income Taxes and Accumulated Deferred Income Taxes. Supporting workpapers for this adjustment are included at Exhibit KGK – 3 Support for Company Proposed Adjustments.

Q. To what do these amendments relate?

A. At the time that the rate case was filed (July 2007), the Company was still finalizing its consolidated Federal and state income tax returns for tax year 2006. The returns have now been filed, and more current and accurate tax factors necessary for the rate case tax computations are now available. The amounts associated with book-tax depreciation timing difference calculations have been updated. Moreover, the effects of the Delayed Plant Unitization adjustment have been incorporated into the tax calculations. Finally, a reconsideration based on the extent to which certain costs have been previously permitted for recovery in ratemaking has led to the removal of certain deferred tax assets that were included in pro forma income tax expense in the Company's original filing.

Q. What specific adjustment revisions are you now proposing?

A. I am proposing a revised adjustment to Deferred Income Taxes to reduce the original adjustment filed in this case. Initially, the amount of Deferred Income Taxes recorded during the test year was $11,209,866, to which a reduction adjustment of $19,248,359 was applied. The revised adjustment has been reduced from $19,248, 359 to $10,914,305.

I am also proposing to revise the original adjustment to Accumulated Deferred Income Taxes. The recorded test year amount was initially reduced by $119,238,838. That

amount has been increased by $44,216,776 to a new proposed reduction from the recorded test year amounts to $163,455,614.

The foregoing amounts are on a total Company, cost of service basis. They are jurisdictionalized in our revised revenue requirement. Also, additional revisions have been provided for the Deferred Income Tax Expense and ADIT for the Hybrid and Market versions of our rate case filing.

D. <u>Fuel Inventory as a Component of Working Capital.</u>

Q. Have any of the witnesses challenged the appropriateness of a 13-month weighted average inventory balance as an element of working capital?

A. Yes. ACC Staff Witness Medine has indicated that the use of an optimal balance would be more appropriate.

Q. Do you agree with her assertion?

A. No, I do not. The purpose of calculating working capital is to determine the amount of cash it takes to operate a business over time, recognizing that some costs of operations, like inventory, have to be paid for in advance of service delivery, and others are paid for after services are delivered. Hence, the use of a lead-lag study for parts of the determination of working capital. The use of an optimum calculation incorrectly presumes the Company has full control over all aspects of the fuel delivery process. Prior to receiving the coal, the coal is subject to delivery issues both at the mine site (such as shut downs for operational or strike issues, moves of long walls) and during the delivery process while in the hands of the rail shipper. At times, coal will need to be acquired in advance of need, so there will be more on hand than optimal, and at others, you simply won't be able to receive the shipments you need, so you have less than optimal. Similar assertions can be made for oil

inventory, or one may buy a larger quantity than needed immediately to obtain a lower cost per barrel. In either event, the actual working capital need is based on what fuel inventory you actually received (and paid for) and are holding on site. The thirteen-month historical average more properly recognizes the cash used in the business, and that circumstances (over and short as compared to optimal) will vary over time. The Company should not be economically penalized by rate base exclusion for what are prudent inventory levels maintained to assure continuous uninterrupted service.

E. <u>Accumulated Depreciation and Accumulated Deferred Income Taxes for Cost of Removal and Depreciation Changes.</u>

Q. Both Staff and RUCO propose adjustments to accumulated depreciation for the fact that the Company recognized the accumulated cost of removal for generation in 2003 and ceased accruing cost of removal since that time. Do you agree with such adjustment?

A. No. As stated earlier in Section III of my testimony, I believe any issue related to amounts the Company might have recorded or incurred as a cost-based regulated entity should be considered as an additive element of the calculation of the TCRA. In addition, I believe any amounts calculated for cost of removal should be based on depreciation rates actually used by the Company during those years, which represent the economic useful lives of the assets, rather than the outdated rates included in the Company's 1996 Rate Settlement.

Q. Staff and RUCO also propose adjustments to accumulated depreciation to apply the depreciation rates from the 1996 Rate Settlement to prior periods. Do you agree with that adjustment?

A. No. As stated earlier in Section III of my testimony, the changes made to depreciation rates are exactly the same ones we would have requested in rate proceedings during the

period of the rate freeze, had we been allowed to file rate cases. These rates are just and reasonable. I will note that the parties do not question the rates proposed on a going-forward basis in the study of Dr. Kataregga, challenging those rates as too low due to improper economic useful lives. The same economic useful life information underlies both the changes made earlier and the current study.

Q. Have your reviewed the computations prepared by Mr. Smith in connection with his proposed rate base adjustments related to Cost of Removal and Depreciation Rate Changes?

A. Yes I have. I have reviewed both proposed rate base adjustments as well as the related adjustment to pro forma annualized depreciation expense.

Q. Do you have any comments with respect to such calculations?

A. Yes I do. While, as explained earlier in my rebuttal testimony, I do not agree with either rate base adjustment proposed by Mr. Smith, I do wish to point out a double counting that occurs between them.

Q. Please explain the double counting.

A. In his rate base adjustment B-5 relating to cost of removal, Mr. Smith proposes to reverse the entry transferring the cumulative net salvage accrued on Generation assets through December 31, 2002, from accumulated depreciation to income, that was made in connection with the Company adopting FAS 143 in January 2003. The $112 million that Mr. Smith added back to accumulated depreciation includes $5,835,844 of net salvage accrued in 2002, as indicated on the response to Staff Data Request 22-24. Then in his $47 million rate base adjustment B-6 related to depreciation rate changes, Mr. Smith includes the $5,835,844 amount for 2002 a second time as an addback to accumulated depreciation.

Q. Does that double counting affect any other amounts?

A. Yes. In his proposed adjustment C-15 to the Company's pro forma annualized test year depreciation expense, Mr. Smith uses the same $112 million and $47 million in attempting to quantify the effect of his two rate base adjustments on the new remaining life depreciation rates sponsored by Company consultant Dr. Kateregga. Due to the inclusion of the $5.8 million of net salvage accrued in 2002 in both the $112 million and the $47 million, the depreciation adjustment is computed incorrectly. By removing the double counting from the calculation, the $1,741,000 proposed increase to depreciation expense should be $1,984,392. While I point out this computational error, I wish to renew my objection to both of the rate base adjustments proposed by Mr. Smith, as well as the related depreciation adjustment.

Q. In addition to your testimony explaining why the FAS 143 adjustments proposed by Staff and RUCO are not appropriate, do you have any other comments on the proposed adjustment?

A. Yes. Prior to the adoption of FAS 143, the Company accrued the cost of removal as a component of book depreciation for generation assets. Removal costs are not deductible for tax purposes however, until the removal expenditure actually occurs. That creates a book-tax timing difference and resulting deferred tax asset. As a practical matter, such timing differences are tracked and included as part of the computation of book-tax depreciation timing differences and deferred income taxes recorded in Acct. 282, Accumulated Deferred Income Taxes – Other Property. Any reversal of the transfer of negative net salvage to income back into accumulated depreciation also requires an adjustment to accumulated deferred income taxes. The restoration of $112 million back to the depreciation reserve requires an adjustment to reduce the deferred income tax reserve by $44.7 million. Staff witness Mr. Smith made such an adjustment to the deferred tax reserve; RUCO did not.

Q. What is a functionalization factor?

A. It is a factor applied to allocate total Company amounts among the various functions performed by the Company. In this specific case, it relates to the portion of accumulated deferred income taxes that should be apportioned to generation assets as compared to transmission or distribution assets.

Q. ACC witness Smith develops two rate base adjustments (See Schedule B-5 and Schedule B-6) which are related to generation-related cost of removal and generation-related depreciation rate changes. Each of these adjustments identifies an accumulated depreciation total company impact and functionalizes this amount using a 94.53% amount. Next, a total company accumulated deferred income tax amount related to these adjustments is developed. This amount is functionalized to the ACC jurisdiction using a factor of 73.68%. Do you agree with these adjustments?

A. No. As I have previously covered in my testimony, I disagree in principle with these adjustments. However, if the ACC were to agree in concept with these adjustments, I believe that the ADIT functionalization factor of 73.68% used by Mr. Smith is understated.

Q. Can you explain the origin of the 73.68% ADIT functionalization factor?

A. Yes, this rate represents the overall functionalization of historical accumulated deferred income taxes to the ACC jurisdiction in this rate case. This factor treats wholesale transactions and transmission as non-jurisdictional. Transmission is non-jurisdictional as these amounts are the jurisdiction of FERC.

Q. Why does this overall ADIT functionalization factor not apply to the cost of removal adjustments developed by Mr. Smith?

A. They do not apply because Mr. Smith's adjustments B-5 and B-6 are wholly related to generation-related operations. Accordingly, the ADIT functionalization should mirror the related accumulated depreciation functionalization factor.

Q. Will you please expand on how you can arrive at the appropriate amount of jurisdictional ADIT related to these adjustments?

A. Yes. There are two ways this can be done. One way is to apply the accumulated depreciation functionalization factor 94.53% to the total Company ADIT computed by Mr. Smith.

Q. What is the other way?

A. The other way to develop the appropriate ACC ADIT would be to multiply the ACC jurisdictionalized cost of removal by the combined federal and state tax rate of approximately 39.6%. This is logical because the total company ADIT equals the cost of removal adjustment proposed by Mr. Smith multiplied by the combined federal and state tax rate of approximately 39.6%.

Q. Does Mr. Smith agree with the approaches you suggest above?

A. Yes. He agrees as indicated in his deposition at page 131.

Q. Mr. Smith also indicates that he may need to circle back and look at the overall ADIT functionalization of 73.68%. Do you agree that this is necessary?

A. No. As I explained above, the historical functionalization of ADIT appropriately considers wholesale and transmission activities as non-jurisdictional. The incremental ADIT

identified by Mr. Smith relates only to generation assets and accordingly, a generation specific functionalization should be applied to these amounts.

F. <u>Other ADIT and Deferred Credit Adjustments.</u>

Q. Do you have any comments regarding Mr. Smith's proposal regarding CC&B?

A. Yes. While Company witness Mr. Dukes addresses the Company's position as to the errors in Mr. Smith's general position as to how to treat the CC&B intangible software asset, I will address an ADIT implication of his adjustment.

The Company's investment in the CC&B intangible software asset is amortized differently for book and tax purposes, thereby creating a deferred tax liability. Such amount is deducted in arriving at the investment base included in the computation of the rate at which CC&B costs are charged to the affiliated utilities that also use the billing system. To the extent that an adjustment to test year allocations of CC&B costs is made, such as had been proposed by Mr. Smith, in addition to reductions in plant in service and accumulated depreciation, accumulated deferred income taxes must also be correspondingly reduced. The adjustment proposed by Mr. Smith includes no change in ADIT.

In this instance, the <u>tax</u> depreciation that has been taken on the $6.2 million of plant in service through the end of the test year that Mr. Smith is removing from rate base is $1,468,840. That is in comparison to the $485,157 of accumulated <u>book</u> depreciation that his adjustment would remove from rate base in this rate case. When applying the combined 39.6% Federal-state income tax rate the $983,683 timing difference between book and tax depreciation, the corresponding accumulated deferred income taxes is computed as $389,538.

Q. Mr. Smith makes a number of adjustments to both ADIT and Deferred Credits to attempt to provide a better matching of rate base elements with their related amounts of ADIT. Are these adjustments required?

A. ADIT should reflect the extent and period of the Company's normalization authority. To the extent a deferred tax asset or liability exists on the books at the end of a test year that relates to a cost or revenue not previously allowed for ratemaking, it should not be reflected in rate base, however, to the extent that we are seeking recovery of such costs in the current rate case, and the cost gives rise to a book-tax timing difference, that should be reflected in the computation of current and deferred income tax expense. Deferred tax assets and deferred tax liabilities associated with specific deferred assets or deferred credits, should not be reflected in rate base unless the corresponding deferred asset or credit is also in rate base. The only exclusion is that, in accordance with a 1987 ACC Decision, the receipt and repayment of Advances and Contributions in Aid of Construction are not recognized in computing current or deferred income tax for ratemaking purposes, however, rate base may include the corresponding deferred tax asset at the average test year level.

Mr. Smith was correct in that the company had inadvertently included a mismatch of deferred income taxes with certain items included in rate base in the Company's initial filing. In reviewing our ADIT calculations in response to data requests, we identified a number of these mismatches and we have filed revisions to our case to alleviate that issue as explained in IV. C. of this testimony. Therefore, Mr. Smith's revisions are not required. To be more specific, our revised ADIT calculations no longer include elements for reclamation costs, headquarters building lease costs or environmental costs. Therefore, there is no need for the reduction of rate base for the deferred credits identified by Mr. Smith. Further, the Company has now excluded the ADIT related to the SERP, stock based compensation, FAS 106 and FAS 112 from rate base. Since the Company has not to

date received rate recovery of these issues on a GAAP accrual basis, there are no associated deferred income taxes that should be identified.

G. <u>Luna in Rate Base.</u>

Q. Do the Staff and RUCO concur with the inclusion of Luna on a market-based recovery path?

A. No, they do not. The Company's position with respect to how Luna should be recovered in rates is covered by TEP Witness Mr. Hutchens. However, since other witnesses used incorrect numbers for Luna to propose adjustments, I wish to identify the correct amounts that should appear if Luna were to be recovered under a cost-of-service methodology. If the Staff and RUCO were to prevail in having Luna recovered on a cost-of-service basis, the totality of costs related to Luna would need to be added back to rate base and cost of service. This would include adding back to rate base the cost of the asset, less accumulated depreciation and accumulated deferred income taxes, as well as the materials, supplies and prepayment elements of working capital removed in developing the market adjustment. Also, depreciation expense would have to be added back on an annualized basis, as well as all property taxes and operating expenses, including a normalized plant overhaul adjustment. The appropriate rate base amounts for Luna, if adopted on a cost of service basis, are as follows:

Line No.	Description	Total Company Amount	ACC Jurisdictional Amount
1	Reverse TEP Adjustment to Plant in Service	$48,930,185	**$46,122,514**
2	Reverse TEP Adjustment to Accumulated Depreciation	(891,120)	**(839,459)**
3	Reverse TEP Adjustment to Allowance for Working Capital	719,868	**545,980**
4	Net Adjustment to Include Luna Plant in Rate Base at Cost	$48,758,933	**$45,829,035**
	Original as filed by ACC Staff		**$46,109,239**
	Change - Increase in rate base from Staff		**$ 280,204**

The only difference between the Company's calculation and Mr. Smith's calculation, is that the Company has corrected the jurisdictional allocation factors applicable to certain of the assets.

Q. Please explain the operating income adjustments that you believe were not computed correctly.

A. As part of the exclusion of Luna from test year amounts and results, the Company's filing included a pro forma adjustment for the removal of $2,096,177 from various operations and maintenance accounts, reflecting Luna operations during the test year beginning with its April 2006 in-service date. If Luna costs were to be recovered on a cost-of-service recovery basis, the recorded test year operating and maintenance expenses would have to be annualized to reflect a full 12 months of operations. A simple way of computing the annualized amount would be to divide the $2,096,177 by .75, thereby producing an annual expense level of $2,794,903. In his proposed inclusion of Luna in the rate case, Staff witness Mr. Smith correctly computed the required increase and added $2,794,903 to test year results. In its proposed inclusion of Luna, RUCO added back only the $2,096,177 incurred during the portion of the test year Luna was in service. Additionally, the Company's filing in this case included a Maintenance Overhaul normalization adjustment

sponsored by Mr. DeConcini. The adjustment reflects in the cost of service a normal annual level of the cost of major and minor unit maintenance overhauls that occur regularly, but not annually. To the extent that Luna is included in the rate case on a cost-of-service basis, the maintenance expense adjustment proposed by Mr. DeConcini should be increased by $1,076,923. Such incremental amount for Luna was computed in a manner consistent with the adjustment already submitted. Neither Staff nor RUCO have reflected any normalized annual maintenance overhaul amounts in their proposed inclusion of Luna in this rate case.

Q. Are there other computations made by Staff or RUCO in connection with their proposed inclusion of Luna with which you disagree?

A. Yes, I disagree with the computation of annualized depreciation and property taxes for Luna made by RUCO.

Q. Please explain your disagreement with the computation of Luna annualized depreciation.

A. RUCO did not compute annualized depreciation for Luna specifically; rather, it included the Luna plant balances that it was adding to the case in the respective plant accounts with all other TEP assets and then computed annualized depreciation on total Generation by plant account using composite depreciation rates for the various plant accounts. That is incorrect. TEP computes depreciation on its Generation assets using specific rates for the assets recorded in each FERC plant account at each generation unit. The annual depreciation for Luna should be computed using the actual Luna plant balances and the specific depreciation rates applicable to Luna. I have determined that implicit in RUCO's annual depreciation adjustment is $1,150,116 applicable to Luna. A computation based solely on Luna assets and the applicable depreciation rates, produces an annual

depreciation expense of $1,219,068. I note that this amount was the same Luna depreciation add-back used by Staff Witness Mr. Smith.

Q. Please explain your disagreement with the computation of Luna property taxes.

A. In computing the annual property taxes for Luna, RUCO applied the assessment ratio (23%) and tax rates (10.66%) for Arizona for all assets, including Luna. Luna is located in New Mexico, where the applicable assessment ratio is 33 and 1/3 percent, and the average tax rate is 2.305%. Applying the correct factors produces an annual property tax for Luna totaling $377,829.

Q. In his testimony relating to the Luna issue, Mr. Smith refers to having received two different measures of ADIT for Luna as of the end of the test year. Can you comment on that?

A. Yes. At the time the rate case was prepared and filed, the ADIT recorded on TEP's books at 12/31/06 included an estimate for Luna totaling $382,415. In one of Mr. Smith's earlier data requests, he inquired about the ADIT for Luna. TEP reported $382,415 in its response. Subsequently, after all of the required analyses and computations required for TEP's Federal and State income tax returns were prepared, the final number for Luna ADIT was computed as $359,747. In response to one of the latter data requests received from Mr. Smith, the Luna ADIT was reported as being $359,747. That represents the final, computed ADIT and is what would apply in this rate case.

H. <u>Plant Held for Future Use.</u>

Q. How does Staff treat Plant Held for Future Use in this case?

A. Staff Witness Smith has removed it from rate base in his adjustment B-1. He removes it from total Company plant, and then notes that none is allocated to the ACC jurisdiction.

Q. Is this treatment consistent with prior TEP rate orders?

A. It is not. In Decision No. 58497 (January 13, 1994 at Page 25-26), the ACC gave TEP Plant Held for Future Use in rate base. It was land purchased for future substation sites in advance of actual community growth and the Commission found that to be a reasonable business practice. The next Commission order, Decision No. 59594 (issued March 29, 1996), was a settlement but Plant Held For Future Use was included in ACC jurisdictional rate base in the schedule as filed at 99.68%.

Q. If the amount is not ACC jurisdictional at this point, why are you bringing this up?

A. In the rate design testimony of Staff, they indicate that in surrebuttal they may disagree with TEP's use of the OATT to set transmission rates. The Plant Held for Future Use in this case relates 100% to transmission. In the event the ACC does not use the OATT, this Plant Held for Future Use is appropriately authorized by the ACC to be included in rate base.

V. OPERATING INCOME ADJUSTMENTS.

A. FAS 143 Cost of Removal Increase to Current Depreciation Rates.

Q. Do you concur with Mr. Smith's adjustment C-15, to change depreciation rates to address cost of removal?

A. If the parties agree that cost of removal should again be accrued as a component of depreciation expense, and the Company once again qualifies to account for depreciation under FAS 71, we could again begin accruing for cost of removal. However, the right amount to accrue would be the amounts calculated by Dr. Kateregga of Foster and Associates to change the currently proposed depreciation rates to include a factor for cost of removal. The calculations should be based on the facts and circumstances as they really

exist today, and have existed for the last nine years, not a hypothetical situation. The net negative salvage, or cost of removal, rates previously authorized by the ACC for TEP generation assets were 17% for steam production and 11% for other production. I have no evidence to indicate that these rates would no longer be appropriate. The generation depreciation rates as initially proposed by the Company but increased by Foster and Associates to include these net negative salvage rates previously approved by the ACC appear in the table attached to this testimony as Exhibit KGK-2 2007 Depreciation Study (Generation with Net Salvage).

Statement B of Exhibit KGK – 2 shows that the increase in accruals from the proposed rates in TEP's originally filed study is $2,258,678 for local generation and $7,074,001 for non–local generation. Future net salvage rates used in the analysis were -17 percent for steam production and -11 percent for other production. Consistent with prior TEP studies, interim net salvage rates were set at zero percent. This assumption reduces the future net salvage rate applied to plant in service at December 31, 2006. Realized net salvage was recognized in the computation of average net salvage rates.

B. <u>Amortization of the ICRA.</u>

Q. What adjustment does Staff propose for the ICRA?

A. Relying on guidance from Ms. Medine, Mr. Smith eliminates recovery of costs for the Sundt coal contract buyout and extends the amortization period for the San Juan Coal Contract amendment to the life of the contract. He also eliminates recovery of the financing costs. RUCO's Ms. Diaz Cortez makes similar adjustments, though for the San Juan Coal contract buyout, she eliminates 100% for recovery.

Q. Does the Company agree with such adjustments?

A. No. There is no assertion that the buyouts of the coal contracts were imprudent, nor that the refinancing costs were imprudently incurred. The Staff and RUCO appear to rely on traditional, cost of service principles that TEP was not allowed to rely upon during the nine years of the rate freeze that came as part of the 1999 Settlement. During the rate freeze, TEP was specifically precluded from requesting recovery of items that increased costs. These payments were made to reduce the costs incurred to serve the customers of TEP over an extended period of time. Since current customers are benefiting from such renegotiations, they should bear the cost. There was no way that TEP could have sought to recover the costs any earlier, so saying that the amortization relates to prior periods is irrelevant – they relate to periods for which the Company was told not to ask for increases. While I would not consider it the preferable path, if the ACC finds it appropriate to relate the recovery of the buyout costs to the remaining lives of the contracts as of January 1, 2009, the full amount of the $14.7 million San Juan buyout payment should be amortized over nine years, at a rate of $1,636,788 per year. As of January 1, 2009, the full amount of the $11.3 million Sundt buyout payment should then be amortized over the seven years remaining of the former agreement, for an amortization of $1,608,562 per year. I strongly believe the full amounts of the buyouts should be recoverable, given that the Company was precluded from asking for increases during the rate freeze.

C. <u>Property Taxes.</u>

Q. Please explain the supplemental Property Tax adjustment.

A. As indicated on page 22 of my direct testimony, pro forma property taxes in the rate case filing were computed using the final adjusted plant in service and inventory balances in rate base at December 31, 2006, a 23.5% property tax assessment ratio scheduled to become effective as of January 1, 2008, and an average property tax rate based on the

property tax bills received in September 2006. At that time I committed to update the pro forma calculation, if and when more definitive information becomes available.

As promised, pro forma property tax was recomputed, based on a lower assessment ratio of 23%, and the average tax rate implicit in the tax bills received in September 2007, resulting in a change in our proposed annualization adjustment. In the initial filing, an adjustment reducing annual property tax expense by $2,682,245 was proposed. After recalculating pro forma property taxes, the reduction adjustment is increased by $493,889 to $3,176,134. Supporting workpapers for this adjustment are included at Exhibit KGK – 3 Support for Company Proposed Adjustments.

Q. Have you reviewed the property tax recommendations by Staff Witness Mr. Smith and RUCO Witness Mr. Moore?

A. Yes I have.

Q. Did they compute property taxes in the same manner as the Company?

A. The overall computational methodology was the same, but portions of their computations were different. Their computations reflected <u>their</u> proposed final adjusted plant and inventory values, the assessment ratio now scheduled to become effective in January 2009, and the average tax rate from the September 2006 tax bills.

Q. Do you agree with their computations?

A. I agree with the overall methodology based on final adjusted plant and inventory values however, as I cover elsewhere in my rebuttal testimony, I disagree with their plant and inventory adjustments. Moreover, the most current tax rates should be used when known. The most current information known at the time of our initial filing was the average tax rate of 10.66%, based on tax bills received in September 2006. That was the tax rate used

by both Mr. Smith and Mr. Moore. The average tax rate implicit in the tax bills received in September 2007 was 10.70%, and since it is now known, the September 2007 rate should be used in the tax calculations in this rate case.

Finally, I disagree with their use of an assessment ratio not scheduled to be in effect until January 2009, on both conceptual grounds as well as issues of common sense and equity.

Q. Please explain your disagreement.

A. I would agree that a reduction in the assessment ratio will produce lower property taxes, if nothing else changes. However, the calculation of pro forma property tax expense for ratemaking should consider changes in all of the elements of the computation. Focusing on only one element without considering likely changes in the other elements of the computation is unreasonable.

Setting property tax rates involves establishing a fraction, the numerator of which is the annual budget of the taxing authority that needs to be collected from the taxes assessed and levied to its constituents, and a denominator that reflects the total valuation of taxable property within the taxing district. A reduction in the statutory assessment ratio used in establishing the property valuation will result in a lower denominator, and thus a higher property tax rate, absent a reduction in the budget. To reflect an assessment ratio reduction in computing pro forma property taxes without considering the likely impact on property tax rates is not reasonable.

The computation of an average tax rate based on the tax bills received in September 2007 reflects the valuation of plant and inventory as of January 1, 2006. Such assets were valued using the 24% assessment ratio in effect on that date. Had the assessment ratio used in that 2006 valuation process been the rate now scheduled to be implemented in

January 2009, the average tax rates implicit in the September 2007 bills would have been higher to achieve the required tax receipts needed by the taxing authority, absent a reduction in their budgets. To the extent that the taxing authorities do not increase property tax rates, the assessment ratio reduction scheduled for January 2009 will not appear in lower tax bills until September 2009.

Q. Are there any other factors to consider in evaluating property taxes in this rate case?

A. Yes. In 2006, the Arizona State Legislature passed and the Governor signed legislation that set the State equalization property tax rate at zero for three years, starting with tax year 2006. Without further legislative action and approval by the Governor, the tax will be reinstated in 2009. Absent intervention, the Joint Legislative Budget Committee has estimated that the State property tax equalization rate would be $0.3859 per $100 of assessed valuation in tax year 2009. That would result in pro forma property taxes computed in this rate case increasing by $1,016,724. It is unreasonable to consider the scheduled reduction in the assessment ratio and yet ignore the existence of other factors that affect the total amount of property taxes incurred by the Company. The Company has gone a full year past the end of the test year to capture the assessment ratio used in computing pro forma property taxes. Any further expansion of the measurement point for a single factor without exploring potential changes in other factors is unwarranted.

D. <u>Gains on Land Sales.</u>

Q. Does RUCO make any adjustments with regard to land sales?

A. Yes. Ms. Diaz Cortez indicates that the Company has recorded gains on land sales of approximately $2 million over the last few years, for which she believes half should be shared with customers, with the gains amortized over a period of four years. This is RUCO Operating Adjustment 27.

Q. Do you concur with such adjustment?

A. No. RUCO appears to rely on traditional, cost of service principles that TEP was not allowed to rely upon during the nine years of the rate freeze that came as part of the 1999 Settlement. During the rate freeze, TEP was specifically precluded from requesting recovery of items that increased costs. For that reason RUCO has proposed adjustments to remove any incremental cost for which the Company now seeks recovery, indicating that the Company did not get an accounting order for such. See my discussion of the ICRA in section III of my testimony for why I believe that is inappropriate under the circumstances. However, in spite of a nine year rate freeze, RUCO believes TEP should share gains on land sales incurred. In other words, the position seems to be that TEP absorbs all the bad stuff and gives back the good stuff. I would ask for equity and fairness. If the ACC defers and amortizes these gains, it should also defer and amortize the losses realized during the same period for fuel contract buyouts and debt refinancings. As noted earlier, there is no indication of imprudence in any of those costs incurred to renegotiate fuel contracts or refinance debt.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT

KGK-2

EXHIBIT KGK – 2

2007 Depreciation Study
(Generation with Net Salvage)

2007 Depreciation Rate Study

Tucson Electric Power Company

–Local Generation (with Net Salvage)
–Non–Local Generation (with Net Salvage)

Prepared by
Foster Associates, Inc.

Statements A through F

TUCSON ELECTRIC POWER COMPANY

Statement A

Comparison of Present and Proposed Accrual Rates
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present Rem. Life	Present Fut. Net Salvage	Present Accrual Rate	Proposed Avg. Life	Proposed Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H	I
STEAM PRODUCTION								
311.00 Structures and Improvements			2.42%		8.72	-16.4%	76.86%	5.42%
312.00 Boiler Plant Equipment			3.92%		9.94	-16.3%	64.09%	6.29%
314.00 Turbogenerator Units			2.94%		14.07	-16.1%	57.86%	4.80%
315.00 Accessory Electric Equipment			3.34%		13.99	-16.2%	51.24%	5.26%
316.00 Miscellaneous Power Plant Equipment			3.41%		13.16	-16.2%	58.72%	5.14%
317.00 Asset Retirement Costs					24.68		6.52%	3.79%
Total Steam Production Plant			3.46%		11.20	-16.2%	62.26%	5.72%
OTHER PRODUCTION								
341.00 Structures and Improvements			2.47%		18.01	-10.4%	49.27%	3.10%
342.00 Fuel Holders and Accessories			2.39%		32.31	-10.0%	17.77%	2.78%
343.00 Prime Movers			1.48%		10.36	-10.7%	46.07%	6.24%
344.00 Generators			1.82%		27.79	-10.1%	35.37%	2.40%
345.00 Accessory Electric Equipment			2.24%		17.82	-10.4%	51.57%	2.98%
346.00 Miscellaneous Power Plant Equipment			2.19%		18.72	-10.4%	53.55%	2.68%
Total Other Production Plant			1.87%		26.47	-10.2%	36.69%	2.48%
TOTAL UTILITY			2.80%		15.99	-13.7%	51.70%	4.38%
STEAM PRODUCTION (by Unit)								
Sundt								
311.00 Structures and Improvements			2.42%		8.72	-16.4%	76.86%	5.42%
312.00 Boiler Plant Equipment			3.92%		9.94	-16.3%	64.09%	6.29%
314.00 Turbogenerator Units			2.94%		14.07	-16.1%	57.86%	4.80%
315.00 Accessory Electric Equipment			3.34%		13.99	-16.2%	51.24%	5.26%
316.00 Miscellaneous Power Plant Equipment			3.41%		13.16	-16.2%	58.72%	5.14%
317.00 Asset Retirement Costs					24.68		6.52%	3.79%
Total Sundt			3.46%		11.20	-16.2%	62.26%	5.72%
Sundt Unit 1								
311.00 Structures and Improvements			0.58%		21.81	-16.0%	74.05%	1.92%
312.00 Boiler Plant Equipment			2.19%		21.84	-16.0%	61.53%	2.49%
314.00 Turbogenerator Units			0.65%		21.81	-16.0%	74.01%	1.93%
315.00 Accessory Electric Equipment			1.00%		21.82	-16.0%	64.94%	2.34%
316.00 Miscellaneous Power Plant Equipment			2.30%		21.83	-16.0%	58.56%	2.63%
317.00 Asset Retirement Costs								
Total Sundt Unit 1			1.53%		21.83	-16.0%	66.37%	2.27%
Sundt Unit 2								
311.00 Structures and Improvements			0.62%		23.68	-15.9%	68.10%	2.02%
312.00 Boiler Plant Equipment			2.45%		23.71	-15.9%	50.11%	2.77%
314.00 Turbogenerator Units			0.94%		23.68	-15.9%	68.37%	2.01%
315.00 Accessory Electric Equipment			1.34%		23.71	-15.9%	52.80%	2.66%
316.00 Miscellaneous Power Plant Equipment			2.77%		23.72	-15.9%	41.95%	3.12%
317.00 Asset Retirement Costs								
Total Sundt Unit 2			1.81%		23.70	-15.9%	56.78%	2.49%
Sundt Unit 3								
311.00 Structures and Improvements			0.68%		24.61	-15.8%	79.31%	1.48%
312.00 Boiler Plant Equipment			1.24%		24.64	-15.8%	65.13%	2.06%
314.00 Turbogenerator Units			1.91%		24.65	-15.9%	52.93%	2.55%
315.00 Accessory Electric Equipment			3.06%		24.67	-15.9%	32.48%	3.38%
316.00 Miscellaneous Power Plant Equipment			2.11%		24.64	-15.9%	61.30%	2.22%
317.00 Asset Retirement Costs					24.68		6.52%	3.79%
Total Sundt Unit 3			1.84%		24.65	-15.7%	53.71%	2.51%

TUCSON ELECTRIC POWER COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present Rem. Life	Present Fut. Net Salvage	Present Accrual Rate	Proposed Avg. Life	Proposed Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H	I
Sundt Unit 4								
311.00 Structures and Improvements			9.36%		4.47	-16.8%	41.65%	16.81%
312.00 Boiler Plant Equipment			13.20%		4.47	-16.8%	35.49%	18.19%
314.00 Turbogenerator Units			11.41%		4.47	-16.8%	34.92%	18.32%
315.00 Accessory Electric Equipment			7.35%		4.47	-16.8%	50.43%	14.85%
316.00 Miscellaneous Power Plant Equipment			11.06%		4.47	-16.8%	37.58%	17.72%
317.00 Asset Retirement Costs								
Total Sundt Unit 4			12.27%		4.47	-16.8%	35.81%	18.12%
Sundt Coal Conversion								
311.00 Structures and Improvements			3.58%		4.47	-16.8%	81.35%	7.93%
312.00 Boiler Plant Equipment			3.76%		4.47	-16.8%	80.89%	8.03%
314.00 Turbogenerator Units			3.51%		4.47	-16.8%	81.72%	7.85%
315.00 Accessory Electric Equipment			5.27%		4.47	-16.8%	74.89%	9.38%
316.00 Miscellaneous Power Plant Equipment			3.40%		4.47	-16.8%	81.72%	7.85%
317.00 Asset Retirement Costs								
Total Sundt Coal Conversion			3.90%		4.47	-16.8%	80.30%	8.16%
Sundt Coal Handling								
311.00 Structures and Improvements								
312.00 Boiler Plant Equipment			19.22%		4.47	-16.8%	6.92%	24.58%
314.00 Turbogenerator Units								
315.00 Accessory Electric Equipment			1.30%		4.47	-16.8%	4.23%	25.18%
316.00 Miscellaneous Power Plant Equipment								
317.00 Asset Retirement Costs								
Total Sundt Coal Handling			15.84%		4.47	-16.8%	6.41%	24.69%
OTHER PRODUCTION (by Unit)								
DeMoss Petrie Gas Unit 1								
341.00 Structures and Improvements			2.18%		37.52	-9.9%	13.08%	2.58%
342.00 Fuel Holders and Accessories			2.18%		37.52	-9.9%	13.08%	2.58%
343.00 Prime Movers								
344.00 Generators			2.18%		37.52	-9.9%	13.08%	2.58%
345.00 Accessory Electric Equipment			2.18%		37.52	-9.9%	13.08%	2.58%
346.00 Miscellaneous Power Plant Equipment			2.28%		37.53	-9.9%	10.71%	2.64%
Total DeMoss Petrie Gas Unit 1			2.18%		37.52	-9.9%	13.06%	2.58%
Sundt Gas								
341.00 Structures and Improvements			0.41%		10.36	-10.7%	85.84%	2.40%
342.00 Fuel Holders and Accessories			4.29%		10.36	-10.7%	62.96%	4.61%
343.00 Prime Movers			0.42%		10.36	-10.7%	46.60%	6.19%
344.00 Generators			0.95%		10.36	-10.7%	90.54%	1.95%
345.00 Accessory Electric Equipment			1.63%		10.36	-10.7%	83.80%	2.60%
346.00 Miscellaneous Power Plant Equipment			0.48%		10.35	-10.7%	102.59%	0.78%
Total Sundt Gas			1.05%		10.36	-10.7%	88.91%	2.10%
Sundt Gas Unit 1								
341.00 Structures and Improvements			0.07%		10.36	-10.7%	87.46%	2.24%
342.00 Fuel Holders and Accessories			4.14%		10.36	-10.7%	64.15%	4.49%
343.00 Prime Movers			0.07%		10.36	-10.7%	47.48%	6.10%
344.00 Generators			0.57%		10.35	-10.7%	94.64%	1.55%
345.00 Accessory Electric Equipment			1.04%		10.36	-10.7%	87.88%	2.20%
346.00 Miscellaneous Power Plant Equipment			0.07%		10.35	-10.7%	105.32%	0.52%
Total Sundt Gas Unit 1			0.65%		10.35	-10.7%	92.97%	1.71%

TUCSON ELECTRIC POWER COMPANY

Statement A

Comparison of Present and Proposed Accrual Rates
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present Rem. Life	Present Fut. Net Salvage	Present Accrual Rate	Proposed Avg. Life	Proposed Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H	I
Sundt Gas Unit 2								
341.00 Structures and Improvements			0.76%		10.36	-10.7%	84.22%	2.56%
342.00 Fuel Holders and Accessories			4.44%		10.36	-10.7%	61.77%	4.72%
343.00 Prime Movers			0.77%		10.36	-10.7%	45.72%	6.27%
344.00 Generators			1.34%		10.36	-10.7%	86.23%	2.36%
345.00 Accessory Electric Equipment			2.16%		10.36	-10.7%	80.09%	2.95%
346.00 Miscellaneous Power Plant Equipment			0.76%		10.35	-10.7%	100.76%	0.96%
Total Sundt Gas Unit 2			1.46%		10.36	-10.7%	84.73%	2.50%
North Loop Gas								
341.00 Structures and Improvements			2.66%		11.87	-10.6%	69.03%	3.50%
342.00 Fuel Holders and Accessories			2.20%		37.52	-9.9%	12.52%	2.60%
343.00 Prime Movers			2.18%		10.36	-10.7%	45.72%	6.27%
344.00 Generators			1.66%		24.31	-10.2%	44.75%	2.69%
345.00 Accessory Electric Equipment			2.49%		16.78	-10.4%	51.27%	3.52%
346.00 Miscellaneous Power Plant Equipment			2.28%		12.83	-10.6%	71.57%	3.04%
Total North Loop Gas			1.79%		22.44	-10.3%	46.37%	2.50%
North Loop Gas Unit 1								
341.00 Structures and Improvements			4.10%		10.36	-10.7%	60.96%	4.80%
342.00 Fuel Holders and Accessories								
343.00 Prime Movers			2.09%		10.36	-10.7%	45.88%	6.26%
344.00 Generators			1.20%		10.36	-10.7%	85.68%	2.42%
345.00 Accessory Electric Equipment			3.67%		10.36	-10.7%	64.71%	4.44%
346.00 Miscellaneous Power Plant Equipment			4.21%		10.36	-10.7%	62.44%	4.66%
Total North Loop Gas Unit 1			1.98%		10.36	-10.7%	78.77%	3.09%
North Loop Gas Unit 2								
341.00 Structures and Improvements			1.26%		10.35	-10.7%	89.08%	2.09%
342.00 Fuel Holders and Accessories								
343.00 Prime Movers			1.83%		10.36	-10.7%	46.09%	6.24%
344.00 Generators			0.69%		10.35	-10.7%	93.03%	1.71%
345.00 Accessory Electric Equipment			1.82%		10.36	-10.7%	80.27%	2.94%
346.00 Miscellaneous Power Plant Equipment			0.01%		10.35	-10.7%	103.23%	0.72%
Total North Loop Gas Unit 2			0.84%		10.35	-10.7%	90.89%	1.92%
North Loop Gas Unit 3								
341.00 Structures and Improvements			1.25%		10.35	-10.7%	87.36%	2.26%
342.00 Fuel Holders and Accessories								
343.00 Prime Movers			2.63%		10.36	-10.7%	45.19%	6.32%
344.00 Generators			0.75%		10.35	-10.7%	92.35%	1.77%
345.00 Accessory Electric Equipment			1.85%		10.36	-10.7%	78.82%	3.08%
346.00 Miscellaneous Power Plant Equipment			0.01%		10.35	-10.7%	101.23%	0.91%
Total North Loop Gas Unit 3			0.91%		10.35	-10.7%	89.97%	2.00%
North Loop Gas Unit 4								
341.00 Structures and Improvements			2.27%		37.53	-9.9%	17.78%	2.45%
342.00 Fuel Holders and Accessories			2.20%		37.52	-9.9%	12.52%	2.60%
343.00 Prime Movers								
344.00 Generators			2.19%		37.52	-9.9%	12.93%	2.58%
345.00 Accessory Electric Equipment			2.20%		37.52	-9.9%	14.06%	2.55%
346.00 Miscellaneous Power Plant Equipment			2.19%		37.52	-9.9%	16.46%	2.49%
Total North Loop Gas Unit 4			2.19%		37.52	-9.9%	13.04%	2.58%

TUCSON ELECTRIC POWER COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/06 Plant Investment	2007 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
STEAM PRODUCTION				
311.00 Structures and Improvements	$10,046,860	$242,654	$545,041	$302,387
312.00 Boiler Plant Equipment	54,922,617	2,154,107	3,452,415	1,298,308
314.00 Turbogenerator Units	24,243,970	712,553	1,163,643	451,090
315.00 Accessory Electric Equipment	11,173,775	373,269	587,702	214,433
316.00 Miscellaneous Power Plant Equipment	596,390	20,343	30,659	10,316
317.00 Asset Retirement Costs	274,147		10,390	10,390
Total Steam Production Plant	$101,257,759	$3,502,926	$5,789,850	$2,286,924
OTHER PRODUCTION				
341.00 Structures and Improvements	$1,360,095	$33,568	$42,203	$8,635
342.00 Fuel Holders and Accessories	1,164,895	27,837	32,400	4,563
343.00 Prime Movers	354,045	5,233	22,085	16,852
344.00 Generators	62,855,652	1,142,319	1,510,490	368,171
345.00 Accessory Electric Equipment	4,475,216	100,116	133,164	33,048
346.00 Miscellaneous Power Plant Equipment	1,038,308	22,773	27,847	5,074
Total Other Production Plant	$71,248,211	$1,331,846	$1,768,189	$436,343
TOTAL UTILITY	$172,505,970	$4,834,772	$7,558,039	$2,723,267
STEAM PRODUCTION (by Unit)				
Sundt				
311.00 Structures and Improvements	$10,046,860	$242,654	$545,041	$302,387
312.00 Boiler Plant Equipment	54,922,617	2,154,107	3,452,415	1,298,308
314.00 Turbogenerator Units	24,243,970	712,553	1,163,643	451,090
315.00 Accessory Electric Equipment	11,173,775	373,269	587,702	214,433
316.00 Miscellaneous Power Plant Equipment	596,390	20,343	30,659	10,316
317.00 Asset Retirement Costs	274,147		10,390	10,390
Total Sundt	$101,257,759	$3,502,926	$5,789,850	$2,286,924
Sundt Unit 1				
311.00 Structures and Improvements	$2,068,058	$11,995	$39,707	$27,712
312.00 Boiler Plant Equipment	10,537,114	230,763	262,374	31,611
314.00 Turbogenerator Units	4,978,412	32,360	96,083	63,723
315.00 Accessory Electric Equipment	1,266,340	12,663	29,632	16,969
316.00 Miscellaneous Power Plant Equipment	132,739	3,053	3,491	438
317.00 Asset Retirement Costs				
Total Sundt Unit 1	$18,982,663	$290,834	$431,287	$140,453
Sundt Unit 2				
311.00 Structures and Improvements	$1,108,052	$6,870	$22,383	$15,513
312.00 Boiler Plant Equipment	10,144,535	248,541	281,004	32,463
314.00 Turbogenerator Units	5,379,936	50,571	108,137	57,566
315.00 Accessory Electric Equipment	1,359,387	18,216	36,160	17,944
316.00 Miscellaneous Power Plant Equipment	119,819	3,319	3,738	419
317.00 Asset Retirement Costs				
Total Sundt Unit 2	$18,111,729	$327,517	$451,422	$123,905

TUCSON ELECTRIC POWER COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/06 Plant Investment	2007 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
Sundt Unit 3				
311.00 Structures and Improvements	$1,394,535	$9,483	$20,639	$11,156
312.00 Boiler Plant Equipment	7,894,810	97,896	162,633	64,737
314.00 Turbogenerator Units	10,036,388	191,695	255,928	64,233
315.00 Accessory Electric Equipment	5,007,840	153,240	169,265	16,025
316.00 Miscellaneous Power Plant Equipment	163,803	3,456	3,636	180
317.00 Asset Retirement Costs	274,147		10,390	10,390
Total Sundt Unit 3	$24,771,523	$455,770	$622,491	$166,721
Sundt Unit 4				
311.00 Structures and Improvements	$315,862	$29,565	$53,096	$23,531
312.00 Boiler Plant Equipment	5,841,120	771,028	1,062,500	291,472
314.00 Turbogenerator Units	3,833,146	437,362	702,232	264,870
315.00 Accessory Electric Equipment	224,373	16,491	33,319	16,828
316.00 Miscellaneous Power Plant Equipment	57,359	6,344	10,164	3,820
317.00 Asset Retirement Costs				
Total Sundt Unit 4	$10,271,860	$1,260,790	$1,861,311	$600,521
Sundt Coal Conversion				
311.00 Structures and Improvements	$5,160,353	$184,741	$409,216	$224,475
312.00 Boiler Plant Equipment	20,279,361	762,504	1,628,433	865,929
314.00 Turbogenerator Units	16,088	565	1,263	698
315.00 Accessory Electric Equipment	3,263,296	171,976	306,097	134,121
316.00 Miscellaneous Power Plant Equipment	122,670	4,171	9,630	5,459
317.00 Asset Retirement Costs				
Total Sundt Coal Conversion	$28,841,768	$1,123,957	$2,354,639	$1,230,682
Sundt Coal Handling				
311.00 Structures and Improvements				
312.00 Boiler Plant Equipment	225,677	43,375	55,471	12,096
314.00 Turbogenerator Units				
315.00 Accessory Electric Equipment	52,539	683	13,229	12,546
316.00 Miscellaneous Power Plant Equipment				
317.00 Asset Retirement Costs				
Total Sundt Coal Handling	$278,216	$44,058	$68,700	$24,642
OTHER PRODUCTION (by Unit)				
DeMoss Petrie Gas Unit 1				
341.00 Structures and Improvements	$483,671	$10,544	$12,479	$1,935
342.00 Fuel Holders and Accessories	750,386	16,358	19,360	3,002
343.00 Prime Movers				
344.00 Generators	30,560,746	666,224	788,467	122,243
345.00 Accessory Electric Equipment	824,709	17,979	21,277	3,298
346.00 Miscellaneous Power Plant Equipment	332,738	7,586	8,784	1,198
Total DeMoss Petrie Gas Unit 1	$32,952,250	$718,691	$850,367	$131,676

TUCSON ELECTRIC POWER COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/06 Plant Investment	2007 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
Sundt Gas				
341.00 Structures and Improvements	$11,090	$46	$266	$220
342.00 Fuel Holders and Accessories	112,888	4,843	5,198	355
343.00 Prime Movers	141,618	595	8,759	8,164
344.00 Generators	8,263,470	78,147	160,742	82,595
345.00 Accessory Electric Equipment	1,009,518	16,411	26,169	9,758
346.00 Miscellaneous Power Plant Equipment	49,750	241	391	150
Total Sundt Gas	$9,588,334	$100,283	$201,525	$101,242
Sundt Gas Unit 1				
341.00 Structures and Improvements	$5,545	$4	$124	$120
342.00 Fuel Holders and Accessories	56,444	2,337	2,534	197
343.00 Prime Movers	70,809	50	4,319	4,269
344.00 Generators	4,231,667	24,121	65,591	41,470
345.00 Accessory Electric Equipment	481,584	5,008	10,595	5,587
346.00 Miscellaneous Power Plant Equipment	19,906	14	104	90
Total Sundt Gas Unit 1	$4,865,955	$31,534	$83,267	$51,733
Sundt Gas Unit 2				
341.00 Structures and Improvements	$5,545	$42	$142	$100
342.00 Fuel Holders and Accessories	56,444	2,506	2,664	158
343.00 Prime Movers	70,809	545	4,440	3,895
344.00 Generators	4,031,803	54,026	95,151	41,125
345.00 Accessory Electric Equipment	527,934	11,403	15,574	4,171
346.00 Miscellaneous Power Plant Equipment	29,844	227	287	60
Total Sundt Gas Unit 2	$4,722,379	$68,749	$118,258	$49,509
North Loop Gas				
341.00 Structures and Improvements	$865,334	$22,978	$29,458	$6,480
342.00 Fuel Holders and Accessories	301,621	6,636	7,842	1,206
343.00 Prime Movers	212,427	4,638	13,326	8,688
344.00 Generators	24,031,436	397,948	561,281	163,333
345.00 Accessory Electric Equipment	2,640,989	65,726	85,718	19,992
346.00 Miscellaneous Power Plant Equipment	655,820	14,946	18,672	3,726
Total North Loop Gas	$28,707,627	$512,872	$716,297	$203,425
North Loop Gas Unit 1				
341.00 Structures and Improvements	$396,584	$16,260	$19,036	$2,776
342.00 Fuel Holders and Accessories				
343.00 Prime Movers	70,809	1,480	4,433	2,953
344.00 Generators	3,604,298	43,252	87,224	43,972
345.00 Accessory Electric Equipment	747,678	27,440	33,197	5,757
346.00 Miscellaneous Power Plant Equipment	306,369	12,898	14,277	1,379
Total North Loop Gas Unit 1	$5,125,738	$101,330	$158,167	$56,837

TUCSON ELECTRIC POWER COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/06 Plant Investment	2007 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
North Loop Gas Unit 2				
341.00 Structures and Improvements	$193,230	$2,435	$4,039	$1,604
342.00 Fuel Holders and Accessories				
343.00 Prime Movers	70,809	1,296	4,418	3,122
344.00 Generators	3,209,424	22,145	54,881	32,736
345.00 Accessory Electric Equipment	461,617	8,401	13,572	5,171
346.00 Miscellaneous Power Plant Equipment	128,559	13	926	913
Total North Loop Gas Unit 2	$4,063,639	$34,290	$77,836	$43,546
North Loop Gas Unit 3				
341.00 Structures and Improvements	$193,231	$2,415	$4,367	$1,952
342.00 Fuel Holders and Accessories				
343.00 Prime Movers	70,809	1,862	4,475	2,613
344.00 Generators	3,091,437	23,186	54,718	31,532
345.00 Accessory Electric Equipment	460,658	8,522	14,188	5,666
346.00 Miscellaneous Power Plant Equipment	128,559	13	1,170	1,157
Total North Loop Gas Unit 3	$3,944,694	$35,998	$78,918	$42,920
North Loop Gas Unit 4				
341.00 Structures and Improvements	$82,289	$1,868	$2,016	$148
342.00 Fuel Holders and Accessories	301,621	6,636	7,842	1,206
343.00 Prime Movers				
344.00 Generators	14,126,277	309,365	364,458	55,093
345.00 Accessory Electric Equipment	971,036	21,363	24,761	3,398
346.00 Miscellaneous Power Plant Equipment	92,333	2,022	2,299	277
Total North Loop Gas Unit 4	$15,573,556	$341,254	$401,376	$60,122

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
STEAM PRODUCTION							
311.00 Structures and Improvements	$10,046,860	$8,307,357	82.69%	$7,976,385	79.39%	$7,721,832	76.86%
312.00 Boiler Plant Equipment	54,922,617	33,278,665	60.59%	36,948,227	67.27%	35,201,387	64.09%
314.00 Turbogenerator Units	24,243,970	15,394,357	63.50%	13,489,217	55.64%	14,026,519	57.86%
315.00 Accessory Electric Equipment	11,173,775	5,626,540	50.35%	5,736,270	51.34%	5,725,884	51.24%
316.00 Miscellaneous Power Plant Equipment	596,390	308,065	51.65%	350,132	58.71%	350,213	58.72%
317.00 Asset Retirement Costs	274,147	128,711	46.95%	14,816	5.40%	17,861	6.52%
Total Steam Production Plant	$101,257,759	$63,043,695	62.26%	$64,515,047	63.71%	$63,043,695	62.26%
OTHER PRODUCTION							
341.00 Structures and Improvements	$1,360,095	$636,836	46.82%	$566,027	41.62%	$670,125	49.27%
342.00 Fuel Holders and Accessories	1,164,895	197,799	16.98%	193,286	16.59%	207,008	17.77%
343.00 Prime Movers	354,045	347,068	98.03%	133,634	37.75%	163,112	46.07%
344.00 Generators	62,855,652	22,186,621	35.30%	19,248,651	30.62%	22,234,573	35.37%
345.00 Accessory Electric Equipment	4,475,216	2,256,626	50.42%	1,937,352	43.29%	2,307,886	51.57%
346.00 Miscellaneous Power Plant Equipment	1,038,308	513,793	49.48%	467,065	44.98%	556,039	53.55%
Total Other Production Plant	$71,248,211	$26,138,743	36.69%	$22,546,016	31.64%	$26,138,743	36.69%
TOTAL UTILITY	$172,505,970	$89,182,438	51.70%	$87,061,063	50.47%	$89,182,438	51.70%
STEAM PRODUCTION (by Unit)							
Sundt							
311.00 Structures and Improvements	$10,046,860	$8,307,357	82.69%	$7,976,385	79.39%	$7,721,832	76.86%
312.00 Boiler Plant Equipment	54,922,617	33,278,665	60.59%	36,948,227	67.27%	35,201,387	64.09%
314.00 Turbogenerator Units	24,243,970	15,394,357	63.50%	13,489,217	55.64%	14,026,519	57.86%
315.00 Accessory Electric Equipment	11,173,775	5,626,540	50.35%	5,736,270	51.34%	5,725,884	51.24%
316.00 Miscellaneous Power Plant Equipment	596,390	308,065	51.65%	350,132	58.71%	350,213	58.72%
317.00 Asset Retirement Costs	274,147	128,711	46.95%	14,816	5.40%	17,861	6.52%
Total Sundt	$101,257,759	$63,043,695	62.26%	$64,515,047	63.71%	$63,043,695	62.26%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Sundt Unit 1							
311.00 Structures and Improvements	$2,068,058	$1,807,844	87.42%	$1,412,902	68.32%	$1,531,468	74.05%
312.00 Boiler Plant Equipment	10,537,114	5,466,055	51.87%	5,981,334	56.76%	6,483,271	61.53%
314.00 Turbogenerator Units	4,978,412	4,282,296	86.02%	3,399,212	68.28%	3,684,464	74.01%
315.00 Accessory Electric Equipment	1,266,340	976,393	77.10%	758,709	59.91%	822,378	64.94%
316.00 Miscellaneous Power Plant Equipment	132,739	66,724	50.27%	71,713	54.03%	77,731	58.56%
317.00 Asset Retirement Costs							
Total Sundt Unit 1	$18,982,663	$12,599,312	66.37%	$11,623,870	61.23%	$12,599,312	66.37%
Sundt Unit 2							
311.00 Structures and Improvements	$1,108,052	$945,423	85.32%	$726,968	65.61%	$754,611	68.10%
312.00 Boiler Plant Equipment	10,144,535	4,227,187	41.67%	4,897,146	48.27%	5,083,359	50.11%
314.00 Turbogenerator Units	5,379,936	4,177,526	77.65%	3,543,731	65.87%	3,678,480	68.37%
315.00 Accessory Electric Equipment	1,359,387	898,429	66.09%	691,491	50.87%	717,784	52.80%
316.00 Miscellaneous Power Plant Equipment	119,819	35,936	29.99%	48,425	40.42%	50,267	41.95%
317.00 Asset Retirement Costs							
Total Sundt Unit 2	$18,111,729	$10,284,501	56.78%	$9,907,761	54.70%	$10,284,501	56.78%
Sundt Unit 3							
311.00 Structures and Improvements	$1,394,535	$1,158,419	83.07%	$917,473	65.79%	$1,106,058	79.31%
312.00 Boiler Plant Equipment	7,894,810	5,467,201	69.25%	4,265,300	54.03%	5,142,025	65.13%
314.00 Turbogenerator Units	10,036,388	5,275,383	52.56%	4,406,315	43.90%	5,312,026	52.93%
315.00 Accessory Electric Equipment	5,007,840	1,197,301	23.91%	1,349,247	26.94%	1,626,583	32.48%
316.00 Miscellaneous Power Plant Equipment	163,803	77,950	47.59%	83,291	50.85%	100,411	61.30%
317.00 Asset Retirement Costs	274,147	128,711	46.95%	14,816	5.40%	17,861	6.52%
Total Sundt Unit 3	$24,771,523	$13,304,964	53.71%	$11,036,442	44.55%	$13,304,964	53.71%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Sundt Unit 4							
311.00 Structures and Improvements	$315,862	$168,097	53.22%	$208,884	66.13%	$131,549	41.65%
312.00 Boiler Plant Equipment	5,841,120	1,696,434	29.04%	3,292,132	56.36%	2,073,299	35.49%
314.00 Turbogenerator Units	3,833,146	1,645,892	42.94%	2,125,208	55.44%	1,338,401	34.92%
315.00 Accessory Electric Equipment	224,373	141,879	63.23%	179,660	80.07%	113,145	50.43%
316.00 Miscellaneous Power Plant Equipment	57,359	25,649	44.72%	34,231	59.68%	21,558	37.58%
317.00 Asset Retirement Costs							
Total Sundt Unit 4	$10,271,860	$3,677,952	35.81%	$5,840,115	56.86%	$3,677,952	35.81%
Sundt Coal Conversion							
311.00 Structures and Improvements	$5,160,353	$4,227,573	81.92%	$4,710,159	91.28%	$4,198,145	81.35%
312.00 Boiler Plant Equipment	20,279,361	16,412,959	80.93%	18,404,469	90.75%	16,403,827	80.89%
314.00 Turbogenerator Units	16,088	13,261	82.43%	14,751	91.69%	13,147	81.72%
315.00 Accessory Electric Equipment	3,263,296	2,403,541	73.65%	2,741,821	84.02%	2,443,774	74.89%
316.00 Miscellaneous Power Plant Equipment	122,670	101,805	82.99%	112,473	91.69%	100,246	81.72%
317.00 Asset Retirement Costs							
Total Sundt Coal Conversion	$28,841,768	$23,159,140	80.30%	$25,983,673	90.09%	$23,159,140	80.30%
Sundt Coal Handling							
311.00 Structures and Improvements							
312.00 Boiler Plant Equipment	225,677	8,829	3.91%	107,845	47.79%	15,606	6.92%
314.00 Turbogenerator Units							
315.00 Accessory Electric Equipment	52,539	8,996	17.12%	15,341	29.20%	2,220	4.23%
316.00 Miscellaneous Power Plant Equipment							
317.00 Asset Retirement Costs							
Total Sundt Coal Handling	$278,216	$17,826	6.41%	$123,186	44.28%	$17,826	6.41%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
OTHER PRODUCTION (by Unit)							
DeMoss Petrie Gas Unit 1							
341.00 Structures and Improvements	$483,671	$62,914	13.01%	$62,396	12.90%	$63,276	13.08%
342.00 Fuel Holders and Accessories	750,386	97,607	13.01%	96,804	12.90%	98,169	13.08%
343.00 Prime Movers		49,646					
344.00 Generators	30,560,746	3,955,317	12.94%	3,942,494	12.90%	3,998,105	13.08%
345.00 Accessory Electric Equipment	824,709	107,275	13.01%	106,392	12.90%	107,892	13.08%
346.00 Miscellaneous Power Plant Equipment	332,738	30,320	9.11%	35,141	10.56%	35,637	10.71%
Total DeMoss Petrie Gas Unit 1	$32,952,250	$4,303,079	13.06%	$4,243,227	12.88%	$4,303,079	13.06%
Sundt Gas							
341.00 Structures and Improvements	$11,090	$10,606	95.64%	$7,711	69.54%	$9,520	85.84%
342.00 Fuel Holders and Accessories	112,888	62,078	54.99%	57,572	51.00%	71,072	62.96%
343.00 Prime Movers	141,618	135,453	95.65%	53,454	37.75%	65,988	46.60%
344.00 Generators	8,263,470	7,432,634	89.95%	6,054,505	73.27%	7,481,572	90.54%
345.00 Accessory Electric Equipment	1,009,518	837,209	82.93%	685,543	67.91%	846,007	83.80%
346.00 Miscellaneous Power Plant Equipment	49,750	47,216	94.91%	41,496	83.41%	51,036	102.59%
Total Sundt Gas	$9,588,334	$8,525,196	88.91%	$6,900,281	71.97%	$8,525,196	88.91%
Sundt Gas Unit 1							
341.00 Structures and Improvements	$5,545	$5,506	99.29%	$3,856	69.54%	$4,850	87.46%
342.00 Fuel Holders and Accessories	56,444	31,919	56.55%	28,786	51.00%	36,207	64.15%
343.00 Prime Movers	70,809	70,310	99.29%	26,727	37.75%	33,617	47.48%
344.00 Generators	4,231,667	3,967,460	93.76%	3,184,178	75.25%	4,005,010	94.64%
345.00 Accessory Electric Equipment	481,584	428,889	89.06%	336,466	69.87%	423,202	87.88%
346.00 Miscellaneous Power Plant Equipment	19,906	19,766	99.30%	16,668	83.73%	20,965	105.32%
Total Sundt Gas Unit 1	$4,865,955	$4,523,850	92.97%	$3,596,681	73.92%	$4,523,850	92.97%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Sundt Gas Unit 2							
341.00 Structures and Improvements	$5,545	$5,100	91.98%	$3,856	69.54%	$4,670	84.22%
342.00 Fuel Holders and Accessories	56,444	30,159	53.43%	28,786	51.00%	34,866	61.77%
343.00 Prime Movers	70,809	65,143	92.00%	26,727	37.75%	32,372	45.72%
344.00 Generators	4,031,803	3,465,174	85.95%	2,870,327	71.19%	3,476,562	86.23%
345.00 Accessory Electric Equipment	527,934	408,320	77.34%	349,077	66.12%	422,805	80.09%
346.00 Miscellaneous Power Plant Equipment	29,844	27,450	91.98%	24,828	83.19%	30,071	100.76%
Total Sundt Gas Unit 2	$4,722,379	$4,001,346	84.73%	$3,303,600	69.96%	$4,001,346	84.73%
North Loop Gas							
341.00 Structures and Improvements	$865,334	$563,316	65.10%	$495,920	57.31%	$597,329	69.03%
342.00 Fuel Holders and Accessories	301,621	38,115	12.64%	38,911	12.90%	37,766	12.52%
343.00 Prime Movers	212,427	161,969	76.25%	80,181	37.75%	97,123	45.72%
344.00 Generators	24,031,436	10,798,670	44.94%	9,251,652	38.50%	10,754,897	44.75%
345.00 Accessory Electric Equipment	2,640,989	1,312,141	49.68%	1,145,417	43.37%	1,353,987	51.27%
346.00 Miscellaneous Power Plant Equipment	655,820	436,257	66.52%	390,428	59.53%	469,366	71.57%
Total North Loop Gas	$28,707,627	$13,310,468	46.37%	$11,402,508	39.72%	$13,310,468	46.37%
North Loop Gas Unit 1							
341.00 Structures and Improvements	$396,584	$221,847	55.94%	$198,880	50.15%	$241,757	60.96%
342.00 Fuel Holders and Accessories							
343.00 Prime Movers	70,809	54,887	77.51%	26,727	37.75%	32,489	45.88%
344.00 Generators	3,604,298	3,140,468	87.13%	2,540,590	70.49%	3,088,332	85.68%
345.00 Accessory Electric Equipment	747,678	452,867	60.57%	397,997	53.23%	483,804	64.71%
346.00 Miscellaneous Power Plant Equipment	306,369	167,625	54.71%	157,381	51.37%	191,312	62.44%
Total North Loop Gas Unit 1	$5,125,738	$4,037,694	78.77%	$3,321,575	64.80%	$4,037,694	78.77%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
North Loop Gas Unit 2							
341.00 Structures and Improvements	$193,230	$166,929	86.39%	$140,983	72.96%	$172,138	89.08%
342.00 Fuel Holders and Accessories							
343.00 Prime Movers	70,809	56,735	80.12%	26,727	37.75%	32,633	46.09%
344.00 Generators	3,209,424	2,971,216	92.58%	2,445,246	76.19%	2,985,607	93.03%
345.00 Accessory Electric Equipment	461,617	370,370	80.23%	303,474	65.74%	370,537	80.27%
346.00 Miscellaneous Power Plant Equipment	128,559	128,378	99.86%	108,693	84.55%	132,713	103.23%
Total North Loop Gas Unit 2	$4,063,639	$3,693,628	90.89%	$3,025,123	74.44%	$3,693,628	90.89%
North Loop Gas Unit 3							
341.00 Structures and Improvements	$193,231	$166,611	86.22%	$140,984	72.96%	$168,804	87.36%
342.00 Fuel Holders and Accessories							
343.00 Prime Movers	70,809	50,347	71.10%	26,727	37.75%	32,001	45.19%
344.00 Generators	3,091,437	2,836,355	91.75%	2,384,322	77.13%	2,854,815	92.35%
345.00 Accessory Electric Equipment	460,658	367,055	79.68%	303,250	65.83%	363,089	78.82%
346.00 Miscellaneous Power Plant Equipment	128,559	128,482	99.94%	108,693	84.55%	130,142	101.23%
Total North Loop Gas Unit 3	$3,944,694	$3,548,851	89.97%	$2,963,976	75.14%	$3,548,851	89.97%
North Loop Gas Unit 4							
341.00 Structures and Improvements	$82,289	$7,928	9.63%	$15,073	18.32%	$14,629	17.78%
342.00 Fuel Holders and Accessories	301,621	38,115	12.64%	38,911	12.90%	37,766	12.52%
343.00 Prime Movers							
344.00 Generators	14,126,277	1,850,632	13.10%	1,881,494	13.32%	1,826,143	12.93%
345.00 Accessory Electric Equipment	971,036	121,850	12.55%	140,696	14.49%	136,557	14.06%
346.00 Miscellaneous Power Plant Equipment	92,333	11,771	12.75%	15,660	16.96%	15,199	16.46%
Total North Loop Gas Unit 4	$15,573,556	$2,030,295	13.04%	$2,091,833	13.43%	$2,030,295	13.04%

TUCSON ELECTRIC POWER COMPANY

Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
STEAM PRODUCTION									
311.00 Structures and Improvements	$10,211,683	$164,823	$10,046,860		-16.4%		($1,647,410)	($1,647,410)	-16.1%
312.00 Boiler Plant Equipment	59,943,454	5,020,837	54,922,617	41.4%	-16.3%	2,080,633	(8,972,454)	(6,891,821)	-11.5%
314.00 Turbogenerator Units	24,987,670	743,700	24,243,970	-12.7%	-16.1%	(94,800)	(3,894,413)	(3,989,213)	-16.0%
315.00 Accessory Electric Equipment	12,220,042	1,046,267	11,173,775	-6.3%	-16.2%	(65,920)	(1,809,758)	(1,875,678)	-15.3%
316.00 Miscellaneous Power Plant Equipment	596,390		596,390		-16.2%		(96,579)	(96,579)	-16.2%
317.00 Asset Retirement Costs	274,147		274,147						
Total Steam Production Plant	$108,233,386	$6,975,627	$101,257,759	27.5%	-16.2%	$1,919,913	($16,420,614)	($14,500,701)	-13.4%
OTHER PRODUCTION									
341.00 Structures and Improvements	$1,363,222	$3,127	$1,360,095	230.0%	-10.4%	$7,192	($141,002)	($133,810)	-9.8%
342.00 Fuel Holders and Accessories	1,164,895		1,164,895		-10.0%		(116,228)	(116,228)	-10.0%
343.00 Prime Movers	354,045		354,045		-10.7%		(37,883)	(37,883)	-10.7%
344.00 Generators	65,062,585	2,206,933	62,855,652	-2.2%	-10.1%	(47,893)	(6,368,059)	(6,415,952)	-9.9%
345.00 Accessory Electric Equipment	4,749,889	274,673	4,475,216	-0.2%	-10.4%	(515)	(464,482)	(464,997)	-9.8%
346.00 Miscellaneous Power Plant Equipment	1,117,749	79,441	1,038,308		-10.4%		(107,698)	(107,698)	-9.6%
Total Other Production Plant	$73,812,385	$2,564,174	$71,248,211	-1.6%	-10.2%	($41,216)	($7,235,352)	($7,276,568)	-9.9%
TOTAL UTILITY	$182,045,771	$9,539,801	$172,505,970	-0.4%	-13.7%	($41,216)	($23,655,966)	($21,777,269)	-12.0%
STEAM PRODUCTION (by Unit)									
Sundt									
311.00 Structures and Improvements	$10,211,683	$164,823	$10,046,860		-16.4%		($1,647,410)	($1,647,410)	-16.1%
312.00 Boiler Plant Equipment	59,943,454	5,020,837	54,922,617		-16.3%	2,080,633	(8,972,454)	(6,891,821)	-11.5%
314.00 Turbogenerator Units	24,987,670	743,700	24,243,970		-16.1%	(94,800)	(3,894,413)	(3,989,213)	-16.0%
315.00 Accessory Electric Equipment	12,220,042	1,046,267	11,173,775		-16.2%	(65,920)	(1,809,758)	(1,875,678)	-15.3%
316.00 Miscellaneous Power Plant Equipment	596,390		596,390		-16.2%		(96,579)	(96,579)	-16.2%
317.00 Asset Retirement Costs	274,147		274,147						
Total Sundt	$108,233,386	$6,975,627	$101,257,759	27.5%	-16.2%	$1,919,913	($16,420,614)	($14,500,701)	-13.4%
Sundt Unit 1									
311.00 Structures and Improvements	$2,092,525	$24,467	$2,068,058		-16.0%		($330,889)	($330,889)	-15.8%
312.00 Boiler Plant Equipment	12,546,809	2,009,695	10,537,114	113.8%	-16.0%	2,287,033	(1,685,938)	601,095	4.8%
314.00 Turbogenerator Units	5,031,931	53,519	4,978,412	-8.4%	-16.0%	(4,496)	(796,546)	(801,042)	-15.9%
315.00 Accessory Electric Equipment	1,300,768	34,428	1,266,340	-11.5%	-16.0%	(3,959)	(202,614)	(206,574)	-15.9%
316.00 Miscellaneous Power Plant Equipment	132,739		132,739		-16.0%		(21,238)	(21,238)	-16.0%
317.00 Asset Retirement Costs									
Total Sundt Unit 1	$21,104,772	$2,122,109	$18,982,663	107.4%	-16.0%	$2,278,578	($3,037,226)	($758,648)	-3.6%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Sundt Unit 2									
311.00 Structures and Improvements	$1,130,557	$22,505	$1,108,052		-15.9%		($176,180)	($176,180)	-15.6%
312.00 Boiler Plant Equipment	10,415,151	270,616	10,144,535	-19.7%	-15.9%	(53,311)	(1,612,981)	(1,666,292)	-16.0%
314.00 Turbogenerator Units	5,656,745	276,809	5,379,936	-6.2%	-15.9%	(17,162)	(855,410)	(872,572)	-15.4%
315.00 Accessory Electric Equipment	1,421,210	61,823	1,359,387	-7.7%	-15.9%	(4,760)	(216,143)	(220,903)	-15.5%
316.00 Miscellaneous Power Plant Equipment	119,819		119,819		-15.9%		(19,051)	(19,051)	-15.9%
317.00 Asset Retirement Costs									
Total Sundt Unit 2	$18,743,482	$631,753	$18,111,729	-11.9%	-15.9%	($75,234)	($2,879,765)	($2,954,999)	-15.8%
Sundt Unit 3									
311.00 Structures and Improvements	$1,442,460	$47,925	$1,394,535		-15.8%		($220,337)	($220,337)	-15.3%
312.00 Boiler Plant Equipment	8,002,825	108,015	7,894,810	-12.2%	-15.8%	(13,178)	(1,247,380)	(1,260,558)	-15.8%
314.00 Turbogenerator Units	10,259,015	222,627	10,036,388	-25.4%	-15.9%	(56,547)	(1,595,786)	(1,652,333)	-16.1%
315.00 Accessory Electric Equipment	5,665,314	657,474	5,007,840	-8.7%	-15.9%	(57,200)	(796,247)	(853,447)	-15.1%
316.00 Miscellaneous Power Plant Equipment	163,803		163,803		-15.9%		(26,045)	(26,045)	-15.9%
317.00 Asset Retirement Costs	274,147		274,147						
Total Sundt Unit 3	$25,807,564	$1,036,041	$24,771,523	-12.3%	-15.7%	($126,925)	($3,885,793)	($4,012,719)	-15.5%
Sundt Unit 4									
311.00 Structures and Improvements	$325,172	$9,310	$315,862		-16.8%		($53,065)	($53,065)	-16.3%
312.00 Boiler Plant Equipment	8,017,703	2,176,583	5,841,120	-2.5%	-16.8%	(54,415)	(981,308)	(1,035,723)	-12.9%
314.00 Turbogenerator Units	4,023,891	190,745	3,833,146	-8.7%	-16.8%	(16,595)	(643,969)	(660,563)	-16.4%
315.00 Accessory Electric Equipment	234,570	10,197	224,373		-16.8%		(37,695)	(37,695)	-16.1%
316.00 Miscellaneous Power Plant Equipment	57,359		57,359		-16.8%		(9,636)	(9,636)	-16.8%
317.00 Asset Retirement Costs									
Total Sundt Unit 4	$12,658,695	$2,386,835	$10,271,860	-3.0%	-16.8%	($71,009)	($1,725,672)	($1,796,682)	-14.2%
Sundt Coal Conversion									
311.00 Structures and Improvements	$5,220,969	$60,616	$5,160,353		-16.8%		($866,939)	($866,939)	-16.6%
312.00 Boiler Plant Equipment	20,533,525	254,164	20,279,361	-33.4%	-16.8%	(84,891)	(3,406,933)	(3,491,823)	-17.0%
314.00 Turbogenerator Units	16,088		16,088		-16.8%		(2,703)	(2,703)	-16.8%
315.00 Accessory Electric Equipment	3,545,641	282,345	3,263,296		-16.8%		(548,234)	(548,234)	-15.5%
316.00 Miscellaneous Power Plant Equipment	122,670		122,670		-16.8%		(20,609)	(20,609)	-16.8%
317.00 Asset Retirement Costs									
Total Sundt Coal Conversion	$29,438,893	$597,125	$28,841,768	-14.2%	-16.8%	($84,891)	($4,845,417)	($4,930,308)	-16.7%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Sundt Coal Handling									
311.00 Structures and Improvements									
312.00 Boiler Plant Equipment	427,441	201,764	225,677	-0.3%	-16.8%	(605)	(37,914)	(38,519)	-9.0%
314.00 Turbogenerator Units									
315.00 Accessory Electric Equipment	52,539		52,539		-16.8%		(8,827)	(8,827)	-16.8%
316.00 Miscellaneous Power Plant Equipment									
317.00 Asset Retirement Costs									
Total Sundt Coal Handling	$479,980	$201,764	$278,216	-0.3%	-16.8%	($605)	($46,740)	($47,346)	-9.9%
OTHER PRODUCTION (by Unit)									
DeMoss Petrie Gas Unit 1									
341.00 Structures and Improvements	$483,671		$483,671		-9.9%		($47,883)	($47,883)	-9.9%
342.00 Fuel Holders and Accessories	750,386		750,386		-9.9%		(74,288)	(74,288)	-9.9%
343.00 Prime Movers									
344.00 Generators	30,560,746		30,560,746		-9.9%		(3,025,514)	(3,025,514)	-9.9%
345.00 Accessory Electric Equipment	824,709		824,709		-9.9%		(81,646)	(81,646)	-9.9%
346.00 Miscellaneous Power Plant Equipment	332,738		332,738		-9.9%		(32,941)	(32,941)	-9.9%
Total DeMoss Petrie Gas Unit 1	$32,952,250		$32,952,250		-9.9%		($3,262,273)	($3,262,273)	-9.9%
Sundt Gas									
341.00 Structures and Improvements	$11,090		$11,090		-10.7%		($1,187)	($1,187)	-10.7%
342.00 Fuel Holders and Accessories	112,888		112,888		-10.7%		(12,079)	(12,079)	-10.7%
343.00 Prime Movers	141,618		141,618		-10.7%		(15,153)	(15,153)	-10.7%
344.00 Generators	8,945,226	681,756	8,263,470	-1.3%	-10.7%	(8,688)	(884,191)	(892,880)	-10.0%
345.00 Accessory Electric Equipment	1,035,243	25,725	1,009,518	-0.8%	-10.7%	(206)	(108,018)	(108,224)	-10.5%
346.00 Miscellaneous Power Plant Equipment	49,750		49,750		-10.7%		(5,323)	(5,323)	-10.7%
Total Sundt Gas	$10,295,815	$707,481	$9,588,334	-1.3%	-10.7%	($8,894)	($1,025,952)	($1,034,846)	-10.1%
Sundt Gas Unit 1									
341.00 Structures and Improvements	$5,545		$5,545		-10.7%		($593)	($593)	-10.7%
342.00 Fuel Holders and Accessories	56,444		56,444		-10.7%		(6,040)	(6,040)	-10.7%
343.00 Prime Movers	70,809		70,809		-10.7%		(7,577)	(7,577)	-10.7%
344.00 Generators	4,400,782	169,115	4,231,667	-1.5%	-10.7%	(2,537)	(452,788)	(455,325)	-10.3%
345.00 Accessory Electric Equipment	494,447	12,863	481,584	-0.8%	-10.7%	(103)	(51,529)	(51,632)	-10.4%
346.00 Miscellaneous Power Plant Equipment	19,906		19,906		-10.7%		(2,130)	(2,130)	-10.7%
Total Sundt Gas Unit 1	$5,047,933	$181,978	$4,865,955	-1.5%	-10.7%	($2,640)	($520,657)	($523,297)	-10.4%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Sundt Gas Unit 2									
341.00 Structures and Improvements	$5,545		$5,545		-10.7%		($593)	($593)	-10.7%
342.00 Fuel Holders and Accessories	56,444		56,444		-10.7%		(6,040)	(6,040)	-10.7%
343.00 Prime Movers	70,809		70,809		-10.7%		(7,577)	(7,577)	-10.7%
344.00 Generators	4,544,444	512,641	4,031,803	-1.2%	-10.7%	(6,152)	(431,403)	(437,555)	-9.6%
345.00 Accessory Electric Equipment	540,796	12,862	527,934	-0.8%	-10.7%	(103)	(56,489)	(56,592)	-10.5%
346.00 Miscellaneous Power Plant Equipment	29,844		29,844		-10.7%		(3,193)	(3,193)	-10.7%
Total Sundt Gas Unit 2	$5,247,882	$525,503	$4,722,379	-1.2%	-10.7%	($6,255)	($505,295)	($511,549)	-9.7%
North Loop Gas									
341.00 Structures and Improvements	$868,461	$3,127	$865,334	230.0%	-10.6%	$7,192	($91,932)	($84,740)	-9.8%
342.00 Fuel Holders and Accessories	301,621		301,621		-9.9%		(29,860)	(29,860)	-9.9%
343.00 Prime Movers	212,427		212,427		-10.7%		(22,730)	(22,730)	-10.7%
344.00 Generators	25,556,613	1,525,177	24,031,436	-2.6%	-10.2%	(39,205)	(2,458,353)	(2,497,558)	-9.8%
345.00 Accessory Electric Equipment	2,889,937	248,948	2,640,989	-0.1%	-10.4%	(309)	(274,818)	(275,126)	-9.5%
346.00 Miscellaneous Power Plant Equipment	735,261	79,441	655,820		-10.6%		(69,434)	(69,434)	-9.4%
Total North Loop Gas	$30,564,320	$1,856,693	$28,707,627	-1.7%	-10.3%	($32,322)	($2,947,128)	($2,979,449)	-9.7%
North Loop Gas Unit 1									
341.00 Structures and Improvements	$396,584		$396,584		-10.7%		($42,434)	($42,434)	-10.7%
342.00 Fuel Holders and Accessories									
343.00 Prime Movers	70,809		70,809		-10.7%		(7,577)	(7,577)	-10.7%
344.00 Generators	3,924,114	319,816	3,604,298	-10.6%	-10.7%	(33,900)	(385,660)	(419,560)	-10.7%
345.00 Accessory Electric Equipment	760,540	12,862	747,678	-0.8%	-10.7%	(103)	(80,002)	(80,104)	-10.5%
346.00 Miscellaneous Power Plant Equipment	306,369		306,369		-10.7%		(32,781)	(32,781)	-10.7%
Total North Loop Gas Unit 1	$5,458,416	$332,678	$5,125,738	-10.2%	-10.7%	($34,003)	($548,454)	($582,457)	-10.7%
North Loop Gas Unit 2									
341.00 Structures and Improvements	$193,230		$193,230		-10.7%		($20,676)	($20,676)	-10.7%
342.00 Fuel Holders and Accessories									
343.00 Prime Movers	70,809		70,809		-10.7%		(7,577)	(7,577)	-10.7%
344.00 Generators	3,409,263	199,839	3,209,424	-1.2%	-10.7%	(2,398)	(343,408)	(345,806)	-10.1%
345.00 Accessory Electric Equipment	474,480	12,863	461,617	-0.8%	-10.7%	(103)	(49,393)	(49,496)	-10.4%
346.00 Miscellaneous Power Plant Equipment	128,559		128,559		-10.7%		(13,756)	(13,756)	-10.7%
Total North Loop Gas Unit 2	$4,276,341	$212,702	$4,063,639	-1.2%	-10.7%	($2,501)	($434,809)	($437,310)	-10.2%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
North Loop Gas Unit 3									
341.00 Structures and Improvements	$193,231		$193,231		-10.7%		($20,676)	($20,676)	-10.7%
342.00 Fuel Holders and Accessories	70,809		70,809		-10.7%		(7,577)	(7,577)	-10.7%
343.00 Prime Movers	3,355,656	264,219	3,091,437	-1.1%	-10.7%	(2,906)	(330,784)	(333,690)	-9.9%
344.00 Generators	473,521	12,863	460,658	-0.8%	-10.7%	(103)	(49,290)	(49,393)	-10.4%
345.00 Accessory Electric Equipment	128,559		128,559		-10.7%		(13,756)	(13,756)	-10.7%
346.00 Miscellaneous Power Plant Equipment									
Total North Loop Gas Unit 3	$4,221,776	$277,082	$3,944,694	-1.1%	-10.7%	($3,009)	($422,082)	($425,092)	-10.1%
North Loop Gas Unit 4									
341.00 Structures and Improvements	$85,416	$3,127	$82,289	230.0%	-9.9%	$7,192	($8,147)	($955)	-1.1%
342.00 Fuel Holders and Accessories	301,621		301,621		-9.9%		(29,860)	(29,860)	-9.9%
343.00 Prime Movers	14,867,580	741,303	14,126,277		-9.9%		(1,398,501)	(1,398,501)	-9.4%
344.00 Generators	1,181,396	210,360	971,036		-9.9%		(96,133)	(96,133)	-8.1%
345.00 Accessory Electric Equipment	171,774	79,441	92,333		-9.9%		(9,141)	(9,141)	-5.3%
346.00 Miscellaneous Power Plant Equipment									
Total North Loop Gas Unit 4	$16,607,787	$1,034,231	$15,573,556	0.7%	-9.9%	$7,192	($1,541,782)	($1,534,590)	-9.2%

TUCSON ELECTRIC POWER COMPANY

Future Net Salvage
Steam Production

Statement E

Account Description	12/31/06 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
STEAM PRODUCTION (by Unit)									
Sundt									
311.00 Structures and Improvements	$10,046,860	$353,040	$9,693,820		-17.0%		($1,647,949)	($1,647,949)	-16.4%
312.00 Boiler Plant Equipment	54,922,617	2,063,329	52,859,288		-17.0%		(8,986,079)	(8,986,079)	-16.4%
314.00 Turbogenerator Units	24,243,970	1,368,598	22,875,372		-17.0%		(3,888,813)	(3,888,813)	-16.0%
315.00 Accessory Electric Equipment	11,173,775	522,966	10,650,809		-17.0%		(1,810,637)	(1,810,637)	-16.2%
316.00 Miscellaneous Power Plant Equipment	596,390	28,385	568,005		-17.0%		(96,561)	(96,561)	-16.2%
317.00 Asset Retirement Costs	274,147	17,199	256,948						
Total Sundt	$101,257,759	$4,353,517	$96,904,242		-17.0%		($16,430,040)	($16,430,040)	-16.2%
Sundt Unit 1									
311.00 Structures and Improvements	$2,068,058	$126,262	$1,941,796		-17.0%		($330,105)	($330,105)	-16.0%
312.00 Boiler Plant Equipment	10,537,114	607,536	9,929,578		-17.0%		(1,688,028)	(1,688,028)	-16.0%
314.00 Turbogenerator Units	4,978,412	302,866	4,675,546		-17.0%		(794,843)	(794,843)	-16.0%
315.00 Accessory Electric Equipment	1,266,340	76,238	1,190,102		-17.0%		(202,317)	(202,317)	-16.0%
316.00 Miscellaneous Power Plant Equipment	132,739	7,907	124,832		-17.0%		(21,221)	(21,221)	-16.0%
317.00 Asset Retirement Costs									
Total Sundt Unit 1	$18,982,663	$1,120,809	$17,861,854		-17.0%		($3,036,515)	($3,036,515)	-16.0%
Sundt Unit 2									
311.00 Structures and Improvements	$1,108,052	$73,406	$1,034,646		-17.0%		($175,890)	($175,890)	-15.9%
312.00 Boiler Plant Equipment	10,144,535	647,973	9,496,562		-17.0%		(1,614,416)	(1,614,416)	-15.9%
314.00 Turbogenerator Units	5,379,936	357,378	5,022,558		-17.0%		(853,835)	(853,835)	-15.9%
315.00 Accessory Electric Equipment	1,359,387	87,825	1,271,562		-17.0%		(216,166)	(216,166)	-15.9%
316.00 Miscellaneous Power Plant Equipment	119,819	7,619	112,200		-17.0%		(19,074)	(19,074)	-15.9%
317.00 Asset Retirement Costs									
Total Sundt Unit 2	$18,111,729	$1,174,200	$16,937,529		-17.0%		($2,879,380)	($2,879,380)	-15.9%
Sundt Unit 3									
311.00 Structures and Improvements	$1,394,535	$96,355	$1,298,180		-17.0%		($220,691)	($220,691)	-15.8%
312.00 Boiler Plant Equipment	7,894,810	534,995	7,359,815		-17.0%		(1,251,169)	(1,251,169)	-15.8%
314.00 Turbogenerator Units	10,036,388	669,418	9,366,970		-17.0%		(1,592,385)	(1,592,385)	-15.9%
315.00 Accessory Electric Equipment	5,007,840	322,209	4,685,631		-17.0%		(796,557)	(796,557)	-15.9%
316.00 Miscellaneous Power Plant Equipment	163,803	10,997	152,806		-17.0%		(25,977)	(25,977)	-15.9%
317.00 Asset Retirement Costs	274,147	17,199	256,948						
Total Sundt Unit 3	$24,771,523	$1,651,173	$23,120,350		-16.8%		($3,886,778)	($3,886,778)	-15.7%

TUCSON ELECTRIC POWER COMPANY

Future Net Salvage
Steam Production

Statement E

Account Description	12/31/06 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Sundt Unit 4									
311.00 Structures and Improvements	$315,862	$3,211	$312,651		-17.0%		($53,151)	($53,151)	-16.8%
312.00 Boiler Plant Equipment	5,841,120	59,212	5,781,908		-17.0%		(982,924)	(982,924)	-16.8%
314.00 Turbogenerator Units	3,833,146	38,767	3,794,379		-17.0%		(645,044)	(645,044)	-16.8%
315.00 Accessory Electric Equipment	224,373	2,319	222,054		-17.0%		(37,749)	(37,749)	-16.8%
316.00 Miscellaneous Power Plant Equipment	57,359	583	56,776		-17.0%		(9,652)	(9,652)	-16.8%
317.00 Asset Retirement Costs									
Total Sundt Unit 4	$10,271,860	$104,092	$10,167,768		-17.0%		($1,728,521)	($1,728,521)	-16.8%
Sundt Coal Conversion									
311.00 Structures and Improvements	$5,160,353	$53,806	$5,106,547		-17.0%		($868,113)	($868,113)	-16.8%
312.00 Boiler Plant Equipment	20,279,361	211,331	20,068,030		-17.0%		(3,411,565)	(3,411,565)	-16.8%
314.00 Turbogenerator Units	16,088	168	15,920		-17.0%		(2,706)	(2,706)	-16.8%
315.00 Accessory Electric Equipment	3,263,296	33,848	3,229,448		-17.0%		(549,006)	(549,006)	-16.8%
316.00 Miscellaneous Power Plant Equipment	122,670	1,279	121,391		-17.0%		(20,636)	(20,636)	-16.8%
317.00 Asset Retirement Costs									
Total Sundt Coal Conversion	$28,841,768	$300,433	$28,541,335		-17.0%		($4,852,027)	($4,852,027)	-16.8%
Sundt Coal Handling									
311.00 Structures and Improvements									
312.00 Boiler Plant Equipment	225,677	2,283	223,394		-17.0%		(37,977)	(37,977)	-16.8%
314.00 Turbogenerator Units									
315.00 Accessory Electric Equipment	52,539	527	52,012		-17.0%		(8,842)	(8,842)	-16.8%
316.00 Miscellaneous Power Plant Equipment									
317.00 Asset Retirement Costs									
Total Sundt Coal Handling	$278,216	$2,810	$275,406		-17.0%		($46,819)	($46,819)	-16.8%
OTHER PRODUCTION (by Unit)									
DeMoss Petrie Gas Unit 1									
341.00 Structures and Improvements	$483,671	$47,815	$435,856		-11.0%		($47,944)	($47,944)	-9.9%
342.00 Fuel Holders and Accessories	750,386	74,183	676,203		-11.0%		(74,382)	(74,382)	-9.9%
343.00 Prime Movers									
344.00 Generators	30,560,746	3,021,219	27,539,527		-11.0%		(3,029,348)	(3,029,348)	-9.9%
345.00 Accessory Electric Equipment	824,709	81,530	743,179		-11.0%		(81,750)	(81,750)	-9.9%
346.00 Miscellaneous Power Plant Equipment	332,738	32,806	299,932		-11.0%		(32,993)	(32,993)	-9.9%
Total DeMoss Petrie Gas Unit 1	$32,952,250	$3,257,553	$29,694,697		-11.0%		($3,266,417)	($3,266,417)	-9.9%

TUCSON ELECTRIC POWER COMPANY

Future Net Salvage
Steam Production

Statement E

Account Description	12/31/06 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Sundt Gas									
341.00 Structures and Improvements	$11,090	$294	$10,796		-11.0%		($1,188)	($1,188)	-10.7%
342.00 Fuel Holders and Accessories	112,888	2,939	109,949		-11.0%		(12,094)	(12,094)	-10.7%
343.00 Prime Movers	141,618	3,590	138,028		-11.0%		(15,183)	(15,183)	-10.7%
344.00 Generators	8,263,470	221,130	8,042,340		-11.0%		(884,657)	(884,657)	-10.7%
345.00 Accessory Electric Equipment	1,009,518	26,926	982,592		-11.0%		(108,085)	(108,085)	-10.7%
346.00 Miscellaneous Power Plant Equipment	49,750	1,355	48,395		-11.0%		(5,323)	(5,323)	-10.7%
Total Sundt Gas	$9,588,334	$256,234	$9,332,100		-11.0%		($1,026,531)	($1,026,531)	-10.7%
Sundt Gas Unit 1									
341.00 Structures and Improvements	$5,545	$147	$5,398		-11.0%		($594)	($594)	-10.7%
342.00 Fuel Holders and Accessories	56,444	1,470	54,974		-11.0%		(6,047)	(6,047)	-10.7%
343.00 Prime Movers	70,809	1,795	69,014		-11.0%		(7,592)	(7,592)	-10.7%
344.00 Generators	4,231,667	113,418	4,118,249		-11.0%		(453,007)	(453,007)	-10.7%
345.00 Accessory Electric Equipment	481,584	12,879	468,705		-11.0%		(51,558)	(51,558)	-10.7%
346.00 Miscellaneous Power Plant Equipment	19,906	543	19,363		-11.0%		(2,130)	(2,130)	-10.7%
Total Sundt Gas Unit 1	$4,865,955	$130,251	$4,735,704		-11.0%		($520,927)	($520,927)	-10.7%
Sundt Gas Unit 2									
341.00 Structures and Improvements	$5,545	$147	$5,398		-11.0%		($594)	($594)	-10.7%
342.00 Fuel Holders and Accessories	56,444	1,470	54,974		-11.0%		(6,047)	(6,047)	-10.7%
343.00 Prime Movers	70,809	1,795	69,014		-11.0%		(7,592)	(7,592)	-10.7%
344.00 Generators	4,031,803	107,712	3,924,091		-11.0%		(431,650)	(431,650)	-10.7%
345.00 Accessory Electric Equipment	527,934	14,048	513,886		-11.0%		(56,528)	(56,528)	-10.7%
346.00 Miscellaneous Power Plant Equipment	29,844	812	29,032		-11.0%		(3,194)	(3,194)	-10.7%
Total Sundt Gas Unit 2	$4,722,379	$125,983	$4,596,396		-11.0%		($505,604)	($505,604)	-10.7%
North Loop Gas									
341.00 Structures and Improvements	$865,334	$28,847	$836,487		-11.0%		($92,014)	($92,014)	-10.6%
342.00 Fuel Holders and Accessories	301,621	29,818	271,803		-11.0%		(29,898)	(29,898)	-9.9%
343.00 Prime Movers	212,427	5,385	207,042		-11.0%		(22,775)	(22,775)	-10.7%
344.00 Generators	24,031,436	1,662,720	22,368,716		-11.0%		(2,460,559)	(2,460,559)	-10.2%
345.00 Accessory Electric Equipment	2,640,989	140,027	2,500,962		-11.0%		(275,106)	(275,106)	-10.4%
346.00 Miscellaneous Power Plant Equipment	655,820	24,162	631,658		-11.0%		(69,482)	(69,482)	-10.6%
Total North Loop Gas	$28,707,627	$1,890,959	$26,816,668		-11.0%		($2,949,833)	($2,949,833)	-10.3%

TUCSON ELECTRIC POWER COMPANY

Future Net Salvage
Steam Production

Statement E

Account Description	12/31/06 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
North Loop Gas Unit 1									
341.00 Structures and Improvements	$396,584	$10,337	$386,247		-11.0%		($42,487)	($42,487)	-10.7%
342.00 Fuel Holders and Accessories									
343.00 Prime Movers	70,809	1,795	69,014		-11.0%		(7,592)	(7,592)	-10.7%
344.00 Generators	3,604,298	96,260	3,508,038		-11.0%		(385,884)	(385,884)	-10.7%
345.00 Accessory Electric Equipment	747,678	19,507	728,171		-11.0%		(80,099)	(80,099)	-10.7%
346.00 Miscellaneous Power Plant Equipment	306,369	8,001	298,368		-11.0%		(32,820)	(32,820)	-10.7%
Total North Loop Gas Unit 1	$5,125,738	$135,900	$4,989,838		-11.0%		($548,882)	($548,882)	-10.7%
North Loop Gas Unit 2									
341.00 Structures and Improvements	$193,230	$5,199	$188,031		-11.0%		($20,683)	($20,683)	-10.7%
342.00 Fuel Holders and Accessories									
343.00 Prime Movers	70,809	1,795	69,014		-11.0%		(7,592)	(7,592)	-10.7%
344.00 Generators	3,209,424	86,455	3,122,969		-11.0%		(343,527)	(343,527)	-10.7%
345.00 Accessory Electric Equipment	461,617	12,274	449,343		-11.0%		(49,428)	(49,428)	-10.7%
346.00 Miscellaneous Power Plant Equipment	128,559	3,516	125,043		-11.0%		(13,755)	(13,755)	-10.7%
Total North Loop Gas Unit 2	$4,063,639	$109,240	$3,954,399		-11.0%		($434,984)	($434,984)	-10.7%
North Loop Gas Unit 3									
341.00 Structures and Improvements	$193,231	$5,199	$188,032		-11.0%		($20,683)	($20,683)	-10.7%
342.00 Fuel Holders and Accessories									
343.00 Prime Movers	70,809	1,795	69,014		-11.0%		(7,592)	(7,592)	-10.7%
344.00 Generators	3,091,437	83,527	3,007,910		-11.0%		(330,870)	(330,870)	-10.7%
345.00 Accessory Electric Equipment	460,658	12,250	448,408		-11.0%		(49,325)	(49,325)	-10.7%
346.00 Miscellaneous Power Plant Equipment	128,559	3,516	125,043		-11.0%		(13,755)	(13,755)	-10.7%
Total North Loop Gas Unit 3	$3,944,694	$106,288	$3,838,406		-11.0%		($422,225)	($422,225)	-10.7%
North Loop Gas Unit 4									
341.00 Structures and Improvements	$82,289	$8,112	$74,177		-11.0%		($8,160)	($8,160)	-9.9%
342.00 Fuel Holders and Accessories	301,621	29,818	271,803		-11.0%		(29,898)	(29,898)	-9.9%
343.00 Prime Movers									
344.00 Generators	14,126,277	1,396,478	12,729,799		-11.0%		(1,400,278)	(1,400,278)	-9.9%
345.00 Accessory Electric Equipment	971,036	95,996	875,040		-11.0%		(96,254)	(96,254)	-9.9%
346.00 Miscellaneous Power Plant Equipment	92,333	9,128	83,205		-11.0%		(9,153)	(9,153)	-9.9%
Total North Loop Gas Unit 4	$15,573,556	$1,539,532	$14,034,024		-11.0%		($1,543,743)	($1,543,743)	-9.9%

TUCSON ELECTRIC POWER COMPANY

Present and Proposed Parameters

Company Vintage Group Procedure

Statement F

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
STEAM PRODUCTION												
311.00 Structures and Improvements									27.34	8.72	-16.1	-16.4
312.00 Boiler Plant Equipment									22.31	9.94	-11.5	-16.3
314.00 Turbogenerator Units									27.00	14.07	-16.0	-16.1
315.00 Accessory Electric Equipment									24.88	13.99	-15.3	-16.2
316.00 Miscellaneous Power Plant Equipment									26.57	13.16	-16.2	-16.2
317.00 Asset Retirement Costs									26.09	24.68		
Total Steam Production Plant									24.06	11.20	-13.4	-16.2
OTHER PRODUCTION												
341.00 Structures and Improvements									28.68	18.01	-9.8	-10.4
342.00 Fuel Holders and Accessories									38.04	32.31	-10.0	-10.0
343.00 Prime Movers									15.72	10.36	-10.7	-10.7
344.00 Generators									38.38	27.79	-9.9	-10.1
345.00 Accessory Electric Equipment									29.11	17.82	-9.8	-10.4
346.00 Miscellaneous Power Plant Equipment									31.38	18.72	-9.6	-10.4
Total Other Production Plant									37.01	26.47	-9.9	-10.2
TOTAL UTILITY									28.12	15.99	-12.0	-13.7
STEAM PRODUCTION (by Unit)												
Sundt												
311.00 Structures and Improvements									27.34	8.72	-16.1	-16.4
312.00 Boiler Plant Equipment									22.31	9.94	-11.5	-16.3
314.00 Turbogenerator Units									27.00	14.07	-16.0	-16.1
315.00 Accessory Electric Equipment									24.88	13.99	-15.3	-16.2
316.00 Miscellaneous Power Plant Equipment									26.57	13.16	-16.2	-16.2
317.00 Asset Retirement Costs									26.09	24.68		
Total Sundt									24.06	11.20	-13.4	-16.2

TUCSON ELECTRIC POWER COMPANY

Present and Proposed Parameters

Company Vintage Group Procedure

Statement F

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Sundt Unit 1												
311.00 Structures and Improvements	2029	SQ					2029	200-SC	52.97	21.81	-15.8	-16.0
312.00 Boiler Plant Equipment	2029	SQ					2029	200-SC	35.10	21.84	4.8	-16.0
314.00 Turbogenerator Units	2029	SQ					2029	200-SC	52.97	21.81	-15.9	-16.0
315.00 Accessory Electric Equipment	2029	SQ					2029	200-SC	45.09	21.82	-15.9	-16.0
316.00 Miscellaneous Power Plant Equipment	2029	SQ					2029	200-SC	40.86	21.83	-16.0	-16.0
317.00 Asset Retirement Costs												
Total Sundt Unit 1									40.86	21.83	-3.6	-16.0
Sundt Unit 2												
311.00 Structures and Improvements	2031	SQ					2031	200-SC	54.43	23.68	-15.6	-15.9
312.00 Boiler Plant Equipment	2031	SQ					2031	200-SC	40.67	23.71	-16.0	-15.9
314.00 Turbogenerator Units	2031	SQ					2031	200-SC	54.62	23.68	-15.4	-15.9
315.00 Accessory Electric Equipment	2031	SQ					2031	200-SC	42.11	23.71	-15.5	-15.9
316.00 Miscellaneous Power Plant Equipment	2031	SQ					2031	200-SC	36.42	23.72	-15.9	-15.9
317.00 Asset Retirement Costs												
Total Sundt Unit 2									44.85	23.70	-15.8	-15.9
Sundt Unit 3												
311.00 Structures and Improvements	2032	SQ					2032	200-SC	56.74	24.61	-15.3	-15.8
312.00 Boiler Plant Equipment	2032	SQ					2032	200-SC	46.19	24.64	-15.8	-15.8
314.00 Turbogenerator Units	2032	SQ					2032	200-SC	39.75	24.65	-16.1	-15.9
315.00 Accessory Electric Equipment	2032	SQ					2032	200-SC	31.92	24.67	-15.1	-15.9
316.00 Miscellaneous Power Plant Equipment	2032	SQ					2032	200-SC	43.90	24.64	-15.9	-15.9
317.00 Asset Retirement Costs	2032	SQ					2032	200-SC	26.09	24.68		
Total Sundt Unit 3									40.01	24.65	-15.5	-15.7

TUCSON ELECTRIC POWER COMPANY

Present and Proposed Parameters

Company Vintage Group Procedure

Statement F

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Sundt Unit 4												
311.00 Structures and Improvements	2011	SQ					2011	200-SC	10.26	4.47	-16.3	-16.8
312.00 Boiler Plant Equipment	2011	SQ					2011	200-SC	8.35	4.47	-12.9	-16.8
314.00 Turbogenerator Units	2011	SQ					2011	200-SC	8.48	4.47	-16.4	-16.8
315.00 Accessory Electric Equipment	2011	SQ					2011	200-SC	14.13	4.47	-16.1	-16.8
316.00 Miscellaneous Power Plant Equipment	2011	SQ					2011	200-SC	9.14	4.47	-16.8	-16.8
317.00 Asset Retirement Costs												
Total Sundt Unit 4									8.53	4.47	-14.2	-16.8
Sundt Coal Conversion												
311.00 Structures and Improvements	2011	SQ					2011	200-SC	20.42	4.47	-16.6	-16.8
312.00 Boiler Plant Equipment	2011	SQ					2011	200-SC	20.08	4.47	-17.0	-16.8
314.00 Turbogenerator Units	2011	SQ					2011	200-SC	20.79	4.47	-16.8	-16.8
315.00 Accessory Electric Equipment	2011	SQ					2011	200-SC	15.75	4.47	-15.5	-16.8
316.00 Miscellaneous Power Plant Equipment	2011	SQ					2011	200-SC	20.79	4.47	-16.8	-16.8
317.00 Asset Retirement Costs												
Total Sundt Coal Conversion									19.53	4.47	-16.7	-16.8
Sundt Coal Handling												
311.00 Structures and Improvements												
312.00 Boiler Plant Equipment	2011	SQ					2011	200-SC	7.06	4.47	-9.0	-16.8
314.00 Turbogenerator Units												
315.00 Accessory Electric Equipment	2011	SQ					2011	200-SC	5.96	4.47	-16.8	-16.8
316.00 Miscellaneous Power Plant Equipment												
317.00 Asset Retirement Costs												
Total Sundt Coal Handling									6.82	4.47	-9.9	-16.8

TUCSON ELECTRIC POWER COMPANY

Statement F

Present and Proposed Parameters
Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
OTHER PRODUCTION (by Unit)												
DeMoss Petrie Gas Unit 1												
341.00 Structures and Improvements	2046	SQ					2046	200-SC	42.51	37.52	-9.9	-9.9
342.00 Fuel Holders and Accessories	2046	SQ					2046	200-SC	42.51	37.52	-9.9	-9.9
343.00 Prime Movers												
344.00 Generators	2046	SQ					2046	200-SC	42.51	37.52	-9.9	-9.9
345.00 Accessory Electric Equipment	2046	SQ					2046	200-SC	42.51	37.52	-9.9	-9.9
346.00 Miscellaneous Power Plant Equipment	2046	SQ					2046	200-SC	41.52	37.53	-9.9	-9.9
Total DeMoss Petrie Gas Unit 1									42.50	37.52	-9.9	-9.9
Sundt Gas												
341.00 Structures and Improvements									27.86	10.36	-10.7	-10.7
342.00 Fuel Holders and Accessories									19.21	10.36	-10.7	-10.7
343.00 Prime Movers									15.72	10.36	-10.7	-10.7
344.00 Generators									30.41	10.36	-10.0	-10.7
345.00 Accessory Electric Equipment									26.74	10.36	-10.5	-10.7
346.00 Miscellaneous Power Plant Equipment									41.98	10.35	-10.7	-10.7
Total Sundt Gas									29.42	10.36	-10.1	-10.7
Sundt Gas Unit 1												
341.00 Structures and Improvements	2017	SQ					2017	200-SC	27.86	10.36	-10.7	-10.7
342.00 Fuel Holders and Accessories	2017	SQ					2017	200-SC	19.21	10.36	-10.7	-10.7
343.00 Prime Movers	2017	SQ					2017	200-SC	15.72	10.36	-10.7	-10.7
344.00 Generators	2017	SQ					2017	200-SC	32.20	10.35	-10.3	-10.7
345.00 Accessory Electric Equipment	2017	SQ					2017	200-SC	28.01	10.36	-10.4	-10.7
346.00 Miscellaneous Power Plant Equipment	2017	SQ					2017	200-SC	42.49	10.35	-10.7	-10.7
Total Sundt Gas Unit 1									31.05	10.35	-10.4	-10.7

TUCSON ELECTRIC POWER COMPANY

Statement F

Present and Proposed Parameters
Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Sundt Gas Unit 2												
341.00 Structures and Improvements	2017	SQ					2017	200-SC	27.86	10.36	-10.7	-10.7
342.00 Fuel Holders and Accessories	2017	SQ					2017	200-SC	19.21	10.36	-10.7	-10.7
343.00 Prime Movers	2017	SQ					2017	200-SC	15.72	10.36	-10.7	-10.7
344.00 Generators	2017	SQ					2017	200-SC	28.74	10.36	-9.6	-10.7
345.00 Accessory Electric Equipment	2017	SQ					2017	200-SC	25.68	10.36	-10.5	-10.7
346.00 Miscellaneous Power Plant Equipment	2017	SQ					2017	200-SC	41.65	10.35	-10.7	-10.7
Total Sundt Gas Unit 2									27.91	10.36	-9.7	-10.7
North Loop Gas												
341.00 Structures and Improvements									24.27	11.87	-9.8	-10.6
342.00 Fuel Holders and Accessories									42.51	37.52	-9.9	-9.9
343.00 Prime Movers									15.72	10.36	-10.7	-10.7
344.00 Generators									37.13	24.31	-9.8	-10.2
345.00 Accessory Electric Equipment									27.34	16.78	-9.5	-10.4
346.00 Miscellaneous Power Plant Equipment									27.45	12.83	-9.4	-10.6
Total North Loop Gas									34.84	22.44	-9.7	-10.3
North Loop Gas Unit 1												
341.00 Structures and Improvements	2017	SQ					2017	200-SC	18.94	10.36	-10.7	-10.7
342.00 Fuel Holders and Accessories												
343.00 Prime Movers	2017	SQ					2017	200-SC	15.72	10.36	-10.7	-10.7
344.00 Generators	2017	SQ					2017	200-SC	28.52	10.36	-10.7	-10.7
345.00 Accessory Electric Equipment	2017	SQ					2017	200-SC	19.92	10.36	-10.5	-10.7
346.00 Miscellaneous Power Plant Equipment	2017	SQ					2017	200-SC	19.33	10.36	-10.7	-10.7
Total North Loop Gas Unit 1									24.98	10.36	-10.7	-10.7

TUCSON ELECTRIC POWER COMPANY

Present and Proposed Parameters
Company Vintage Group Procedure

Statement F

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
North Loop Gas Unit 2												
341.00 Structures and Improvements	2017	SQ					2017	200-SC	30.36	10.35	-10.7	-10.7
342.00 Fuel Holders and Accessories												
343.00 Prime Movers	2017	SQ					2017	200-SC	15.72	10.36	-10.7	-10.7
344.00 Generators	2017	SQ					2017	200-SC	33.02	10.35	-10.1	-10.7
345.00 Accessory Electric Equipment	2017	SQ					2017	200-SC	25.44	10.36	-10.4	-10.7
346.00 Miscellaneous Power Plant Equipment	2017	SQ					2017	200-SC	43.81	10.35	-10.7	-10.7
Total North Loop Gas Unit 2									31.47	10.35	-10.2	-10.7
North Loop Gas Unit 3												
341.00 Structures and Improvements	2017	SQ					2017	200-SC	30.36	10.35	-10.7	-10.7
342.00 Fuel Holders and Accessories												
343.00 Prime Movers	2017	SQ					2017	200-SC	15.72	10.36	-10.7	-10.7
344.00 Generators	2017	SQ					2017	200-SC	33.88	10.35	-9.9	-10.7
345.00 Accessory Electric Equipment	2017	SQ					2017	200-SC	25.49	10.36	-10.4	-10.7
346.00 Miscellaneous Power Plant Equipment	2017	SQ					2017	200-SC	43.81	10.35	-10.7	-10.7
Total North Loop Gas Unit 3									32.04	10.35	-10.1	-10.7
North Loop Gas Unit 4												
341.00 Structures and Improvements	2046	SQ					2046	200-SC	41.43	37.53	-1.1	-9.9
342.00 Fuel Holders and Accessories	2046	SQ					2046	200-SC	42.51	37.52	-9.9	-9.9
343.00 Prime Movers												
344.00 Generators	2046	SQ					2046	200-SC	42.50	37.52	-9.4	-9.9
345.00 Accessory Electric Equipment	2046	SQ					2046	200-SC	42.51	37.52	-8.1	-9.9
346.00 Miscellaneous Power Plant Equipment	2046	SQ					2046	200-SC	42.51	37.52	-5.3	-9.9
Total North Loop Gas Unit 4									42.50	37.52	-9.2	-9.9

Statements A through F

TUCSON ELECTRIC POWER COMPANY

Statement A

Comparison of Present and Proposed Accrual Rates
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present			Proposed				
	Rem. Life	Fut. Net Salvage	Accrual Rate	Avg. Life	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H	I
STEAM PRODUCTION								
310.00 Rights-of-Way	13.43		4.80%		10.52		49.19%	4.89%
311.00 Structures and Improvements	18.37		2.53%		17.87	-16.0%	55.52%	3.73%
312.00 Boiler Plant Equipment	22.26		1.82%		25.12	-15.6%	50.84%	2.69%
314.00 Turbogenerator Units	23.35		1.70%		27.34	-15.5%	49.86%	2.50%
315.00 Accessory Electric Equipment	27.51		1.49%		30.45	-15.5%	52.30%	2.08%
316.00 Miscellaneous Power Plant Equipment	21.21		1.75%		23.73	-15.8%	55.25%	2.65%
317.00 Asset Retirement Cost	18.50		0.95%		22.26		75.57%	1.16%
Total Steam Production Plant			1.86%		24.80	-15.6%	51.31%	2.73%
TOTAL UTILITY			1.86%		24.80	-15.6%	51.31%	2.73%
STEAM PRODUCTION (by Unit)								
Four Corners								
310.00 Rights-of-Way								
311.00 Structures and Improvements	26.50		0.94%		23.71	-15.9%	86.40%	1.24%
312.00 Boiler Plant Equipment	26.51		0.73%		23.71	-15.9%	81.42%	1.45%
314.00 Turbogenerator Units	26.50		0.75%		23.72	-15.9%	74.32%	1.75%
315.00 Accessory Electric Equipment	26.47		0.49%		23.68	-15.9%	99.17%	0.71%
316.00 Miscellaneous Power Plant Equipment	26.53		1.81%		23.73	-16.0%	50.46%	2.76%
317.00 Asset Retirement Cost	26.47		0.46%		23.67		92.29%	0.33%
Total Four Coners			0.78%		23.71	-15.9%	79.66%	1.53%
Four Corners Unit 4								
310.00 Rights-of-Way								
311.00 Structures and Improvements	26.50		0.90%		23.71	-15.9%	86.41%	1.24%
312.00 Boiler Plant Equipment	26.51		0.68%		23.71	-15.9%	82.71%	1.40%
314.00 Turbogenerator Units	26.50		0.66%		23.72	-15.9%	69.60%	1.95%
315.00 Accessory Electric Equipment	26.47		0.43%		23.68	-15.9%	99.62%	0.69%
316.00 Miscellaneous Power Plant Equipment	26.53		1.81%		23.73	-16.0%	51.21%	2.73%
317.00 Asset Retirement Cost	26.47		0.41%		23.67		95.12%	0.21%
Total Four Corners Unit 4			0.72%		23.71	-15.9%	80.07%	1.51%
Four Corners Unit 5								
310.00 Rights-of-Way								
311.00 Structures and Improvements	26.50		0.98%		23.70	-15.9%	86.39%	1.25%
312.00 Boiler Plant Equipment	26.51		0.78%		23.71	-15.9%	79.99%	1.51%
314.00 Turbogenerator Units	26.50		0.87%		23.71	-15.9%	81.20%	1.46%
315.00 Accessory Electric Equipment	26.48		0.56%		23.69	-15.9%	98.69%	0.73%
316.00 Miscellaneous Power Plant Equipment	26.53		1.80%		23.73	-15.9%	49.70%	2.79%
317.00 Asset Retirement Cost	26.47		0.52%		23.67		89.71%	0.43%
Total Four Corners Unit 5			0.83%		23.71	-15.9%	79.19%	1.54%
Navajo								
310.00 Rights-of-Way	21.82		0.40%		18.99		66.99%	1.74%
311.00 Structures and Improvements	21.85		2.37%		19.00	-16.1%	55.93%	3.17%
312.00 Boiler Plant Equipment	21.84		2.28%		19.01	-16.2%	53.99%	3.27%
314.00 Turbogenerator Units	21.84		1.67%		19.00	-16.1%	58.59%	3.03%
315.00 Accessory Electric Equipment	21.83		1.71%		18.99	-16.1%	68.18%	2.52%
316.00 Miscellaneous Power Plant Equipment	21.85		2.20%		19.00	-16.2%	54.25%	3.26%
317.00 Asset Retirement Cost	21.82		1.23%		18.98		66.66%	1.76%
Total Navajo			2.16%		19.01	-16.2%	55.96%	3.17%

TUCSON ELECTRIC POWER COMPANY

Statement A

Comparison of Present and Proposed Accrual Rates
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present			Proposed				
	Rem. Life	Fut. Net Salvage	Accrual Rate	Avg. Life	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H	I
Navajo Unit 1								
310.00 Rights-of-Way								
311.00 Structures and Improvements	21.83		1.60%		18.99	-16.1%	74.70%	2.18%
312.00 Boiler Plant Equipment	21.85		2.25%		19.01	-16.2%	52.55%	3.35%
314.00 Turbogenerator Units	21.84		1.61%		19.01	-16.2%	59.25%	3.00%
315.00 Accessory Electric Equipment	21.82		1.28%		18.99	-16.1%	79.09%	1.95%
316.00 Miscellaneous Power Plant Equipment	21.82		1.46%		18.99	-16.1%	75.62%	2.13%
317.00 Asset Retirement Cost	21.82		1.11%		18.98		69.50%	1.61%
Total Navajo Unit 1			2.02%		19.01	-16.2%	57.45%	3.09%
Navajo Unit 2								
310.00 Rights-of-Way								
311.00 Structures and Improvements	21.84		1.26%		19.00	-16.1%	66.06%	2.63%
312.00 Boiler Plant Equipment	21.84		2.25%		19.00	-16.1%	57.95%	3.06%
314.00 Turbogenerator Units	21.84		1.88%		19.00	-16.1%	57.50%	3.08%
315.00 Accessory Electric Equipment	21.84		1.60%		19.00	-16.1%	66.14%	2.63%
316.00 Miscellaneous Power Plant Equipment	21.83		1.57%		18.99	-16.1%	69.15%	2.47%
317.00 Asset Retirement Cost	21.82		1.20%		18.98		66.30%	1.78%
Total Navajo Unit 2			2.08%		19.00	-16.1%	59.01%	3.00%
Navajo Unit 3								
310.00 Rights-of-Way								
311.00 Structures and Improvements	21.84		2.00%		19.00	-16.1%	65.33%	2.67%
312.00 Boiler Plant Equipment	21.84		2.15%		19.01	-16.2%	54.76%	3.23%
314.00 Turbogenerator Units	21.83		1.53%		19.00	-16.1%	59.14%	3.00%
315.00 Accessory Electric Equipment	21.83		1.86%		18.99	-16.1%	67.40%	2.56%
316.00 Miscellaneous Power Plant Equipment	21.83		0.10%		18.99	-16.1%	70.78%	2.39%
317.00 Asset Retirement Cost	21.82		1.34%		18.99		64.63%	1.86%
Total Navajo Unit 3			1.98%		19.01	-16.2%	57.99%	3.06%
Navajo Common								
310.00 Rights-of-Way	21.82		0.40%		18.99		66.99%	1.74%
311.00 Structures and Improvements	21.86		3.06%		19.01	-16.2%	42.39%	3.88%
312.00 Boiler Plant Equipment	21.86		3.17%		19.01	-16.2%	38.52%	4.09%
314.00 Turbogenerator Units					19.02	-16.2%	19.44%	5.09%
315.00 Accessory Electric Equipment	21.86		3.26%		19.02	-16.2%	27.71%	4.65%
316.00 Miscellaneous Power Plant Equipment	21.86		3.14%		19.01	-16.2%	40.33%	3.99%
317.00 Asset Retirement Cost								
Total Navajo Common			3.11%		19.01	-16.2%	40.48%	3.98%
San Juan								
310.00 Rights-of-Way								
311.00 Structures and Improvements	29.84		0.82%		27.08	-15.7%	81.69%	1.26%
312.00 Boiler Plant Equipment	29.74		1.09%		26.99	-15.7%	69.44%	1.71%
314.00 Turbogenerator Units	29.79		1.13%		26.95	-15.7%	70.85%	1.67%
315.00 Accessory Electric Equipment	29.46		0.79%		26.70	-15.8%	80.67%	1.31%
316.00 Miscellaneous Power Plant Equipment	28.99		0.87%		26.27	-15.8%	80.84%	1.33%
317.00 Asset Retirement Cost	29.90		0.89%		27.13		77.17%	0.84%
Total San Juan			1.06%		26.96	-15.7%	71.41%	1.64%

TUCSON ELECTRIC POWER COMPANY

Statement A

Comparison of Present and Proposed Accrual Rates
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present Rem. Life	Present Fut. Net Salvage	Present Accrual Rate	Proposed Avg. Life	Proposed Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H	I
San Juan Unit 1								
310.00 Rights-of-Way								
311.00 Structures and Improvements	31.10		0.75%		28.34	-15.7%	80.37%	1.25%
312.00 Boiler Plant Equipment	31.12		1.00%		28.35	-15.7%	69.18%	1.64%
314.00 Turbogenerator Units	31.11		1.04%		28.35	-15.7%	72.06%	1.54%
315.00 Accessory Electric Equipment	31.10		0.87%		28.34	-15.7%	75.77%	1.41%
316.00 Miscellaneous Power Plant Equipment	31.10		0.75%		28.35	-15.7%	70.97%	1.58%
317.00 Asset Retirement Cost	31.08		0.97%		28.32		74.84%	0.89%
Total San Juan Unit 1			0.98%		28.35	-15.7%	70.99%	1.58%
San Juan Unit 2								
310.00 Rights-of-Way								
311.00 Structures and Improvements	28.34		0.90%		25.56	-15.8%	83.33%	1.27%
312.00 Boiler Plant Equipment	28.36		1.11%		25.58	-15.8%	71.53%	1.73%
314.00 Turbogenerator Units	28.36		1.23%		25.58	-15.8%	69.54%	1.81%
315.00 Accessory Electric Equipment	28.34		0.73%		25.56	-15.8%	84.00%	1.24%
316.00 Miscellaneous Power Plant Equipment	28.34		0.91%		25.56	-15.8%	83.96%	1.25%
317.00 Asset Retirement Cost	28.32		0.77%		25.54		80.26%	0.77%
Total San Juan Unit 2			1.09%		25.58	-15.8%	73.04%	1.67%
San Juan Common								
310.00 Rights-of-Way								
311.00 Structures and Improvements								
312.00 Boiler Plant Equipment	31.16		2.33%		28.39	-15.7%	38.37%	2.72%
314.00 Turbogenerator Units								
315.00 Accessory Electric Equipment								
316.00 Miscellaneous Power Plant Equipment								
317.00 Asset Retirement Cost								
Total San Juan Common			2.33%		28.39	-15.7%	38.37%	2.72%
Springerville								
310.00 Rights-of-Way	13.42		4.81%		10.51		49.14%	4.90%
311.00 Structures and Improvements	19.52		3.08%		16.14	-16.0%	47.63%	4.59%
312.00 Boiler Plant Equipment	35.22		2.38%		26.15	-15.4%	31.95%	3.40%
314.00 Turbogenerator Units	36.76		2.13%		29.43	-15.3%	33.92%	2.96%
315.00 Accessory Electric Equipment	39.69		1.73%		34.90	-15.2%	36.87%	2.31%
316.00 Miscellaneous Power Plant Equipment	37.58		2.32%		24.76	-15.4%	33.54%	3.53%
317.00 Asset Retirement Cost								
Total Springerville			2.39%		25.47	-15.3%	34.98%	3.40%
Springerville Unit 1								
310.00 Rights-of-Way								
311.00 Structures and Improvements	11.33		-1.24%		8.41	-16.7%	32.06%	10.06%
312.00 Boiler Plant Equipment	11.33		7.40%		8.41	-16.7%	19.41%	11.57%
314.00 Turbogenerator Units	11.33		6.97%		8.41	-16.7%	25.70%	10.82%
315.00 Accessory Electric Equipment	11.33		7.08%		8.41	-16.7%	16.90%	11.87%
316.00 Miscellaneous Power Plant Equipment	11.33		6.25%		8.41	-16.7%	21.22%	11.35%
317.00 Asset Retirement Cost								
Total Springerville Unit 1			7.15%		8.41	-16.7%	20.97%	11.38%

TUCSON ELECTRIC POWER COMPANY

Statement A

Comparison of Present and Proposed Accrual Rates
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present			Proposed				
	Rem. Life	Fut. Net Salvage	Accrual Rate	Avg. Life	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H	I
Springerville Unit 2								
310.00 Rights-of-Way								
311.00 Structures and Improvements	43.70		1.57%		41.03	-15.1%	36.28%	1.92%
312.00 Boiler Plant Equipment	43.71		1.49%		41.05	-15.1%	33.60%	1.99%
314.00 Turbogenerator Units	43.70		1.50%		41.04	-15.1%	34.84%	1.96%
315.00 Accessory Electric Equipment	43.70		1.50%		41.03	-15.1%	36.26%	1.92%
316.00 Miscellaneous Power Plant Equipment	43.70		1.51%		41.04	-15.1%	34.36%	1.97%
317.00 Asset Retirement Cost								
Total Springerville Unit 2			1.50%		41.04	-15.1%	34.29%	1.97%
Springerville Unit 1 Common								
310.00 Rights-of-Way	11.33		5.38%		8.41		51.31%	5.79%
311.00 Structures and Improvements	11.33		4.61%		8.41	-16.6%	56.40%	7.16%
312.00 Boiler Plant Equipment	11.33		6.91%		8.41	-16.7%	37.88%	9.37%
314.00 Turbogenerator Units	11.33		6.62%		8.41	-16.7%	41.30%	8.97%
315.00 Accessory Electric Equipment	11.33		6.99%		8.41	-16.7%	25.69%	10.82%
316.00 Miscellaneous Power Plant Equipment	11.33		5.26%		8.41	-16.7%	29.90%	10.32%
317.00 Asset Retirement Cost								
Total Springerville Unit 1 Common			5.06%		8.41	-15.3%	52.64%	7.45%
Springerville Unit 2 Common								
310.00 Rights-of-Way	16.15		4.24%		13.26		46.95%	4.00%
311.00 Structures and Improvements	16.15		3.41%		13.26	-16.4%	51.84%	4.87%
312.00 Boiler Plant Equipment	16.15		4.53%		13.27	-16.4%	42.57%	5.56%
314.00 Turbogenerator Units	16.15		4.49%		13.27	-16.4%	38.75%	5.85%
315.00 Accessory Electric Equipment	16.15		3.25%		13.26	-16.4%	53.69%	4.73%
316.00 Miscellaneous Power Plant Equipment	16.15		3.86%		13.27	-16.4%	40.65%	5.71%
317.00 Asset Retirement Cost								
Total Springerville Unit 2 Common			3.62%		13.26	-15.4%	50.05%	4.93%
Springerville Coal Handling								
310.00 Rights-of-Way								
311.00 Structures and Improvements								
312.00 Boiler Plant Equipment	11.33		4.69%		8.41	-16.7%	34.68%	9.75%
314.00 Turbogenerator Units								
315.00 Accessory Electric Equipment								
316.00 Miscellaneous Power Plant Equipment								
317.00 Asset Retirement Cost								
Total Springerville Coal Handling			4.69%		8.41	-16.7%	34.68%	9.75%

TUCSON ELECTRIC POWER COMPANY

Statement B

Comparison of Present and Proposed Accruals
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/06 Plant Investment	2007 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
STEAM PRODUCTION				
310.00 Rights-of-Way	$4,603,469	$221,057	$225,219	$4,162
311.00 Structures and Improvements	111,087,557	2,815,717	4,144,221	1,328,504
312.00 Boiler Plant Equipment	652,150,583	11,853,922	17,527,090	5,673,168
314.00 Turbogenerator Units	206,960,796	3,523,993	5,170,363	1,646,370
315.00 Accessory Electric Equipment	71,511,709	1,065,926	1,489,648	423,722
316.00 Miscellaneous Power Plant Equipment	19,281,167	337,309	510,302	172,993
317.00 Asset Retirement Cost	69,982	667	811	144
Total Steam Production Plant	$1,065,665,263	$19,818,591	$29,067,654	$9,249,063
TOTAL UTILITY	$1,065,665,263	$19,818,591	$29,067,654	$9,249,063
STEAM PRODUCTION (by Unit)				
Four Corners				
310.00 Rights-of-Way				
311.00 Structures and Improvements	1,691,269	15,874	21,054	5,180
312.00 Boiler Plant Equipment	66,217,489	481,770	961,685	479,915
314.00 Turbogenerator Units	9,486,313	70,718	166,065	95,347
315.00 Accessory Electric Equipment	1,049,881	5,179	7,449	2,270
316.00 Miscellaneous Power Plant Equipment	3,352,180	60,509	92,508	31,999
317.00 Asset Retirement Cost	15,554	72	51	(21)
Total Four Coners	$81,812,686	$634,122	$1,248,812	$614,690
Four Corners Unit 4				
310.00 Rights-of-Way				
311.00 Structures and Improvements	876,104	7,885	10,864	2,979
312.00 Boiler Plant Equipment	34,726,085	236,137	486,165	250,028
314.00 Turbogenerator Units	5,625,444	37,128	109,696	72,568
315.00 Accessory Electric Equipment	538,552	2,316	3,716	1,400
316.00 Miscellaneous Power Plant Equipment	1,697,131	30,718	46,332	15,614
317.00 Asset Retirement Cost	7,407	30	16	(14)
Total Four Corners Unit 4	$43,470,723	$314,214	$656,789	$342,575
Four Corners Unit 5				
310.00 Rights-of-Way				
311.00 Structures and Improvements	815,165	7,989	10,190	2,201
312.00 Boiler Plant Equipment	31,491,404	245,633	475,520	229,887
314.00 Turbogenerator Units	3,860,869	33,590	56,369	22,779
315.00 Accessory Electric Equipment	511,329	2,863	3,733	870
316.00 Miscellaneous Power Plant Equipment	1,655,049	29,791	46,176	16,385
317.00 Asset Retirement Cost	8,147	42	35	(7)
Total Four Corners Unit 5	$38,341,963	$319,908	$592,023	$272,115
Navajo				
310.00 Rights-of-Way	$12,229	$49	$213	$164
311.00 Structures and Improvements	$17,061,160	$403,952	$540,180	$136,228
312.00 Boiler Plant Equipment	$81,964,899	$1,867,719	$2,681,504	$813,785
314.00 Turbogenerator Units	$18,825,320	$314,925	$570,215	$255,290
315.00 Accessory Electric Equipment	$9,708,735	$166,296	$244,747	$78,451
316.00 Miscellaneous Power Plant Equipment	$3,499,563	$77,083	$113,984	$36,901
317.00 Asset Retirement Cost	$33,016	$405	$580	$175
Total Navajo	$131,104,922	$2,830,429	$4,151,423	$1,320,994

TUCSON ELECTRIC POWER COMPANY

Statement B

Comparison of Present and Proposed Accruals
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/06 Plant Investment	2007 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
Navajo Unit 1				
310.00 Rights-of-Way				
311.00 Structures and Improvements	3,215,311	51,445	70,094	18,649
312.00 Boiler Plant Equipment	25,495,011	573,638	854,083	280,445
314.00 Turbogenerator Units	6,327,101	101,866	189,813	87,947
315.00 Accessory Electric Equipment	2,276,860	29,144	44,399	15,255
316.00 Miscellaneous Power Plant Equipment	484,264	7,070	10,315	3,245
317.00 Asset Retirement Cost	9,975	111	161	50
Total Navajo Unit 1	$37,808,522	$763,274	$1,168,865	$405,591
Navajo Unit 2				
310.00 Rights-of-Way				
311.00 Structures and Improvements	1,754,012	22,101	46,131	24,030
312.00 Boiler Plant Equipment	25,161,828	566,141	769,952	203,811
314.00 Turbogenerator Units	6,322,311	118,859	194,727	75,868
315.00 Accessory Electric Equipment	2,555,079	40,881	67,199	26,318
316.00 Miscellaneous Power Plant Equipment	527,267	8,278	13,023	4,745
317.00 Asset Retirement Cost	10,972	132	195	63
Total Navajo Unit 2	$36,331,469	$756,392	$1,091,227	$334,835
Navajo Unit 3				
310.00 Rights-of-Way				
311.00 Structures and Improvements	3,736,208	74,724	99,757	25,033
312.00 Boiler Plant Equipment	25,933,886	557,579	837,665	280,086
314.00 Turbogenerator Units	6,156,885	94,200	184,707	90,507
315.00 Accessory Electric Equipment	4,479,497	83,319	114,675	31,356
316.00 Miscellaneous Power Plant Equipment	539,126	539	12,885	12,346
317.00 Asset Retirement Cost	12,069	162	224	62
Total Navajo Unit 3	$40,857,671	$810,523	$1,249,913	$439,390
Navajo Common				
310.00 Rights-of-Way	$12,229	$49	$213	$164
311.00 Structures and Improvements	8,355,629	255,682	324,198	68,516
312.00 Boiler Plant Equipment	5,374,174	170,361	219,804	49,443
314.00 Turbogenerator Units	19,023		968	968
315.00 Accessory Electric Equipment	397,299	12,952	18,474	5,522
316.00 Miscellaneous Power Plant Equipment	1,948,906	61,196	77,761	16,565
317.00 Asset Retirement Cost				
Total Navajo Common	$16,107,260	$500,240	$641,418	$141,178
San Juan				
310.00 Rights-of-Way				
311.00 Structures and Improvements	19,641,908	160,429	247,273	86,844
312.00 Boiler Plant Equipment	192,931,275	2,102,935	3,305,685	1,202,750
314.00 Turbogenerator Units	66,352,523	750,422	1,107,599	357,177
315.00 Accessory Electric Equipment	16,759,984	131,841	219,351	87,510
316.00 Miscellaneous Power Plant Equipment	6,120,364	53,340	81,361	28,021
317.00 Asset Retirement Cost	21,412	190	180	(10)
Total San Juan	$301,827,466	$3,199,157	$4,961,449	$1,762,292

TUCSON ELECTRIC POWER COMPANY

Statement B

Comparison of Present and Proposed Accruals
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/06 Plant Investment	2007 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
San Juan Unit 1				
310.00 Rights-of-Way				
311.00 Structures and Improvements	10,898,556	81,739	136,232	54,493
312.00 Boiler Plant Equipment	95,024,476	950,245	1,558,401	608,156
314.00 Turbogenerator Units	34,585,905	359,693	532,623	172,930
315.00 Accessory Electric Equipment	6,780,954	58,994	95,611	36,617
316.00 Miscellaneous Power Plant Equipment	1,471,859	11,039	23,255	12,216
317.00 Asset Retirement Cost	12,226	119	109	(10)
Total San Juan Unit 1	$148,773,976	$1,461,829	$2,346,231	$884,402
San Juan Unit 2				
310.00 Rights-of-Way				
311.00 Structures and Improvements	8,743,352	78,690	111,041	32,351
312.00 Boiler Plant Equipment	92,503,107	1,026,784	1,600,304	573,520
314.00 Turbogenerator Units	31,766,618	390,729	574,976	184,247
315.00 Accessory Electric Equipment	9,979,030	72,847	123,740	50,893
316.00 Miscellaneous Power Plant Equipment	4,648,505	42,301	58,106	15,805
317.00 Asset Retirement Cost	9,186	71	71	
Total San Juan Unit 2	$147,649,798	$1,611,422	$2,468,238	$856,816
San Juan Common				
310.00 Rights-of-Way				
311.00 Structures and Improvements				
312.00 Boiler Plant Equipment	5,403,692	125,906	146,980	21,074
314.00 Turbogenerator Units				
315.00 Accessory Electric Equipment				
316.00 Miscellaneous Power Plant Equipment				
317.00 Asset Retirement Cost				
Total San Juan Common	$5,403,692	$125,906	$146,980	$21,074
Springerville				
310.00 Rights-of-Way	$4,591,240	$221,008	$225,006	$3,998
311.00 Structures and Improvements	72,693,220	2,235,462	3,335,714	1,100,252
312.00 Boiler Plant Equipment	311,036,920	7,401,498	10,578,216	3,176,718
314.00 Turbogenerator Units	112,296,640	2,387,928	3,326,484	938,556
315.00 Accessory Electric Equipment	43,993,109	762,610	1,018,101	255,491
316.00 Miscellaneous Power Plant Equipment	6,309,060	146,377	222,449	76,072
317.00 Asset Retirement Cost				
Total Springerville	$550,920,189	$13,154,883	$18,705,970	$5,551,087
Springerville Unit 1				
310.00 Rights-of-Way				
311.00 Structures and Improvements	861,114	(10,678)	86,628	97,306
312.00 Boiler Plant Equipment	40,245,601	2,978,174	4,656,416	1,678,242
314.00 Turbogenerator Units	11,950,982	832,983	1,293,096	460,113
315.00 Accessory Electric Equipment	842,972	59,682	100,061	40,379
316.00 Miscellaneous Power Plant Equipment	588,381	36,774	66,781	30,007
317.00 Asset Retirement Cost				
Total Springerville Unit 1	$54,489,050	$3,896,935	$6,202,982	$2,306,047

TUCSON ELECTRIC POWER COMPANY

Statement B

Comparison of Present and Proposed Accruals
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/06 Plant Investment	2007 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
Springerville Unit 2				
310.00 Rights-of-Way				
311.00 Structures and Improvements	24,743,434	388,472	475,074	86,602
312.00 Boiler Plant Equipment	261,188,107	3,891,703	5,197,643	1,305,940
314.00 Turbogenerator Units	99,064,402	1,485,966	1,941,662	455,696
315.00 Accessory Electric Equipment	40,369,977	605,550	775,104	169,554
316.00 Miscellaneous Power Plant Equipment	4,882,984	73,733	96,195	22,462
317.00 Asset Retirement Cost				
Total Springerville Unit 2	$430,248,904	$6,445,424	$8,485,678	$2,040,254
Springerville Unit 1 Common				
310.00 Rights-of-Way	$2,310,402	$124,300	$133,772	$9,472
311.00 Structures and Improvements	20,995,381	967,887	1,503,269	535,382
312.00 Boiler Plant Equipment	3,997,828	276,250	374,596	98,346
314.00 Turbogenerator Units	537,568	35,587	48,220	12,633
315.00 Accessory Electric Equipment	187,766	13,125	20,316	7,191
316.00 Miscellaneous Power Plant Equipment	252,514	13,282	26,059	12,777
317.00 Asset Retirement Cost				
Total Springerville Unit 1 Common	$28,281,459	$1,430,431	$2,106,232	$675,801
Springerville Unit 2 Common				
310.00 Rights-of-Way	$2,280,838	$96,708	$91,234	($5,474)
311.00 Structures and Improvements	26,093,291	889,781	1,270,743	380,962
312.00 Boiler Plant Equipment	4,700,824	212,947	261,366	48,419
314.00 Turbogenerator Units	743,688	33,392	43,506	10,114
315.00 Accessory Electric Equipment	2,592,394	84,253	122,620	38,367
316.00 Miscellaneous Power Plant Equipment	585,181	22,588	33,414	10,826
317.00 Asset Retirement Cost				
Total Springerville Unit 2 Common	$36,996,216	$1,339,669	$1,822,883	$483,214
Springerville Coal Handling				
310.00 Rights-of-Way				
311.00 Structures and Improvements				
312.00 Boiler Plant Equipment	904,560	42,424	88,195	45,771
314.00 Turbogenerator Units				
315.00 Accessory Electric Equipment				
316.00 Miscellaneous Power Plant Equipment				
317.00 Asset Retirement Cost				
Total Springerville Coal Handling	$904,560	$42,424	$88,195	$45,771

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

Statement C

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
STEAM PRODUCTION							
310.00 Rights-of-Way	$4,603,469	$2,243,896	48.74%	$2,703,740	58.73%	$2,264,543	49.19%
311.00 Structures and Improvements	111,087,557	62,031,397	55.84%	58,579,982	52.73%	61,671,155	55.52%
312.00 Boiler Plant Equipment	652,150,583	332,664,743	51.01%	255,653,619	39.20%	331,533,623	50.84%
314.00 Turbogenerator Units	206,960,796	101,243,094	48.92%	80,581,622	38.94%	103,183,848	49.86%
315.00 Accessory Electric Equipment	71,511,709	38,182,016	53.39%	30,037,991	42.00%	37,400,834	52.30%
316.00 Miscellaneous Power Plant Equipment	19,281,167	10,338,786	53.62%	8,148,458	42.26%	10,653,389	55.25%
317.00 Asset Retirement Cost	69,982	56,347	80.52%	40,637	58.07%	52,886	75.57%
Total Steam Production Plant	$1,065,665,263	$546,760,278	51.31%	$435,746,049	40.89%	$546,760,278	51.31%
TOTAL UTILITY	$1,065,665,263	$546,760,278	51.31%	$435,746,049	40.89%	$546,760,278	51.31%
STEAM PRODUCTION (by Unit)							
Four Corners							
310.00 Rights-of-Way	1,691,269	1,326,997	78.46%	941,017	55.64%	1,461,305	86.40%
311.00 Structures and Improvements	66,217,489	54,976,583	83.02%	34,694,103	52.39%	53,914,192	81.42%
312.00 Boiler Plant Equipment	9,486,313	6,453,998	68.03%	4,531,816	47.77%	7,049,967	74.32%
314.00 Turbogenerator Units	1,049,881	903,960	86.10%	670,547	63.87%	1,041,156	99.17%
315.00 Accessory Electric Equipment	3,352,180	1,497,055	44.66%	1,089,546	32.50%	1,691,612	50.46%
316.00 Miscellaneous Power Plant Equipment	15,554	13,994	89.97%	9,256	59.51%	14,354	92.29%
317.00 Asset Retirement Cost	$81,812,686	$65,172,587	79.66%	$41,936,284	51.26%	$65,172,587	79.66%
Total Four Coners							
Four Corners Unit 4							
310.00 Rights-of-Way	876,104	686,109	78.31%	476,326	54.37%	757,056	86.41%
311.00 Structures and Improvements	34,726,085	29,403,344	84.67%	18,072,083	52.04%	28,723,151	82.71%
312.00 Boiler Plant Equipment	5,625,444	3,457,471	61.46%	2,463,307	43.79%	3,915,095	69.60%
314.00 Turbogenerator Units	538,552	471,168	87.49%	337,570	62.68%	536,522	99.62%
315.00 Accessory Electric Equipment	1,697,131	783,147	46.15%	546,839	32.22%	869,128	51.21%
316.00 Miscellaneous Power Plant Equipment	7,407	6,758	91.24%	4,433	59.85%	7,045	95.12%
317.00 Asset Retirement Cost	$43,470,723	$34,807,998	80.07%	$21,900,558	50.38%	$34,807,998	80.07%
Total Four Corners Unit 4							

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Four Corners Unit 5							
310.00 Rights-of-Way	815,165	640,888	78.62%	464,691	57.01%	704,249	86.39%
311.00 Structures and Improvements	31,491,404	25,573,240	81.21%	16,622,020	52.78%	25,191,041	79.99%
312.00 Boiler Plant Equipment	3,860,869	2,996,527	77.61%	2,068,509	53.58%	3,134,872	81.20%
314.00 Turbogenerator Units	511,329	432,792	84.64%	332,977	65.12%	504,634	98.69%
315.00 Accessory Electric Equipment	1,655,049	713,907	43.14%	542,707	32.79%	822,484	49.70%
316.00 Miscellaneous Power Plant Equipment	8,147	7,236	88.81%	4,823	59.20%	7,309	89.71%
317.00 Asset Retirement Cost	$38,341,963	$30,364,589	79.19%	$20,035,726	52.26%	$30,364,589	79.19%
Total Four Corners Unit 5							
Navajo							
310.00 Rights-of-Way	$12,229	$11,328	92.63%	$7,297	59.67%	$8,192	66.99%
311.00 Structures and Improvements	17,061,160	9,600,745	56.27%	8,651,130	50.71%	9,542,844	55.93%
312.00 Boiler Plant Equipment	81,964,899	44,523,169	54.32%	40,553,560	49.48%	44,251,877	53.99%
314.00 Turbogenerator Units	18,825,320	10,624,131	56.44%	10,112,602	53.72%	11,029,308	58.59%
315.00 Accessory Electric Equipment	9,708,735	6,563,222	67.60%	6,089,978	62.73%	6,619,654	68.18%
316.00 Miscellaneous Power Plant Equipment	3,499,563	2,024,017	57.84%	1,720,624	49.17%	1,898,362	54.25%
317.00 Asset Retirement Cost	33,016	25,633	77.64%	20,203	61.19%	22,009	66.66%
Total Navajo	$131,104,922	$73,372,246	55.96%	$67,155,394	51.22%	$73,372,246	55.96%
Navajo Unit 1							
310.00 Rights-of-Way	3,215,311	2,275,871	70.78%	2,142,278	66.63%	2,401,760	74.70%
311.00 Structures and Improvements	25,495,011	13,705,332	53.76%	11,949,900	46.87%	13,397,327	52.55%
312.00 Boiler Plant Equipment	6,327,101	3,637,290	57.49%	3,343,979	52.85%	3,749,017	59.25%
314.00 Turbogenerator Units	2,276,860	1,742,143	76.52%	1,606,163	70.54%	1,800,708	79.09%
315.00 Accessory Electric Equipment	484,264	353,348	72.97%	326,639	67.45%	366,204	75.62%
316.00 Miscellaneous Power Plant Equipment	9,975	7,966	79.86%	6,184	61.99%	6,933	69.50%
317.00 Asset Retirement Cost	$37,808,522	$21,721,949	57.45%	$19,375,143	51.25%	$21,721,949	57.45%
Total Navajo Unit 1							

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Navajo Unit 2							
310.00 Rights-of-Way							
311.00 Structures and Improvements	1,754,012	1,350,038	76.97%	1,070,563	61.04%	1,158,755	66.06%
312.00 Boiler Plant Equipment	25,161,828	14,479,408	57.55%	13,472,394	53.54%	14,582,244	57.95%
314.00 Turbogenerator Units	6,322,311	3,418,510	54.07%	3,358,875	53.13%	3,635,578	57.50%
315.00 Accessory Electric Equipment	2,555,079	1,808,197	70.77%	1,561,249	61.10%	1,689,864	66.14%
316.00 Miscellaneous Power Plant Equipment	527,267	373,600	70.86%	336,858	63.89%	364,609	69.15%
317.00 Asset Retirement Cost	10,972	8,571	78.12%	6,721	61.26%	7,275	66.30%
Total Navajo Unit 2	$36,331,469	$21,438,325	59.01%	$19,806,661	54.52%	$21,438,325	59.01%
Navajo Unit 3							
310.00 Rights-of-Way							
311.00 Structures and Improvements	3,736,208	2,357,702	63.10%	2,283,475	61.12%	2,440,711	65.33%
312.00 Boiler Plant Equipment	25,933,886	14,284,466	55.08%	13,286,997	51.23%	14,201,916	54.76%
314.00 Turbogenerator Units	6,156,885	3,566,339	57.92%	3,406,454	55.33%	3,641,016	59.14%
315.00 Accessory Electric Equipment	4,479,497	2,945,208	65.75%	2,824,482	63.05%	3,018,971	67.40%
316.00 Miscellaneous Power Plant Equipment	539,126	529,170	98.15%	356,985	66.22%	381,567	70.78%
317.00 Asset Retirement Cost	12,069	9,096	75.37%	7,298	60.47%	7,801	64.63%
Total Navajo Unit 3	$40,857,671	$23,691,981	57.99%	$22,165,691	54.25%	$23,691,981	57.99%
Navajo Common							
310.00 Rights-of-Way	$12,229	$11,328	92.63%	$7,297	59.67%	$8,192	66.99%
311.00 Structures and Improvements	8,355,629	3,617,134	43.29%	3,154,814	37.76%	3,541,618	42.39%
312.00 Boiler Plant Equipment	5,374,174	2,053,963	38.22%	1,844,269	34.32%	2,070,390	38.52%
314.00 Turbogenerator Units	19,023	1,992	10.47%	3,293	17.31%	3,697	19.44%
315.00 Accessory Electric Equipment	397,299	67,674	17.03%	98,085	24.69%	110,111	27.71%
316.00 Miscellaneous Power Plant Equipment	1,948,906	767,899	39.40%	700,140	35.92%	785,983	40.33%
317.00 Asset Retirement Cost							
Total Navajo Common	$16,107,260	$6,519,991	40.48%	$5,807,899	36.06%	$6,519,991	40.48%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
San Juan							
310.00 Rights-of-Way							
311.00 Structures and Improvements	19,641,908	15,643,238	79.64%	10,857,689	55.28%	16,045,843	81.69%
312.00 Boiler Plant Equipment	192,931,275	136,110,708	70.55%	90,598,061	46.96%	133,980,371	69.44%
314.00 Turbogenerator Units	66,352,523	45,812,497	69.04%	31,825,333	47.96%	47,012,267	70.85%
315.00 Accessory Electric Equipment	16,759,984	13,271,065	79.18%	9,190,053	54.83%	13,520,301	80.67%
316.00 Miscellaneous Power Plant Equipment	6,120,364	4,668,549	76.28%	3,378,297	55.20%	4,947,472	80.84%
317.00 Asset Retirement Cost	21,412	16,720	78.09%	11,178	52.20%	16,523	77.17%
Total San Juan	$301,827,466	$215,522,776	71.41%	$145,860,611	48.33%	$215,522,776	71.41%
San Juan Unit 1							
310.00 Rights-of-Way							
311.00 Structures and Improvements	10,898,556	8,679,482	79.64%	5,854,122	53.71%	8,759,684	80.37%
312.00 Boiler Plant Equipment	95,024,476	66,399,880	69.88%	43,932,388	46.23%	65,737,245	69.18%
314.00 Turbogenerator Units	34,585,905	24,355,868	70.42%	16,655,009	48.16%	24,921,350	72.06%
315.00 Accessory Electric Equipment	6,780,954	5,090,781	75.07%	3,433,738	50.64%	5,137,998	75.77%
316.00 Miscellaneous Power Plant Equipment	1,471,859	1,074,950	73.03%	698,136	47.43%	1,044,640	70.97%
317.00 Asset Retirement Cost	12,226	9,106	74.48%	6,115	50.02%	9,150	74.84%
Total San Juan Unit 1	$148,773,976	$105,610,067	70.99%	$70,579,508	47.44%	$105,610,067	70.99%
San Juan Unit 2							
310.00 Rights-of-Way							
311.00 Structures and Improvements	8,743,352	6,963,756	79.65%	5,003,567	57.23%	7,286,159	83.33%
312.00 Boiler Plant Equipment	92,503,107	67,637,690	73.12%	45,440,402	49.12%	66,169,988	71.53%
314.00 Turbogenerator Units	31,766,618	21,456,629	67.54%	15,170,323	47.76%	22,090,916	69.54%
315.00 Accessory Electric Equipment	9,979,030	8,180,284	81.97%	5,756,314	57.68%	8,382,304	84.00%
316.00 Miscellaneous Power Plant Equipment	4,648,505	3,593,600	77.31%	2,680,161	57.66%	3,902,832	83.96%
317.00 Asset Retirement Cost	9,186	7,614	82.88%	5,063	55.11%	7,372	80.26%
Total San Juan Unit 2	$147,649,798	$107,839,571	73.04%	$74,055,831	50.16%	$107,839,571	73.04%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
San Juan Common							
310.00 Rights-of-Way							
311.00 Structures and Improvements							
312.00 Boiler Plant Equipment	5,403,692	2,073,137	38.37%	1,225,271	22.67%	2,073,137	38.37%
314.00 Turbogenerator Units							
315.00 Accessory Electric Equipment							
316.00 Miscellaneous Power Plant Equipment							
317.00 Asset Retirement Cost							
Total San Juan Common	$5,403,692	$2,073,137	38.37%	$1,225,271	22.67%	$2,073,137	38.37%
Springerville							
310.00 Rights-of-Way	$4,591,240	$2,232,567	48.63%	$2,696,443	58.73%	$2,256,351	49.14%
311.00 Structures and Improvements	72,693,220	35,460,417	48.78%	38,130,146	52.45%	34,621,162	47.63%
312.00 Boiler Plant Equipment	311,036,920	97,054,282	31.20%	89,807,894	28.87%	99,387,183	31.95%
314.00 Turbogenerator Units	112,296,640	38,352,468	34.15%	34,111,872	30.38%	38,092,305	33.92%
315.00 Accessory Electric Equipment	43,993,109	17,443,769	39.65%	14,087,413	32.02%	16,219,723	36.87%
316.00 Miscellaneous Power Plant Equipment	6,309,060	2,149,165	34.06%	1,959,992	31.07%	2,115,943	33.54%
317.00 Asset Retirement Cost							
Total Springerville	$550,920,189	$192,692,669	34.98%	$180,793,760	32.82%	$192,692,669	34.98%
Springerville Unit 1							
310.00 Rights-of-Way							
311.00 Structures and Improvements	861,114	683,406	79.36%	428,640	49.78%	276,031	32.06%
312.00 Boiler Plant Equipment	40,245,601	7,213,196	17.92%	12,128,996	30.14%	7,810,706	19.41%
314.00 Turbogenerator Units	11,950,982	3,235,721	27.07%	4,768,975	39.90%	3,071,075	25.70%
315.00 Accessory Electric Equipment	842,972	165,506	19.63%	221,230	26.24%	142,465	16.90%
316.00 Miscellaneous Power Plant Equipment	588,381	127,330	21.64%	193,923	32.96%	124,881	21.22%
317.00 Asset Retirement Cost							
Total Springerville Unit 1	$54,489,050	$11,425,158	20.97%	$17,741,764	32.56%	$11,425,158	20.97%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Springerville Unit 2							
310.00 Rights-of-Way							
311.00 Structures and Improvements	24,743,434	8,935,832	36.11%	7,474,447	30.21%	8,976,591	36.28%
312.00 Boiler Plant Equipment	261,188,107	86,535,343	33.13%	73,063,375	27.97%	87,746,959	33.60%
314.00 Turbogenerator Units	99,064,402	34,585,543	34.91%	28,735,941	29.01%	34,511,018	34.84%
315.00 Accessory Electric Equipment	40,369,977	15,752,197	39.02%	12,187,687	30.19%	14,637,052	36.26%
316.00 Miscellaneous Power Plant Equipment	4,882,984	1,740,420	35.64%	1,396,967	28.61%	1,677,716	34.36%
317.00 Asset Retirement Cost							
Total Springerville Unit 2	$430,248,904	$147,549,335	34.29%	$122,858,417	28.56%	$147,549,335	34.29%
Springerville Unit 1 Common							
310.00 Rights-of-Way	$2,310,402	$1,238,521	53.61%	$1,450,646	62.79%	$1,185,565	51.31%
311.00 Structures and Improvements	20,995,381	12,077,285	57.52%	14,488,936	69.01%	11,841,328	56.40%
312.00 Boiler Plant Equipment	3,997,828	1,226,592	30.68%	1,853,157	46.35%	1,514,524	37.88%
314.00 Turbogenerator Units	537,568	231,279	43.02%	271,645	50.53%	222,007	41.30%
315.00 Accessory Electric Equipment	187,766	46,997	25.03%	59,017	31.43%	48,232	25.69%
316.00 Miscellaneous Power Plant Equipment	252,514	66,475	26.33%	92,374	36.58%	75,495	29.90%
317.00 Asset Retirement Cost							
Total Springerville Unit 1 Common	$28,281,459	$14,887,150	52.64%	$18,215,776	64.41%	$14,887,150	52.64%
Springerville Unit 2 Common							
310.00 Rights-of-Way	$2,280,838	$994,046	43.58%	$1,245,797	54.62%	$1,070,786	46.95%
311.00 Structures and Improvements	26,093,291	13,763,894	52.75%	15,738,123	60.31%	13,527,213	51.84%
312.00 Boiler Plant Equipment	4,700,824	1,765,492	37.56%	2,328,437	49.53%	2,001,336	42.57%
314.00 Turbogenerator Units	743,688	299,925	40.33%	335,311	45.09%	288,206	38.75%
315.00 Accessory Electric Equipment	2,592,394	1,479,069	57.05%	1,619,480	62.47%	1,391,973	53.69%
316.00 Miscellaneous Power Plant Equipment	585,181	214,940	36.73%	276,727	47.29%	237,852	40.65%
317.00 Asset Retirement Cost							
Total Springerville Unit 2 Common	$36,996,216	$18,517,365	50.05%	$21,543,874	58.23%	$18,517,365	50.05%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Springerville Coal Handling							
310.00 Rights-of-Way							
311.00 Structures and Improvements							
312.00 Boiler Plant Equipment	904,560	313,659	34.68%	433,928	47.97%	313,659	34.68%
314.00 Turbogenerator Units							
315.00 Accessory Electric Equipment							
316.00 Miscellaneous Power Plant Equipment							
317.00 Asset Retirement Cost							
Total Springerville Coal Handling	$904,560	$313,659	34.68%	$433,928	47.97%	$313,659	34.68%

TUCSON ELECTRIC POWER COMPANY

Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
STEAM PRODUCTION									
310.00 Rights-of-Way	$4,603,469		$4,603,469						
311.00 Structures and Improvements	111,919,481	831,924	111,087,557	-6.5%	-16.0%	(54,147)	(17,761,235)	(17,815,381)	-15.9%
312.00 Boiler Plant Equipment	716,108,137	63,957,554	652,150,583	-2.8%	-15.6%	(1,814,866)	(101,914,499)	(103,729,366)	-14.5%
314.00 Turbogenerator Units	213,664,701	6,703,905	206,960,796	-7.9%	-15.5%	(529,577)	(32,160,937)	(32,690,513)	-15.3%
315.00 Accessory Electric Equipment	71,685,142	173,433	71,511,709	-10.6%	-15.5%	(18,316)	(11,064,884)	(11,083,199)	-15.5%
316.00 Miscellaneous Power Plant Equipment	19,722,702	441,535	19,281,167	-0.5%	-15.8%	(2,288)	(3,039,348)	(3,041,636)	-15.4%
317.00 Asset Retirement Cost	69,982		69,982						
Total Steam Production Plant	$1,137,773,614	$72,108,351	$1,065,665,263	-3.4%	-15.6%	($2,419,194)	($165,940,902)	($168,360,096)	-14.8%
TOTAL UTILITY	$1,137,773,614	$72,108,351	$1,065,665,263	-3.4%	-15.6%	($2,419,194)	($165,940,902)	($168,360,096)	-14.8%
STEAM PRODUCTION (by Unit)									
Four Corners									
310.00 Rights-of-Way									
311.00 Structures and Improvements	1,692,747	1,478	1,691,269		-15.9%		(268,912)	(268,912)	-15.9%
312.00 Boiler Plant Equipment	70,348,322	4,130,833	66,217,489	-0.5%	-15.9%	(19,255)	(10,528,581)	(10,547,836)	-15.0%
314.00 Turbogenerator Units	10,479,360	993,047	9,486,313		-15.9%		(1,508,324)	(1,508,324)	-14.4%
315.00 Accessory Electric Equipment	1,515,975	466,094	1,049,881		-15.9%		(166,931)	(166,931)	-11.0%
316.00 Miscellaneous Power Plant Equipment	3,495,104	142,924	3,352,180		-16.0%		(534,694)	(534,694)	-15.3%
317.00 Asset Retirement Cost	15,554		15,554						
Total Four Coners	$87,547,062	$5,734,376	$81,812,686	-0.3%	-15.9%	($19,255)	($13,007,441)	($13,026,696)	-14.9%
Four Corners Unit 4									
310.00 Rights-of-Way									
311.00 Structures and Improvements	877,582	1,478	876,104		-15.9%		(139,301)	(139,301)	-15.9%
312.00 Boiler Plant Equipment	37,935,271	3,209,186	34,726,085	-0.6%	-15.9%	(19,255)	(5,521,448)	(5,540,703)	-14.6%
314.00 Turbogenerator Units	6,526,153	900,709	5,625,444		-15.9%		(894,446)	(894,446)	-13.7%
315.00 Accessory Electric Equipment	950,453	411,901	538,552		-15.9%		(85,630)	(85,630)	-9.0%
316.00 Miscellaneous Power Plant Equipment	1,787,450	90,319	1,697,131		-16.0%		(271,541)	(271,541)	-15.2%
317.00 Asset Retirement Cost	7,407		7,407						
Total Four Corners Unit 4	$48,084,316	$4,613,593	$43,470,723	-0.4%	-15.9%	($19,255)	($6,912,364)	($6,931,619)	-14.4%
Four Corners Unit 5									
310.00 Rights-of-Way									
311.00 Structures and Improvements	815,165		815,165		-15.9%		(129,611)	(129,611)	-15.9%
312.00 Boiler Plant Equipment	32,413,051	921,647	31,491,404		-15.9%		(5,007,133)	(5,007,133)	-15.4%
314.00 Turbogenerator Units	3,953,207	92,338	3,860,869		-15.9%		(613,878)	(613,878)	-15.5%
315.00 Accessory Electric Equipment	565,522	54,193	511,329		-15.9%		(81,301)	(81,301)	-14.4%
316.00 Miscellaneous Power Plant Equipment	1,707,654	52,605	1,655,049		-15.9%		(263,153)	(263,153)	-15.4%
317.00 Asset Retirement Cost	8,147		8,147						
Total Four Corners Unit 5	$39,462,746	$1,120,783	$38,341,963		-15.9%		($6,095,077)	($6,095,077)	-15.4%

TUCSON ELECTRIC POWER COMPANY

Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Navajo									
310.00 Rights-of-Way	$12,229		$12,229						
311.00 Structures and Improvements	17,007,839	(53,321)	17,061,160	-0.1%	-16.1%	47	(2,755,202)	(2,755,155)	-16.2%
312.00 Boiler Plant Equipment	86,303,345	4,338,446	81,964,899	-4.3%	-16.2%	(186,761)	(13,253,152)	(13,439,913)	-15.6%
314.00 Turbogenerator Units	19,847,764	1,022,444	18,825,320	-0.9%	-16.1%	(9,262)	(3,037,223)	(3,046,485)	-15.3%
315.00 Accessory Electric Equipment	9,254,823	(453,912)	9,708,735	-0.7%	-16.1%	3,353	(1,563,504)	(1,560,151)	-16.9%
316.00 Miscellaneous Power Plant Equipment	3,418,884	(80,679)	3,499,563	2.8%	-16.2%	(2,288)	(565,379)	(567,667)	-16.6%
317.00 Asset Retirement Cost	33,016		33,016						
Total Navajo	$135,877,900	$4,772,978	$131,104,922	-4.1%	-16.2%	($194,911)	($21,174,459)	($21,369,371)	-15.7%
Navajo Unit 1									
310.00 Rights-of-Way									
311.00 Structures and Improvements	3,158,605	(56,706)	3,215,311		-16.1%		(517,665)	(517,665)	-16.4%
312.00 Boiler Plant Equipment	26,737,456	1,242,445	25,495,011	-10.8%	-16.2%	(134,184)	(4,130,192)	(4,264,376)	-15.9%
314.00 Turbogenerator Units	6,871,927	544,826	6,327,101	-1.7%	-16.2%	(9,262)	(1,024,990)	(1,034,252)	-15.1%
315.00 Accessory Electric Equipment	2,323,462	46,602	2,276,860	-2.8%	-16.1%	(1,305)	(366,574)	(367,879)	-15.8%
316.00 Miscellaneous Power Plant Equipment	492,336	8,072	484,264	-10.8%	-16.1%	(872)	(77,967)	(78,838)	-16.0%
317.00 Asset Retirement Cost	9,975		9,975						
Total Navajo Unit 1	$39,593,761	$1,785,239	$37,808,522	-8.2%	-16.2%	($145,623)	($6,117,388)	($6,263,011)	-15.8%
Navajo Unit 2									
310.00 Rights-of-Way									
311.00 Structures and Improvements	1,754,012		1,754,012		-16.1%		(282,396)	(282,396)	-16.1%
312.00 Boiler Plant Equipment	26,327,572	1,165,744	25,161,828	-1.7%	-16.1%	(19,818)	(4,051,054)	(4,070,872)	-15.5%
314.00 Turbogenerator Units	6,202,040	(120,271)	6,322,311		-16.1%		(1,017,892)	(1,017,892)	-16.4%
315.00 Accessory Electric Equipment	2,565,359	10,280	2,555,079	-10.3%	-16.1%	(1,059)	(411,368)	(412,427)	-16.1%
316.00 Miscellaneous Power Plant Equipment	535,987	8,720	527,267	-10.0%	-16.1%	(872)	(84,890)	(85,762)	-16.0%
317.00 Asset Retirement Cost	10,972		10,972						
Total Navajo Unit 2	$37,395,942	$1,064,473	$36,331,469	-2.0%	-16.1%	($21,748)	($5,847,600)	($5,869,349)	-15.7%
Navajo Unit 3									
310.00 Rights-of-Way									
311.00 Structures and Improvements	3,736,208		3,736,208		-16.1%		(601,529)	(601,529)	-16.1%
312.00 Boiler Plant Equipment	27,831,526	1,897,640	25,933,886	-0.2%	-16.2%	(3,795)	(4,201,290)	(4,205,085)	-15.1%
314.00 Turbogenerator Units	6,754,774	597,889	6,156,885		-16.1%		(991,258)	(991,258)	-14.7%
315.00 Accessory Electric Equipment	3,939,021	(540,476)	4,479,497	0.2%	-16.1%	(1,081)	(721,199)	(722,280)	-18.3%
316.00 Miscellaneous Power Plant Equipment	424,864	(114,262)	539,126	0.8%	-16.1%	(914)	(86,799)	(87,713)	-20.6%
317.00 Asset Retirement Cost	12,069		12,069						
Total Navajo Unit 3	$42,698,462	$1,840,791	$40,857,671	-0.3%	-16.2%	($5,790)	($6,602,076)	($6,607,866)	-15.5%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Navajo Common									
310.00 Rights-of-Way	$12,229		$12,229						
311.00 Structures and Improvements	8,359,014	3,385	8,355,629	1.4%	-16.2%	47	(1,353,612)	(1,353,565)	-16.2%
312.00 Boiler Plant Equipment	5,406,791	32,617	5,374,174	-88.8%	-16.2%	(28,964)	(870,616)	(899,580)	-16.6%
314.00 Turbogenerator Units	19,023		19,023		-16.2%		(3,082)	(3,082)	-16.2%
315.00 Accessory Electric Equipment	426,981	29,682	397,299	22.9%	-16.2%	6,797	(64,362)	(57,565)	-13.5%
316.00 Miscellaneous Power Plant Equipment	1,965,697	16,791	1,948,906	2.2%	-16.2%	369	(315,723)	(315,353)	-16.0%
317.00 Asset Retirement Cost									
Total Navajo Common	$16,189,735	$82,475	$16,107,260	-26.4%	-16.2%	($21,750)	($2,607,395)	($2,629,145)	-16.2%
San Juan									
310.00 Rights-of-Way									
311.00 Structures and Improvements	20,182,217	540,309	19,641,908	-7.8%	-15.7%	(42,101)	(3,092,523)	(3,134,624)	-15.5%
312.00 Boiler Plant Equipment	225,480,360	32,549,085	192,931,275	-1.2%	-15.7%	(390,726)	(30,382,713)	(30,773,439)	-13.6%
314.00 Turbogenerator Units	67,211,769	859,246	66,352,523		-15.7%		(10,449,113)	(10,449,113)	-15.5%
315.00 Accessory Electric Equipment	16,547,642	(212,342)	16,759,984		-15.8%		(2,641,297)	(2,641,297)	-16.0%
316.00 Miscellaneous Power Plant Equipment	6,427,900	307,536	6,120,364		-15.8%		(965,546)	(965,546)	-15.0%
317.00 Asset Retirement Cost	21,412		21,412						
Total San Juan	$335,871,300	$34,043,834	$301,827,466	-1.3%	-15.7%	($432,827)	($47,531,191)	($47,964,018)	-14.3%
San Juan Unit 1									
310.00 Rights-of-Way									
311.00 Structures and Improvements	11,285,211	386,655	10,898,556		-15.7%		(1,711,073)	(1,711,073)	-15.2%
312.00 Boiler Plant Equipment	110,041,867	15,017,391	95,024,476	0.2%	-15.7%	30,035	(14,918,843)	(14,888,808)	-13.5%
314.00 Turbogenerator Units	34,758,116	172,211	34,585,905		-15.7%		(5,429,987)	(5,429,987)	-15.6%
315.00 Accessory Electric Equipment	6,871,277	90,323	6,780,954		-15.7%		(1,064,610)	(1,064,610)	-15.5%
316.00 Miscellaneous Power Plant Equipment	1,663,658	191,799	1,471,859		-15.7%		(231,082)	(231,082)	-13.9%
317.00 Asset Retirement Cost	12,226		12,226						
Total San Juan Unit 1	$164,632,355	$15,858,379	$148,773,976	0.2%	-15.7%	$30,035	($23,355,595)	($23,325,560)	-14.2%
San Juan Unit 2									
310.00 Rights-of-Way									
311.00 Structures and Improvements	8,897,006	153,654	8,743,352	-27.4%	-15.8%	(42,101)	(1,381,450)	(1,423,551)	-16.0%
312.00 Boiler Plant Equipment	110,034,801	17,531,694	92,503,107	-2.4%	-15.8%	(420,761)	(14,615,491)	(15,036,252)	-13.7%
314.00 Turbogenerator Units	32,453,653	687,035	31,766,618		-15.8%		(5,019,126)	(5,019,126)	-15.5%
315.00 Accessory Electric Equipment	9,676,365	(302,665)	9,979,030		-15.8%		(1,576,687)	(1,576,687)	-16.3%
316.00 Miscellaneous Power Plant Equipment	4,764,242	115,737	4,648,505		-15.8%		(734,464)	(734,464)	-15.4%
317.00 Asset Retirement Cost	9,186		9,186						
Total San Juan Unit 2	$165,835,253	$18,185,455	$147,649,798	-2.5%	-15.8%	($462,862)	($23,327,217)	($23,790,079)	-14.3%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
San Juan Common									
310.00 Rights-of-Way									
311.00 Structures and Improvements									
312.00 Boiler Plant Equipment	5,403,692		5,403,692		-15.7%		(848,380)	(848,380)	-15.7%
314.00 Turbogenerator Units									
315.00 Accessory Electric Equipment									
316.00 Miscellaneous Power Plant Equipment									
317.00 Asset Retirement Cost									
Total San Juan Common	$5,403,692		$5,403,692		-15.7%		($848,380)	($848,380)	-15.7%
Springerville									
310.00 Rights-of-Way	$4,591,240		$4,591,240						
311.00 Structures and Improvements	73,036,678	343,458	72,693,220	-3.5%	-16.0%	(12,093)	(11,644,598)	(11,656,691)	-16.0%
312.00 Boiler Plant Equipment	333,976,110	22,939,190	311,036,920	-5.3%	-15.4%	(1,218,124)	(47,750,053)	(48,968,178)	-14.7%
314.00 Turbogenerator Units	116,125,808	3,829,168	112,296,640	-13.6%	-15.3%	(520,315)	(17,166,277)	(17,686,592)	-15.2%
315.00 Accessory Electric Equipment	44,366,702	373,593	43,993,109	-5.8%	-15.2%	(21,668)	(6,693,152)	(6,714,821)	-15.1%
316.00 Miscellaneous Power Plant Equipment	6,380,814	71,754	6,309,060		-15.4%		(973,730)	(973,730)	-15.3%
317.00 Asset Retirement Cost									
Total Springerville	$578,477,352	$27,557,163	$550,920,189	-6.4%	-15.3%	($1,772,200)	($84,227,811)	($86,000,011)	-14.9%
Springerville Unit 1									
310.00 Rights-of-Way									
311.00 Structures and Improvements	893,199	32,085	861,114		-16.7%		(143,806)	(143,806)	-16.1%
312.00 Boiler Plant Equipment	42,487,117	2,241,516	40,245,601	-4.0%	-16.7%	(89,661)	(6,721,015)	(6,810,676)	-16.0%
314.00 Turbogenerator Units	11,950,982		11,950,982		-16.7%		(1,995,814)	(1,995,814)	-16.7%
315.00 Accessory Electric Equipment	842,972		842,972		-16.7%		(140,776)	(140,776)	-16.7%
316.00 Miscellaneous Power Plant Equipment	588,381		588,381		-16.7%		(98,260)	(98,260)	-16.7%
317.00 Asset Retirement Cost									
Total Springerville Unit 1	$56,762,651	$2,273,601	$54,489,050	-3.9%	-16.7%	($89,661)	($9,099,671)	($9,189,332)	-16.2%
Springerville Unit 2									
310.00 Rights-of-Way									
311.00 Structures and Improvements	24,839,410	95,976	24,743,434	-12.6%	-15.1%	(12,093)	(3,736,259)	(3,748,352)	-15.1%
312.00 Boiler Plant Equipment	281,705,629	20,517,522	261,188,107	-5.5%	-15.1%	(1,128,464)	(39,439,404)	(40,567,868)	-14.4%
314.00 Turbogenerator Units	102,890,244	3,825,842	99,064,402	-13.6%	-15.1%	(520,315)	(14,958,725)	(15,479,039)	-15.0%
315.00 Accessory Electric Equipment	40,743,570	373,593	40,369,977	-5.8%	-15.1%	(21,668)	(6,095,867)	(6,117,535)	-15.0%
316.00 Miscellaneous Power Plant Equipment	4,954,738	71,754	4,882,984		-15.1%		(737,331)	(737,331)	-14.9%
317.00 Asset Retirement Cost									
Total Springerville Unit 2	$455,133,591	$24,884,687	$430,248,904	-6.8%	-15.1%	($1,682,540)	($64,967,585)	($66,650,124)	-14.6%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Springerville Unit 1 Common									
310.00 Rights-of-Way	$2,310,402		$2,310,402						
311.00 Structures and Improvements	21,210,778	215,397	20,995,381		-16.6%		(3,485,233)	(3,485,233)	-16.4%
312.00 Boiler Plant Equipment	4,145,566	147,738	3,997,828		-16.7%		(667,637)	(667,637)	-16.1%
314.00 Turbogenerator Units	540,894	3,326	537,568		-16.7%		(89,774)	(89,774)	-16.6%
315.00 Accessory Electric Equipment	187,766		187,766		-16.7%		(31,357)	(31,357)	-16.7%
316.00 Miscellaneous Power Plant Equipment	252,514		252,514		-16.7%		(42,170)	(42,170)	-16.7%
317.00 Asset Retirement Cost									
Total Springerville Unit 1 Common	$28,647,920	$366,461	$28,281,459		-15.3%		($4,316,171)	($4,316,171)	-15.1%
Springerville Unit 2 Common									
310.00 Rights-of-Way	$2,280,838		$2,280,838						
311.00 Structures and Improvements	26,093,291		26,093,291		-16.4%		(4,279,300)	(4,279,300)	-16.4%
312.00 Boiler Plant Equipment	4,733,238	32,414	4,700,824		-16.4%		(770,935)	(770,935)	-16.3%
314.00 Turbogenerator Units	743,688		743,688		-16.4%		(121,965)	(121,965)	-16.4%
315.00 Accessory Electric Equipment	2,592,394		2,592,394		-16.4%		(425,153)	(425,153)	-16.4%
316.00 Miscellaneous Power Plant Equipment	585,181		585,181		-16.4%		(95,970)	(95,970)	-16.4%
317.00 Asset Retirement Cost									
Total Springerville Unit 2 Common	$37,028,630	$32,414	$36,996,216		-15.4%		($5,693,322)	($5,693,322)	-15.4%
Springerville Coal Handling									
310.00 Rights-of-Way									
311.00 Structures and Improvements									
312.00 Boiler Plant Equipment	904,560		904,560		-16.7%		(151,062)	(151,062)	-16.7%
314.00 Turbogenerator Units									
315.00 Accessory Electric Equipment									
316.00 Miscellaneous Power Plant Equipment									
317.00 Asset Retirement Cost									
Total Springerville Coal Handling	$904,560		$904,560		-16.7%		($151,062)	($151,062)	-16.7%

TUCSON ELECTRIC POWER COMPANY

Future Net Salvage
Steam Production

Statement E

Account Description	12/31/06 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
STEAM PRODUCTION (by Unit)									
Four Corners									
310.00 Rights-of-Way									
311.00 Structures and Improvements	1,691,269	108,324	1,582,945		-17.0%		(269,101)	(269,101)	-15.9%
312.00 Boiler Plant Equipment	66,217,489	4,205,582	62,011,907		-17.0%		(10,542,024)	(10,542,024)	-15.9%
314.00 Turbogenerator Units	9,486,313	601,431	8,884,882		-17.0%		(1,510,430)	(1,510,430)	-15.9%
315.00 Accessory Electric Equipment	1,049,881	68,870	981,011		-17.0%		(166,772)	(166,772)	-15.9%
316.00 Miscellaneous Power Plant Equipment	3,352,180	207,084	3,145,096		-17.0%		(534,666)	(534,666)	-15.9%
317.00 Asset Retirement Cost	15,554	1,028	14,526						
Total Four Coners	$81,812,686	$5,192,321	$76,620,365		-17.0%		($13,022,993)	($13,022,993)	-15.9%
Four Corners Unit 4									
310.00 Rights-of-Way									
311.00 Structures and Improvements	876,104	56,037	820,067		-17.0%		(139,411)	(139,411)	-15.9%
312.00 Boiler Plant Equipment	34,726,085	2,205,328	32,520,757		-17.0%		(5,528,529)	(5,528,529)	-15.9%
314.00 Turbogenerator Units	5,625,444	354,843	5,270,601		-17.0%		(896,002)	(896,002)	-15.9%
315.00 Accessory Electric Equipment	538,552	35,374	503,178		-17.0%		(85,540)	(85,540)	-15.9%
316.00 Miscellaneous Power Plant Equipment	1,697,131	104,813	1,592,318		-17.0%		(270,694)	(270,694)	-16.0%
317.00 Asset Retirement Cost	7,407	490	6,917						
Total Four Corners Unit 4	$43,470,723	$2,756,885	$40,713,838		-17.0%		($6,920,177)	($6,920,177)	-15.9%
Four Corners Unit 5									
310.00 Rights-of-Way									
311.00 Structures and Improvements	815,165	52,288	762,877		-17.0%		(129,689)	(129,689)	-15.9%
312.00 Boiler Plant Equipment	31,491,404	2,000,254	29,491,150		-17.0%		(5,013,496)	(5,013,496)	-15.9%
314.00 Turbogenerator Units	3,860,869	246,588	3,614,281		-17.0%		(614,428)	(614,428)	-15.9%
315.00 Accessory Electric Equipment	511,329	33,496	477,833		-17.0%		(81,232)	(81,232)	-15.9%
316.00 Miscellaneous Power Plant Equipment	1,655,049	102,272	1,552,777		-17.0%		(263,972)	(263,972)	-15.9%
317.00 Asset Retirement Cost	8,147	538	7,609						
Total Four Corners Unit 5	$38,341,963	$2,435,435	$35,906,528		-17.0%		($6,102,816)	($6,102,816)	-15.9%

TUCSON ELECTRIC POWER COMPANY

Future Net Salvage
Steam Production

Statement E

Account Description	12/31/06 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Navajo									
310.00 Rights-of-Way	$12,229	$627	$11,602						
311.00 Structures and Improvements	17,061,160	848,987	16,212,173		-17.0%		(2,756,069)	(2,756,069)	-16.2%
312.00 Boiler Plant Equipment	81,964,899	4,081,685	77,883,214		-17.0%		(13,240,146)	(13,240,146)	-16.2%
314.00 Turbogenerator Units	18,825,320	942,375	17,882,945		-17.0%		(3,040,101)	(3,040,101)	-16.1%
315.00 Accessory Electric Equipment	9,708,735	493,995	9,214,740		-17.0%		(1,566,506)	(1,566,506)	-16.1%
316.00 Miscellaneous Power Plant Equipment	3,499,563	173,868	3,325,695		-17.0%		(565,368)	(565,368)	-16.2%
317.00 Asset Retirement Cost	33,016	1,702	31,314						
Total Navajo	$131,104,922	$6,543,239	$124,561,683		-17.0%		($21,168,190)	($21,168,190)	-16.1%
Navajo Unit 1									
310.00 Rights-of-Way									
311.00 Structures and Improvements	3,215,311	164,428	3,050,883		-17.0%		(518,650)	(518,650)	-16.1%
312.00 Boiler Plant Equipment	25,495,011	1,266,803	24,228,208		-17.0%		(4,118,795)	(4,118,795)	-16.2%
314.00 Turbogenerator Units	6,327,101	315,834	6,011,267		-17.0%		(1,021,915)	(1,021,915)	-16.2%
315.00 Accessory Electric Equipment	2,276,860	117,406	2,159,454		-17.0%		(367,107)	(367,107)	-16.1%
316.00 Miscellaneous Power Plant Equipment	484,264	24,846	459,418		-17.0%		(78,101)	(78,101)	-16.1%
317.00 Asset Retirement Cost	9,975	516	9,459						
Total Navajo Unit 1	$37,808,522	$1,889,832	$35,918,690		-17.0%		($6,104,569)	($6,104,569)	-16.1%
Navajo Unit 2									
310.00 Rights-of-Way									
311.00 Structures and Improvements	1,754,012	88,789	1,665,223		-17.0%		(283,088)	(283,088)	-16.1%
312.00 Boiler Plant Equipment	25,161,828	1,260,260	23,901,568		-17.0%		(4,063,266)	(4,063,266)	-16.1%
314.00 Turbogenerator Units	6,322,311	316,264	6,006,047		-17.0%		(1,021,028)	(1,021,028)	-16.1%
315.00 Accessory Electric Equipment	2,555,079	129,561	2,425,518		-17.0%		(412,338)	(412,338)	-16.1%
316.00 Miscellaneous Power Plant Equipment	527,267	26,867	500,400		-17.0%		(85,068)	(85,068)	-16.1%
317.00 Asset Retirement Cost	10,972	566	10,406						
Total Navajo Unit 2	$36,331,469	$1,822,307	$34,509,162		-17.0%		($5,864,788)	($5,864,788)	-16.1%

TUCSON ELECTRIC POWER COMPANY

Future Net Salvage
Steam Production

Statement E

Account Description	12/31/06 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Navajo Unit 3									
310.00 Rights-of-Way									
311.00 Structures and Improvements	3,736,208	189,091	3,547,117		-17.0%		(603,010)	(603,010)	-16.1%
312.00 Boiler Plant Equipment	25,933,886	1,293,691	24,640,195		-17.0%		(4,188,833)	(4,188,833)	-16.2%
314.00 Turbogenerator Units	6,156,885	309,366	5,847,519		-17.0%		(994,078)	(994,078)	-16.1%
315.00 Accessory Electric Equipment	4,479,497	227,884	4,251,613		-17.0%		(722,774)	(722,774)	-16.1%
316.00 Miscellaneous Power Plant Equipment	539,126	27,436	511,690		-17.0%		(86,987)	(86,987)	-16.1%
317.00 Asset Retirement Cost	12,069	621	11,448						
Total Navajo Unit 3	$40,857,671	$2,048,088	$38,809,583		-17.0%		($6,595,683)	($6,595,683)	-16.1%
Navajo Common									
310.00 Rights-of-Way	$12,229	$627	$11,602						
311.00 Structures and Improvements	8,355,629	406,679	7,948,950		-17.0%		(1,351,322)	(1,351,322)	-16.2%
312.00 Boiler Plant Equipment	5,374,174	260,932	5,113,242		-17.0%		(869,251)	(869,251)	-16.2%
314.00 Turbogenerator Units	19,023	912	18,111		-17.0%		(3,079)	(3,079)	-16.2%
315.00 Accessory Electric Equipment	397,299	19,143	378,156		-17.0%		(64,287)	(64,287)	-16.2%
316.00 Miscellaneous Power Plant Equipment	1,948,906	94,719	1,854,187		-17.0%		(315,212)	(315,212)	-16.2%
317.00 Asset Retirement Cost									
Total Navajo Common	$16,107,260	$783,011	$15,324,249		-17.0%		($2,603,150)	($2,603,150)	-16.2%
San Juan									
310.00 Rights-of-Way									
311.00 Structures and Improvements	19,641,908	1,457,745	18,184,163		-17.0%		(3,091,308)	(3,091,308)	-15.7%
312.00 Boiler Plant Equipment	192,931,275	14,062,556	178,868,719		-17.0%		(30,407,682)	(30,407,682)	-15.8%
314.00 Turbogenerator Units	66,352,523	4,844,526	61,507,997		-17.0%		(10,456,359)	(10,456,359)	-15.8%
315.00 Accessory Electric Equipment	16,759,984	1,222,482	15,537,502		-17.0%		(2,641,375)	(2,641,375)	-15.8%
316.00 Miscellaneous Power Plant Equipment	6,120,364	438,126	5,682,238		-17.0%		(965,980)	(965,980)	-15.8%
317.00 Asset Retirement Cost	21,412	1,611	19,801						
Total San Juan	$301,827,466	$22,027,047	$279,800,419		-17.0%		($47,562,705)	($47,562,705)	-15.8%

TUCSON ELECTRIC POWER COMPANY

Statement E

Future Net Salvage
Steam Production

Account Description	12/31/06 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
San Juan Unit 1									
310.00 Rights-of-Way									
311.00 Structures and Improvements	10,898,556	846,893	10,051,663		-17.0%		(1,708,783)	(1,708,783)	-15.7%
312.00 Boiler Plant Equipment	95,024,476	7,292,254	87,732,222		-17.0%		(14,914,478)	(14,914,478)	-15.7%
314.00 Turbogenerator Units	34,585,905	2,663,365	31,922,540		-17.0%		(5,426,832)	(5,426,832)	-15.7%
315.00 Accessory Electric Equipment	6,780,954	524,249	6,256,705		-17.0%		(1,063,640)	(1,063,640)	-15.7%
316.00 Miscellaneous Power Plant Equipment	1,471,859	113,095	1,358,764		-17.0%		(230,990)	(230,990)	-15.7%
317.00 Asset Retirement Cost	12,226	960	11,266						
Total San Juan Unit 1	$148,773,976	$11,440,816	$137,333,160		-17.0%		($23,344,722)	($23,344,722)	-15.7%
San Juan Unit 2									
310.00 Rights-of-Way									
311.00 Structures and Improvements	8,743,352	610,853	8,132,499		-17.0%		(1,382,525)	(1,382,525)	-15.8%
312.00 Boiler Plant Equipment	92,503,107	6,371,001	86,132,106		-17.0%		(14,642,458)	(14,642,458)	-15.8%
314.00 Turbogenerator Units	31,766,618	2,181,161	29,585,457		-17.0%		(5,029,528)	(5,029,528)	-15.8%
315.00 Accessory Electric Equipment	9,979,030	698,233	9,280,797		-17.0%		(1,577,735)	(1,577,735)	-15.8%
316.00 Miscellaneous Power Plant Equipment	4,648,505	325,031	4,323,474		-17.0%		(734,991)	(734,991)	-15.8%
317.00 Asset Retirement Cost	9,186	652	8,534						
Total San Juan Unit 2	$147,649,798	$10,186,931	$137,462,867		-17.0%		($23,367,237)	($23,367,237)	-15.8%
San Juan Common									
310.00 Rights-of-Way									
311.00 Structures and Improvements									
312.00 Boiler Plant Equipment	5,403,692	399,301	5,004,391		-17.0%		(850,747)	(850,747)	-15.7%
314.00 Turbogenerator Units									
315.00 Accessory Electric Equipment									
316.00 Miscellaneous Power Plant Equipment									
317.00 Asset Retirement Cost									
Total San Juan Common	$5,403,692	$399,301	$5,004,391		-17.0%		($850,747)	($850,747)	-15.7%

TUCSON ELECTRIC POWER COMPANY

Future Net Salvage
Steam Production

Statement E

Account Description	12/31/06 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Springerville									
310.00 Rights-of-Way	$4,591,240	$125,263	$4,465,977						
311.00 Structures and Improvements	72,693,220	4,107,229	68,585,991		-17.0%		(11,659,618)	(11,659,618)	-16.0%
312.00 Boiler Plant Equipment	311,036,920	30,236,158	280,800,762		-17.0%		(47,736,129)	(47,736,129)	-15.3%
314.00 Turbogenerator Units	112,296,640	11,362,270	100,934,370		-17.0%		(17,158,843)	(17,158,843)	-15.3%
315.00 Accessory Electric Equipment	43,993,109	4,632,945	39,360,164		-17.0%		(6,691,228)	(6,691,228)	-15.2%
316.00 Miscellaneous Power Plant Equipment	6,309,060	582,461	5,726,599		-17.0%		(973,522)	(973,522)	-15.4%
317.00 Asset Retirement Cost									
Total Springerville	$550,920,189	$51,046,326	$499,873,863		-17.0%		($84,219,341)	($84,219,341)	-15.3%
Springerville Unit 1									
310.00 Rights-of-Way									
311.00 Structures and Improvements	861,114	17,580	843,534		-17.0%		(143,401)	(143,401)	-16.7%
312.00 Boiler Plant Equipment	40,245,601	812,317	39,433,284		-17.0%		(6,703,658)	(6,703,658)	-16.7%
314.00 Turbogenerator Units	11,950,982	242,743	11,708,239		-17.0%		(1,990,401)	(1,990,401)	-16.7%
315.00 Accessory Electric Equipment	842,972	16,985	825,987		-17.0%		(140,418)	(140,418)	-16.7%
316.00 Miscellaneous Power Plant Equipment	588,381	11,878	576,503		-17.0%		(98,005)	(98,005)	-16.7%
317.00 Asset Retirement Cost									
Total Springerville Unit 1	$54,489,050	$1,101,504	$53,387,546		-17.0%		($9,075,883)	($9,075,883)	-16.7%
Springerville Unit 2									
310.00 Rights-of-Way									
311.00 Structures and Improvements	24,743,434	2,773,077	21,970,357		-17.0%		(3,734,961)	(3,734,961)	-15.1%
312.00 Boiler Plant Equipment	261,188,107	29,166,666	232,021,441		-17.0%		(39,443,645)	(39,443,645)	-15.1%
314.00 Turbogenerator Units	99,064,402	11,083,817	87,980,585		-17.0%		(14,956,699)	(14,956,699)	-15.1%
315.00 Accessory Electric Equipment	40,369,977	4,524,379	35,845,598		-17.0%		(6,093,752)	(6,093,752)	-15.1%
316.00 Miscellaneous Power Plant Equipment	4,882,984	545,877	4,337,107		-17.0%		(737,308)	(737,308)	-15.1%
317.00 Asset Retirement Cost									
Total Springerville Unit 2	$430,248,904	$48,093,815	$382,155,089		-17.0%		($64,966,365)	($64,966,365)	-15.1%

TUCSON ELECTRIC POWER COMPANY

Future Net Salvage
Steam Production

Statement E

Account Description	12/31/06 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Springerville Unit 1 Common									
310.00 Rights-of-Way	$2,310,402	$47,946	$2,262,456						
311.00 Structures and Improvements	20,995,381	434,433	20,560,948		-17.0%		(3,495,361)	(3,495,361)	-16.6%
312.00 Boiler Plant Equipment	3,997,828	81,380	3,916,448		-17.0%		(665,796)	(665,796)	-16.7%
314.00 Turbogenerator Units	537,568	10,942	526,626		-17.0%		(89,526)	(89,526)	-16.7%
315.00 Accessory Electric Equipment	187,766	3,790	183,976		-17.0%		(31,276)	(31,276)	-16.7%
316.00 Miscellaneous Power Plant Equipment	252,514	5,119	247,395		-17.0%		(42,057)	(42,057)	-16.7%
317.00 Asset Retirement Cost									
Total Springerville Unit 1 Common	$28,281,459	$583,611	$27,697,848		-17.0%		($4,324,017)	($4,324,017)	-15.3%
Springerville Unit 2 Common									
310.00 Rights-of-Way	$2,280,838	$77,317	$2,203,521						
311.00 Structures and Improvements	26,093,291	882,139	25,211,152		-17.0%		(4,285,896)	(4,285,896)	-16.4%
312.00 Boiler Plant Equipment	4,700,824	157,271	4,543,553		-17.0%		(772,404)	(772,404)	-16.4%
314.00 Turbogenerator Units	743,688	24,767	718,921		-17.0%		(122,217)	(122,217)	-16.4%
315.00 Accessory Electric Equipment	2,592,394	87,791	2,504,603		-17.0%		(425,783)	(425,783)	-16.4%
316.00 Miscellaneous Power Plant Equipment	585,181	19,586	565,595		-17.0%		(96,151)	(96,151)	-16.4%
317.00 Asset Retirement Cost									
Total Springerville Unit 2 Common	$36,996,216	$1,248,871	$35,747,345		-17.0%		($5,702,450)	($5,702,450)	-15.4%
Springerville Coal Handling									
310.00 Rights-of-Way									
311.00 Structures and Improvements									
312.00 Boiler Plant Equipment	904,560	18,526	886,034		-17.0%		(150,626)	(150,626)	-16.7%
314.00 Turbogenerator Units									
315.00 Accessory Electric Equipment									
316.00 Miscellaneous Power Plant Equipment									
317.00 Asset Retirement Cost									
Total Springerville Coal Handling	$904,560	$18,526	$886,034		-17.0%		($150,626)	($150,626)	-16.7%

TUCSON ELECTRIC POWER COMPANY

Statement F

Present and Proposed Parameters
Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
STEAM PRODUCTION												
310.00 Rights-of-Way			25.39	13.43					25.50	10.52		
311.00 Structures and Improvements			31.91	18.37					32.72	17.87	-15.9	-16.0
312.00 Boiler Plant Equipment			35.11	22.26					37.64	25.12	-14.5	-15.6
314.00 Turbogenerator Units			37.80	23.35					41.13	27.34	-15.3	-15.5
315.00 Accessory Electric Equipment			44.00	27.51					47.83	30.45	-15.5	-15.5
316.00 Miscellaneous Power Plant Equipment			37.44	21.21					37.26	23.73	-15.4	-15.8
317.00 Asset Retirement Cost			46.67	18.50					53.09	22.26		
Total Steam Production Plant									38.13	24.80	-14.8	-15.6
TOTAL UTILITY									38.13	24.80	-14.8	-15.6
STEAM PRODUCTION (by Unit)												
Four Corners												
310.00 Rights-of-Way												
311.00 Structures and Improvements			46.03	26.50					45.59	23.71	-15.9	-15.9
312.00 Boiler Plant Equipment			43.41	26.51					42.93	23.71	-15.0	-15.9
314.00 Turbogenerator Units			45.00	26.50					39.81	23.72	-14.4	-15.9
315.00 Accessory Electric Equipment			53.14	26.47					50.76	23.68	-11.0	-15.9
316.00 Miscellaneous Power Plant Equipment			36.98	26.53					32.79	23.73	-15.3	-16.0
317.00 Asset Retirement Cost			58.19	26.47					58.45	23.67		
Total Four Coners									42.15	23.71	-14.9	-15.9

TUCSON ELECTRIC POWER COMPANY

Statement F

Present and Proposed Parameters
Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Four Corners Unit 4												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2031	200-SC	45.61	26.50			2031	200-SC	44.66	23.71	-15.9	-15.9
312.00 Boiler Plant Equipment	2031	200-SC	42.93	26.51			2031	200-SC	42.55	23.71	-14.6	-15.9
314.00 Turbogenerator Units	2031	200-SC	44.55	26.50			2031	200-SC	37.40	23.72	-13.7	-15.9
315.00 Accessory Electric Equipment	2031	200-SC	51.10	26.47			2031	200-SC	48.50	23.68	-9.0	-15.9
316.00 Miscellaneous Power Plant Equipment	2031	200-SC	36.21	26.53			2031	200-SC	32.63	23.73	-15.2	-16.0
317.00 Asset Retirement Cost	2031	200-SC	58.68	26.47			2031	200-SC	58.95	23.67		
Total Four Corners Unit 4									41.42	23.71	-14.4	-15.9
Four Corners Unit 5												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2031	200-SC	46.48	26.50			2031	200-SC	46.64	23.70	-15.9	-15.9
312.00 Boiler Plant Equipment	2031	200-SC	43.95	26.51			2031	200-SC	43.35	23.71	-15.4	-15.9
314.00 Turbogenerator Units	2031	200-SC	45.53	26.50			2031	200-SC	43.94	23.71	-15.5	-15.9
315.00 Accessory Electric Equipment	2031	200-SC	55.48	26.48			2031	200-SC	53.37	23.69	-14.4	-15.9
316.00 Miscellaneous Power Plant Equipment	2031	200-SC	37.78	26.53			2031	200-SC	32.95	23.73	-15.4	-15.9
317.00 Asset Retirement Cost	2031	200-SC	57.75	26.47			2031	200-SC	58.01	23.67		
Total Four Corners Unit 5									43.00	23.71	-15.4	-15.9
Navajo												
310.00 Rights-of-Way			47.03	21.82					47.09	18.99		
311.00 Structures and Improvements			33.64	21.85					33.74	19.00	-16.2	-16.1
312.00 Boiler Plant Equipment			34.31	21.84					32.94	19.01	-15.6	-16.2
314.00 Turbogenerator Units			41.53	21.84					35.14	19.00	-15.3	-16.1
315.00 Accessory Electric Equipment			42.23	21.83					41.58	18.99	-16.9	-16.1
316.00 Miscellaneous Power Plant Equipment			33.60	21.85					33.05	19.00	-16.6	-16.2
317.00 Asset Retirement Cost			48.77	21.82					48.92	18.98		
Total Navajo									33.88	19.01	-15.7	-16.2

TUCSON ELECTRIC POWER COMPANY

Present and Proposed Parameters
Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Navajo Unit 1												
310.00 Rights-of-Way	2026	200-SC	44.41	21.83			2026	200-SC	44.68	18.99	-16.4	-16.1
311.00 Structures and Improvements	2026	200-SC	33.44	21.85			2026	200-SC	31.78	19.01	-15.9	-16.2
312.00 Boiler Plant Equipment	2026	200-SC	40.63	21.84			2026	200-SC	34.54	19.01	-15.1	-16.2
314.00 Turbogenerator Units	2026	200-SC	48.32	21.82			2026	200-SC	48.27	18.99	-15.8	-16.1
315.00 Accessory Electric Equipment	2026	200-SC	45.44	21.82			2026	200-SC	45.28	18.99	-16.0	-16.1
316.00 Miscellaneous Power Plant Equipment	2026	200-SC	49.71	21.82			2026	200-SC	49.94	18.98		
317.00 Asset Retirement Cost									33.90	19.01	-15.8	-16.2
Total Navajo Unit 1												
Navajo Unit 2												
310.00 Rights-of-Way	2026	200-SC	39.91	21.84			2026	200-SC	40.06	19.00	-16.1	-16.1
311.00 Structures and Improvements	2026	200-SC	35.54	21.84			2026	200-SC	35.08	19.00	-15.5	-16.1
312.00 Boiler Plant Equipment	2026	200-SC	40.94	21.84			2026	200-SC	35.12	19.00	-16.4	-16.1
314.00 Turbogenerator Units	2026	200-SC	39.96	21.84			2026	200-SC	40.11	19.00	-16.1	-16.1
315.00 Accessory Electric Equipment	2026	200-SC	42.30	21.83			2026	200-SC	42.19	18.99	-16.0	-16.1
316.00 Miscellaneous Power Plant Equipment	2026	200-SC	48.76	21.82			2026	200-SC	48.99	18.98		
317.00 Asset Retirement Cost									35.71	19.00	-15.7	-16.1
Total Navajo Unit 2												
Navajo Unit 3												
310.00 Rights-of-Way	2026	200-SC	39.98	21.84			2026	200-SC	40.12	19.00	-16.1	-16.1
311.00 Structures and Improvements	2026	200-SC	35.64	21.84			2026	200-SC	33.68	19.01	-15.1	-16.2
312.00 Boiler Plant Equipment	2026	200-SC	43.16	21.83			2026	200-SC	35.86	19.00	-14.7	-16.1
314.00 Turbogenerator Units	2026	200-SC	42.18	21.83			2026	200-SC	42.35	18.99	-18.3	-16.1
315.00 Accessory Electric Equipment	2026	200-SC	45.08	21.83			2026	200-SC	45.91	18.99	-20.6	-16.1
316.00 Miscellaneous Power Plant Equipment	2026	200-SC	47.82	21.82			2026	200-SC	48.04	18.99		
317.00 Asset Retirement Cost									35.45	19.01	-15.5	-16.2
Total Navajo Unit 3												

TUCSON ELECTRIC POWER COMPANY

Statement F

Present and Proposed Parameters
Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Navajo Common												
310.00 Rights-of-Way	2026	200-SC	46.88	21.82			2026	200-SC	47.09	18.99		
311.00 Structures and Improvements	2026	200-SC	28.12	21.86			2026	200-SC	28.16	19.01	-16.2	-16.2
312.00 Boiler Plant Equipment	2026	200-SC	27.76	21.86			2026	200-SC	27.07	19.01	-16.6	-16.2
314.00 Turbogenerator Units							2026	200-SC	22.35	19.02	-16.2	-16.2
315.00 Accessory Electric Equipment	2026	200-SC	27.37	21.86			2026	200-SC	23.59	19.02	-13.5	-16.2
316.00 Miscellaneous Power Plant Equipment	2026	200-SC	27.99	21.86			2026	200-SC	27.47	19.01	-16.0	-16.2
317.00 Asset Retirement Cost												
Total Navajo Common									27.57	19.01	-16.2	-16.2
San Juan												
310.00 Rights-of-Way												
311.00 Structures and Improvements			51.86	29.84					51.74	27.08	-15.5	-15.7
312.00 Boiler Plant Equipment			45.79	29.74					44.61	26.99	-13.6	-15.7
314.00 Turbogenerator Units			47.37	29.79					45.94	26.95	-15.5	-15.7
315.00 Accessory Electric Equipment			51.49	29.46					50.81	26.70	-16.0	-15.8
316.00 Miscellaneous Power Plant Equipment			51.58	28.99					49.86	26.27	-15.0	-15.8
317.00 Asset Retirement Cost			56.54	29.90					56.76	27.13		
Total San Juan									45.72	26.96	-14.3	-15.7
San Juan Unit 1												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2036	200-SC	52.87	31.10			2036	200-SC	52.67	28.34	-15.2	-15.7
312.00 Boiler Plant Equipment	2036	200-SC	47.97	31.12			2036	200-SC	46.32	28.35	-13.5	-15.7
314.00 Turbogenerator Units	2036	200-SC	49.20	31.11			2036	200-SC	48.52	28.35	-15.6	-15.7
315.00 Accessory Electric Equipment	2036	200-SC	51.07	31.10			2036	200-SC	50.31	28.34	-15.5	-15.7
316.00 Miscellaneous Power Plant Equipment	2036	200-SC	50.31	31.10			2036	200-SC	47.30	28.35	-13.9	-15.7
317.00 Asset Retirement Cost	2036	200-SC	56.45	31.08			2036	200-SC	56.66	28.32		
Total San Juan Unit 1									47.42	28.35	-14.2	-15.7

TUCSON ELECTRIC POWER COMPANY

Statement F

Present and Proposed Parameters
Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
San Juan Unit 2												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2033	200-SC	50.66	28.34			2033	200-SC	50.62	25.56	-16.0	-15.8
312.00 Boiler Plant Equipment	2033	200-SC	44.55	28.36			2033	200-SC	43.62	25.58	-13.7	-15.8
314.00 Turbogenerator Units	2033	200-SC	45.39	28.36			2033	200-SC	43.42	25.58	-15.5	-15.8
315.00 Accessory Electric Equipment	2033	200-SC	51.77	28.34			2033	200-SC	51.15	25.56	-16.3	-15.8
316.00 Miscellaneous Power Plant Equipment	2033	200-SC	51.97	28.34			2033	200-SC	50.73	25.56	-15.4	-15.8
317.00 Asset Retirement Cost	2033	200-SC	56.66	28.32			2033	200-SC	56.90	25.54		
Total San Juan Unit 2									44.58	25.58	-14.3	-15.8
San Juan Common												
310.00 Rights-of-Way												
311.00 Structures and Improvements												
312.00 Boiler Plant Equipment	2036	200-SC	35.40	31.16			2036	200-SC	35.31	28.39	-15.7	-15.7
314.00 Turbogenerator Units												
315.00 Accessory Electric Equipment												
316.00 Miscellaneous Power Plant Equipment												
317.00 Asset Retirement Cost												
Total San Juan Common									35.31	28.39	-15.7	-15.7
Springerville												
310.00 Rights-of-Way			25.36	13.42					25.47	10.51		
311.00 Structures and Improvements			30.97	19.52					29.40	16.14	-16.0	-16.0
312.00 Boiler Plant Equipment			44.79	35.22					34.67	26.15	-14.7	-15.4
314.00 Turbogenerator Units			47.30	36.76					39.92	29.43	-15.2	-15.3
315.00 Accessory Electric Equipment			51.35	39.69					48.29	34.90	-15.1	-15.2
316.00 Miscellaneous Power Plant Equipment			49.17	37.58					33.82	24.76	-15.3	-15.4
317.00 Asset Retirement Cost												
Total Springerville									35.46	25.47	-14.9	-15.3

TUCSON ELECTRIC POWER COMPANY

Present and Proposed Parameters

Company Vintage Group Procedure

Statement F

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Springerville Unit 1												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2015	200-SC	17.22	11.33			2015	200-SC	14.59	8.41	-16.1	-16.7
312.00 Boiler Plant Equipment	2015	200-SC	15.05	11.33			2015	200-SC	11.27	8.41	-16.0	-16.7
314.00 Turbogenerator Units	2015	200-SC	17.04	11.33			2015	200-SC	12.78	8.41	-16.7	-16.7
315.00 Accessory Electric Equipment	2015	200-SC	14.10	11.33			2015	200-SC	10.85	8.41	-16.7	-16.7
316.00 Miscellaneous Power Plant Equipment	2015	200-SC	17.72	11.33			2015	200-SC	11.72	8.41	-16.7	-16.7
317.00 Asset Retirement Cost												
Total Springerville Unit 1									11.61	8.41	-16.2	-16.7
Springerville Unit 2												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2050	200-SC	55.63	43.70			2050	200-SC	55.63	41.03	-15.1	-15.1
312.00 Boiler Plant Equipment	2050	200-SC	55.14	43.71			2050	200-SC	53.90	41.05	-14.4	-15.1
314.00 Turbogenerator Units	2050	200-SC	55.61	43.70			2050	200-SC	54.82	41.04	-15.0	-15.1
315.00 Accessory Electric Equipment	2050	200-SC	55.60	43.70			2050	200-SC	55.57	41.03	-15.0	-15.1
316.00 Miscellaneous Power Plant Equipment	2050	200-SC	55.58	43.70			2050	200-SC	54.52	41.04	-14.9	-15.1
317.00 Asset Retirement Cost												
Total Springerville Unit 2									54.37	41.04	-14.6	-15.1
Springerville Unit 1 Common												
310.00 Rights-of-Way	2015	200-SC	22.50	11.33			2015	200-SC	22.60	8.41		
311.00 Structures and Improvements	2015	200-SC	21.88	11.33			2015	200-SC	20.57	8.41	-16.4	-16.6
312.00 Boiler Plant Equipment	2015	200-SC	16.86	11.33			2015	200-SC	13.88	8.41	-16.1	-16.7
314.00 Turbogenerator Units	2015	200-SC	15.06	11.33			2015	200-SC	14.82	8.41	-16.6	-16.7
315.00 Accessory Electric Equipment	2015	200-SC	13.92	11.33			2015	200-SC	11.51	8.41	-16.7	-16.7
316.00 Miscellaneous Power Plant Equipment	2015	200-SC	19.76	11.33			2015	200-SC	12.25	8.41	-16.7	-16.7
317.00 Asset Retirement Cost												
Total Springerville Unit 1 Common									19.06	8.41	-15.1	-15.3

TUCSON ELECTRIC POWER COMPANY

Statement F

Present and Proposed Parameters
Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Springerville Unit 2 Common												
310.00 Rights-of-Way	2020	200-SC	29.10	16.15			2020	200-SC	29.22	13.26		
311.00 Structures and Improvements	2020	200-SC	28.53	16.15			2020	200-SC	27.52	13.26	-16.4	-16.4
312.00 Boiler Plant Equipment	2020	200-SC	24.08	16.15			2020	200-SC	23.08	13.27	-16.3	-16.4
314.00 Turbogenerator Units	2020	200-SC	21.82	16.15			2020	200-SC	21.66	13.27	-16.4	-16.4
315.00 Accessory Electric Equipment	2020	200-SC	28.62	16.15			2020	200-SC	28.62	13.26	-16.4	-16.4
316.00 Miscellaneous Power Plant Equipment	2020	200-SC	28.12	16.15			2020	200-SC	22.35	13.27	-16.4	-16.4
317.00 Asset Retirement Cost												
Total Springerville Unit 2 Common									26.79	13.26	-15.4	-15.4
Springerville Coal Handling												
310.00 Rights-of-Way												
311.00 Structures and Improvements												
312.00 Boiler Plant Equipment	2015	200-SC	23.90	11.33			2015	200-SC	14.28	8.41	-16.7	-16.7
314.00 Turbogenerator Units												
315.00 Accessory Electric Equipment												
316.00 Miscellaneous Power Plant Equipment												
317.00 Asset Retirement Cost												
Total Springerville Coal Handling									14.28	8.41	-16.7	-16.7

EXHIBIT

KGK-3

EXHIBIT KGK – 3

SUPPORT FOR COMPANY PROPOSED ADJUSTMENTS

TUCSON ELECTRIC POWER COMPANY
RATE BASE ADJUSTMENT ENTRY FORM
TEST YEAR ENDED DECEMBER 31, 2006

NEW PRO FORMA FOR REBUTTAL PER STF 1.86

ADJUSTMENT NAME:	Plant in Service - Delayed Unitization
ADJUSTMENT TO:	Rate Base
DATE SUBMITTED:	February 11, 2008
PREPARED BY:	Plant Accounting
REVIEWED BY:	Carl Dabelstein

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
311	Structures & Improvements	$4,386,000	
311	Structures & Improvements - Accumulated Depreciation		$131,960
	Total	$4,386,000	$131,960

INCREMENTAL CHANGE $4,254,040

Reason for Adjustment

To increase plant in service and accumulated depreciation for generation plant that was in service at 12/31/06 but not unitized or included in FERC 106 (Completed Construction Not Classified).

2/11/2008 2:42 PM

TEP(0402)032954

TUCSON ELECTRIC POWER COMPANY
RATE BASE ADJUSTMENT ENTRY FORM
TEST YEAR ENDED DECEMBER 31, 2006

NEW PRO FORMA FOR REBUTTAL PER STF 1.86

ADJUSTMENT NAME:	ADIT - Delayed Unitization
ADJUSTMENT TO:	Rate Base
DATE SUBMITTED:	February 11, 2008
PREPARED BY:	Tax Services
REVIEWED BY:	Carl Dabelstein

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
282	ADIT - Other Property		$77,369
	NET ENTRY	$0	$77,369

Reason for Adjustment

To adjust test year recorded deferred income taxes associated with the increase in plant in service for generation plant that was in service at 12/31/06 but not unitized or included in FERC 106 (Completed Construction Not Classified).

TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2006

NEW PRO FORMA FOR REBUTTAL PER STF 1.86

ADJUSTMENT NAME:	Depreciation Expense - Delayed Unitization
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	February 11, 2008
PREPARED BY:	Plant Accounting
CHECKED BY:	Carl Dabelstein

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
403	Depreciation Expense	$160,966	
	INCREMENTAL CHANGE	$160,966	$0

Reason for Adjustment

To increase test year recorded depreciation expense associated with the increase In plant in service for generation plant that was in service at 12/31/06 but not unitized or included in FERC 106 (Completed Construction Not Classified).

TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2006

NEW PRO FORMA FOR REBUTTAL PER STF 1.86

ADJUSTMENT NAME:	Property Tax Expense - Delayed Unitization
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	February 11, 2008
PREPARED BY:	Tax Services
CHECKED BY:	Carl Dabelstein

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
408.1	Taxes Other than Income Taxes	$106,358	
	INCREMENTAL CHANGE	$106,358	$0

Reason for Adjustment

To increase test year recorded property tax expense associated with the increase in plant in service for generation plant that was in service at 12/31/06 but not unitized or included in FERC 106 (Completed Construction Not Classified).

2/11/2008 2:22 PM

Tucson Electric Power Company
STF 1.86 - Additional Pro Forma Adjustment
Delayed Unitization Adjustment

Rate Base

Plant In Service	$4,386,000
Accumulated Depreciation	($131,960)
	$4,254,040
A.D.I.T.	($77,369)
Increased rate base	$4,176,671

Operating Expenses

Depreciation Expense	$160,966
Property Taxes	$106,358
Increased Operating Expenses	$267,324

Schedule M for Current Tax

Book Depreciation Add Back	$160,966
Tax Depreciation Deduct	($242,736)
	($81,770)

From: C. Dabelstein 2/11/08

Tucson Electric Power
Delayed Plant Closing - SGS Gen Plant
Supplemental 2007

Source: Carl Dabelstein Plant Acctng

Project	Ref	Task (W/O)	Ref	New_Category (Group Assets)	Ref	In SVC Date	Ref	Amount	Rate	End Date	True-up	Accum Depreciation thru 12/31/06	
D05AS86	1A	GC51777	1B	01.311XX.001.SPC01.000		31-Jul-05	1E	2,020,500.00	4.61%	12/31/2006	17.5	135,836.53	
		GC51777	1B	01.311XX.001.SPC01.000		31-Oct-06	1E	1,265,000.00	4.61%	12/31/2006	2.5	12,149.27	
		GC51777	1B	01.311XX.001.SPC01.000		30-Sep-06	1E	660,000.00	4.61%	12/31/2006	3.5	8,874.25	
		GC51777	1B	01.311XX.001.SPC01.000		31-May-06	1E	205,000.00	4.61%	12/31/2006	7.5	5,906.56	
		GC51777	1B	01.311XX.001.SPC01.000		30-Jun-05	1E	91,500.00	4.61%	12/31/2006	18.5	6,502.98	
		GC51777	1B	01.311XX.001.SPC01.000		31-Aug-05	1E	100,000.00	4.61%	12/31/2006	16.5	6,338.75	
		GC51777	1B	01.311XX.001.SPC01.000		31-Aug-05	1E	44,000.00	4.61%	12/31/2006	16.5	2,789.05	
								4,386,000.00				178,397.40	Out of Case
		GC51777	1B	01.311XX.001.SPC02.000		31-Jul-05	1E	2,020,500.00 1	3.41%	12/31/2006	17.5	100,477.78	
		GC51777	1B	01.311XX.001.SPC02.000		31-Oct-06	1E	1,265,000.00 2	3.41%	12/31/2006	2.5	8,986.77	
		GC51777	1B	01.311XX.001.SPC02.000		30-Sep-06	1E	660,000.00	3.41%	12/31/2006	3.5	6,564.25	
		GC51777	1B	01.311XX.001.SPC02.000		31-May-06	1E	205,000.00	3.41%	12/31/2006	7.5	4,369.06	
		GC51777	1B	01.311XX.001.SPC02.000		30-Jun-05	1E	91,500.00 1	3.41%	12/31/2006	18.5	4,810.23	
		GC51777	1B	01.311XX.001.SPC02.000		31-Aug-05	1E	100,000.00	3.41%	12/31/2006	16.5	4,688.75	
		GC51777	1B	01.311XX.001.SPC02.000		31-Aug-05	1E	44,000.00	3.41%	12/31/2006	16.5	2,063.05	In Case
								4,386,000.00 A				131,959.90 B	
D05AS86		TOTAL						8,772,000.00		Total		310,357.29	

Note: Springerville No 1 Common investment is excluded from the rate case.

Note: Annual Depreciation on Springerville No2 Common:

Plant Amount	4,386,000.00
Depreciation Rate	3.67%
Annual Depreciation	160,966.20 E

Σ 1 = V 2005 = 2,256,000 C

Σ 2 = V 2006 = 2,130,000 D

TEP(0402)032956

TEP
Additional ADIT and Current/Deferred Expense on SPC02
for the Rate Case Test Year ended 12/31/06

MACRS-20 Rates	
Yr 1	0.03750
Yr 2	0.07219

G:\TAXSVCS\Rate Cases\TEP\12-31-06 Test Year\Plant\[SPC02 ADIT and Expense Calc in Feb-08.xls]Tax Depr

		V 2005		V 2006	Total
Cost	2.1 C	2,256,000	2.1 D	2,130,000	4,386,000
2005 Tax Depr		84,600			
2006 Tax Depr		162,861		79,875	242,736
A/D		247,461		79,875	327,336

Note: All Basis Differences, including AFUDC, were already calculated in years 2005 and 2006 based on actual activity recorded on the G/L. Therefore, for this asset, tax basis equals book basis.

→*Caution: Table 1, below, may not be used for three-, five-, seven-, or ten-year farm business property generally placed in service after 1988. Table 14, below, incorporates the 150-percent declining-balance method and a half-year convention that may be used for such property.*←

TABLE 1
General Depreciation System
Applicable Depreciation Method: 200- or 150-Percent
Declining Balance Switching to Straight Line
Applicable Recovery Periods: 3, 5, 7, 10, 15, 20 years
Applicable Convention: Half-Year

If the Recovery Year is:	and the Recovery Period is: 3-year	5-year	7-year	10-year	15-year	20-year
	the Depreciation Rate is:					
1	33.33	20.00	14.29	10.00	5.00	3.750
2	44.45	32.00	24.49	18.00	9.50	7.219
3	14.81	19.20	17.49	14.40	8.55	6.677
4	7.41	11.52	12.49	11.52	7.70	6.177
5		11.52	8.93	9.22	6.93	5.713
6		5.76	8.92	7.37	6.23	5.285
7			8.93	6.55	5.90	4.888
8			4.46	6.55	5.90	4.522
9				6.56	5.91	4.462
10				6.55	5.90	4.461
11				3.28	5.91	4.462
12					5.90	4.461
13					5.91	4.462
14					5.90	4.461
15					5.91	4.462
16					2.95	4.461
17						4.462
18						4.461
19						4.462
20						4.461
21						2.231

→*Caution: Table 2, be*
year farm business pr
15, below, incorporate
mid-quarter convention

Applicab
Decl
Applicab
Applicable

If the Recovery Year is:
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21

TEP(0402)032950

TEP
Additional ADIT and Current/Deferred Expense on SPC02
for the Rate Case Test Year ended 12/31/06

Tax Rate	0.396

G:\TAXSVCS\Rate Cases\TEP\12-31-06 Test Year\Plant\[SPC02 ADIT and Expense Calc in Feb-08.xls]Sheet1

ADIT

Asset 311XX.SPC02

	REF	Book	REF	Tax	Difference	Deferred Tax Asset/<Liab>
Cost	2.1 A	4,386,000	3.1 A	4,386,000		
A/D	2.1 B	131,960	3.1 B	327,336		
Net Value		4,254,040		4,058,664	(195,376)	(77,369)

Expense

Book Depreciation Expense	2.1 E	160,966
Tax Depreciation Expense	3.1 C	(242,736)

Tucson Electric Power
Delayed Plant Closing - SGS Gen Plant
Supplemental 2007
G:\TAXSVCS\Rate Cases\TEP\12-31-06 Test Year\Property Tax\[Property Tax Workpapers 12-31-06 - Updated Information for 2007 Property Taxes.xls]A10 SGS Gen Supplemental 2007

SGS Common Unit 1

Project	Task	New_Category (Group Assets)	In SVC Date	Amount		ADOR Valuation Factor	2006 Full Cash Value	2006 Assessment Ratio	Assessed Value	Tax Rate	Property Tax for SGS Unit 1
D05AS86	GC51777	01.311XX.001 SPC01.000	30-Jun-05	91,500.00	uz	0.9992	91,426.80	23%	21,028.16		
D05AS86	GC51777	01.311XX.001.SPC01.000	31-Jul-05	2,020,500.00	uz	0.9992	2,018,883.80	23%	464,343.23		
D05AS86	GC51777	01.311XX.001.SPC01.000	31-Aug-05	100,000.00	uz	0.9992	99,920.00	23%	22,981.60		
D05AS86	GC51777	01.311XX.001.SPC01.000	31-Aug-05	44,000.00	uz	0.9992	43,964.80	23%	10,111.90		
D05AS86	GC51777	01.311XX.001.SPC01.000	31-May-06	205,000.00	uz	0.9714	199,137.00	23%	45,801.51		
D05AS86	GC51777	01.311XX.001.SPC01.000	30-Sep-06	660,000.00	uz	0.9714	641,124.00	23%	147,458.52		
D05AS86	GC51777	01.311XX.001.SPC01.000	31-Oct-06	1,265,000.00	uz	0.9714	1,228,821.00	23%	282,628.83		
									994,353.76	ct	10.6963% 106,358.82

SGS Common Unit 2

Project	Task	New_Category (Group Assets)	In SVC Date	Amount		ADOR Valuation Factor	2006 Full Cash Value	2006 Assessment Ratio	Assessed Value	Tax Rate	Property Tax Added to Cost of Service
D05AS86	GC51777	01.311XX.001 SPC02.000	30-Jun-05	91,500.00	uz	0.9992	91,426.80	23%	21,028.16		
D05AS86	GC51777	01.311XX.001.SPC02.000	31-Jul-05	2,020,500.00	uz	0.9992	2,018,883.80	23%	464,343.23		
D05AS86	GC51777	01.311XX.001.SPC02.000	31-Aug-05	100,000.00	uz	0.9992	99,920.00	23%	22,981.60		
D05AS86	GC51777	01.311XX.001.SPC02.000	31-Aug-05	44,000.00	uz	0.9992	43,964.80	23%	10,111.90		
D05AS86	GC51777	01.311XX.001.SPC02.000	31-May-06	205,000.00	uz	0.9714	199,137.00	23%	45,801.51		
D05AS86	GC51777	01.311XX.001.SPC02.000	30-Sep-06	660,000.00	uz	0.9714	641,124.00	23%	147,458.52		
D05AS86	GC51777	01.311XX.001.SPC02.000	31-Oct-06	1,265,000.00	uz	0.9714	1,228,821.00	23%	282,628.83		
									994,353.76	ct	10.6963% 106,358.82

ote: Detail information for project, task category, in service date and amount provided by Plant Accounting. FERC 311 is for structures
nd therefore are valued as real property improvements under Arizona Department of Revenue Generation Valuation tables.

TUCSON ELECTRIC POWER COMPANY
RATE BASE ADJUSTMENT ENTRY FORM
TEST YEAR ENDED DECEMBER 31, 2006

REVISED FOR REBUTTAL

ADJUSTMENT NAME:	Accumulated Def Income Taxes - Cost of Service
ADJUSTMENT TO:	Rate Base
DATE SUBMITTED:	February 15, 2008
PREPARED BY:	Rigo Ramirez, Pauline Rush, & Jay Rademacher
REVIEWED BY:	Nona Donahue & Carl Dabelstein

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
	AS FILED		
190	ADIT		$349,511,141
282	ADIT - Other Property	$170,812,804	
283	ADIT - Other	$59,459,499	
	Total	$230,272,303	$349,511,141
	Net Adjustment		$119,238,838
	REVISED FOR REBUTTAL		
190	ADIT		$386,469,652
282	ADIT - Other Property	$166,838,686	
283	ADIT - Other	$56,175,352	
	Total	$223,014,038	$386,469,652
	Net Adjustment		$163,455,614
	INCREMENTAL CHANGE	$0	$44,216,776

Reason for Adjustment

To adjust test year recorded accumulated deferred income taxes to reflect adjusted test year operating results and the level of income tax normalization authorized by the ACC.

REVISED FOR REBUTTAL

To adjust test year accumulated deferred income taxes for updates and adjustments to the original rate case filing.

Tucson Electric Power
ADIT Adjustment Summary
Rate Case Test Year Ended 12/31/2006

REVISED FOR REBUTTAL

See ADIT Summaries

FERC	Full Cost of Service Pro Forma Computed	Market Pro Forma Computed	12/31/06 Per Books	**Full Cost of Service Adjustment**	Market Adjustment	Four Corners Hybrid Adjustment	Navajo Hybrid Adjustment	Hybrid Pro Forma Computed
190	$3,225,072	$3,225,072	$389,694,724	**($386,469,652)**	($386,469,652)			$3,225,072
282	($252,196,680)	($252,196,680)	($419,035,366)	**$166,838,686**	$166,838,686	$6,582,333	$8,473,808	($237,140,539)
283	($12,748,437)	($4,331,035)	($68,923,789)	**$56,175,352**	$64,592,754			($12,748,437)
	($261,720,045)	($253,302,643)	($98,264,431)	**($163,455,614)**	($155,038,212)	$6,582,333	$8,473,808	($246,663,904)

3/20/2008 3:26 PM

Tucson Electric Power Company

To:	Files
From:	Jason Rademacher
Date:	March 20, 2008
Re:	TEP 12/31/06 Rate Case – Explanation for Changes in Ratemaking ADIT

- *Account 190 ADIT* – To the extent an item of ADIT did not relate to a specific item of rate base or a component of the cash working capital calculation, it was removed. We determined that Customer Advances and Microwave equipment ADIT were the only items of Account 190 ADIT that met these criteria.
- *Implementation Costs Regulatory Asset* – The amount originally included with the filing included ADIT for the Deferred Direct Access, San Juan Coal Contract Amendment, and Sundt Coal Contract Termination Fee components of the ICRA. The adjusted ADIT amount has been revised to also include ADIT for the Desert Star & West Connect Funding and Financing Costs – Generation components of the ICRA. The two remaining components of the ICRA (Deferred Divestiture Costs & Deferred Genco Separation Costs) don't have any associated ADIT. No ADIT – Tax
- *Plant Related ADIT & Lee Ranch Coal Spur* - ADIT was adjusted to reflect the 2006 timing differences that were included in the 2006 Federal Income Tax Return. The ADIT that was originally included with the filing was based on TEP's best estimate of the timing differences.

TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2006

REVISED FOR REBUTTAL

ADJUSTMENT NAME:	Deferred Income Tax Expense - Cost of Service
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	January 29, 2008
PREPARED BY:	Rigo Ramirez, Pauline Rush, & Jay Rademacher
REVIEWED BY:	Nona Donahue & Carl Dabelstein

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
	AS FILED		
411	Deferred Income Tax Expense (credit)		$19,248,359
	REVISED FOR REBUTTAL		
411	Deferred Income Tax Expense (credit)		$10,914,305
	INCREMENTAL CHANGE	$8,334,054	

Reason for Adjustment

To record pro forma deferred income tax expense

REVISED FOR REBUTTAL

To adjust test year deferred income tax expense for updates and adjustments to the original rate case filing.

Tucson Electric Power
Schedule M's for Deferred Expense
For Test Year Ended 12/31/06

REVISED FOR REBUTTAL

	Ref.	Year Ended 12/31/06	Year Ended 12/31/06	Year Ended 12/31/06	Year Ended 12/31/06
Timing Differences		Full Cost	Market	Hybrid	Hybrid Difference
263A Deductible Service Costs	**See Original - No Change**	(2,566,776)	(2,566,776)	(2,566,776)	0
ICRA - Implementation Costs Regulatory Asset	**2**	10,741,510	2,775,709	10,741,510	0
Cost of Goods Sold	**3**	512,372	512,372	(116,999)	(629,371)
Depreciation - Tax	**See Plant Schedule M's Summary**	(66,485,101)	(66,485,101)	(62,593,867)	3,891,234
Depreciation - Book	**See Plant Schedule M's Summary**	74,073,189	74,073,189	66,290,526	(7,782,663)
Cost of Removal	**See Plant Schedule M's Summary**	(1,066,639)	(1,066,639)	(1,046,734)	19,905
Salvage	**See Plant Schedule M's Summary**	476,911	476,911	476,911	0
Dividend Equivalents	**7**	41,706	41,706	41,706	0
Lee Ranch Coal Spur (LRCS)	**8**	75,622	75,622	75,622	0
L-T Incentive Compensation	**9**	(147,929)	(147,929)	(147,929)	0
Microwave Equipment	**See Original - No Change**	(116,376)	(116,376)	(116,376)	0
Lease/Moratorium Expense	**See Lease Sch M & ADIT Summary**	(13,344,600)	(13,344,600)	(13,344,600)	0
Pension	**See Original - No Change**	N/A	N/A	N/A	0
Rabbi Trust Plan	**See Original - No Change**	651,604	651,604	651,604	0
Reclamation Costs	**See Original - No Change**	838,270	838,270	498,972	(339,298)
Repairs Capitalized	**See Original Based on 4 year Avg - No Change**	(9,587,740)	(9,587,740)	(9,348,132)	239,608
Restricted Stock and Executive Performance Shares	**See Original - No Change**	222,855	222,855	222,855	0
Severance Plan	**18**	(5,568)	(5,568)	(5,568)	0
Stock Option	**See Original - No Change**	925,759	925,759	925,759	0
Supplemental Executive Retirement Plan (SERP)	**See Original - No Change**	(210,347)	(210,347)	(210,347)	0
UET Rent	**See Original - No Change**	(28,217)	(28,217)	(28,217)	0
FAS 106	**See Original - No Change**	3,248,975	3,248,975	3,248,975	0
FAS 112	**See Original - No Change**	354,987	354,987	354,987	0
					0
Total Timing Differences		(1,395,533)	(9,361,334)	(5,996,118)	(4,600,585)
Tax Rate		0.396	0.396	0.396	0.396
Deferred Tax Expense		552,631	3,707,088	2,374,463	1,821,832
Less: Amortization of Excess Deferred		(257,070)	(257,070)	(257,070)	0
Pro Forma Deferred Tax Expense		295,561	3,450,018	2,117,393	1,821,832
Recored Test Year Deferred Expense		11,209,866	11,209,866	11,209,866	0
Deferred Tax Expense Adjustment		**(10,914,305)**	**(7,759,848)**	(9,092,473)	**1,821,832**

TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2006

REVISED FOR REBUTTAL — Cost of Service & Market

ADJUSTMENT NAME:	Property Taxes
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	January 30, 2008
PREPARED BY:	C. Kelling
CHECKED BY:	N. Donahue
REVIEWED BY:	C. Dabelstein

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
408.1	Taxes Other than Income Taxes - **AS FILED**		$2,682,245
408.1	Taxes Other than Income Taxes - **REVISED FOR REBUTTAL**		$3,176,134
	INCREMENTAL CHANGE		**$493,889**

Reason for Adjustment

To adjust expense to reflect final adjusted balance of utility plant subject to property taxation, the property tax assessment rate scheduled to become effective 1/1/08, and the most current average property tax rates.

REVISED FOR REBUTTAL

To adjust expense as originally filed for a change in the assessment rate and most current average property tax rate.

Tucson Electric Power Company
12/31/06 Property Tax Adjustment
12/31/06 GRC
Functional Breakout of Property Taxes

REVISED FOR REBUTTAL
Source: C. Kelling 1/30/08

Function	12/31/2006 Book	12/31/2006 Base Case	Pro Forma
Steam Production	15,072,711	11,160,116	(3,912,595)
Other Production	1,284,001	1,306,060	22,059
Transmission EHV	2,246,236	2,192,040	(54,196)
Transmission Non-EHV	3,071,550	2,844,376	(227,174)
Distribution	11,077,963	12,754,903	1,676,940
General	681,169	0	(681,169)
Total	33,433,630	30,257,496	**(3,176,134)**

3/20/2008 3:31 PM

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-0402

Rebuttal Testimony of

Kevin P. Larson

on Behalf of

Tucson Electric Power Company

April 1, 2008

Executive Summary of the
Rebuttal Testimony of Kevin P. Larson

Mr. Larson is the Senior Vice President, Chief Financial Officer and Treasurer for UniSource Energy Corporation ("UniSource Energy") Tucson Electric Power Company ("TEP" or the "Company"). Mr. Larson's Rebuttal Testimony addresses the following matters:

1. **The impact of Staff and RUCO's recommended rate decreases on TEP's Financial Condition.**

   The Company is very proud of the steps it has taken to restore its financial stability since TEP's last general rate case in 1994. Since 1994, the Company has reduced debt obligations by more than $1 billion and improved common stock equity by more than $600 million. Over this same time period, TEP's ratio of equity to total capitalization ("equity ratio") and credit ratings have improved substantially. A Commission order adopting either Staff or RUCO's recommendations, coupled with a refund of the true-up revenues, would be devastating to TEP's financial condition. Even with no or only a partial refund, their recommendations create the potential for serious long-term adverse impacts.

   Both Staff and RUCO are recommending rate decreases from TEP's current average retail rate of 8.4 cents per kWh. The Company estimates that Staff's recommendation would result in a decrease in revenues and cash flows of approximately $14 million to $22 million per year, while RUCO's recommendation would result in a $54 million reduction in revenues and cash flow per year. In addition, the Company will collect approximately $65 million of revenues during 2008 that are potentially subject to refund or credit or other such mechanism, pending a decision in the current rate proceeding.

   The rate reductions proposed by Staff and RUCO would cripple TEP's ability to achieve and sustain solid financial health. The potential consequences of Staff and RUCO's recommended rate decreases include (i) the violation of TEP's debt covenants, (ii) borrowing limitations under a recent ACC financing order, (iii) higher financing costs and difficulty accessing the capital markets on favorable terms, (iv) difficulty maintaining safe and reliable service and (vi) credit rating downgrades.

   Both Staff and RUCO take extreme positions on many of the historical 2006 test year adjustments they propose to TEP's revenue requirement. Yet, both Staff and RUCO failed to provide any evidence or testimony that showed an analysis of how their recommendations would impact TEP's financial or operating condition in 2009 or beyond, which the Company views as a material oversight. While Staff and RUCO's proposed rate decreases may provide short-term benefits to customers, the long-term risk of operational and financial instability must be considered and should help guide the public interest considerations and ultimate outcome in this matter. It will not help customers to provide a small rate decrease now only to cause a much larger rate increase in the near future.

2. **Specific Rebuttal to Staff.**

   a. **Cost of Capital.** TEP proposes that the Commission adopt an overall cost of capital (rate of return) of 8.35% based on (i) a return on equity ("ROE") of 10.75%, (ii) an average cost of debt of 6.39% and (iii) a capital structure

consisting of 45% pro forma equity and 55% debt. Staff is recommending a much lower rate of return of 7.93% based on (i) an ROE of 10.25%, (ii) an average cost of debt of 6.40%, and (iii) a capital structure consisting of 40% equity and 60% debt. TEP witness Hadaway will address ROE.

b. **Equity ratio.** Despite the improvement in TEP's financial condition since the Company's last general rate case in 1994, TEP's equity ratio is still far below the industry average and the average equity ratio needed to achieve an investment grade credit rating. Rates should be set with, at a minimum, the average equity anticipated over the period rates are in effect. Under TEP's rate proposals, the Company will be increasing the equity as it reinvests earnings in new plant and equipment. Allowing TEP to set rates using a pro forma equity ratio will help the Company to continue to make gradual improvements in its capital structure and position TEP to access the capital markets on more favorable terms.

c. **ICRA.** TEP's proposed ICRA of $47 million includes approximately $7 million of generation-related financing costs. TEP maintains that the generation-related financing costs should be included as part of the ICRA because The Company should be compensated if TEP's generation assets become rate regulated once again, since the cost of debt component of the overall rate of return is lower as the result of incurring these generation-related debt costs. If customers are to receive the benefit of lower interest costs, then the expense to achieve these benefits should also be borne by the customer.

Staff opposes the inclusion of the generation-related financing costs in the ICRA because the Company did not seek an ACC order to defer these costs. However, Staff failed to consider TEP's accounting treatment of its generation assets. Upon final execution of the approved 1999 Settlement Agreement, pursuant to *Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation* ("FAS 71"), the Company's generation operations no longer qualified as cost-based rate-regulated operations for financial reporting purposes. These financing costs were no longer able to be deferred and amortized when debt was reacquired or refinanced. Companies not following the FERC chart of accounts or qualifying for accounting under FAS 71 are not able to defer and amortize these costs, but rather recognize such costs as expense when incurred. Since these costs were not deferred and amortized, they are not included in the amortization of debt costs which form a part of the Company's on-going cost of debt used in determining its cost of capital for rate purposes. Had these amounts been deferred and amortized, they would have become part of such calculation for rate purposes. TEP witness Karen G. Kissinger offers additional rebuttal testimony to RUCO regarding the ICRA.

d. **Securitization of Transition Revenues.** The ACC's decision approving the Settlement Agreement (Decision No. 62103) contemplated securitizing transition revenues. As a result, TEP contemplated (i) creating a bankruptcy proof special purpose entity ("SPE"), (ii) transferring the property rights of the Fixed CTC revenues to the SPE and (iii) issuing debt at the SPE and using the proceeds to retire higher cost debt at TEP. Securitization is a financing structure that provides access to lower cost sources of funding through the isolation of specified revenues and/or assets that provide

security for the debt, thus helping achieve a lower overall cost of capital.

Staff witness Antonuk questioned the efforts TEP took to analyze the securitization of the transition revenues. However, TEP carefully considered and analyzed securitizing transition revenues. In 1998, prior to the Commission's final order approving the Settlement Agreement, TEP retained outside counsel and an investment banking firm to analyze how the Company might be able to securitize transition revenues. In August of 1998, TEP's outside counsel and investment bankers made presentations to ACC Staff regarding TEP's proposed securitization plan. In November 1998, TEP filed Direct Testimony in Docket Nos. E-01933A-98-0471, 97-0772, E-01345A-98-0473, 97-0773, and RE-00000C-94-165. TEP witness Dean E. Criddle, partner in the law firm of Orrick, Herrington & Sutcliffe LLP ("Orrick"), filed testimony on the topic of securitizing transition revenues.

Based on Orrick's analysis in 1998, several legal elements needed to be in place to achieve the full financial benefits of securitization. These included (i) successful transfer of property rights to the SPE, (ii) assurance from the Commission that future ACC rulings would not alter the transition revenues during the securitization period and (iii) legislative authorization of the securitization.

TEP continued to monitor the legal obstacles of securitization after the Settlement Agreement was executed. Ultimately, the IRS ruled in 2002 that securitized bonds must be issued under a state utility commission financing order that is authorized by specific State legislation. The mounting legal obstacles stalled TEP's securitization efforts.

3. **Specific Rebuttal to RUCO.**

a. **Cost of Capital.** As stated above, TEP is recommending an overall cost of capital of 8.35%. RUCO witness William Rigsby recommends a 7.76% cost of capital, which is lower than the cost of capital proposed by Staff. The primary difference between RUCO and the Company is ROE, which is addressed by TEP witness Dr. Samuel C. Hadaway.

b. **Equity ratio.** RUCO supports the Company's proposed pro forma equity ratio of 45%.

c. **ICRA.** RUCO takes a similar position to Staff regarding the exclusion of generation-related financing costs from the ICRA. The Company maintains that the generation-related financing costs should be included in the ICRA RUCO, like Staff, failed to recognize the GAAP accounting treatment of TEP's generation assets. Once the Settlement Agreement became effective, TEP's generation assets no longer qualified as regulated assets pursuant to FAS 71. Thus, the Company was not allowed to defer these financing costs. If the Commission decides to use a cost of service methodology to set TEP's rates, and re-regulate the Company's generation assets, then TEP is entitled to recover these costs. TEP witness Karen G. Kissinger offers additional rebuttal testimony to RUCO regarding the ICRA.

4. Conclusion.

Staff and RUCO failed to provide any testimony, evidence or analysis of the potentially devastating effects their recommended rate decreases would have on TEP's financial health. The consequences of adopting Staff or RUCO's rate proposals would (i) erase years of financial recovery, (ii) increase the Company's cost of debt capital, leading to higher costs for future customers, (iii) compromise the ability of TEP to continue providing safe, reliable energy service to its customers, (iv) limit the Company's ability to procure energy resources that provide long-term price stability for customers, and (v) limit TEP's ability to access the capital markets on favorable terms in order to fund the improvement and expansion of the Company's utility infrastructure.

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KPL-8 Revised Schedule D-2

I. INTRODUCTION

Q. Please state your name and address.

A. Kevin P. Larson. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. Are you the same Kevin P. Larson that previously submitted Direct Testimony on behalf of Tucson Electric Power Company in this Docket?

A. Yes.

Q. Have you reviewed the Direct Testimony filed by the Commission Staff and other parties to this rate case?

A. Yes I have.

Q. On whose behalf are you filing your rebuttal testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of Tucson Electric Power Company ("TEP").

Q. What is the purpose of your rebuttal testimony?

A. I will discuss the financial impact of Staff and RUCO's proposals on TEP if the ACC adopts one of their proposals without any modifications. I will also offer rebuttal to the Direct Testimonies of both Arizona Corporation Commission Staff ("Staff") and the Residential Utility Consumer Office ("RUCO") on the subjects of cost of capital and a specific component of the Company's propose Implementation Cost Regulatory Asset ("ICRA").

Q. Please provide your general response to Staff and RUCO.

A. A Commission order adopting either Staff or RUCO's recommendations, coupled with a refund of the true-up revenues, would be devastating to TEP's financial condition. Even with no or only a partial refund, their recommendations create the potential for serious long-term adverse impacts.

Both Staff and RUCO are recommending rate decreases from TEP's current average retail rate of 8.4 cents per kWh. The Company estimates that Staff's recommendation would result in a decrease in revenues and cash flows of approximately $14 million to $22 million per year, while RUCO's recommendation would result in a $54 million reduction in revenues and cash flow per year. In addition, the Company will collect approximately $65 million of revenues during 2008 that are potentially subject to refund or credit or other such mechanism, pending a decision in the current rate proceeding.

The rate reductions proposed by Staff and RUCO would cripple TEP's ability to achieve and sustain solid financial health. TEP's financial condition and ability to access capital on favorable terms is in the long-term interest of customers. Both Staff and RUCO take extreme positions on many of the historical 2006 test year adjustments they propose to TEP's revenue requirement. Yet, both Staff and RUCO failed to provide any evidence or testimony that showed an analysis of how their recommendations would impact TEP's financial or operating condition in 2009 or beyond, which the Company views as a material oversight. While Staff and RUCO's proposed rate decreases may provide short-term benefits to customers, the long-term risk of operational and financial instability must be considered and should help guide the public interest considerations and ultimate outcome in this matter. It will not help customers to provide a small rate decrease now only to cause a much larger rate increase in the near future.

II. TEP's Financial Condition.

Summary

Q. How would Staff or RUCO's proposed rate decreases impact TEP's financial condition?

A. Staff and RUCO's recommended rate decreases could be devastating to TEP's financial condition. The potential consequences include:

- Violation of debt covenants
- Borrowing limitations under a recent ACC financing order
- Higher financing costs and difficulty accessing the capital markets on reasonable terms
- Compromise TEP's ability to provide safe, reliable service
- Credit rating downgrades

Q. Can you summarize TEP's current financial position?

A. Certainly. The Company is very proud of the steps it has taken to restore its financial stability since 1994, the test year used in TEP's last general rate case. Since 1994, the Company has reduced debt obligations by more than $1 billion and improved common stock equity by more than $600 million. Over this same time period, TEP's ratio of equity to total capitalization ("equity ratio") and credit ratings have improved substantially.

The Commission acknowledged TEP's efforts to improve the Company's financial situation in Decision No. 66946 (dated October 30, 2007):

> "In the last 15 years, TEP has been able to increase its equity position substantially, and has demonstrated the financial expertise

and management integrity to make positive financial decisions."[1]

Despite these improvements, TEP's unsecured debt is rated speculative grade by two rating agencies due primarily to (i) TEP's high ratio of debt to total capitalization (ii) the absence of a purchased power and fuel adjustor clause ("PPFAC") and (iii) "a challenging regulatory environment."[2]

Over the next five years, TEP estimates that it will need to invest approximately $1.4 billion in capital projects to maintain, reinforce and expand its utility system to continue providing safe, reliable electric service. Historically, TEP paid for all of its capital investments with internally generated funds; however, that trend is changing. In 2008, TEP estimates that its operating cash flows will be sufficient to fund only a portion of the Company's capital investments and repayments of capital lease obligations. TEP's proposed rate increase would give the Company the necessary flexibility to fund most of TEP's capital investments and repayments of capital lease obligations, as well as use discretionary cash flow to continue to improve TEP's capital structure. Moreover, it would help ensure long-term access to lower cost power supplies, including potentially the ultimate acquisition of Springerville Unit 1 which is now leased by the Company.

Q. Can you be more specific as to how Staff and RUCO's recommendations would harm TEP's financial condition?

A. Yes. As described above, TEP's cash flow from operations historically exceeded the Company's capital investments and required lease payments, leaving TEP with excess cash flow to make discretionary debt reductions. However, this trend will reverse in 2008 due to (i) TEP's increasing annual capital budget, (ii) the absence of a PPFAC and (iii) continuing upward pressure on general operating and maintenance costs.

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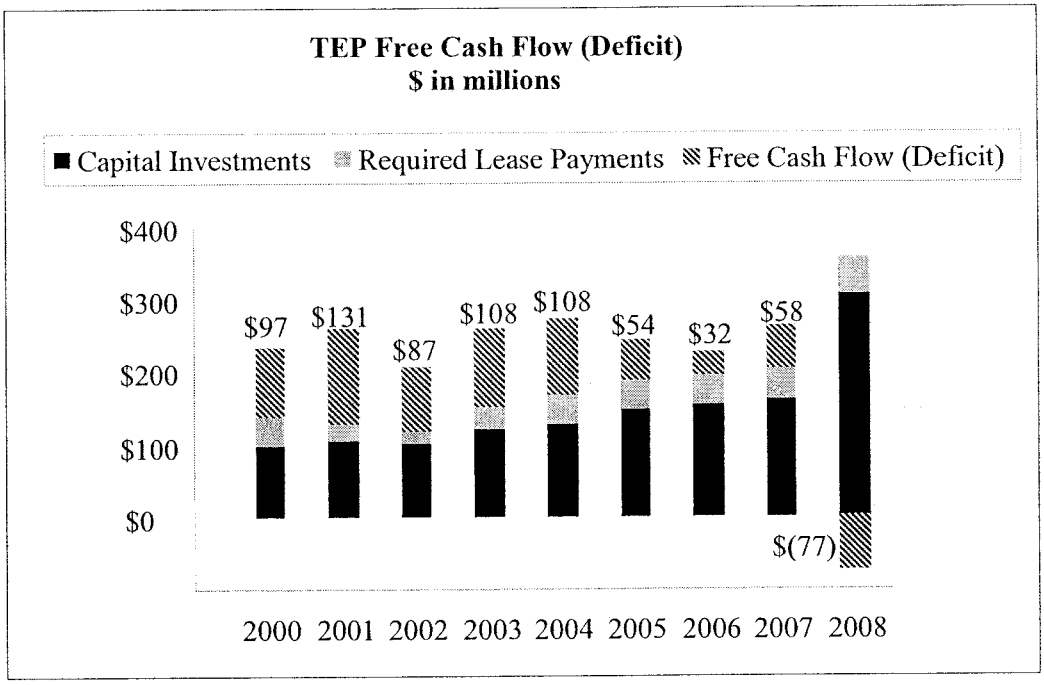
[1] Page 9, lines 12-14

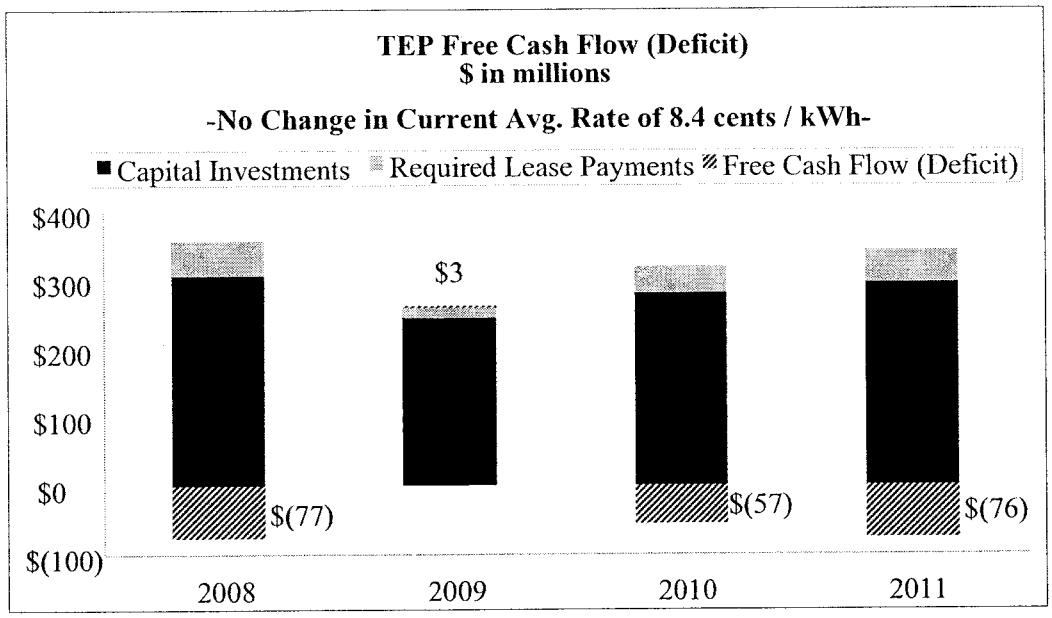
[2] Exhibit KPL-3, Moody's report dated December 10, 2007, includes an analysis of TEP's regulatory environment.



As shown above, TEP estimates that in 2008 the Company's operating cash flow will fall $77 million short of meeting expected capital investments and repayments of capital lease obligations[3]. The Company will issue new long-term tax-exempt debt, and, on an interim basis, rely on its $150 million revolving credit facility to meet this deficit.

The table below shows TEP's expected free cash flow (deficit) for 2008-2011, assuming no change in TEP's current average retail rate of 8.4 cents per kWh.

[3] Consists of mandatory payments made by TEP to retire capital lease obligations. The capital lease payments are shown net of the principal amount received by the Company for the lease debt it has purchased and holds as an investment on its balance sheet.

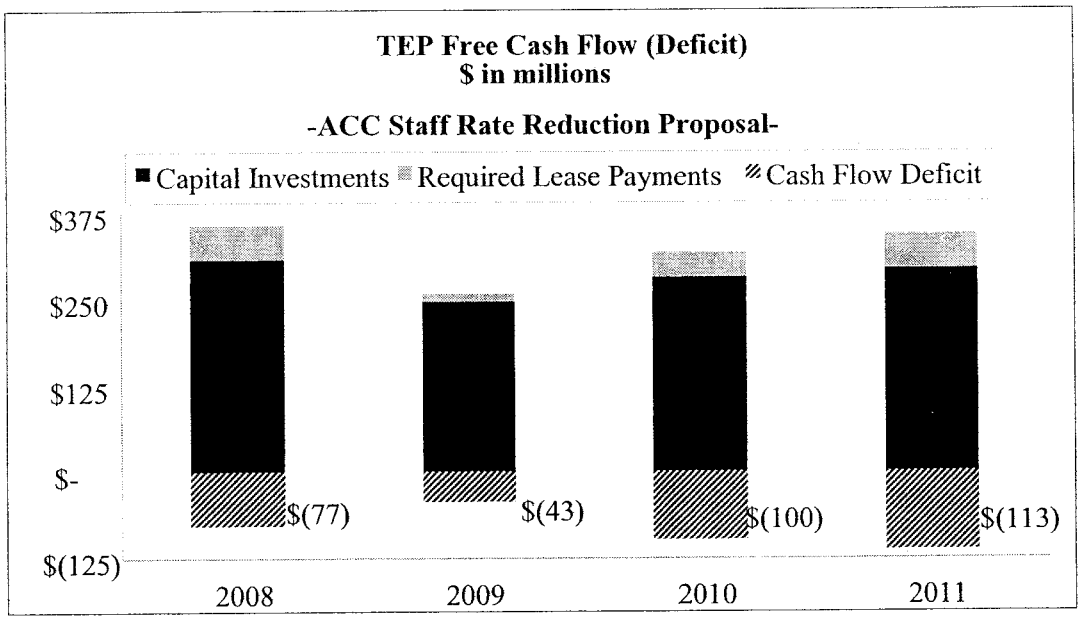


As shown above, TEP estimates internal cash flow deficits would occur in 2010 and 2011 assuming no change in the current average retail rate of 8.4 cents per kWh. Taking into account dividends paid to TEP's parent company, a cash outlay needed to maintain access to common equity capital, the cash flow deficits cited above become even higher. Consequently, a reduction in TEP's current average retail rate, as recommended by Staff and RUCO, would be clearly detrimental to the Company's financial condition and ability to attract capital on reasonable terms.

Q. Will Staff and RUCO's recommendations in the current rate proceeding impact TEP's ability to continue to improve its overall financial condition?

A. Yes. The rate decreases proposed by Staff and RUCO would all but eliminate TEP's financial flexibility. Staff and RUCO expect TEP to absorb a revenue decrease at the same time the Company faces rising operating and capital investments.

The graph below shows TEP's estimated operating cash flow deficits under Staff's recommendations compared with projected capital investments and lease payments.



As shown above, the deficit between operating cash flows and capital investments and required lease payments grows larger over time; and totals more than $250 million in only three years.

This analysis does not factor in a potential refund of the true-up revenues. If all or a portion of the true-up revenues are refunded, the deficit would be worse. TEP has a $150 million revolving credit facility to help fund capital expenditures on an interim basis. Other than reducing operating costs or eliminating capital projects, the Company's liquidity options become very limited once the revolving credit facility is fully used. TEP's ability to provide safe, reliable energy would be clearly compromised if Staff's revenue requirement recommendations were adopted; and even worse when combined with a refund of the true-up revenues.

The proposed recommendations by Staff and RUCO would undo all of the financial progress made by the Company since 1994 and compromise the ability of TEP to continue providing safe, reliable energy to its customers. TEP's rate proposals make it possible for

the Company to continue making sound financial and operational decisions that are in the best long-term interest of customers and shareholders.

Q. Can you please explain the "true-up" revenues mentioned above?

A. Yes. On May 21, 2007, the ACC issued Decision No. 69568. The decision allows TEP to maintain its current average retail rate, including the continued collection of an amount equal to the Fixed Competitive Transition Charge ("Fixed CTC") until the effective date of a final order in the current rate proceeding. Decision No. 69568 also states that the incremental revenue ("true-up revenues") collected as a result of continuing to charge the Fixed CTC after it would otherwise terminate shall be subject to refund or credit or other such mechanism to protect customers, which will be determined in the current rate proceeding. TEP estimates that the true-up revenues will total approximately $65 million to $70 million in 2008. Prior to an ACC order in this proceeding, the revenues will not be recognized as income because the revenues are subject to refund.

Q. What is Staff's position regarding the true-up revenues?

A. Staff did not provide an analysis of the "true-up" revenues in their Direct Testimony.

Q. Does Staff's position lead to any other negative financial consequences?

A. Yes. If Staff's accumulated depreciation adjustments for depreciation rate changes and cost of removal are accepted, TEP would have to write off $159 million. This would reduce TEP's equity by approximately 17 percent, negatively impacting its equity ratio and hindering its ability to finance under a recent Commission order.

Q. Did Staff or RUCO's testimony consider the financial ramifications of their recommendations?

A. No. Staff and RUCO failed to produce any evidence or testimony that showed they

analyzed how their recommendations could impact the overall long-term financial health of TEP or the long-term impacts on customers. Commission approval of Staff or RUCO's proposed rate decrease, coupled with a requirement to refund the true-up revenues, would take a vicious toll on the Company's financial well-being.

Debt Covenants

Q. Would TEP violate any existing debt covenants under Staff or RUCO's recommendations?

A. Yes. In 2009, TEP would violate financial covenants contained in its Credit Agreement under the proposed rate decreases by Staff and RUCO.

Q. Please explain the consequences of violating a debt covenant?

A. An immediate consequence would prohibit TEP from making additional borrowings on its revolving credit facility. In addition, a default arising from TEP's credit agreement would trigger cross-defaults in the Company's other debt agreements and long-term purchased power and gas contracts, causing numerous financial and operational concerns.

Q. What steps would TEP need to take to remedy the default?

A. TEP would be required to ask the lending group to waive the default or amend the credit agreement to reset the financial covenant so compliance is achieved. If the banks agree to a waiver or an amendment, I would expect them to ask for an up front fee and possibly a higher interest rate. Additional restrictions or conditions imposed by lenders could include (i) a shorter maturity date, which would require TEP to refinance the credit agreement more frequently, causing greater exposure to fluctuating interest rates and (ii) more stringent covenants than what previously existed.

ACC Financing Order

Q. Can you briefly describe the financing authority TEP sought in Docket No. E-01933A-07-0080?

A. TEP asked the Commission, among other things, to (i) have a maximum $1 billion long-term debt threshold, an increase of $179 million from its outstanding long-term debt as of December 31, 2006 (ii) exclude capital lease obligations and short-term revolving credit facility borrowings in the determination of the long-term debt threshold and (iii) receive equity contributions from UniSource Energy in an amount not to exceed $150 million.

Q. Did Staff support the Company's financing authority request?

A. Yes, but with some conditions. Staff's report dated June 22, 2007 stated the following:

> "Staff concludes that any authorization of long-term debt threshold proposed by TEP should be subject to the condition that subsequent to any debt issuance common equity represents at least 30 percent of total capital."[4]

Staff also recommended a cash coverage test be met subsequent to any debt issuance by TEP.

Q. Did Staff comment on TEP's financial condition or capital structure during this proceeding?

A. Yes. In response to TEP's financing application filed on February 2, 2007, Staff filed a report on June 22, 2007. In their report, Staff evaluated TEP's capital structure and concluded the following:

> "TEP's highly leveraged capital structure at December 31, 2006, consisted of...27.0 percent equity. Staff typically considers equity at 30 percent of total capital as a minimum financially prudent

[4] Page 3 of Staff's report dated June 22, 2007 (Docket No. E-01933A-07-0080)

capital structure for utility such as TEP and 40 percent as the normal minimum."[5]

Q. Did Staff file Direct Testimony in TEP's financing application proceeding?

A. Yes. On August 13, 2007, Gordon L. Fox filed Direct Testimony on behalf of Staff.

Q. Did Staff's Direct Testimony in TEP's financing application proceeding comment on TEP's capital structure?

A. Yes. Staff's testimony stated the following regarding TEP's financial condition:

> "Staff's recommendations merely place conditions on debt incurrence under a general authorization threshold. Those conditions provide incentives for the Company to continue to improve its highly leveraged capital structure. While borrowing within a threshold under a general authorization does provide additional flexibility over a circumstance requiring specific authorizations, this greater flexibility should be reserved for entities with strong financial metrics. Although TEP's financial metrics have improved, its capital structure remains highly leveraged."[6]

Q. Did the Commission issue an order in this financing authority proceeding?

A. Yes. The Commission issued Decision No. 69946 on October 30, 2007. The order granted TEP the financing authority it was seeking, including the equity ratio and cash coverage tests proposed by Staff.

Q. Did Decision No. 69946 (dated October 30, 2007) address TEP's financial condition?

A. Yes. Decision No. 69946 includes the following:

> "In the last 15 years, TEP has been able to increase its equity position substantially, and has demonstrated the financial expertise and management integrity to make positive financial decisions."[7]

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[5] Page 1 of Executive Summary to Staff's report dated June 22, 2007 (Docket No. E-01933A-07-0080)
[6] Page 6, lines 15-22
[7] Page 9, lines 12-14

Q. Could Staff and RUCO's recommendations in the current rate case proceeding impact the financing authority granted to TEP in Decision No. 69946?

A. Yes. As of December 31, 2007, TEP's GAAP equity ratio was 31% (including capital lease obligations). Staff and RUCO's recommendations in the current rate case proceeding would make it very difficult, if not impossible, for the Company to sustain its current GAAP equity ratio, much less meet the 30% test necessary to issue debt under the currently allowed threshold of $1 billion. TEP's ability to maintain a 30% equity ratio would be further constrained if Staff's accumulated depreciation adjustments for depreciation rate changes and cost of removal are accepted. Those adjustments would reduce TEP's test year common equity by approximately 17% and reduce the Company's December 31, 2007 GAAP equity ratio from 31% to 27%.

Q. What is the difference between the 30% equity ratio contained in Decision No. 69946 and the equity ratio used for ratemaking purposes?

A. The 30% equity ratio required by Decision No. 69946 is calculated using TEP's GAAP financial statements, which treats capital lease obligations as long-term debt. For ratemaking purposes, capital leases are treated as operating leases; therefore, capital lease obligations are not considered long-term debt. Due to the difference in the way capital lease obligations are treated, TEP's GAAP equity ratio is much lower than the equity ratio used for ratemaking purposes.

Q. Did Staff or RUCO consider how their recommendations could impact the Company's financing authority under Decision No. 69946?

A. No.

Cost of Debt Capital and Access Capital Markets

Q. Please explain the impact of Staff and RUCO's recommendations on the Company's cost of capital?

A. Companies with speculative grade ratings, like current credit rating of TEP's unsecured debt, pay higher interest costs than companies with investment grade credit ratings and stronger balance sheets. The table below compares the credit ratings, key credit metrics and the average cost of debt for Arizona Public Service ("APS") and TEP.

	Arizona Public Service	**TEP**
Current Unsecured Credit Ratings (S&P/Moody's/Fitch)	BBB-/Baa2/BBB	BB+/Baa3/BB+
GAAP Equity Ratio[8]	54%	31%
Ratemaking Equity Ratio[9]	55%	45%
Funds from Operations ("FFO") Interest Coverage[10]	4.0x	3.2x
FFO / Total Debt[9]	17.8%	18.0%
Avg. Cost of Debt[11]	5.41%	6.39%

While TEP and APS have similar ratios of FFO to total debt, APS has a much stronger balance sheet with a GAAP equity ratio of 55% and a higher ratio of FFO interest coverage. As a result of higher credit ratings and stronger credit metrics, APS' average

[8] APS and TEP's actual equity ratio at 12/31/2007

[9] APS' received a 55% equity ratio in its last rate case. TEP is proposing a 45% pro forma equity ratio in the current rate proceeding. TEP's equity ratio for ratemaking purposes was 41% as of 12/31/07.

[10] Ratios taken from the most recent S&P reports for APS and TEP

[11] APS received a 5.35% average cost of debt in its last rate case. TEP filed a 6.39% average cost of debt in the current rate proceeding.

cost of debt approved in their last rate case is 98 basis points (.98 percentage points) lower than TEP's average cost of debt as of December 31, 2006, the test year used in the current rate proceeding.

If Staff or RUCO's recommendations are approved without substantial modifications, TEP's credit metrics will deteriorate leading to likely credit rating downgrades. Lower credit ratings and weaker credit metrics will ultimately lead to an even higher cost of debt capital; and make TEP a riskier investment requiring a higher ROE.

Q. Please explain the impact of Staff and RUCO's recommendations on the Company's access to the capital markets?

A. Companies with speculative grade credit ratings and weak financial metrics hold less bargaining power with lending institutions and bond investors. In addition to higher interest rates, lenders tend to seek more restrictive covenants and provisions in order to manage the risk of lending money to riskier borrowers. Staff and RUCO's recommended rate decreases would not only lead to a higher cost of debt capital for TEP, it would also restrict TEP's flexibility to access the capital markets on favorable terms.

<u>Service Reliability</u>

Q. Please explain the impact of Staff and RUCO's recommendations on the Company's ability to provide safe, reliable service to its customers.

A. As described above, the rate reductions proposed by Staff and RUCO will negatively impact the Company's financial condition and ability to access to the capital markets on favorable terms. Over the next five years, the Company estimates that it will need to invest nearly $1.4 billion to maintain and expand TEP's utility infrastructure in order to continue delivering safe, reliable energy to its customers. The rate proposals set forth by the

Company provide TEP with the necessary financial flexibility to (i) fund a large portion of capital investments with internally generated funds and (ii) access the capital markets on favorable terms when external financings is required, without harming TEP's financial health.

If Staff or RUCO's recommendations are approved, the Company would be faced with difficult decisions, such as cutting capital projects or reducing operating costs that could jeopardize TEP's service reliability. Neither Staff nor RUCO provided evidence or testimony that analyzed the impact of their recommendations on TEP's ability to provide safe, reliable energy to its customers.

Q. Could Staff and RUCO's recommendations impact service reliability in other ways?

A. Yes. A weakened financial position would reduce the Company's ability to enter into long-term purchased power or natural gas agreements.

TEP's reliance on purchased power and natural gas resources is increasing as a result of the growing energy needs of the Company's service territory. Sellers of wholesale power and natural gas closely analyze the credit and financial position of a company prior to entering into long-term commitments. Companies with poor credit and a weak financial profile often need to provide guarantees or collateral to offset the potential risk of non-performance under the contract. In other cases, companies simply choose not to do business with other companies because of the level of risk associated with low credit ratings and poor financial condition.

Q. Did Staff or RUCO consider how their recommendations could impact the Company's ability to meet the energy demands of its customers?

A. No.

Credit Ratings

Q. Would Staff or RUCO's recommendations negatively impact TEP's credit ratings?

A. Standard & Poor's ("S&P") and Fitch Ratings, Inc. ("Fitch") recently commented that Staff's recommendation would put downward pressure on TEP's credit metrics and ratings. I cannot speak for the ratings agencies, but based on my experience, I would expect a negative reaction from all three rating agencies if the Commission adopted either Staff or RUCO's recommendations.

Q. Have the rating agencies commented on the testimony filed by Staff or RUCO?

A. Yes. An S&P reported dated March 11, 2008 stated:

> "ACC staff filings recommended a fuel and purchased power adjuster be adopted, which we see as a critical component of protecting future credit quality, but also recommend that TEP's current rates be reduced by 2% to 3%.
>
> The outcome in TEP's current rate case, not expected before the end of 2008 or early in 2009, will be crucial in determining the company's future business risk and financial performance... if the rate case is inadequate or increases business risks, downward pressure could exist for the ratings."[12]

On March 12, 2008, Fitch issued a press release that stated:

> "The Arizona Corporation Commission (ACC) staff filed testimony in the proceeding recommending a $14 million-$22 million rate decrease based on a 10.25% return on equity. While the commission is not bound by the staff recommendation, Fitch notes that a final order by the ACC consistent with the staff proposal would likely result in weaker than anticipated credit metrics. Positively, the staff recommends ACC adoption of a fuel adjustment clause."[13]

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[12] See Exhibit KPL-4, S&P report dated March 11, 2008

[13] See Exhibit KPL-7, Fitch report dated March 12, 2008

Q. Have TEP's credit ratings changed since the Company filed Direct Testimony in July 2007?

A. Yes. In September 2007, Standard & Poor's ("S&P") raised TEP's secured credit ratings by one notch from BBB- to BBB. The change was a result of internal guideline changes at S&P rather than a change in the overall financial condition of TEP; therefore, S&P did not issue a report when the upgrade occurred.

In March 2008, S&P raised TEP's unsecured credit ratings by three notches from B+ to BB+. According to S&P, the upgrades were related to (i) internal guideline changes that apply to all utility companies, including TEP, and (ii) an improvement in the ratio of TEP's secured debt as a percentage of assets.[14] This calculation is used to determine how many notches a company's unsecured debt should rated above or below its corporate credit rating. In TEP's case, the ratio is near 30% which equates to an unsecured rating that is one notch above the Company's corporate credit rating of BB.

Q. Given the recent upgrades by S&P, are TEP's credit ratings comparable to the industry average?

A. No. According to an Edison Electric Institute ("EEI") report, as of December 31, 2007, the average issuer rating for investor-owned electric utilities is BBB. TEP's S&P issuer rating is BB, three notches below the industry average. To put TEP's credit rating into perspective, 95% of investor-owned utilities are rated higher than TEP.[15] Companies rated in the BBB category are considered investment grade, while BB rated companies are considered non-investment grade, or speculative grade.

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[14] See Exhibits KPL-4 and KPL-5, S&P reports dated March 11 and March 19, 2008

[15] See KPL-6, EEI Credit Ratings Report for 12/31/07

Q. What is TEP's secured debt rated?

A. Since June 2006, TEP's secured debt has been rated investment grade by all three rating agencies. TEP's secured rating from S&P is BBB and Baa2 from Moody's, both are two notches above speculative grade; Fitch rates TEP secured debt at BBB-, one notch above investment grade.

Q. Can you quantify the impact of a credit rating downgrade?

A. It is difficult to precisely quantify the incremental financing costs if TEP's secured debt was downgraded; however, recent data from Moody's shows that the difference in interest rates between investment grade and non-investment grade debt with a 10-year maturity is approximately 50-75 basis points (or 0.5% - 0.75%).

A downgrade would also (i) reduce TEP's ability to access the capital markets at certain times and (ii) possibly reduce service reliability because it is more difficult for companies with weaker credit ratings to access the purchased power and natural gas markets.

Q. Have other Commissions, to your knowledge, recognized the importance of maintaining and/or improving a utility's credit ratings at investment grade?

A. Yes. The Nevada Public Utility Commission, in Nevada Power Company's ("NPC") 2007 General Rate Case, indicated its belief that an investment grade credit rating is an important goal. Specifically, the NPUC noted that "investment grade bonds are important to reduce the costs of new generation plan and transmission facilities being financed with 20-year bonds. The move to investment grade could save the ratepayers $10 million per $100 million of bonds issued over the 20-year life of the bonds." This case is illustrative that ratepayers incur less cost when a utility has investment grade ratings. I note that NPC's debt was downgraded sometime in late-2001 to early-2002 and it has taken years for it to build back its credit ratings to the point where it is at or close to investment grade.

The Vermont Public Service Board, in a 2001 rate case involving the Central Vermont Public Service Corporation, also observed that downgraded credit ratings result in increased costs to both the utility and its ratepayers. The importance of these cases is simply to recognize that:

- The lower the credit ratings for a utility the higher the costs to it and its ratepayers;
- Once a utility's credit rating is downgraded, it is not easy and takes several years to repair that damage; and
- The lower the credit rating, the harder it is to compete in the capital markets for whatever capital is available.

III. SPECIFIC REBUTTAL TO STAFF

Cost of Capital and Equity Ratio

Q. Briefly explain TEP's proposed weighted average cost of capital.

A. Based on (i) a pro forma capital structure, (ii) the cost of equity capital outlined in the Direct Testimony of TEP witness Dr. Samuel C. Hadaway, and (iii) the cost of debt I proposed in my Direct Testimony, TEP proposes that the Commission adopt an overall rate of return ("ROR") of 8.35%. This value, reflecting TEP's weighted average cost of capital, is calculated as follows:

	% of Pro forma Capital Structure	Component Cost	Weighted Average Cost
Common Equity	45.00%	10.75%	4.84%
Long-Term Debt	55.00%	6.39%	3.51%
Total	100.00%		8.35%

Q. Have you read Staff's Direct Testimony regarding TEP's proposed cost of capital?

A. Yes.

Q. Does Staff agree with TEP's proposed weighted average cost of capital?

A. No. Staff witness David Parcell recommends a much lower cost of capital of 7.93% based on the following assumptions:

	% of Actual Capital Structure	Component Cost	Weighted Average Cost
Common Equity	39.90%	10.25%	4.09%
Short-Term Debt	2.16%	5.92%	0.13%
Long-Term Debt	57.94%	6.40%	3.71%
Total	100.00%		7.93%

It should be noted that Staff, like the Company, excluded capital lease obligations from its proposed capital structure. This is necessary since TEP's leased assets are not included in rate base.

Q. Which components of TEP's weighted average cost of capital does Staff disagree with?

A. Staff disagrees with (i) TEP's proposed pro forma ratio of equity ratio and (ii) TEP's proposed return on equity ("ROE"). TEP witness Dr. Samuel C. Hadaway offers rebuttal testimony on the issue of ROE.

Q. Please summarize Staff's proposed equity ratio.

A. Staff rejects TEP's proposed pro forma equity ratio of 45% and recommends that TEP's actual equity ratio of 40% be used. Staff witness Parcell's Direct Testimony states, "…it is more appropriate to use the actual capital structure of TEP in establishing cost of capital."[16] Staff's testimony does not explain why they believe it is more appropriate to

[16] Page 38, lines 6-7

use TEP's actual capital structure nor do they explain the financial impact of using TEP's actual equity ratio.

Q. Please explain why TEP proposed a pro forma equity ratio.

A. Despite the improvement in TEP's financial condition since the Company's last general rate case in 1994, TEP's GAAP equity ratio was only 31% as of December 31, 2007. That ratio is far below the industry average. In addition, Staff indicated in a report in June 2007[17] that a 30% GAAP equity ratio is the "minimum financially prudent capital structure" for a company like TEP, while 40% is the "normal minimum." TEP agrees with Staff on this point; however, the rate proposal set forth by Staff would limit TEP's ability to maintain a GAAP equity ratio of 30%, let alone reach a 40% equity ratio. Furthermore, if Staff's recommended accumulated depreciation adjustments for depreciation rate changes and cost of removal are accepted, TEP's December 31, 2007 GAAP equity ratio would be reduced from 31% to 27%.

Rates should be set with, at a minimum, the average equity anticipated over the period rates are in effect. Under TEP's rate proposals, the Company will be increasing the equity as it reinvests earnings in new plant and equipment. Allowing TEP to set rates using a pro forma equity ratio will help the Company to continue to make gradual improvements in its capital structure and position TEP to access the capital markets on more favorable terms.

[17] Page 1 of Executive Summary to Staff's report dated June 22, 2007 (Docket No. E-01933A-07-0080)

Q. Has TEP's ratemaking equity ratio improved since December 31, 2006, the test year used in this rate case?

A. Yes. TEP's ratemaking equity ratio as of December 31, 2007 was 41%, compared with 40% as of December 31, 2006. The improvement is due to an increase in common stock equity through the retention of earnings.

Q. Has TEP's GAAP equity ratio improved since December 31, 2006, the test year used in this rate case?

A. Yes. TEP's GAAP equity ratio as of December 31, 2007 was 31%, compared with 29% as of December 31, 2006 (the test year used in this case). The improvement is due to lower capital lease obligation balances and an increase in common stock equity through the retention of earnings.

Q. Can you please explain the difference in TEP's equity ratio for ratemaking purposes versus how it is calculated on a GAAP basis?

A. Yes. TEP's equity ratio used for ratemaking purposes excludes capital lease obligations from total capitalization. TEP's reported financial statements are presented in accordance with GAAP; GAAP treats capital lease obligations as long-term debt. The financial community, including the rating agencies, relies on GAAP financial statements for analyses purposes. Therefore, TEP's equity ratio as viewed by the financial community and rating agencies is significantly lower than the equity ratio used for ratemaking purposes. Please refer to the table below.

($ Millions)	GAAP 12/31/2006	ACC View 12/31/2006
Long-Term Debt	$ 821	$ 821
Net Capital Lease Obligations	**514**	**0**
Net Debt Outstanding	$1,335	$ 821
Common Equity	553	553
Total Capitalization	$1,888	$1,374
Equity Ratio	29%	40%

Q. Is TEP's GAAP equity ratio lower than industry averages?

A. Yes. TEP's GAAP equity ratio as of the end of the test year, as well as at December 31, 2007, is far below the industry average and S&P's criteria for an investment grade rating. Please refer to the table below.

GAAP **Equity Ratio Comparison**

TEP 12/31/2006	EEI Average[18] 12/31/2006	TEP 12/31/2007	EEI Average[19] 09/30/2007	S&P Investment Grade Range
29%	46%	31%	46%	42%-52%

[18] Average of investor owned utilities tracked by the Edison Electric Institute ("EEI").
[19] Most current EEI data available as of September 30, 2007

Q. Has Staff or the Commission supported a pro forma or hypothetical equity ratio in other cases?

A. Yes. In TEP's 2004 Rate Review, pursuant to Decision No. 62103 (Docket No. E-01933A-04-0408), Staff supported a hypothetical equity ratio. Staff witness James J. Dorf's Direct Testimony stated the following:

> "Q. **Does Staff's cost of capital analysis reflect a position that assists TEP to achieve a higher level of equity in its capital structure?**
>
> A. Yes. Staff's cost of capital analysis continues a practice from the prior rate case to adopt a hypothetical capital structure that recognizes a higher than actual percentage of equity as a portion of total equity. As previously noted, this practice effectively provides for a higher return on actual equity capital resulting in additional earnings available to further grow equity."[20]

Q. What equity ratio did Staff support in the 2004 rate review?

A. Staff witness James J. Dorf supported a hypothetical equity ratio of 40% in his Direct Testimony (page 17, line 1). This compares with TEP's actual equity ratio for ratemaking purposes, as December 31, 2003 (the test year used in the 2004 rate review), of approximately 26%.

Q. Did Staff explain why it supported an equity ratio that was higher than TEP's actual (GAAP) equity ratio in TEP's 2004 rate review?

A. Yes. Staff witness James J. Dorf stated the following in his Direct Testimony:

> "TEP's 73.6 percent test year debt is significantly higher than the debt of the comparable companies. This relatively high leverage represents additional financial risk that negatively affects TEP's bond ratings and, accordingly increases it debt costs. Accordingly, [emphasis added] *TEP should be encouraged to continue increasing the equity portion of total capital.*"[21]

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[20] Page 16, lines 10-16.

[21] Page 16, lines 4-8.

Q. How does TEP's equity ratio at 12/31/2003 compare with the Company's equity ratio at 12/31/2006?

A. Since 12/31/2003, the test year used in the 2004 rate review, TEP's GAAP equity ratio has increased by 10 percentage points; TEP's ratemaking equity ratio increased by 14 percentage points over the same period. Please see the table below.

($ Millions)	12/31/2003	12/31/2006
Long-Term Debt	$1,128	$ 821
Net Capital Lease Obligations	633	514
Net Debt Outstanding	$1,761	$1,335
Common Equity	406	553
Total Capitalization	$2,167	$1,888
GAAP Equity Ratio	19%	29%
Ratemaking Equity Ratio	26%	40%

Q. Please explain the improvement in TEP's equity ratio between 2003 and 2006?

A. TEP's equity ratio has improved since 2003 through (i) scheduled repayments of capital lease obligations, (ii) voluntary debt reductions using the proceeds from the repayment of an inter-company loan and a capital contribution from UniSource Energy in 2005 and (iii) the retention of earnings.

Q. Is TEP's GAAP equity ratio below the industry average?

A. Yes. Even though TEP's equity ratio has improved since 2003, as of December 31, 2006, the Company's GAAP equity ratio is 17 percentage points below the industry average and 13-23 percentage points below S&P's investment grade criteria.

Q. Has Staff or the Commission supported a hypothetical equity ratio in other utility cases?

A. Yes. UNS Gas, a sister company of TEP, requested and was granted an equity ratio that was higher than its actual equity ratio. Decision No. 70011 (November 27, 2007) states the following:

> "We believe the hypothetical capital structure recommendation recommended by UNS Gas and RUCO is reasonable in this case. We believe the Company's efforts to improve its equity ratio over the past several years, through retained earnings and additional equity investment by its parent, [emphasis added] *should be recognized and encouraged.*"[22]

Q. Why should the Commission authorize a ratemaking equity ratio that is higher than the Company's GAAP equity ratio?

A. As I previously mentioned, TEP's GAAP equity ratio is still very low. Allowing TEP to set rates on an equity ratio that is higher than the actual amount of equity shows that the Commission recognizes and encourages the steps TEP has taken, and continues to take, to improve its equity ratio.

Q. Has Staff analyzed TEP's capital structure in any recent proceedings?

A. Yes. In a June 2007 report filed by Staff in a recent TEP financing authority proceeding, Staff indicated that TEP's December 31, 2006 capital structure, as viewed by the financial community, was highly leveraged. Staff's report also stated that they consider a 30% GAAP equity ratio as a, "minimum financially prudent capital structure for a utility such as TEP and 40% as the normal minimum."[23]

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[22] Page 38, lines 21-24

[23] Staff Report filed on June 22, 2007 in a TEP financing application proceeding (Docket No. E-01933A-07-0080)

Q. Does TEP anticipate that its GAAP equity ratio will continue to improve over time?

A. Yes. Assuming the Company gets a just and reasonable rate increase in the current proceeding, TEP's goal is to, over time, achieve a GAAP equity ratio that is more in line with investment grade companies and the industry average.

Q. Did other parties who filed testimony in the current rate proceeding support TEP's proposed pro forma equity ratio for ratemaking proposes?

A. Yes. RUCO supported the use of TEP's pro forma 45% equity ratio. AECC's testimony did not specifically address capital structure.

Q. What if the Commission does not allow TEP to use a pro forma equity ratio?

A. If TEP uses its actual test year capital structure in this rate filing, the cost of equity capital should be adjusted upward from 10.75% to 11.75% to reflect a riskier company. TEP witness Dr. Samuel C. Hadaway addresses this issue in his Direct Testimony and Rebuttal Testimony.

Implementation Cost Regulatory Asset ("ICRA")

Q. Briefly explain TEP's proposed ICRA?

A. TEP is proposing a $47 million asset be created to allow the Company to recover (i) costs incurred by TEP as a result of preparing for retail competition ($14 million), (ii) coal contract amendment fees that the Company would have sought regulatory recovery of had it not been under a rate freeze ($26 million), and (iii) financing costs related to generation assets that would have been amortized rather than immediately written off, had generation continued to be considered "cost-based rate-regulated" for accounting purposes ($7 million).

Q. Briefly explain Staff's recommendation regarding the ICRA?

A. Staff opposes all but $14 million of the ICRA[24], which is related to costs incurred by TEP as a result of transitioning to retail competition. Decision No. 62103, which approved the Settlement Agreement in November 1999, allowed for the future recover of these costs.

Q. Which component of the ICRA will you address?

A. I will address Staff's position on the financing costs related to generation assets. TEP witness Karen G. Kissinger provides Direct and Rebuttal Testimony on the other components of the ICRA.

Q. What is Staff's position regarding the financing costs included in the ICRA?

A. Staff recommends removing these costs from the ICRA. Staff witness Ralph Smith's Direct Testimony states the following:

> "TEP expensed these costs in prior years, 2004 and 2005. TEP has not requested, nor received Commission authorization to defer such costs. Staff proposes no 2006 expense or deferred asset be created for these costs, which TEP expensed on its books in prior years."[25]

Q. Is Staff's position flawed?

A. Yes. Staff failed to consider TEP's accounting treatment of its generation assets. Upon final execution of the approved 1999 Settlement Agreement, pursuant to *Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation* ("FAS 71"), the Company's generation operations no longer qualified as cost-based rate-regulated operations for financial reporting purposes. These financing costs

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[24] Staff witness Smith Direct Testimony, pages 23-28

[25] Page 80, lines 20-23.

were no longer able to be deferred and amortized when debt was reacquired or refinanced. Companies not following the FERC chart of accounts or qualifying for accounting under FAS 71 are not able to defer and amortize these costs, but rather recognize such costs as expense when incurred. Since these costs were not deferred and amortized, they are not included in the amortization of debt costs which form a part of the Company's on-going cost of debt used in determining its cost of capital for rate purposes. Had these amounts been deferred and amortized, they would have become part of such calculation for rate purposes. This element of the ICRA, which totals approximately $7.2 million, is intended to address that inequity.

Q. Why is *not* being on FAS 71 important?

A. One of the reasons that Mr. Smith advances for disallowing recovery of these financing costs is that TEP had not recorded an asset for such costs when they were incurred. Under GAAP, the only entities that could record such an asset would be a rate regulated entity whose rates are based on costs and then only if it was probable that future recovery would be permitted. We could not follow that accounting as our rates were not cost based for generation assets. Mr. Smith seeks to penalize TEP for following GAAP and applies a chicken egg rational to support his position.

Q. Can you address recovery of financing costs from a "fairness" perspective?

A. Yes. We incurred $7.2 million of financing costs in connection with refinancing several debt issues. The refinancing of these issues resulted in lower debt costs reducing overall interest. We are proposing that the beneficiaries of those lower debt cost (ratepayers) pay for the cost of achieving that benefit. To do otherwise, and allow ratepayers to benefit without paying for the cost of achieving such benefit, would be unfair and unreasonable.

Q. Is there any evidence in the record regarding Staff's position on FAS 71?

A. Yes. Staff witness John Antonuk answered a series of questions regarding FAS 71 in a deposition that occurred on March 13, 2008. Below is an excerpt from that deposition.

> "Q. ...Do you have any opinion about whether or not Tucson Electric Power Company was permitted or required to change its accounting to go off of FASB 71 in connection with the '99 settlement agreement?
>
> A. I don't think I would go so far as to say require. They may have been required. Working with Dennis, we certainly reached the agreement that it was appropriate to do so at that time. You know, I think most likely if we had addressed the question of necessity we would have said yes, but we didn't address that question. We just looked and said was it a prudent and reasonable thing to do, and the answer was yes..."

Q. Is it still the Company's position that the Settlement Agreement caused TEP to go off of FAS 71?

A. Yes. This topic is covered more fully vetted in the Direct and Rebuttal Testimony of TEP witness Karen G. Kissinger.

Q. Is there a different method that would allow TEP to recover these financing costs other than including them in the ICRA?

A. Yes. If TEP were to include these costs as interest expense in the test year, then the Company's cost of debt capital would increase from 6.39% to 6.59%. Please refer to Exhibit KPL-8.

Q. Does Staff's testimony include an analysis of the potential impact on TEP's cost of debt capital if the Company is allowed to recover such financing costs?

A. Yes. Staff witness Ralph Smith states that a preliminary analysis showed that including the $7.2 million of financing costs would increase the cost of debt recommended by Staff

by approximately 21 basis points. This is similar to the result calculated by TEP, shown in Exhibit KPL-8.

Q. Does increasing TEP's proposed cost of debt change the Company's proposed ROR?

A. Yes. TEP's proposed ROR would increase from 8.35% to 8.46%, if the Company's cost of debt capital included the $7.2 million of financing costs included in the ICRA. Please refer to the table below.

	% of Actual Capital Structure	Component Cost	Weighted Average Cost
Common Equity	45.00%	10.75%	4.84%
Long-Term Debt	55.00%	6.59%	3.62%
Total	100.00%		8.46%

Q. Is the Company changing its proposal for including financing costs in the ICRA?

A. No. TEP believes that the $7.2 million of financing costs related to generating assets should be included in the ICRA. The Company should be compensated if TEP's generation assets become rate regulated once again, since the cost of debt component of the overall rate of return is lower as the result of incurring these generation-related debt costs. If customers are to receive the benefit of lower interest costs, then the expense to achieve these benefits should also be borne by the customer.

<u>Securitization Efforts</u>

Q. Does ACC Staff accuse TEP of breaching the Settlement Agreement?

A. Yes. ACC Staff witness John Antonuk's Direct Testimony states that TEP, "...breached its duty to fully consider (and use if appropriate) securitization to reduce customer costs under the Settlement Agreement's CTC."[26]

[26] Page 28, lines 1-3

Mr. Antonuk based his claim on a data request response by the Company. TEP has since updated that data response to include more detailed information regarding the Company's securitization efforts.

Q. Can you briefly describe what is meant by securitization?

A. Yes. Securitization is a financing structure that provides access to lower cost sources of funding through the isolation of specified revenues and/or assets that provide security for the debt, thus helping achieve a lower overall cost of capital. The ACC's decision approving the Settlement Agreement (Decision No. 62103) contemplated securitizing transition revenues. As a result, TEP contemplated (i) creating a bankruptcy proof special purpose entity ("SPE"), (ii) transferring the property rights of the Fixed CTC revenues to the SPE and (iii) issuing debt at the SPE and using the proceeds to retire higher cost debt at TEP.

Q. Please briefly describe the steps TEP took to analyze and consider the securitization of transition revenues?

A. TEP carefully considered and analyzed securitizing transition revenues. In 1998, prior to the Commission's final order approving the Settlement Agreement, TEP retained outside counsel and an investment banking firm to analyze how the Company might be able to securitize transition revenues. In August of 1998, TEP's outside counsel and investment bankers made presentations to ACC Staff regarding TEP's proposed securitization plan. In November 1998, TEP filed Direct Testimony in Docket Nos. E-01933A-98-0471, 97-0772, E-01345A-98-0473, 97-0773, and RE-00000C-94-165. TEP witness Dean E. Criddle, partner in the law firm of Orrick, Herrington & Sutcliffe LLP ("Orrick"), filed testimony on the topic of securitizing transition revenues.

Q. What obstacles did TEP face when it considered securitization?

A. Based on Orrick's analysis in 1998, several legal elements needed to be in place to achieve the full financial benefits of securitization. These included (i) successful transfer of property rights to the SPE, (ii) assurance from the Commission that future ACC rulings would not alter the transition revenues during the securitization period and (iii) legislative authorization of the securitization. Establishing these conditions without authorization from the State legislature would not guarantee that the rating agencies would assign the highest credit rating to the SPE. A lower credit rating would raise the interest rate on the debt to be issued by the SPE, thus greatly reducing the potential financial benefits of securitization.

TEP continued to monitor the legal obstacles of securitization after the Settlement Agreement was executed. Ultimately, the IRS ruled in 2002 that securitized bonds must be issued under a state utility commission financing order that is authorized by specific State legislation. The mounting legal obstacles stalled TEP's securitization efforts.

IV. SPECIFIC REBUTTAL TO RUCO.

Cost of Capital

Q. Have you read RUCO's Direct Testimony regarding TEP's proposed cost of capital?

A. Yes.

Q. Does RUCO agree with TEP's proposed weighted average cost of capital?

A. No. RUCO witness William Rigsby recommends a 7.76% cost of capital, which is lower than the cost of capital proposed by Staff.

Q. Which components of TEP's weighted average cost of capital does RUCO disagree with?

A. RUCO disagrees with TEP's proposed ROE. TEP witness Dr. Samuel C. Hadaway offers rebuttal testimony on the issue of ROE.

Q. Does RUCO support TEP's proposed equity ratio?

A. Yes. RUCO's testimony states that the pro forma equity ratio of 45% proposed by TEP is below the industry average equity ratio.[27]

ICRA

Q. Is RUCO's recommendation regarding the Company's proposed ICRA similar to Staff's recommendation?

A. Yes. Like Staff, RUCO recommends reducing the ICRA by $33 million to remove the coal contract amendment fees and the financing costs related to generation assets. The Direct Testimony of RUCO witness Ms. Diaz Cortez states the following:

> "TEP did not seek, nor was granted, a deferral accounting order from the Commission that would allow the Company to capitalize these expenses as regulatory assets. Thus, these costs were expensed when incurred, in periods prior to the test year. Therefore, the Company has no asset related to these costs for which rate base recovery is warranted."[28]

Q. Do you agree with RUCO's recommendation?

A. Not at all. In terms of the financing costs related to generation assets, RUCO, like Staff, failed to recognize the GAAP accounting treatment of TEP's generation assets. Once the Settlement Agreement became effective, TEP's generation assets no longer qualified as

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[27] Direct Testimony of RUCO witness William Rigsby, page 47 lines 10-15.
[28] Page 12, lines 22-23; Page 13, lines 1-4

regulated assets pursuant to FAS 71. Thus, the Company was not allowed to defer these financing costs. If the Commission decides to use a cost of service methodology to set TEP's rates, and re-regulate the Company's generation assets, then TEP is entitled to recover these costs. TEP witness Karen G. Kissinger offers additional rebuttal testimony to RUCO regarding the ICRA.

V. SUMMARY.

Q. Do you have any final thoughts?

A. Yes. The Company appreciates Staff's recognition that TEP needs a PPFAC to help mitigate the Company's growing exposure to volatile purchased power and fuel costs. In addition to a PPFAC, TEP needs a non-fuel rate increase to (i) maintain TEP's existing financial condition and provide an opportunity for the Company to continue the restoration of its financial health, (ii) provide better access to the capital markets to fund infrastructure maintenance and growth, (iii) continue providing safe, reliable energy service and (iv) improve TEP's credit profile to provide broader access to the wholesale power and gas markets which enables TEP to acquire the proper mix of energy resources that maximizes the long-term benefits for customers.

Staff and RUCO failed to provide any testimony, evidence or analysis of the potentially devastating effects their recommended rate decreases would have on TEP's financial health. The consequences of adopting Staff or RUCO's rate proposals could (i) erase years of steady financial improvement, (ii) increase the Company's cost of debt capital, leading to higher costs for customers, (iii) compromise the ability of TEP to continue providing safe, reliable energy service to its customers, (iv) limit the Company's ability to procure energy resources that provide long-term price stability for customers, and (v) reduce TEP's ability to access the capital markets on favorable terms in order to fund the improvement

and expansion of the Company's utility infrastructure.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT

KPL-3

Credit Opinion: Tucson Electric Power Company

Tucson Electric Power Company

United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa3
Sr Sec Bank Credit Facility	Baa2
Senior Secured	Baa2
Parent: UniSource Energy Corporation	
Outlook	Stable
Sr Sec Bank Credit Facility	Ba1

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Key Indicators

[1]
Tucson Electric Power Company

ACTUALS	LTM 9/30/07	2006	2005	2004
(CFO Pre-W/C + Interest) / Interest Expense [2]	3.4x	3.5x	3.0x	2.5x
(CFO Pre-W/C) / Debt [2]	18.6%	19.6%	16.3%	14.0%
(CFO Pre-W/C - Dividends) / Debt [2][3]	14.0%	15.2%	13.1%	12.2%
(CFO Pre-W/C - Dividends) / Capex [2][3]	113.7%	136.7%	125.8%	165.8%
Debt / Book Capitalization	64.4%	66.6%	68.2%	77.3%
EBITA Margin %	26.1%	31.0%	30.1%	33.2%

[1] All ratios are calculated using Moody's Standard Adjustments. [2] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items. [3] CFO pre-W/C-Dividends, is also referred to as retained cash flow ("RCF") in the Global Regulated Electric Utilities Rating Methodology.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Company Profile

Tucson Electric Power Company (TEP: Baa3 senior unsecured, stable outlook) is an integrated electric utility, that provides regulated electricity service to approximately 392,000 retail customers in Southeastern Arizona and is also engaged in wholesale marketing of power in the Western U.S. TEP is the principal operating subsidiary of UniSource Energy Corporation (UNS: Ba1 senior secured bank credit facility (security limited to stock of subsidiaries excluding TEP), stable outlook), a holding company that through its subsidiaries, provides electricity and natural gas to customers across Arizona.

Rating Rationale

TEP's Baa3 senior unsecured rating is driven by its relatively stable, primarily regulated, cash flows, its growing service territory, its low cost predominantly coal-fired generation base, and cash flow metrics that are within the

ranges demonstrated by U.S. electric utilities rated Baa. The rating considers TEP's limited ability to recover cost increases while it is operating under a rate freeze through 2008, as well as the current regulatory environment in Arizona. The stable outlook recognizes that there is considerable uncertainty regarding the manner in which TEP's rates will be established beyond 2008 and incorporates Moody's expectation that the Arizona regulatory environment will continue to be challenging; however, Moody's also believes that a constructive settlement can ultimately be reached. The stable outlook assumes that the company will finance its increasing capital expenditure budget in a manner that remains consistent with its current financial strength and flexibility.

The most important rating drivers are as follows:

CHALLENGING REGULATORY ENVIRONMENT

Currently, almost all of TEP's operations, and the operations of its parent company, UNS, are regulated. A significant percentage of regulated operations are generally viewed as positive for credit quality as regulated cash flows tend to be more stable and predictable than those of unregulated companies. This key factor is tempered somewhat by the challenging regulatory environment of Arizona, which Moody's ranks below average for U.S. regulatory jurisdictions in terms of expectation of timely recovery of costs and predictability of rate decisions.

TEP is operating under a rate freeze through 2008. TEP's rates are currently set in accordance with the terms of a Settlement Agreement entered into with the Arizona Corporation Commission (ACC) in 1999 in conjunction with the ACC's original objective of introducing retail electric competition in Arizona. The Settlement Agreement established the means by which TEP would transition to a market based rate structure for generation in 2009; however, in 2002 and 2003 the ACC reexamined circumstances that had changed since it had entered into the 1999 Agreement and there is now considerable uncertainty regarding the methodology for establishing TEP's retail rates beyond 2008. During the rate freeze period, TEP has been allowed to include in its rates a fixed competitive transition charge (CTC) for the recovery of approximately $450 million stranded investment costs. Although these charges have provided some additional cash flow for TEP, the absence of additional cost recovery mechanisms like fuel clauses, and the inability to file for general rate increases, has caused the company to suffer revenue deficiencies in recent years. Currently, TEP estimates its annual revenue deficiency to be in the range of $117-181 million.

In July 2007, as requested by the ACC, TEP filed for a rate increase to be effective January 2009. As outlined below, TEP proposed three alternative rate methodologies for the ACC's consideration. The increases requested in each case are based on 10.75% ROE and a capital structure of 45% equity and 55% debt; however, the approaches differ with regards to: i) the components of rates that would be established via traditional cost of service rate making, ii) the composition of the rate base, and iii) the implementation of fuel and power purchase cost recovery mechanisms.

Option (1) proposes market-based rates for generation and cost of service based rates for transmission and distribution only. Under this option, TEP has requested a revenue increase of $172 million, reflecting an increase of approximately 22% over current retail rates.

Option (2) proposes cost-of-service based rated for transmission, distribution and also for generation. This option includes in rate base an estimated $788 million Termination Cost Regulatory Asset (TCRA) which TEP has requested be recovered over 10 years. The TCRA represents the company's estimate of the cumulative revenue deficiency incurred while rates were frozen with the intent of transitioning to market generation rates in 2009. TEP also proposes to incorporate a purchased power and fuel adjustor clause (PPFAC) with 90% of short-term wholesale revenues netted against the PPFAC costs. Under this option, TEP has requested an annual revenue increase of $181 million, reflecting an increase of approximately 23% over current rates.

Option (3) proposes a hybrid arrangement that would establish cost-of-service based rates for transmission, distribution and generation on a somewhat smaller rate base. This arrangement would allow TEP to seek a market-based return for specific generation assets that would be removed from its current rate base; specifically, TEP's minority interests in the Navajo and Four Corners generating stations would be excluded from rate base and dedicated to wholesale sales. The hybrid proposal also includes the request for a PPFAC, with 100% of short-term wholesale revenues netted against the PPFAC costs. Under this option, TEP has requested an annual revenue increase of $117 million, reflecting an increase of approximately 15% over current rates.

A procedural schedule has been established requiring staff and intervener testimony be filed on February 22, 2008, with hearings to begin on May 12, 2008. Although each of the proposed options would result in a significant rate increase for consumers, and are therefore likely to encounter customer intervention and resistance by regulators, Moody's believes it is possible a constructive resolution can ultimately be reached. We note that in its decision in APS' most recent rate case, the ACC allowed a prospective adjustment for fuel and purchased power costs.

COMPETITIVE OPERATING PROFILE

TEP benefits from a regionally competitive cost profile that stems from its predominately coal-fired generating base which will supply approximately 85% of its expected power demand in 2007. The balance of TEP's resource needs are met through gas-fired generation and purchased power. TEP's load profile allows somewhat of a natural hedge

for power costs. During winter months, the company sells its excess low cost coal-fired generation into the wholesale market generating revenues that are used to offset the costs associated with purchasing power for its peak load during the summer months.

TEP's generating capacity is modestly diversified across several different plants providing some mitigation of operating risk. Stable operating performance is a key factor in maintaining the company's financial strength as it is currently operating under a rate freeze without any type of a fuel adjustment clause. In 2007, although TEP experienced forced outages at Four Corners, San Juan and Navajo, year-to-date its overall availability factor is 89% reflecting improved performance at Springerville, its largest facility. Over the past five years, TEP's coal plants have been operating at average availability factors above the industry average.

GROWING SERVICE TERRITORY

TEP's customer base has being growing at a steady pace supported by Arizona's robust economic environment. In 2006, TEP's number of retail customers increased by 2%, and it is expected to increase at a similar rate through 2010. Strong customer growth results in a need for incremental capital investments and power purchases to meet load requirements, which in turn increases the company's exposure to timely recovery of investment and fuel costs that are particularly challenging in TEP's service region.

Financial Profile

TEP's financial metrics have improved over the last few years and are currently toward the middle of the ranges identified for integrated electric companies in the U.S. rated in the Baa rating range. For example, TEP's cash from operations before changes in working capital (CFO pre-W/C) to Debt, adjusted in accordance with Moody's standard analytical adjustments, improved from 14% in 2004 to 20% in 2006 and 19% for the twelve months ended September 30, 2007. TEP's interest coverage ratio measured by (CFO pre-W/C + interest) to interest improved from 2.5 times in 2004 to 3.5 times in 2006 and to 3.4 times for the twelve months ended September 30, 2007. TEP's Debt to capitalization ratio was 64% as of September 30, 2007, down from approximately 77% in 2004. TEP's financial metrics have improved as a result of a successful deleveraging strategy which reduced debt levels and interest expense; however, book leverage remains somewhat higher than that of other electric utilities rated Baa3, which in 2006 had an average Debt to capitalization ratio of approximately 50%. Over the next several years, conservatively assuming no significant increase in retail rates beyond the termination of the rate freeze, Moody's anticipates TEP's (CFO pre-W/C) to Debt ratio would remain in the high-to-mid teens and its interest coverage ratio would remain above 3.0 times while its debt to capitalization would remain relatively stable. Given TEP's current business risk profile, these metrics are consistent with its rating.

Liquidity

TEP's relatively stable cash flows are generally a reasonable source of liquidity. Over the last several years, TEP's operating cash flows have been sufficient to cover capital expenditures and dividends to the parent, and to generate marginally positive free cash flow. In the twelve months ended September 30, 2007, cash flow from operations of $250 million, was generally sufficient to cover $170 million of capital expenditures and $62 million of dividends to the parent. In 2007, capital expenditures are projected to be approximately $200 million.

In 2008 and thereafter, TEP's capital expenditures are expected to increase moderately due to investments in transmission facilities, environmental upgrades and maintenance of the generation facilities. Conservatively assuming no significant increase in retail rates, TEP's projected annual outlays for capital expenditures and dividends to the parent are generally expected to exceed its cash flow from operations. Moody's expects cash shortfalls to be funded with external sources of cash including proceeds from both long and short term debt financing.

TEP's near term maturities include $138 million of mortgage bonds due in the third quarter of 2008 as well as approximately $58 million of capital lease obligations due in the next twelve months. Moody's expects TEP to be able to issue new notes at the maturity of its mortgage bonds; however, if the company is unable to issue new debt, it would need to rely on its alternative sources of liquidity to meet this maturity. Moody's assumes TEP will manage its near term maturities within the limits of its readily available sources of cash, including its committed bank credit facility.

TEP short term requirements are supported by a $150 million revolving credit facility for working capital needs. It also has a $341 million letter of credit facility supporting $329 million of tax-exempt variable rate bonds. Both facilities expire on August, 2011. The TEP facilities are secured by its first mortgage bonds. As of October 31, 2007, TEP had approximately $140 million available under the revolving credit facility. The TEP facilities do not contain rating triggers that would cause acceleration payments or make the facilities unavailable; however, they do contain a rating sensitive pricing grid and a material adverse change (MAC) clause that could preclude new borrowings. In our opinion, the requirement for a MAC representation at each borrowing significantly increases the risk that the credit facility may not be available when the company's liquidity needs are greatest. TEP is also required to meet certain financial covenants to access these facilities, including a minimum cash coverage ratio of 2.25 times and a maximum leverage ratio of 4.25 times. As of September 30, 2007, TEP's cash coverage ratio as defined in the agreement was 4.40 times and its leverage ratio was 3.49 times.

Rating Outlook

The rating outlook for TEP is stable reflecting its regionally low cost generating base and the predominately regulated nature of its operations. It recognizes the historically challenging regulatory environment in Arizona and it assumes that planned capital expenditures will be financed in a manner that is consistent with TEP's current level of financial strength and flexibility.

What Could Change the Rating - Up

The ratings or outlook could be revised upward in the event TEP is able to reach agreements with the ACC that are supportive of cash flow and credit quality in light of the company's growing customer base and capital expenditure needs such that, for example, assuming TEP's current business risk level, the ratio of CFO pre-WC to Debt could be expected to remain above 20% on a sustainable basis.

What Could Change the Rating - Down

The ratings could be revised downward if there were to be prolonged operational difficulties or increased costs, or indications that regulatory outcomes were likely to be non-constructive so that, for example, the ratio of CFO pre-WC to Debt were expected to fall below 15% for an extended period. The ratings or outlook could also be revised downward if there were to be a significant increase in the business risk profile of the company without a commensurate improvement in financial metrics.

Rating Factors

Tucson Electric Power Company

769000

Select Key Ratios for Global Regulated Electric Utilities

Rating	**Aa**	**Aa**	**A**	**A**	**Baa**	**Baa**	**Ba**	**Ba**
Level of Business Risk	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**
CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-75	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

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EXHIBIT

KPL-4

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March 11, 2008

Research Update:

Tucson Electric Power's Unsecured Debt Rating Is Raised To 'BB-'; New bond Issue Rated 'BB-'

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Research Update:

Tucson Electric Power's Unsecured Debt Rating Is Raised To 'BB-'; New bond Issue Rated 'BB-'

Rationale

On March 11, 2008, Standard & Poor's Ratings Services raised its unsecured debt ratings for Tucson Electric Power Co. (TEP) by one notch to 'BB-' and assigned its 'BB-' rating to the proposed offering of up to $121 million of 2008 series A industrial development bonds issued by the Pima County Industrial Development Authority in Arizona (Pima). The Pima bonds will be unsecured obligations of TEP, which is the obligor. TEP will use the offering's proceeds to pay down its revolver balances of about $75 million as of March 7, 2007 and to prefinance a portion of TEP's $138 million maturity of collateral trust obligations, due August 2008. The outlook is stable.

The upgrade reflects improvement in TEP's ratio of priority debt to assets. Under our current criteria, we assign speculative-grade debt ratings one notch below the issuer credit rating ('BB', in TEP's case) if the maximum amount of secured debt that could be outstanding is between 15% and 30% of the utility's assets. Increases in TEP's asset base and our expectation that some of the $138 million maturity will be retired with unsecured debt drive the improvement.

TEP's business risk profile is 'strong', reflecting favorable factors that include: TEP's low-cost coal-fired generation sufficient to meet the majority of its retail loads, modest growth in its service territory, and the absence of significant new generation investment. Weaknesses in the business profile include near-term uncertainty over the outcome of TEP's retail rates filed in July 2007, and a retail rate cap in place until the end of 2008 that puts TEP at risk for forced outages, and the potential for carbon regulation, which could impose material costs given TEP's coal-dominated portfolio.

TEP is a vertically integrated, investor-owned utility in Arizona, serving more than 397,000 customers in Tucson and southeastern Arizona. The company is a wholly owned subsidiary of UniSource Energy Corp. (UniSource). Other regulated operations consist of UNS Gas and UNS Electric, which provide retail natural gas and electric services to about 236,000 mostly residential customers in six counties in northern and southern Arizona. (UniSource Energy owns these operating companies through an intermediate company, UniSource Energy Services Inc.). UniSource's other holdings are small and not considered to be material to consolidated credit quality. UniSource Energy Development is an unregulated company that develops generation resources and is currently building the Black Mountain Generating Station (BMGS), a gas turbine project in Northern Arizona that, subject to Arizona Corporation Commission (ACC) approval, is proposed to provide energy to UNS Electric.

We do not rate the debt of parent UniSource ($150 million in convertible unsecured notes as of Dec. 31, 2007), nor that of UniSource's other regulated electric and gas subsidiaries, UNS Electric and UNS Gas ($160 million of unsecured, private-placement notes). However, under our consolidated rating

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methodology, TEP's ratings are based on the performance of the UniSource family of companies. TEP's financial profile is 'highly leveraged', stemming from legacy issues the company faced in the early 1990s. The company has made progress in gradually improving its capital structure, but the utility's debt burden continues to constrain the ratings. Adjusted debt to total capitalization was 72% as of Dec. 31, 2007. (This calculation excludes capital lease obligations that TEP has invested in and holds, paying itself interest expense. We also net from our cash coverage calculations the interest TEP pays to itself). Consolidated debt outstanding was $1.6 billion as of Dec. 31, 2007, including current maturities and capital lease obligations held by third parties.

Cash flow metrics have shown modest improvement over the past two years. At year-end 2007, adjusted funds from operations (FFO) to total debt stood at about 18%; FFO interest coverage was about 3.2x. The company has achieved stronger interest coverage in recent years by renegotiating parent and utility bank loans at more favorable rates, TEP's investment in its own high coupon lease debt, and a recapitalization in 2005. Cash coverage metrics would have been higher had it not been for fuel and purchased power pressures on TEP, which has been operating under a rate cap since 1999. TEP's FFO however, was about $320 million, its strongest year to date.

Future financial performance of UniSource (of which TEP is by far the largest subsidiary, contributing about 82% of consolidated operating cash flows in 2007), will hinge largely on the outcome of TEP's general rate case, which is pending before the ACC.

TEP's 1999 settlement was crafted in an era that envisioned power markets being deregulated at both the wholesale and retail levels. The settlement fixed rates through 2008 and provided TEP with accelerated depreciation and $450 million in competitive transition charges (CTC) recovery, which in recent years has provided $80 million to $90 million in incremental cash flow. At the time of the settlement, it was envisioned that at the end of the rate freeze, the generation component of TEP customer rates would be priced at market. TEP has argued that the settlement is a binding legal contract, and under its terms, it should be permitted to charge customers market rates at the end of the rate freeze.

In July 2007, in response to hearings as to how to address this issue, TEP filed three proposals with the ACC--a market-based approach for setting generation rates, a traditional cost-of-service method, and a hybrid. We focus our discussion on the request's cost-of-service component because we think based on recent intervenor filings it is unlikely the ACC will support the other two proposals TEP has offered.

The cost-of-service methodology would use traditional rate-making principles for transmission & distribution and generation, but TEP also requested recovery of a regulatory asset of $788 million over 10 years. The company argues the regulatory asset represents forgone revenues under the settlement and is reasonable economic compensation under the settlement agreement. TEP also requested a fuel and purchased power mechanism. The propsosal would result in a 23% increase in retail rates (or 8% without the regulatory asset). TEP has also asked that in this scenario the ACC restore its exclusive right to serve, although currently retail competition is effectively dead.

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Parties filed testimony in February favoring the cost-of-service approach, but rejected TEP's request for the recovery of a regulatory asset. ACC staff filings recommended a fuel and purchased power adjuster be adopted, which we see as a critical component of protecting future credit quality, but also recommend that TEP's current rates be reduced by 2% to 3%. With TEP's current rate of about 8.4 cents per kilowatt-hour (kWh), the commission staff's recommendation would imply a rate of about 7.6 cents/kWh. Staff also recommended that customers be refunded amounts TEP is now collecting under the CTC. (In May 2007, the ACC ruled that the current CTC, which is about 0.9 cents/kWh of the total system average retail rate of 8.4 cents/kWh, will be permitted to continue, subject to refund, until the case is decided.) Assuming the ACC supports staff's recommendation, 2009 cash flows could be hampered by a customer refund of an estimated $65 million.

TEP has indicated if it is returned to cost of service without some meaningful regulatory asset, it will seek court relief on the basis that the ACC violated the terms of the 1999 settlement. Whether this will influence the ACC's decision is difficult to assess. The case is expected to be concluded at the end of 2008 or early 2009. The timing of the decision could be problematic for the company if it is not voted on before January 2009, when three of the five ACC commissioners' terms expire. This raises the possibility that the case could be heard by a different set of commissioners than that which votes on a final decision.

Short-term rating factors

TEP's short-term credit rating is 'B-2', reflecting satisfactory cash flows from consolidated operations. Consolidated cash and equivalents, including TEP cash balances, stood at $90 million as of Dec. 31, 2007, relative to $104 million as of Dec. 31, 2006.

Total revolving credit facilities are $280 million. TEP maintains a $491 million senior secured credit agreement, of which $341 million is committed as collateral that supports about $329 million in outstanding industrial development bonds. The remaining $150 million capacity is a revolver available for general corporate purposes, of which $70 million was utilized as of Feb. 26, 2008. This agreement was amended and restated in August 2006 and terminates in August 2011.

UniSource has a $100 million credit agreement, of which $30 million is a term-loan facility and $70 million is a revolver available for general corporate purposes, drawn at $33 million as of Feb. 26, 2008. The agreement contains cash flow and leverage tests and restricts dividend payments unless UniSource has more than $15 million in unrestricted cash and revolving credit. A $60 million revolver, due in August 2011, is also available to support UNS Gas and UNS Electric; $40 million was utilized as of Feb. 26, 2008.

UniSource's consolidated operations have typically generated modest free operating cash of between $35 million and $50 million over the past few years, but in 2008 capital investment will result in slightly negative cash flows. After several years of no or low maturities, about $204 million is due on a consolidated basis this year--$138 million at TEP and $60 million at UNS Electric.

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Outlook

The stable outlook reflects recent improvements to consolidated credit metrics that we believe to be sustainable through 2008. The outcome in TEP's current rate case, not expected before the end of 2008 or early in 2009, will be crucial in determining the company's future business risk and financial performance. For this reason, positive movement in the ratings is unlikely to occur until the case is concluded. A favorable ruling that allows the company to improve its credit metrics would likely result in a ratings upgrade. Barring a substantial forced outage, an adverse change in the outlook or ratings is not expected, as we believe the ACC is likely to provide rate relief at least adequate to sustain current financial performance. However, if the rate case is inadequate or increases business risks, downward pressure could exist for the ratings.

Ratings List

Ratings Affirmed

Tucson Electric Power Co.	
Corporate Credit Rating	BB/Stable/B-2
Senior Secured	
$150 mil revolv credit fac bank ln due 2011	BBB
Recovery Rating	1+
$341 mil term bank ln due 2011	BBB
Recovery Rating	1+

Upgraded

	To	From
Senior Unsecured		
Local Currency	BB-	B+

New

Up to $121 mil 2008 series A indstl devlpmnt bonds	BB-

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March 19, 2008

Standard & Poor's Extends Recovery Ratings To Unsecured Speculative-Grade Corporate Issues

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Issue-Level Rating Changes

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Standard & Poor's Extends Recovery Ratings To Unsecured Speculative-Grade Corporate Issues

Standard & Poor's today has assigned recovery ratings to more than 1,800 unsecured loan and bond issues sold by nearly 900 speculative-grade rated corporate issuers in the U.S., Canada, and Europe. Recovery ratings are indicators of estimated recovery prospects for creditors in the event of a debt issuer's payment default (see "Criteria Guidelines For Recovery Ratings On Global Industrials Issuers' Speculative-Grade Debt," published Jan. 7, 2008), and serve as inputs to Standard & Poor's traditional issue-level ratings. A list of all newly assigned recovery ratings, along with the corresponding issue-level rating for each debt issue, is provided at the end of this report.

The expansion of recovery ratings to unsecured debt follows the release of our revised issue rating framework and recovery rating scale for speculative-grade secured debt issues in June 2007. We now have assigned recovery ratings to a total of approximately 4,000 non-investment-grade rated issues. Both the leveraged loan market and speculative-grade rated bond market have grown dramatically in the past few years. Standard & Poor's introduced recovery ratings to the market in 2003 to provide more consistent differentiation among speculative-grade debt instruments.

Table 1

Recovery Rating Scale And Issue Rating Criteria

(For issuers with a speculative-grade corporate credit rating)

Recovery rating	Recovery description	Recovery expectations*	Issue rating notches relative to corporate credit rating
1+	Highest expectation, full recovery	100%¶	+3 notches
1	Very high recovery	90%-100%	+2 notches
2	Substantial recovery	70%-90%	+1 notch
3	Meaningful recovery	50%-70%	0 notches
4	Average recovery	30%-50%	0 notches
5	Modest recovery	10%-30%	-1 notch
6	Negligible recovery	0%-10%	-2 notches

*Recovery of principal plus accrued but unpaid interest at the time of default.

¶Very high confidence of full recovery resulting from significant overcollateralization or strong structural features.

Standard & Poor's is also publishing a "recovery report" write-up for each issuer that was assigned a new recovery rating. These reports explain the rationale behind our recovery rating conclusions.

Importance Of Recovery In The Current Leveraged Debt Markets

The rollout of our recovery ratings to unsecured debt issues comes at a time when recovery and recovery ratings are playing an increasing role in the pricing of speculative-grade debt in the U.S. With the greater focus on credit and the potential for rising defaults on corporate leveraged debt, secondary market prices have begun to show a greater focus on recovery, reflected in rising price differences between debt issues by recovery ratings.

Based on data compiled by Standard & Poor's Leveraged Commentary & Data group, averaged secondary market

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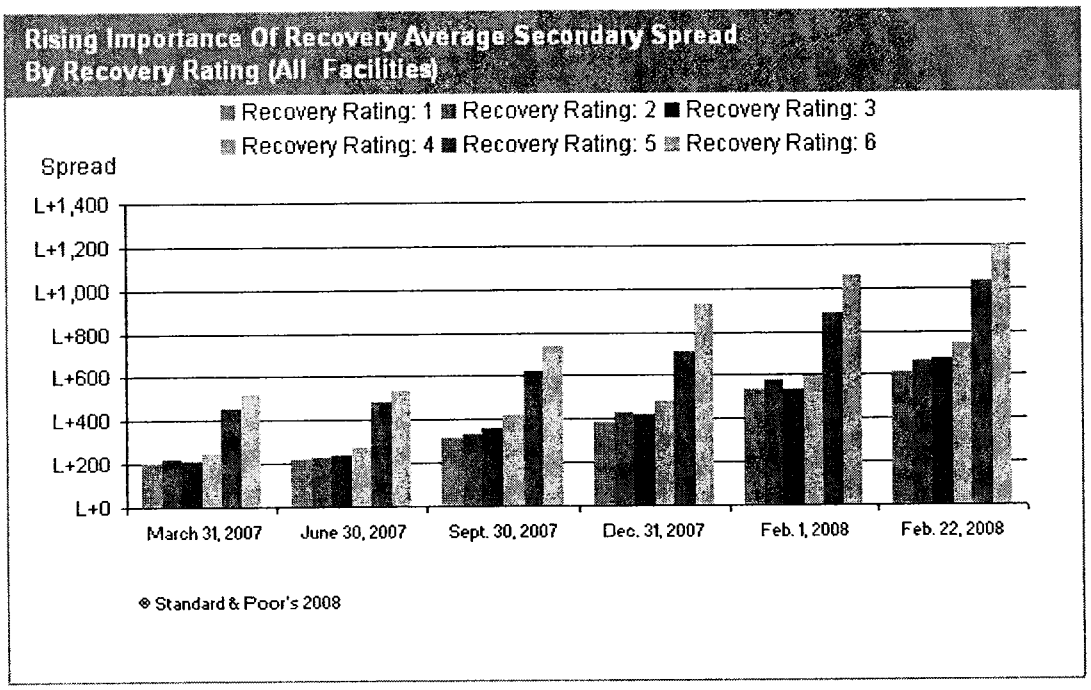
prices for the 200 loans in the Standard & Poor's LSTA index that carry recovery ratings now show a spread of nearly 600 basis points between loans with the highest recovery potential, indicated by a recovery rating of '1', and those with the lowest potential, indicated by a recovery rating of '6' (see chart 1). This is up from a spread of 400 basis points in the first half of 2007 before the rapid reversal in the leveraged debt market after July 2007. (See "For Leveraged Debt, Investors Go From Credit Amnesia To Credit Obsession," published Jan. 8, 2008.

Chart 1



Recovery Ratings For Unsecured Issues Of 'BB' Rated Companies

For issuers rated in the 'BB' category, Standard & Poor's generally capped its recovery ratings at '3' (expected recovery of 50% to 70%) to reflect a limit on recovery prospects because of the potential for additional debt on parity with, and prior to, the rated unsecured obligations. Using a fundamental approach to assess the recovery prospects of a company with a corporate credit rating in the 'BB' category is significantly more problematic than using this approach on 'B' and 'CCC' rated credits since the latter are inherently closer to default and the visibility of a path to default is much clearer.

Issuers rated 'BB' often have very limited, if any, secured debt, and the terms of their existing debt issues generally leave ample room for additional debt issuance. While our methodology assumes that all committed debt is fully funded prior to default, it does not make any assumptions regarding the addition of any new debt prior to default, although as a company's credit profile heads toward default, the capital structure will, in reality, look very different.

In recognition that default and valuation modeling is much more difficult for these high-speculative-grade companies and that unsecured creditors are more likely to be negatively affected by capital structure changes, Standard & Poor's typically caps its recovery ratings on the unsecured debt of companies with corporate credit ratings in the

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'BB' category (subject to certain exceptions). The recovery rating cap of '3' effectively caps our issue-level rating on such debt at the level of the corporate credit rating on the issuer.

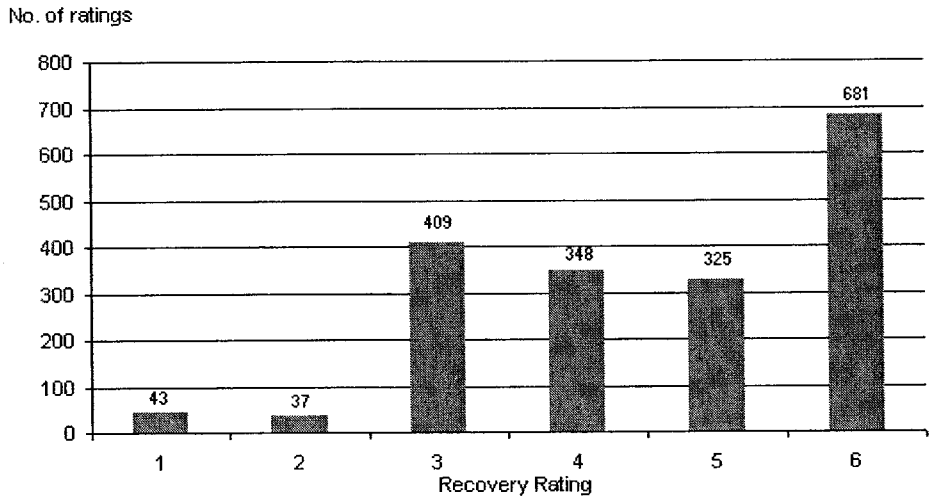
Exceptions to this cap are issues for which Standard & Poor's concludes that there is little potential for additional debt prior to, or on parity with, the issuer's current unsecured debt, such as U.S. investor-owned electric utilities. In the case of regulated U.S. utilities, the typically strong values that we have ascribed to the asset coverage of unsecured debt derive largely from the stronger recovery experience of the very few utilities that have filed for bankruptcy over the past 75 years. The strict indenture limitations on secured debt that a utility can issue (which have never been compromised), the recovery experience of unsecured debt holders (which has not been weaker than the equivalent of a recovery rating of '2'), and the stable EBITDA performance relative to other corporate entities lend substantial support to utility asset values. Further support for the recovery of unsecured debt post default for utility investors derives from regulatory oversight of utility capitalization structures and the common regulatory limitation on the amount of unsecured debt that may be issued.

Profile Of Recovery Ratings On Unsecured Debt

Chart 2 shows the distribution of all recovery ratings for the U.S., Canada, and Europe. The ratings concentrate at the lower end of the recovery spectrum, with a mean recovery rating of '4.6', equivalent to an expectation for recovery of principal and past due interest of 29.64%, with '6' being the most frequent rating.

Chart 2

U.S., Canada, & Europe: Distribution Of All Recovery Ratings On Unsecured Debt



N = 1,805 (issues with ratings on CreditWatch were not assigned recovery ratings)
Nominal mean recovery rating = 4.61
Mean recovery rating in percentage = 29.64%
Standard deviation recovery rating in percentage = 9.85%
Standard deviation nominal mean recovery rating = 1.83

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Charts 3 and 4 show the distribution of recovery ratings for senior unsecured and subordinated debt, respectively. The average recovery ratings for these classes were '4.3' (equivalent to 34.51% recovery) for senior unsecured debt and '5.5' (equivalent to 13.50% recovery) for subordinated debt, with the most frequent rating remaining '6'.

Chart 3

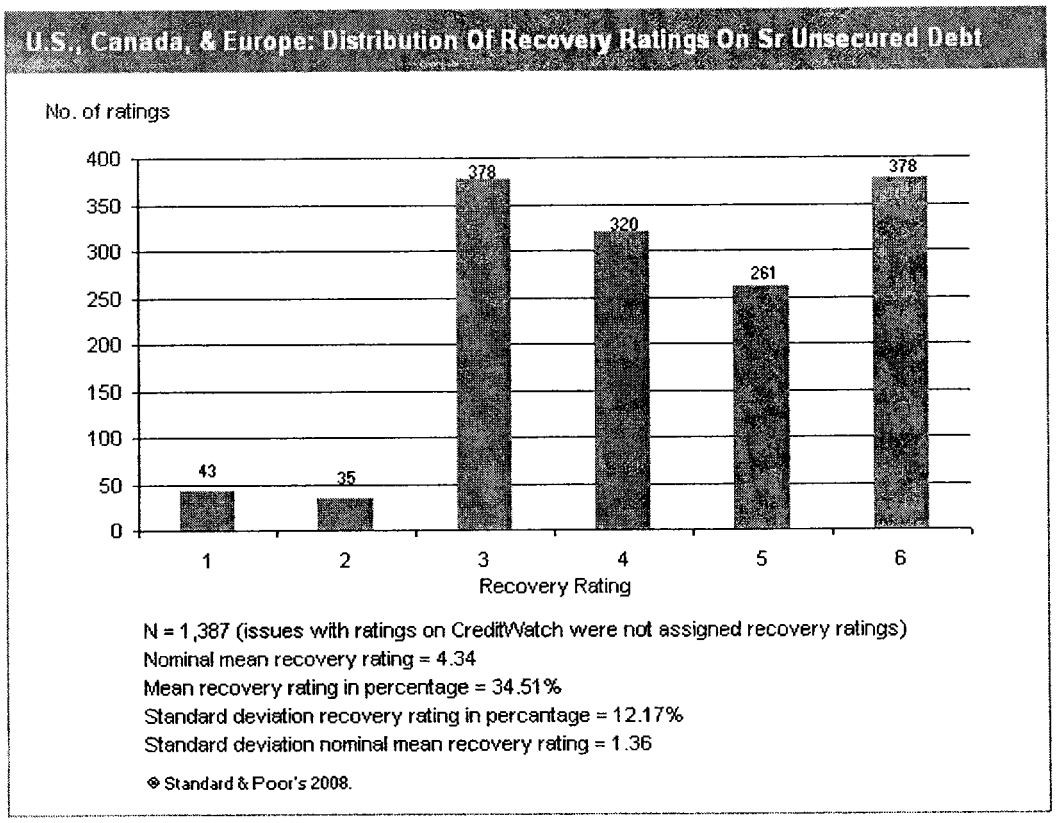

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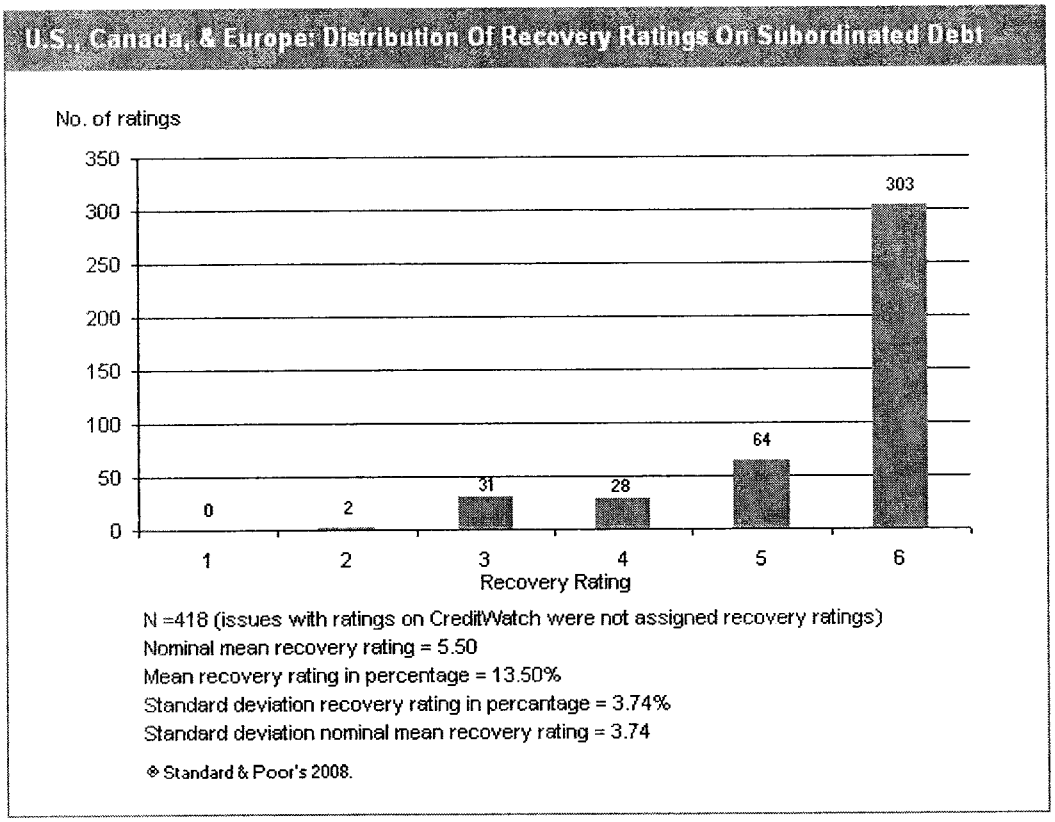
Chart 4



(For the reasoning behind the specific recovery rating assigned to each of the unsecured debt issues, as well as the corresponding issue-level rating changes, see Standard & Poor's individual recovery reports, available on the "Related Research" page for each respective issuer on RatingsDirect.)

Issue-Level Rating Changes

Prior to the initial launch of its recovery ratings, Standard & Poor's already incorporated an estimate of recovery prospects into its issue-level ratings. As previously noted, the further analysis that is undertaken in the recovery rating process has allowed us to discern more consistently and accurately the differences in recovery prospects among debt issues across a company's capital structure.

About 72% of Standard & Poor's issue-level ratings on unsecured speculative-grade debt instruments remain unchanged as a result of today's assignment of recovery ratings. The 28% of issue-level ratings that did experience a change occurred in instances where the previous approach did not fully reflect the effect of issue-specific recovery estimates. These changes can be summarized as follows:

- Of the total set of issue-level ratings (including those that remained unchanged), 17.06% moved by only one notch, with 16.01% moving one notch up and 1.05% moving one notch down.
- 8.70% moved two notches up. These chiefly were on issues for which recovery ratings showed value available for

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unsecured issues well above the recovery implied in our previous issue-level rating methodology.

- Less than 0.2% moved two notches down.
- 1.16% moved three notches up, and 0.78% moved four notches up. These were cases where our previous methodology called for the debt issue to be rated two notches lower than the corresponding corporate credit rating on the issuer, while our recovery analysis estimated that more than 70% of principal and pre-petition interest would be recovered post default, thus resulting in an issue rating one or two notches higher than the corporate credit rating.

We note that the issue-level rating changes announced today are solely due to the extension of recovery ratings to unsecured debt, and do not reflect any change in our corporate credit ratings, which are measures of issuers' default probability.

Table 2

Summary of Unsecured Issue-Level Rating Changes

(U.S., Canada, & Europe)

	No. of Issues	Percentage
No change	1,303	72.19%
Downgrade 2 notches	2	0.11%
Downgrade 1 notch	19	1.05%
Upgrade 1 notch	289	16.01%
Upgrade 2 notches	157	8.70%
Upgrade 3 notches	21	1.16%
Upgrade 4 notches	14	0.78%
Total	1,805	100.00%

Table 3

Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)

U.S. & Canada

Sector	Issuer	Issue Description	From Rating	To Rating	Recovery Rating
AEROSPACE/DEFENSE	Penske Automotive Group Inc.	US$ 75 mil 2.875% sr nts Convertible due 02/01/2024	BB	BB	4
AEROSPACE/DEFENSE	AAR Corp.	US$112.5 mil 2.25% sr nts Convertible due 03/01/2016	BB	BB	4
AEROSPACE/DEFENSE	AAR Corp.	US$137.5 mil 1.625% sr nts Convertible due 03/01/2014	BB	BB	4
AEROSPACE/DEFENSE	AAR Corp.	US$150 mil 1.75% sr nts Convertible due 02/01/2026	BB	BB	4
AEROSPACE/DEFENSE	Communications & Power Industries Inc.	US$ 125 mil 8% sr sub nts due 02/01/2012	B-	B-	6
AEROSPACE/DEFENSE	CPI International Inc.	US$80 mil fltg rate sr PIK nts due 02/15/2015	B-	B-	6
AEROSPACE/DEFENSE	DAE Aviation Holdings Inc.	US$325 mil sr nts due 2015	B-	B-	6
AEROSPACE/DEFENSE	DRS Technologies Inc.	US$550 mil 6.875% sr sub nts due 11/01/2013	B	B	6
AEROSPACE/DEFENSE	DRS Technologies Inc.	US$250 mil 7.625% sr sub nts due 02/01/2018	B	B	6

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Table 3

Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
AEROSPACE/DEFENSE	DRS Technologies Inc.	US$350 mil 6.625% sr nts due 02/01/2016	B+	BB-	4
AEROSPACE/DEFENSE	DRS Technologies Inc.	US$345 mil 2% sr nts Convertible due 02/01/2026	B+	BB-	4
AEROSPACE/DEFENSE	DynCorp International LLC	US$320 mil 9.5% sr sub nts due 02/15/2013	B	B	6
AEROSPACE/DEFENSE	Esterline Technologies Corp.	US$175 mil 7.75% sr sub nts due 06/15/2013	B+	B+	6
AEROSPACE/DEFENSE	Esterline Technologies Corp.	US$175 mil 6.625% sr nts due 03/01/2017	BB-	BB	3
AEROSPACE/DEFENSE	GenCorp Inc.	US$150 mil 9.5% sr sub nts due 08/15/2013	B-	B-	6
AEROSPACE/DEFENSE	GenCorp Inc.	US$125 mil 4% contingent sub nts Convertible due 01/16/2024	B-	B-	6
AEROSPACE/DEFENSE	GenCorp Inc.	US$146.4 mil 2.25% sub deb Convertible due 11/15/2024	B-	B-	6
AEROSPACE/DEFENSE	Hawker Beechcraft Acquisition Co. LLC	US$400 mil 8.5% sr cash nts due 04/01/2015	B-	B-	6
AEROSPACE/DEFENSE	Hawker Beechcraft Acquisition Co. LLC	US$400 mil 8.875% sr PIK toggle nts due 04/01/2015	B-	B-	6
AEROSPACE/DEFENSE	Hawker Beechcraft Acquisition Co. LLC	US$300 mil 9.75% sr sub nts due 04/01/2017	B-	B-	6
AEROSPACE/DEFENSE	Hexcel Corp.	US$225 mil 6.75% sr sub nts due 02/01/2015	B+	B+	6
AEROSPACE/DEFENSE	Mecachrome International Inc.	EUR200 mil 9% sr sub nts due 05/15/2014	B-	B+	4
AEROSPACE/DEFENSE	Moog Inc.	US$150 mil 6.25% sr sub nts due 01/15/2015	BB-	BB-	6
AEROSPACE/DEFENSE	Moog Inc.	US$50 mil 6.25% sr sub nts due 01/15/2015	BB-	BB-	6
AEROSPACE/DEFENSE	Orbital Sciences Corp.	US$143.75 mil 2.438% sr sub nts Convertible due 01/15/2027	BB-	BB-	6
AEROSPACE/DEFENSE	Sequa Corp.	US$ 450 mil sr unsecd nts due 2015	CCC+	B-	5
AEROSPACE/DEFENSE	Sequa Corp.	US$250 mil sr nts due 2015	CCC+	B-	5
AEROSPACE/DEFENSE	TransDigm Inc.	US$575 mil 7.75% sr sub nts due 07/15/2014	B-	B-	6
AEROSPACE/DEFENSE	Vought Aircraft Industries Inc.	US$270 mil 8% sr nts due 07/15/2011	CCC	CCC	6
AUTO/TRUCKS	Accuride Corp.	US$275 mil 8.5% sr sub nts due 02/01/2015	B-	B-	6
AUTO/TRUCKS	Affinia Group Inc.	US$300 mil 9% sr sub nts due 11/30/2014	CCC+	CCC+	6
AUTO/TRUCKS	Allison Transmission Inc.	US$550 mil sr nts due 2015	B-	B-	6
AUTO/TRUCKS	Allison Transmission Inc.	US$550 mil sr PIK toggle nts due 2015	B-	B-	6
AUTO/TRUCKS	American Tire Distributors Inc.	US$140 mil fltg rate sr nts due 04/01/2012	CCC+	CCC+	6
AUTO/TRUCKS	American Tire Distributors Inc.	US$150 mil 10.75% sr nts due 04/01/2013	CCC+	CCC+	6
AUTO/TRUCKS	ArvinMeritor Inc.	US$400 mil 8.75% nts due 03/01/2012	B	B	5
AUTO/TRUCKS	ArvinMeritor Inc.	US$252.537 mil 8.125% sr nts due 09/15/2015	B	B	5

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Table 3

Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
AUTO/TRUCKS	ArvinMeritor Inc.	US$300 mil step up sr nts Convertible due 03/01/2026	B	B	5
AUTO/TRUCKS	ArvinMeritor Inc.	US$200 mil 4% sr nts Convertible due 02/15/2027	B	B	5
AUTO/TRUCKS	ArvinMeritor Inc.	US$500 mil 6.8% nts due 02/15/2009	B	B	5
AUTO/TRUCKS	Asbury Automotive Group Inc.	US$200 mil 8% sr sub nts due 03/15/2014	B	B	6
AUTO/TRUCKS	Asbury Automotive Group Inc.	US$150 mil 7.625% sr sub nts due 03/15/2017	B	B	6
AUTO/TRUCKS	Asbury Automotive Group Inc.	US$115 mil 3% sr sub Convertible due 09/15/2012	B	B	6
AUTO/TRUCKS	Cooper Tire & Rubber Co.	US$200 mil 7.625% nts due 03/15/2027	B+	B+	3
AUTO/TRUCKS	Cooper Tire & Rubber Co.	US$350 mil 7.75% nts due 12/15/2009	B+	B+	3
AUTO/TRUCKS	Cooper Tire & Rubber Co.	US$225 mil 8% nts due 12/15/2019	B+	B+	3
AUTO/TRUCKS	Cooper-Standard Automotive Inc.	US$200 mil 7% sr nts due 12/15/2012	CCC+	B-	5
AUTO/TRUCKS	Cooper-Standard Automotive Inc.	US$350 mil 8.375% sr sub nts due 12/15/2014	CCC+	CCC+	6
AUTO/TRUCKS	Exide Technologies	US$60 mil fltg rate sr sub nts Convertible due 09/18/2013	CCC	CCC	6
AUTO/TRUCKS	FleetPride Corp.	US$150 mil 11.5% sr nts due 10/01/2014	CCC+	B-	5
AUTO/TRUCKS	Ford Motor Co.	US$350 mil 9.5% deb due 09/15/2011	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$700 mil 8.875% deb due 01/15/2022	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$300 mil 9.95% deb due 02/15/2032	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$200 mil 7.75% deb due 06/15/2043	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$300 mil 7.125% deb due 11/15/2025	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$250 mil 7.5% deb due 08/01/2026	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$500 mil 7.25% nts due 10/01/2008	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$500 mil 7.4% deb due 11/01/2046	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$8.333 bil unsecd 5 year bank credit fac bank ln	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$500 mil 7.7% deb due 05/15/2097	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$501.918 mil 8.9% deb due 01/15/2032	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$183.125 mil 9.215% deb due 09/15/2021	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$288.402 mil 9.98% deb due 02/15/2047	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$500 mil 6.5% deb due 08/01/2018	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$1.5 bil 6.625% deb due 10/01/2028	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$1.5 bil 6.375% deb due 02/01/2029	CCC+	CCC+	6

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Table 3

Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
AUTO/TRUCKS	Ford Motor Co.	US$300 mil 6.625% deb due 02/15/2028	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$4.8 bil 7.45% Global Landmark Secs(GlobLS) nts due 07/16/2031	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$600 mil 7.5% nts due 06/10/2043	CCC+	CCC+	6
AUTO/TRUCKS	Ford Motor Co.	US$4.95 bil 4.25% sr nts Convertible due 12/15/2036	CCC+	CCC+	6
AUTO/TRUCKS	Goodyear Tire & Rubber Co. (The)	US$150 mil 7% nts due 03/15/2028	B	BB-	4
AUTO/TRUCKS	Goodyear Tire & Rubber Co. (The)	US$100 mil 6.375% sr nts due 03/15/2008	B	BB-	4
AUTO/TRUCKS	Goodyear Tire & Rubber Co. (The)	US$650 mil 7.857% nts due 08/15/2011	B	BB-	4
AUTO/TRUCKS	Goodyear Tire & Rubber Co. (The)	US$400 mil 9% sr nts due 07/01/2015	B	BB-	4
AUTO/TRUCKS	Goodyear Tire & Rubber Co. (The)	US$500 mil fltg rate sr nts due 12/01/2009	B	BB-	4
AUTO/TRUCKS	Goodyear Tire & Rubber Co. (The)	US$500 mil 8.625% sr nts due 12/01/2011	B	BB-	4
AUTO/TRUCKS	Group 1 Automotive Inc.	US$150 mil 8.25% sr sub nts due 08/15/2013	B+	B+	6
AUTO/TRUCKS	Hayes Lemmerz Finance LLC-Luxembourg S.C.A.	EUR130 mil sr nts due 2017	CCC+	B-	5
AUTO/TRUCKS	KAR Holdings Inc.	US$425 mil 10% sr sub nts due 05/01/2015	CCC	CCC	6
AUTO/TRUCKS	KAR Holdings Inc.	US$150 mil fltg rate sr nts due 05/01/2014	CCC	CCC+	5
AUTO/TRUCKS	KAR Holdings Inc.	US$450 mil 8.75% nts due 05/01/2014	CCC	CCC+	5
AUTO/TRUCKS	Lazy Days' R.V. Center Inc.	US$152 mil 11.75% sr nts due 05/15/2012	CCC+	B-	5
AUTO/TRUCKS	Penske Automotive Group Inc.	US$375 mil 3.5% sr sub nts Convertible due 04/01/2026	B	B+	5
AUTO/TRUCKS	Penske Automotive Group Inc.	US$375 mil sr sub nts due 12/15/2016	B	B+	5
AUTO/TRUCKS	Sonic Automotive Inc.	US$149.5 mil 5.25% sr sub nts Convertible due 05/07/2009	B	B	6
AUTO/TRUCKS	Sonic Automotive Inc.	US$ 275 mil 8.625% sr sub nts due 08/15/2013	B	B	6
AUTO/TRUCKS	Sonic Automotive Inc.	US$150 mil 4.25% sr sub nts Convertible due 11/30/2015	B	B	6
AUTO/TRUCKS	Stanadyne Corp.	US$160 mil 10% sr sub nts due 08/15/2014	CCC+	B-	5
AUTO/TRUCKS	Stanadyne Holdings Inc.	US$58.15 mil 12% sr discount nts due 02/15/2015	CCC+	CCC+	6
AUTO/TRUCKS	Standard Motor Products Inc.	US$90 mil 6.75% conv sub nts due 07/15/2009	CCC	CCC	6
AUTO/TRUCKS	Stoneridge Inc.	US$200 mil 11.5% sr nts due 05/01/2012	B	B+	4
AUTO/TRUCKS	TRW Automotive Inc.	US$500 mil 7% sr nts due 03/15/2014	BB-	BB	5
AUTO/TRUCKS	TRW Automotive Inc.	EUR275 mil sr nts due 03/15/2014	BB-	BB	5

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Table 3

Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
AUTO/TRUCKS	TRW Automotive Inc.	US$600 mil 7.25% sr nts due 03/15/2017	BB-	BB	5
AUTO/TRUCKS	UCI Holdco Inc.	US$235 mil fltg rate sr PIK nts due 12/15/2013	CCC+	CCC+	6
AUTO/TRUCKS	United Components Inc.	US$230 mil 9.375% sr sub nts due 06/15/2013	CCC+	CCC+	6
AUTO/TRUCKS	Visteon Corp.	US$700 mil 8.25% nts due 08/01/2010	CCC+	B-	5
AUTO/TRUCKS	Visteon Corp.	US$450 mil 7% sr nts due 03/10/2014	CCC+	B-	5
CAP GOODS/MACHINE&EQUIP	Actuant Corp.	US$150 mil 2% sr sub deb Convertible due 11/15/2023	B+	B+	6
CAP GOODS/MACHINE&EQUIP	Actuant Corp.	US$250 mil 6.875% nts due 06/15/2017	BB-	BB-	5
CAP GOODS/MACHINE&EQUIP	AGCO Corp.	EUR200 mil 6.875% sr sub nts due 04/15/2014	BB-	BB	5
CAP GOODS/MACHINE&EQUIP	AGCO Corp.	US$201.23 mil 1.75% sr sub nts Convertible ser B due 12/31/2033	BB-	BB	5
CAP GOODS/MACHINE&EQUIP	AGCO Corp.	US$201.25 mil 1.25% sr sub nts Convertible due 12/15/2036	BB-	BB	5
CAP GOODS/MACHINE&EQUIP	Altra Industrial Motion Inc.	US$55 mil sr nts due 02/2013	CCC+	CCC+	6
CAP GOODS/MACHINE&EQUIP	American Railcar Industries Inc.	US$275 mil 7.5% sr nts due 03/01/2014	BB-	BB-	4
CAP GOODS/MACHINE&EQUIP	AmeriCast Technologies Inc.	US$105 mil 11% sr nts due 12/01/2014	CCC+	B-	5
CAP GOODS/MACHINE&EQUIP	Baldor Electric Co.	US$550 mil 8.625% sr nts due 02/15/2017	B	B	6
CAP GOODS/MACHINE&EQUIP	Blount Inc.	US$175 mil 8.875% sub nts due 08/01/2012	B	B	6
CAP GOODS/MACHINE&EQUIP	Case Corp.	US$300 mil 7.25% nts due 01/15/2016	BB+	BB+	4
CAP GOODS/MACHINE&EQUIP	Case New Holland Inc.	US$500 mil 6% sr nts due 06/01/2009	BB+	BB+	4
CAP GOODS/MACHINE&EQUIP	Case New Holland Inc.	US$500 mil 7.125% sr nts due 03/01/2014	BB+	BB+	4
CAP GOODS/MACHINE&EQUIP	Columbus McKinnon Corp.	US$136 mil 8.875% sr sub nts due 11/01/2013	B	B+	5
CAP GOODS/MACHINE&EQUIP	DBT GmbH	EUR65 mil Revolving Facility bank ln due 2012	BB-	BB-	3
CAP GOODS/MACHINE&EQUIP	Douglas Dynamics LLC	US$150 mil 7.75% sr nts due 01/15/2012	B-	B-	6
CAP GOODS/MACHINE&EQUIP	Dycom Investments Inc.	US$150 mil 8.125% sr sub nts due 10/15/2015	B+	BB-	5
CAP GOODS/MACHINE&EQUIP	ESCO Corp.	US$100 mil fltg rate sr nts due 12/15/2013	B	B	5
CAP GOODS/MACHINE&EQUIP	ESCO Corp.	US$200 mil 8.625% sr nts due 12/15/2013	B	B	5
CAP GOODS/MACHINE&EQUIP	Gardner Denver Inc.	US$125 mil 8% sr sub nts due 05/01/2013	B	BB-	4
CAP GOODS/MACHINE&EQUIP	Great Lakes Dredge & Dock Corp.	US$175 mil 7.75% sr sub nts due 12/15/2013	CCC+	B-	5
CAP GOODS/MACHINE&EQUIP	Greenbrier Cos. Inc. (The)	US$235 mil 8.375% sr nts due 05/15/2015	B+	B	6

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Table 3

Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
CAP GOODS/MACHINE&EQUIP	Greenbrier Cos. Inc. (The)	US$100 mil 2.375% sr nts Convertible due 05/15/2026	B+	B	6
CAP GOODS/MACHINE&EQUIP	Greif Inc.	US$300 mil 6.75% sr nts due 02/01/2017	BB-	BB	4
CAP GOODS/MACHINE&EQUIP	H&E Equipment Services Inc.	US$250 mil 8.375% sr nts due 07/15/2016	B+	BB-	4
CAP GOODS/MACHINE&EQUIP	Hawk Corp.	US$110 mil 8.75% sr nts due 11/01/2014	B-	B	4
CAP GOODS/MACHINE&EQUIP	HD Supply Inc.	US$2.5 bil Sr Unsecured Nts due 2014	CCC+	B-	5
CAP GOODS/MACHINE&EQUIP	HD Supply Inc.	US$1.3 bil Sr Sub PIK Nts due 2015	CCC+	CCC+	6
CAP GOODS/MACHINE&EQUIP	Itron Inc.	US$125 mil 7.75% sr sub nts due 05/15/2012	B-	B-	6
CAP GOODS/MACHINE&EQUIP	Itron Inc.	US$345 mil 2.5% sr sub nts Convertible due 08/01/2026	B-	B-	6
CAP GOODS/MACHINE&EQUIP	Kaydon Corp.	US$200 mil 4% contingent conv sr sub nts due 05/23/2023	BB-	BB-	6
CAP GOODS/MACHINE&EQUIP	Manitowoc Co. Inc.	US$150 mil 7.125% sr nts due 11/01/2013	BB-	BB	3
CAP GOODS/MACHINE&EQUIP	MasTec Inc.	US$150 mil 7.625% sr nts due 02/01/2017	B+	B+	5
CAP GOODS/MACHINE&EQUIP	Mueller Water Products Inc.	US$223 mil var rate sr disc nts due 04/15/2014	B	B	6
CAP GOODS/MACHINE&EQUIP	Mueller Water Products Inc.	US$425 mil 7.375% sr sub nts due 06/01/2017	B	B	6
CAP GOODS/MACHINE&EQUIP	Neff Corp.	US$230 mil 10% nts due 06/01/2015	B-	B-	6
CAP GOODS/MACHINE&EQUIP	Norcross Safety Products LLC	US$ 152.5 mil 9.875% sr sub nts due 08/15/2011	B-	B	5
CAP GOODS/MACHINE&EQUIP	Park-Ohio Industries Inc.	US$200 mil 8.375% sr sub nts due 11/15/2014	B-	B-	6
CAP GOODS/MACHINE&EQUIP	Penhall Holding Co.	US$60 mil fltg rate PIK toggle bank ln due 2012	CCC+	CCC+	6
CAP GOODS/MACHINE&EQUIP	Poindexter (J.B.) & Co. Inc.	US$200 mil 8.75% sr nts due 03/15/2014	B-	B	4
CAP GOODS/MACHINE&EQUIP	Polypore International Inc.	US$225 mil 8.75% sr sub nts due 05/15/2012	CCC+	B-	5
CAP GOODS/MACHINE&EQUIP	Polypore International Inc.	EUR150 mil 8.75% sr sub nts due 05/15/2012	CCC+	B-	5
CAP GOODS/MACHINE&EQUIP	Quanta Services Inc.	US$270 mil 4.5% conv sub deb due 10/01/2023	B+	BB	4
CAP GOODS/MACHINE&EQUIP	Quanta Services Inc.	US$143.75 mil 3.75% sub nts Convertible due 04/30/2026	B+	BB	4
CAP GOODS/MACHINE&EQUIP	RathGibson Inc.	US$200 mil 11.25% sr nts due 02/15/2014	B-	B	4
CAP GOODS/MACHINE&EQUIP	Rental Service Corp.	US$620 mil 9.5% sr unsecd nts due 12/01/2014	B-	B-	6
CAP GOODS/MACHINE&EQUIP	Rexnord LLC	US$795 mil 9.5% sr nts due 08/01/2014	CCC+	B-	5
CAP GOODS/MACHINE&EQUIP	Rexnord LLC	US$150 mil 8.875% sr nts due 09/01/2016	CCC+	B-	5
CAP GOODS/MACHINE&EQUIP	Rexnord LLC	US$300 mil 11.75% sr sub nts due 08/01/2016	CCC+	CCC+	6

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Table 3

Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
CAP GOODS/MACHINE&EQUIP	Safety Products Holdings Inc.	US$125 mil pay-in-kind sr nts due 01/01/2012	B-	B-	6
CAP GOODS/MACHINE&EQUIP	Sensata Technologies B.V.	US$450 mil 8% sr nts due 05/01/2014	B-	B-	6
CAP GOODS/MACHINE&EQUIP	Sensata Technologies B.V.	EUR245 mil 9% sr sub nts due 05/01/2016	B-	B-	6
CAP GOODS/MACHINE&EQUIP	Sensus Metering Systems Inc.	US$275 mil 8.625% sr sub nts due 12/15/2013	B-	B-	6
CAP GOODS/MACHINE&EQUIP	SPX Corp.	US$500 mil 7.625% sr unsecd nts due 12/15/2014	BB	BB	5
CAP GOODS/MACHINE&EQUIP	Terex Corp.	US$800 mil 8% sr sub nts due 11/15/2017	B+	B+	6
CAP GOODS/MACHINE&EQUIP	Terex Corp.	US$300 mil 7.375% sr sub nts due 01/15/2014	B+	BB	3
CAP GOODS/MACHINE&EQUIP	Thermadyne Holdings Corp.	US$200 mil 9.25% sr sub nts due 02/01/2014	CCC-	CCC-	6
CAP GOODS/MACHINE&EQUIP	Titan International Inc.	US$200 mil 8% nts due 01/15/2012	B	B-	6
CAP GOODS/MACHINE&EQUIP	TriMas Corp.	US$352.773 mil 9.875% sr sub nts due 06/15/2012	B-	B-	6
CAP GOODS/MACHINE&EQUIP	TriMas Corp.	US$85 mil 9.875% sr sub nts due 06/15/2012	B-	B-	6
CAP GOODS/MACHINE&EQUIP	Trinity Industries Inc.	US$450 mil 3.875% sub nts Convertible due 06/01/2036	BB-	BB-	6
CAP GOODS/MACHINE&EQUIP	Trinity Industries Inc.	US$300 mil 6.5% sr nts due 03/15/2014	BB+	BB+	3
CAP GOODS/MACHINE&EQUIP	United Rentals (North America) Inc.	US$ 143.75 mil 1.875% sr sub conv nts due 10/15/2023	B	B	6
CAP GOODS/MACHINE&EQUIP	United Rentals (North America) Inc.	US$525 mil sr sub nts due 11/15/2013	B	B	6
CAP GOODS/MACHINE&EQUIP	United Rentals (North America) Inc.	US$375 mil 7% sr sub nts due 02/15/2014	B	B	6
CAP GOODS/MACHINE&EQUIP	United Rentals (North America) Inc.	US$1 bil 6.5% sr nts due 02/15/2012	B+	BB-	3
CAP GOODS/MACHINE&EQUIP	WESCO Distribution Inc.	US$150 mil 7.5% sr sub nts due 10/15/2017	B	B	6
CAP GOODS/MACHINE&EQUIP	WESCO International Inc.	US$150 mil 2.625% sr debs Convertible due 10/15/2025	B	B	6
CAP GOODS/MACHINE&EQUIP	WESCO International Inc.	US$300 mil 1.75% sr nts Convertible due 11/15/2026	B	B	6
CAP GOODS/MACHINE&EQUIP	Westinghouse Air Brake Technologies Corp.	US$150 mil 6.875% sr nts due 07/31/2013	BB	BB	3
CHEMICALS	Airgas Inc.	US$150 mil 6.25% sr sub nts due 07/15/2014	BB-	BB-	6
CHEMICALS	Allied Waste Industries Inc.	US$200 mil 4.25% sr sub deb Convertible due 04/15/2034	B+	B+	6
CHEMICALS	Allied Waste North America Inc.	US$400 mil 7.375% sr nts due 04/15/2014	B+	B+	6
CHEMICALS	American Pacific Corp.	US$110 mil 9% sr nts due 02/01/2015	B+	B+	4
CHEMICALS	Arteva Global Holdings B.V., INVISTA (Canada) Co., KoSa Lux Finance B.V., KoSa UK Finance B.V.	US$675 mil 9.25% sr nts due 05/01/2012	BB-	BB	4

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
CHEMICALS	Berry Plastics Group Inc.	US$500 mil sr PIK toggle loan bank ln due 2014	CCC+	CCC+	6
CHEMICALS	Berry Plastics Corp.	US$265 mil 10.25% sr sub nts due 03/01/2016	CCC+	CCC+	6
Chemicals	Exopack Holding Corp.	US$220 mil 11.25% sr nts due 2/1/2014	B-	B-	4
CHEMICALS	Georgia Gulf Corp.	US$200 mil 10.75% sr sub nts due 10/15/2016	CCC	CCC	6
CHEMICALS	Georgia Gulf Corp.	US$100 mil 7.125% sr nts due 12/15/2013	CCC+	CCC+	5
CHEMICALS	Georgia Gulf Corp.	US$500 mil 9.5% sr nts due 10/15/2014	CCC+	CCC+	5
CHEMICALS	Graham Packaging Co.	US$250 mil 8.5% sr nts due 10/15/2012	CCC+	CCC+	6
CHEMICALS	Graham Packaging Co.	US$375 mil 9.875% sr sub nts due 10/15/2014	CCC+	CCC+	6
CHEMICALS	Hercules Inc.	US$350 mil 6.5% jr sub deferrable interest deb due 06/30/2029	B+	B+	6
CHEMICALS	Hercules Inc.	US$250 mil 6.75% sr sub nts due 10/15/2029	B+	BB+	4
CHEMICALS	Innophos Holdings Inc.	US$66 mil 9.5% nts due 04/15/2012	CCC+	CCC+	6
CHEMICALS	Innophos Inc.	US$190 mil 8.875% sr sub nts due 08/15/2014	CCC+	B	4
CHEMICALS	KI Holdings Inc.	US$203 mil 9.875% sr discount nts due 11/15/2014	B-	B-	6
CHEMICALS	Kraton Polymers LLC	US$200 mil 8.125% sr sub nts due 01/15/2014	CCC+	CCC+	6
CHEMICALS	MacDermid Inc.	US$350 mil 9.5% sr sub nts due 04/15/2017	CCC+	CCC+	6
CHEMICALS	Momentive Performance Materials Inc.	EUR275 mil 9% sr nts due 12/01/2014	B-	B	4
CHEMICALS	Momentive Performance Materials Inc.	US$765 mil 9.75% sr nts due 12/01/2014	B-	B	4
CHEMICALS	Momentive Performance Materials Inc.	US$300 mil 10.125% sr toggle-PIK nts due 12/01/2014	B-	B	4
CHEMICALS	Momentive Performance Materials Inc.	US$500 mil 11.5% sr sub nts due 12/01/2016	CCC+	CCC+	6
CHEMICALS	Nalco Co.	US$700 mil 8.875% sr sub nts due 11/15/2013	B-	B-	6
CHEMICALS	Nalco Co.	US$900 mil 7.75% sr nts due 11/15/2011	B-	BB-	2
CHEMICALS	Nalco Finance Holdings Inc.	US$450 mil 9% discount nts due 02/01/2014	B-	B-	6
CHEMICALS	NewMarket Corp.	US$150 mil 7.125% sr nts due 2016	BB	BB-	5
CHEMICALS	Nova Chemicals Corp.	US$100 mil 7.875% deb due 09/15/2025	B+	B+	4
CHEMICALS	Nova Chemicals Corp.	US$125 mil 7.25% nts due 08/15/2028	B+	B+	4
CHEMICALS	Nova Chemicals Corp.	US$250 mil 7.4% med-term nts due 04/01/2009	B+	B+	4
CHEMICALS	Nova Chemicals Corp.	CAD250 mil 7.85% sr nts due 08/30/2010	B+	B+	4

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CHEMICALS	Nova Chemicals Corp.	US$400 mil 6.5% sr nts due 01/15/2012	B+	B+	4
CHEMICALS	Nova Chemicals Corp.	US$400 mil fltg rate sr nts due 11/15/2013	B+	B+	4
CHEMICALS	OI European Group B.V.	EUR300 mil 6.875% sr nts due 03/31/2017	B+	BB	3
CHEMICALS	Owens-Brockway Glass Container Inc.	US$450 mil 8.25% nts due 05/15/2013	B+	BB	3
CHEMICALS	Owens-Brockway Glass Container Inc.	US$650 mil 6.75% multicurrency sr nts due 12/01/2014	B+	BB	3
CHEMICALS	Owens-Illinois Inc.	US$250 mil 7.35% sr nts due 05/15/2008	B+	B+	6
CHEMICALS	Owens-Illinois Inc.	US$250 mil 7.5% sr nts due 05/15/2010	B+	B+	6
CHEMICALS	Owens-Illinois Inc.	US$250 mil 7.8% sr nts due 05/15/2018	B+	B+	6
CHEMICALS	PolyOne Corp. (formerly Geon Co.)	US$50 mil 7.5% deb due 12/15/2015	B+	B+	4
CHEMICALS	Silgan Holdings Inc.	US$200 mil 6.75% sr sub nts due 11/15/2013	BB-	BB-	6
CHEMICALS	Solutia Inc.	US$400 mil unsecd bridge fac bank ln due 2015	B-	B	5
CHEMICALS	Terra Capital Inc.	US$330 mil 7% nts due 02/01/2017	BB-	BB-	4
CHEMICALS	Tronox Worldwide LLC	US$350 mil 9.5% sr unsecd nts due 12/01/2012	B	B	5
CHEMICALS	Waste Services Inc.	US$160 mil 9.5% nts due 04/15/2014	CCC+	B-	5
CHEMICALS	Westlake Chemical Corp.	US$250 mil 6.625% sr nts due 01/15/2016	BB+	BB+	4
CHEMICALS	AEP Industries Inc.	US$175 mil 7.875% sr nts due 03/15/2013	B	B	5
CHEMICALS	Ball Corp.	US$300 mil 6.875% sr nts due 12/15/2012	BB	BB+	3
CHEMICALS	Ball Corp.	US$250 mil 6.875% sr nts due 12/15/2012	BB	BB+	3
CHEMICALS	Ball Corp.	US$450 mil 6.625% sr nts due 03/15/2018	BB	BB+	3
CHEMICALS	Bway Corp.	US$200 mil 10% sr sub nts due 10/15/2010	B-	B-	6
CHEMICALS	Casella Waste Systems Inc.	US$195 mil 9.75% sr sub nts due 02/01/2013	B	B	6
CHEMICALS	Constar International Inc.	US$175 mil 11% sr sub nts due 12/01/2012	CCC	CCC	6
CHEMICALS	Gundle/SLT Environmental Inc.	US$150 mil sr nts due 12/31/2011	CCC	CCC+	5
CHEMICALS	Intertape Polymer U.S. Inc.	US$125 mil 8.5% sr sub nts due 08/01/2014	CCC+	CCC+	6
CHEMICALS	JohnsonDiversey Holdings Inc.	US$406.303 mil 10.67% discount nts due 05/15/2013	CCC+	CCC+	6
CHEMICALS	JohnsonDiversey Inc.	US$300 mil 9.625% sr sub nts due 05/15/2012	CCC+	B	3
CHEMICALS	JohnsonDiversey Inc.	EUR225 mil 9.625% sr sub nts Ser B due 05/15/2012	CCC+	B	3

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CHEMICALS	Plastipak Holdings Inc.	US$250 mil 8.5% sr nts due 12/15/2015	B	B	6
CHEMICALS	PolyOne Corp.	US$200 mil 8.875% nts due 05/01/2012	B+	B+	4
CHEMICALS	Portola Packaging Inc.	US$180 mil 8.25% sr nts due 02/01/2012	CC	CCC-	5
CHEMICALS	Pregis Corp.	US$150 mil 12.375% sr sub nts due 10/15/2013	CCC+	CCC+	6
CHEMICALS	Reichhold Industries Inc.	US$195 mil sr nts due 08/15/2014	BB-	B+	5
CHEMICALS	Rockwood Specialties Group Inc.	US$200 mil 7.5% sr sub nts due 11/15/2014	B	BB-	4
CHEMICALS	Rockwood Specialties Group Inc.	EUR375 mil 7.625% sr sub nts due 11/15/2014	B	BB-	4
CHEMICALS	WCA Waste Corp.	US$150 mil 9.25% sr nts due 06/15/2014	B-	B-	5
CONSUMER PRODUCTS	Alliance Laundry Systems LLC	US$150 mil 8.5% sr sub nts due 01/15/2013	CCC	CCC+	5
CONSUMER PRODUCTS	Alliance One International Inc.	US$315 mil 11% sr nts due 05/15/2012	B	B+	4
CONSUMER PRODUCTS	Alliance One International Inc.	US$150 mil 8.5% sr nts due 05/15/2012	B	B+	4
CONSUMER PRODUCTS	Alliance One International Inc.	US$100 mil 12.75% sr sub nts due 11/15/2012	B-	B-	6
CONSUMER PRODUCTS	Allied Security Escrow Corp.	US$180 mil 11.375% sr sub nts due 07/15/2011	CCC+	CCC+	6
CONSUMER PRODUCTS	Amscan Holdings Inc.	US$175 mil 8.75% sr sub nts due 05/01/2014	CCC+	CCC+	6
CONSUMER PRODUCTS	ARAMARK Corp.	US$1.28 bil 8.5% nts due 02/01/2015	B-	B	5
CONSUMER PRODUCTS	ARAMARK Corp.	US$500 mil fltg rate sr nts due 02/01/2015	B-	B	5
CONSUMER PRODUCTS	ARAMARK Corp.	US$250 mil 5% nts due 06/01/2012	B-	B-	6
CONSUMER PRODUCTS	ASG Consolidated LLC	US$196 mil sr disc nts due 11/01/2011	B-	B+	4
CONSUMER PRODUCTS	B&G Foods Inc.	US$240 mil 8% sr nts due 10/01/2011	CCC+	B	4
CONSUMER PRODUCTS	B&G Foods Inc.	US$165 mil 12% sr sub nts due 10/30/2016	CCC+	CCC+	6
CONSUMER PRODUCTS	Blyth Inc.	US$150 mil 7.9% sr nts due 10/01/2009	BB-	BB-	4
CONSUMER PRODUCTS	Blyth Inc.	US$100 mil 5.5% sr nts due 11/01/2013	BB-	BB-	4
CONSUMER PRODUCTS	Blyth Inc.	US$150 mil unsecd revolv cred fac bank ln due 06/02/2010	BB-	BB-	4
CONSUMER PRODUCTS	Briggs & Stratton Corp.	US$275 mil 8.875% sr unsecd nts due 03/15/2011	BB+	BB+	3
CONSUMER PRODUCTS	Broder Bros. Co.	US$225 mil sr nts due 10/15/2010	CCC	CCC	6
CONSUMER PRODUCTS	Central Garden & Pet Co.	US$150 mil 9.125% sr sub nts due 02/01/2013	CCC+	CCC+	6
CONSUMER PRODUCTS	Chattem Inc.	US$125 mil 7% sr sub nts due 03/01/2014	B	B	6
CONSUMER PRODUCTS	Chiquita Brands International Inc.	US$250 mil 7.5% sr nts due 11/01/2014	CCC	CCC+	5

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
CONSUMER PRODUCTS	Chiquita Brands International Inc.	US$225 mil 8.875% sr nts due 12/31/2015	CCC	CCC+	5
CONSUMER PRODUCTS	Chiquita Brands International Inc.	US$200 mil 4.25% conv sr unsecd nts due 08/15/2016	CCC	CCC+	5
CONSUMER PRODUCTS	Church & Dwight Co. Inc.	US$250 mil 6% sr sub nts due 12/15/2012	B+	BB-	5
CONSUMER PRODUCTS	Church & Dwight Co. Inc.	US$ 100 mil 5.25% sr conv deb due 08/15/2033	BB-	BB	3
CONSUMER PRODUCTS	Constellation Brands Inc.	US$250 mil sr sub nts due 01/15/2012	B	B	6
CONSUMER PRODUCTS	Constellation Brands Inc.	£75 mil 8.5% sr nts due 11/15/2009	BB-	BB-	3
CONSUMER PRODUCTS	Constellation Brands Inc.	£80 mil 8.5% sterling sr nts due 11/15/2009	BB-	BB-	3
CONSUMER PRODUCTS	Constellation Brands Inc.	US$200 mil 8% nts due 02/15/2008	BB-	BB-	3
CONSUMER PRODUCTS	Constellation Brands Inc.	US$700 mil 7.25% sr nts due 09/01/2016	BB-	BB-	3
CONSUMER PRODUCTS	Constellation Brands Inc.	US$700 mil 7.25% nts due 05/15/2017	BB-	BB-	3
CONSUMER PRODUCTS	Constellation Brands Inc.	US$500 mil nts due 12/15/2014	BB-	BB-	3
CONSUMER PRODUCTS	Cornell Cos. Inc.	US$112 mil sr nts due 07/01/2012	B-	B	3
CONSUMER PRODUCTS	Corrections Corp. of America	US$250 mil 7.5% nts due 05/01/2011	BB	BB	3
CONSUMER PRODUCTS	Corrections Corp. of America	US$375 mil 6.25% sr nts due 03/15/2013	BB	BB	3
CONSUMER PRODUCTS	Corrections Corp. of America	US$150 mil 6.75% sr nts due 01/31/2014	BB	BB	3
CONSUMER PRODUCTS	Da-Lite Screen Co. Inc.	US$160 mil 9.5% sr nts due 05/15/2011	B-	B	4
CONSUMER PRODUCTS	Dean Foods Co.	US$500 mil 7% sr nts due 06/01/2016	B	B	6
CONSUMER PRODUCTS	Dean Holding Co.	US$150 mil 6.9% sr nts nts due 10/15/2017	B	B	6
CONSUMER PRODUCTS	Dean Holding Co.	US$200 mil 6.625% sr nts due 05/15/2009	B	B	6
CONSUMER PRODUCTS	Del Monte Corp.	US$450 mil 8.625% sr sub nts due 12/15/2012	B	B+	5
CONSUMER PRODUCTS	Del Monte Corp.	US$250 mil 6.75% sr sub nts due 02/15/2015	B	B+	5
CONSUMER PRODUCTS	Dixie Group Inc. (The)	US$50 mil 7% deb due 05/15/2012	B-	B-	6
CONSUMER PRODUCTS	Easton-Bell Sports Inc.	US$140 mil 8.375% sr sub nts due 10/01/2012	CCC+	CCC+	6
CONSUMER PRODUCTS	Elizabeth Arden Inc.	US$225 mil 7.75% sr sub nts due 01/15/2014	B	B+	5
CONSUMER PRODUCTS	GEO Group (The) Inc.	US$150 mil 8.25% sr nts due 07/15/2013	B+	BB-	3
CONSUMER PRODUCTS	Hanesbrands Inc.	US$500 mil fltg rate sr nts due 12/15/2014	B-	B-	6
CONSUMER PRODUCTS	Human Touch LLC.	US$100 mil 7.25% sr nts due 04/01/2011	CCC	CCC	5
CONSUMER PRODUCTS	Iconix Brand Group Inc.	US$250 mil 1.875% convertible sub nts due 06/30/2012	B-	B	5
CONSUMER PRODUCTS	Interface Inc.	US$135 mil 9.5% sr sub nts due 02/01/2014	B-	B-	6

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CONSUMER PRODUCTS	Interface Inc.	US$175 mil 10.375% nts due 02/01/2010	B+	BB-	2
CONSUMER PRODUCTS	Jarden Corp.	US$650 mil 7.5% sr sub nts due 05/01/2017	B-	B	5
CONSUMER PRODUCTS	Jones Apparel Group Inc.	US$250 mil 5.125% sr nts due 11/15/2014	BB+	BB+	4
CONSUMER PRODUCTS	Jones Apparel Group Inc.	US$250 mil 6.125% sr nts due 11/15/2034	BB+	BB+	4
CONSUMER PRODUCTS	Jones Apparel Group Inc.	US$250 mil 4.25% sr nts due 11/15/2006	BB+	BB+	4
CONSUMER PRODUCTS	Land O'Lakes Inc.	US$350 mil 8.75% nts due 11/15/2011	BB-	BB	3
CONSUMER PRODUCTS	Levi Strauss & Co.	US$450 mil 9.75% sr nts due 01/15/2015	B+	B+	4
CONSUMER PRODUCTS	Levi Strauss & Co.	EUR250 mil 8.625% sr nts due 04/01/2013	B+	B+	4
CONSUMER PRODUCTS	Levi Strauss & Co.	US$350 mil 8.875% sr nts due 12/31/2016	B+	B+	4
CONSUMER PRODUCTS	Levi Strauss & Co.	US$325 mil term loan facility bank ln due 2014	B+	B+	4
CONSUMER PRODUCTS	Mac-Gray Corp.	US$150 mil 7.625% sr nts due 08/15/2015	B+	B+	5
CONSUMER PRODUCTS	Merisant Co.	US$225 mil 9.5% sr sub nts due 07/15/2013	CC	CCC-	5
CONSUMER PRODUCTS	Merisant Worldwide Inc.	US$136 mil sr sub disc nts due 05/15/2014	CC	CC	6
CONSUMER PRODUCTS	M-Foods Holdings Inc.	US$100 mil sr discount nts due 2013	B-	B-	6
CONSUMER PRODUCTS	Michael Foods Inc.	US$150 mil sr sub nts due 11/15/2013	B-	B-	6
CONSUMER PRODUCTS	National Beef Packing Co LLC	US$160 mil 10.5% sr nts due 08/01/2011	B-	B-	6
CONSUMER PRODUCTS	NBTY Inc.	US$200 mil 7.125% sr sub nts due 10/01/2015	B+	BB	4
CONSUMER PRODUCTS	Oxford Industries Inc.	US$200 mil 8.875% sr nts due 06/01/2011	B	B+	5
CONSUMER PRODUCTS	Perry Ellis International Inc.	US$ 150 mil 8.875% sr sub nts due 09/15/2013	B-	B-	6
CONSUMER PRODUCTS	Pierre Foods Inc.	US$125 mil 9.875% sr sub nts due 07/15/2012	CCC+	CCC+	6
CONSUMER PRODUCTS	Pilgrim's Pride Corp.	US$250 mil 8.375% sr sub nts due 05/01/2017	B	B	6
CONSUMER PRODUCTS	Pilgrim's Pride Corp.	US$400 mil 7.625% sr nts due 05/01/2015	B	B+	5
CONSUMER PRODUCTS	Pinnacle Foods Finance LLC, Pinnacle Foods Finance Corp.	US$325 mil 9.25% sr unsecd nts due 04/01/2015	CCC	CCC	6
CONSUMER PRODUCTS	Pinnacle Foods Finance LLC, Pinnacle Foods Finance Corp.	US$250 mil 10.625% sub nts due 04/01/2017	CCC	CCC	6
CONSUMER PRODUCTS	Prestige Brands Inc.	US$210 mil 9.25% sr sub nts due 04/15/2012	B-	B-	6
CONSUMER PRODUCTS	Quiksilver Inc.	US$400 mil 6.875% sr nts due 04/15/2015	B+	B	6
CONSUMER PRODUCTS	Reddy Ice Holdings Inc.	US$151 mil 10.5% sr disc nts due 11/01/2012	B-	B-	6

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CONSUMER PRODUCTS	Revlon Consumer Products Corp.	US$310 mil 9.5% sr nts due 04/01/2011	CCC-	CCC	5
CONSUMER PRODUCTS	Revlon Consumer Products Corp.	US$80 mil 9.5% sr nts due 04/01/2011	CCC-	CCC	5
CONSUMER PRODUCTS	RJ Reynolds Tobacco Holdings Inc.	US$500 mil 9.25% deb due 08/15/2013	BB-	BB+	3
CONSUMER PRODUCTS	RJ Reynolds Tobacco Holdings Inc.	US$200 mil 7.875% sr nts due 05/15/2009	BB-	BB+	3
CONSUMER PRODUCTS	RJ Reynolds Tobacco Holdings Inc.	US$450 mil 7.25% nts due 06/01/2012	BB-	BB+	3
CONSUMER PRODUCTS	RJ Reynolds Tobacco Holdings Inc.	US$200 mil 7.3% secd nts due 07/15/2015	BB-	BB+	3
CONSUMER PRODUCTS	Sealy Mattress Co.	US$390 mil 8.25% sr sub nts due 06/15/2014	B	BB-	4
CONSUMER PRODUCTS	Sensient Technologies Corp.	US$150 mil 6.5% sr nts due 04/01/2009	BB+	BB+	3
CONSUMER PRODUCTS	Sensient Technologies Corp.	US$225 mil revolving credit fac bank ln due 08/18/2010	BB+	BB+	3
CONSUMER PRODUCTS	ServiceMaster Co. (The)	US$1.15 bil sr unsecd bridge fac bank ln due 2008	CCC+	B-	5
CONSUMER PRODUCTS	ServiceMaster Co. (The)	US$200 mil 7.45% nts due 08/15/2027	CCC+	CCC+	6
CONSUMER PRODUCTS	ServiceMaster Co. (The)	US$150 mil 7.25% nts due 03/01/2038	CCC+	CCC+	6
CONSUMER PRODUCTS	ServiceMaster Co. (The)	US$150 mil 7.1% nts due 03/01/2018	CCC+	CCC+	6
CONSUMER PRODUCTS	Simmons Bedding Co.	US$ 200 mil sr sub nts due 01/15/2014	CCC+	B	3
CONSUMER PRODUCTS	Simmons Company	US$269 mil step up sr disc nts due 12/15/2014	CCC+	CCC+	6
CONSUMER PRODUCTS	Simmons Super Holding Co.	US$300 mil sr unsecd PIK term bank ln due 2012	CCC+	CCC+	6
CONSUMER PRODUCTS	Southern States Cooperative Inc.	US$100 mil sr nts due 2012	B	B-	6
CONSUMER PRODUCTS	Spectrum Brands Inc.	US$700 mil 7.375% sr sub nts due 02/01/2015	CCC-	CCC-	6
CONSUMER PRODUCTS	Spectrum Brands Inc.	US$350 mil var rate Toggle Senior Subordinated nts due 10/02/2013	CCC-	CCC-	6
CONSUMER PRODUCTS	Steinway Musical Instruments Inc.	US$175 mil 7% sr nts due 03/01/2014	B+	B	5
CONSUMER PRODUCTS	True Temper Sports Inc.	US$125 mil 8.375% sr sub nts due 09/15/2011	CC	CC	6
CONSUMER PRODUCTS	U.S. Investigations Services Inc.	US$290 mil 10.5% sr unsecd nts due 11/01/2015	CCC+	CCC+	6
CONSUMER PRODUCTS	U.S. Investigations Services Inc.	US$150 mil 11.75% sr sub nts due 05/01/2016	CCC+	CCC+	6
CONSUMER PRODUCTS	Warnaco Inc.	US$210 mil 8.875% sr nts due 06/15/2013	BB-	BB	4
CONSUMER PRODUCTS	Yankee Candle Co. Inc. (The)	US$325 mil 8.5% sr nts ser B due 2015	CCC+	B-	5
CONSUMER PRODUCTS	Yankee Candle Co. Inc. (The)	US$200 mil 9.75% sr sub nts ser B due 2017	CCC+	CCC+	6
CORPORATE - UTILITY	North American Energy Partners Inc	US$200 mil 8.75% sr nts due 12/01/2011	B-	B+	4
DIVERSIFIED ENERGY	Copano Energy LLC	US$350 mil 8.125% sr nts due 03/01/2016	B+	B+	5

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
DIVERSIFIED ENERGY	Dynegy Holdings Inc.	US$175 mil 7.625% sr deb due 10/15/2026	B-	B	3
DIVERSIFIED ENERGY	Dynegy Holdings Inc.	US$175 mil 7.125% sr deb due 05/15/2018	B-	B	3
DIVERSIFIED ENERGY	Dynegy Holdings Inc.	US$500 mil 6.875% nts due 04/01/2011	B-	B	3
DIVERSIFIED ENERGY	Dynegy Holdings Inc.	US$500 mil 8.75% sr nts due 02/15/2012	B-	B	3
DIVERSIFIED ENERGY	Dynegy Holdings Inc.	US$1.046834 bil 8.375% sr unsecd nts due 05/01/2016	B-	B	3
DIVERSIFIED ENERGY	Dynegy Holdings Inc.	US$1.1 bil 7.75% sr nts due 06/01/2019	B-	B	3
DIVERSIFIED ENERGY	Dynegy Holdings Inc.	US$550 mil 7.5% sr nts due 06/01/2015	B-	B	3
ENERGY MERCHANT CO.	AES Corp. (The)	US$500 mil 9.5% sr unsecd nts due 06/01/2009	B	BB-	4
ENERGY MERCHANT CO.	AES Corp. (The)	US$250 mil 9.5% sr unsecd nts due 06/01/2009	B	BB-	4
ENERGY MERCHANT CO.	AES Corp. (The)	US$850 mil 9.375% nts due 09/15/2010	B	BB-	4
ENERGY MERCHANT CO.	AES Corp. (The)	US$600 mil 8.875% sr unsec nts due 01/15/2011	B	BB-	4
ENERGY MERCHANT CO.	AES Corp. (The)	£135 mil 8.375% sr unsecd nts due 03/01/2011	B	BB-	4
ENERGY MERCHANT CO.	AES Corp. (The)	US$400 mil 8.75% sr unsecd nts due 06/15/2008	B	BB-	4
ENERGY MERCHANT CO.	AES Corp. (The)	US$500 mil 7.75% sr unsecd nts due 03/01/2014	B	BB-	4
ENERGY MERCHANT CO.	AES Corp. (The)	US$325 mil 8.375% sr sub nts due 08/15/2007	B	BB-	4
ENERGY MERCHANT CO.	Atlas Pipeline Partners LP	US$295.3 mil 8.125% sr nts due 12/15/2015	B	B	5
ENERGY MERCHANT CO.	Covanta Holding Corp.	US$325 mil 1% sr deb Convertible due 02/01/2027	B	B	6
ENERGY MERCHANT CO.	Edison Mission Energy	US$600 mil 7.73% nts due 06/15/2009	BB-	BB-	4
ENERGY MERCHANT CO.	Edison Mission Energy	US$500 mil 7.5% sr nts due 06/15/2013	BB-	BB-	4
ENERGY MERCHANT CO.	Edison Mission Energy	US$500 mil 7.75% sr nts due 06/15/2016	BB-	BB-	4
ENERGY MERCHANT CO.	Edison Mission Energy	US$1.2 bil 7% sr nts due 05/15/2017	BB-	BB-	4
ENERGY MERCHANT CO.	Edison Mission Energy	US$800 mil 7.2% sr nts due 05/19/2019	BB-	BB-	4
ENERGY MERCHANT CO.	Edison Mission Energy	US$700 mil 7.625% sr nts due 05/15/2027	BB-	BB-	4
ENERGY MERCHANT CO.	Ferrellgas L.P.	US$250 mil 6.75% sr nts due 05/01/2014	B+	B+	3
ENERGY MERCHANT CO.	Ferrellgas Partners L.P.	US$268 mil 8.75% sr nts due 06/15/2012	B-	B-	6
ENERGY MERCHANT CO.	Inergy LP	US$425 mil 6.875% sr nts due 12/15/2014	B+	B+	5

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ENERGY MERCHANT CO.	Inergy LP	US$200 mil 8.25% sr nts due 03/01/2016	B+	B+	5
ENERGY MERCHANT CO.	MarkWest Energy Partners LP	US$225 mil 6.875% sr nts due 11/01/2014	B	B	5
ENERGY MERCHANT CO.	McMoRan Exploration Co.	US$300 mil 11.875% sr nts due 11/15/2014	CCC+	CCC+	5
ENERGY MERCHANT CO.	Mirant Americas Generating LLC	US$850 mil 8.3% sr nts due 05/01/2011	B-	B-	6
ENERGY MERCHANT CO.	Mirant Americas Generating LLC	US$400 mil 9.125% sr nts due 05/01/2031	B-	B-	6
ENERGY MERCHANT CO.	Mirant Americas Generating LLC	US$450 mil 8.5% nts due 10/01/2021	B-	B-	6
ENERGY MERCHANT CO.	Mirant North America LLC	US$850 mil sr nts due 12/31/2013	B-	B-	6
ENERGY MERCHANT CO.	MXEnergy Holdings Inc.	US$190 mil fltg rate sr nts due 08/01/2011	CCC+	CCC+	6
ENERGY MERCHANT CO.	NRG Energy Inc.	US$1.2 bil 7.25% sr nts due 02/01/2014	B	B	5
ENERGY MERCHANT CO.	NRG Energy Inc.	US$2.4 bil 7.375% sr nts due 02/01/2016	B	B	5
ENERGY MERCHANT CO.	NRG Energy Inc.	US$1.1 bil 7.375% sr nts due 01/15/2017	B	B	5
ENERGY MERCHANT CO.	Orion Power Holdings Inc	US$375 mil 12% sr nts due 05/01/2010	B	BB-	1
ENERGY MERCHANT CO.	PSEG Energy Holdings LLC	US$400 mil 10% sr nts due 10/01/2009	BB-	BB-	3
ENERGY MERCHANT CO.	PSEG Energy Holdings LLC	US$400 mil 8.625% sr nts due 02/15/2008	BB-	BB-	3
ENERGY MERCHANT CO.	PSEG Energy Holdings LLC	US$550 mil 8.5% sr nts due 06/15/2011	BB-	BB-	3
ENERGY MERCHANT CO.	PSEG Energy Holdings LLC	US$135 mil 8.625% sr nts due 02/15/2008	BB-	BB-	3
ENERGY MERCHANT CO.	Reliant Energy Inc.	US$13 mil 9.5% sr secd nts due 07/15/2013	B	B	3
ENERGY MERCHANT CO.	Reliant Energy Inc.	US$725 mil 7.875% sr nts due 06/15/2017	B-	B	3
ENERGY MERCHANT CO.	Reliant Energy Inc.	US$575 mil 7.625% sr nts due 06/15/2014	B-	B	3
ENERGY MERCHANT CO.	Suburban Propane Partners L.P.	US$425 mil 6.875% sr nts due 12/15/2013	B	B+	5
ENERGY MERCHANT CO.	VeraSun Energy Corp	nts due 2014	B-	B-	6
ENERGY MERCHANT CO.	VeraSun Energy Corp	US$450 mil nts due 06/01/2017	B-	B-	6
FOREST PROD/BLDG MAT/PACKAGING	ACIH	US$174 mil 11.5% ($125 mil gross proceeds) discount nts due 12/15/2012	CCC-	CCC-	6
FOREST PROD/BLDG MAT/PACKAGING	AMH Holdings Inc.	US$446 mil sr discount nts due 03/01/2014	CCC	CCC	6
FOREST PROD/BLDG MAT/PACKAGING	Appleton Papers Inc.	US$150 mil 9.75% sr sub nts due 06/15/2014	B	B	6
FOREST PROD/BLDG MAT/PACKAGING	Appleton Papers Inc.	US$185 mil 8.125% sr nts due 06/15/2011	B+	B	6
FOREST PROD/BLDG MAT/PACKAGING	Associated Materials Inc.	US$165 mil 9.75% sr sub nts due 04/15/2012	CCC	CCC+	5

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
FOREST PROD/BLDG MAT/PACKAGING	BGF Industries Inc.	US$100 mil 10.25% sr sub nts due 01/15/2009	CCC	B-	4
FOREST PROD/BLDG MAT/PACKAGING	Boise Cascade LLC	US$400 mil 7.125% sr sub nts due 10/15/2014	B	BB-	3
FOREST PROD/BLDG MAT/PACKAGING	Buckeye Technologies Inc.	US$150 mil 8% sr sub nts due 10/15/2010	B	B	6
FOREST PROD/BLDG MAT/PACKAGING	Buckeye Technologies Inc.	US$200 mil 8.5% sr nts due 10/01/2013	B+	BB-	4
FOREST PROD/BLDG MAT/PACKAGING	Caraustar Industries Inc.	US$200 mil 7.375% sr nts due 06/01/2009	B-	B-	4
FOREST PROD/BLDG MAT/PACKAGING	Caraustar Industries Inc.	US$29 mil 7.25% sr nts due 05/01/2010	B-	B-	4
FOREST PROD/BLDG MAT/PACKAGING	Cascades Inc.	US$675 mil 7.25% sr nts due 02/15/2013	BB-	BB-	5
FOREST PROD/BLDG MAT/PACKAGING	Catalyst Paper Corp.	US$400 mil 8.625% sr nts due 06/15/2011	B	B-	5
FOREST PROD/BLDG MAT/PACKAGING	Catalyst Paper Corp.	US$250 mil 7.375% sr nts due 03/01/2014	B	B-	5
FOREST PROD/BLDG MAT/PACKAGING	CPG International I Inc.	US$95 mil fltg rate sr nts due 07/01/2012	B-	B	3
FOREST PROD/BLDG MAT/PACKAGING	CPG International I Inc.	US$150 mil 10.5% sr nts due 07/01/2013	B-	B	3
FOREST PROD/BLDG MAT/PACKAGING	CPG International I Inc.	US$95 mil fltg rate sr nts due 07/01/2012	B-	B	3
FOREST PROD/BLDG MAT/PACKAGING	Dayton Superior Corp.	US$170 mil 13% sr sub nts due 06/15/2009	CCC+	CCC+	6
FOREST PROD/BLDG MAT/PACKAGING	Domtar Inc.	US$125 mil 9.5% deb due 08/01/2016	B+	B+	5
FOREST PROD/BLDG MAT/PACKAGING	Domtar Inc.	US$600 mil 7.875% sr unsec nts due 10/15/2011	B+	B+	5
FOREST PROD/BLDG MAT/PACKAGING	Domtar Inc.	US$350 mil 5.375% nts due 12/01/2013	B+	B+	5
FOREST PROD/BLDG MAT/PACKAGING	Domtar Inc.	CAD100 mil 10.85% deb due 08/05/2017	B+	B+	5
FOREST PROD/BLDG MAT/PACKAGING	Domtar Inc.	CAD100 mil 10% deb due 04/15/2011	B+	B+	5
FOREST PROD/BLDG MAT/PACKAGING	Domtar Inc.	US$400 mil 7.125% nts due 08/15/2015	B+	B+	5
FOREST PROD/BLDG MAT/PACKAGING	Georgia-Pacific LLC	US$250 mil 9.5% deb due 12/01/2011	B	B+	5
FOREST PROD/BLDG MAT/PACKAGING	Georgia-Pacific LLC	US$250 mil 7.7% deb due 06/15/2015	B	B+	5
FOREST PROD/BLDG MAT/PACKAGING	Georgia-Pacific LLC	US$250 mil 7.375% deb due 12/01/2025	B	B+	5
FOREST PROD/BLDG MAT/PACKAGING	Georgia-Pacific LLC	US$300 mil 7.25% deb due 06/01/2028	B	B+	5
FOREST PROD/BLDG MAT/PACKAGING	Georgia-Pacific LLC	US$500 mil 7.75% deb due 11/15/2029	B	B+	5
FOREST PROD/BLDG MAT/PACKAGING	Georgia-Pacific LLC	US$600 mil 8.125% sr unsec nts due 05/15/2011	B	B+	5
FOREST PROD/BLDG MAT/PACKAGING	Georgia-Pacific LLC	US$400 mil 8.875% nts due 05/15/2031	B	B+	5

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
FOREST PROD/BLDG MAT/PACKAGING	Georgia-Pacific LLC	US$1.5 bil sr nts due 02/01/2013	B	B+	5
FOREST PROD/BLDG MAT/PACKAGING	Georgia-Pacific LLC	US$350 mil 7.375% sr nts due 07/15/2008	B	B+	5
FOREST PROD/BLDG MAT/PACKAGING	Georgia-Pacific LLC	US$500 mil 8% sr nts due 01/15/2024	B	B+	5
FOREST PROD/BLDG MAT/PACKAGING	Georgia-Pacific LLC	US$500 mil 7% sr gtd nts due 01/15/2015	B	BB-	3
FOREST PROD/BLDG MAT/PACKAGING	Georgia-Pacific LLC	US$750 mil 7.125% sr gtd nts due 01/15/2017	B	BB-	3
FOREST PROD/BLDG MAT/PACKAGING	Gibraltar Industries Inc.	US$204 mil 8% sr sub nts due 12/01/2015	B+	B+	6
FOREST PROD/BLDG MAT/PACKAGING	Glatfelter (P.H.) Co.	US$200 mil revolving credit fac bank ln due 2011	BB+	BB+	4
FOREST PROD/BLDG MAT/PACKAGING	Glatfelter (P.H.) Co.	US$50 mil term loan A bank ln due 2011	BB+	BB+	4
FOREST PROD/BLDG MAT/PACKAGING	Glatfelter (P.H.) Co.	US$50 mil term loan B bank ln due 2011	BB+	BB+	4
FOREST PROD/BLDG MAT/PACKAGING	Glatfelter (P.H.) Co.	US$200 mil 7.125% sr unsecd nts due 05/01/2016	BB+	BB+	4
FOREST PROD/BLDG MAT/PACKAGING	Graphic Packaging International Inc.	US$425 mil 8.5% sr nts due 08/15/2011	B-	B-	6
FOREST PROD/BLDG MAT/PACKAGING	Graphic Packaging International Inc.	US$425 mil 9.5% sr sub nts due 08/15/2013	B-	B-	6
FOREST PROD/BLDG MAT/PACKAGING	Headwaters Inc.	US$172.5 mil 2.875% sub nts Convertible due 06/01/2016	B	B+	5
FOREST PROD/BLDG MAT/PACKAGING	Headwaters Inc.	US$160 mil 2.5% sub notes Convertible due 02/01/2014	B	B+	5
FOREST PROD/BLDG MAT/PACKAGING	Interline Brands Inc.	US$200 mil 8.125% sr sub nts due 06/15/2014	B	B+	5
FOREST PROD/BLDG MAT/PACKAGING	IPS Corp.	US$100 mil sr sub nts due 2014	CCC+	CCC+	6
FOREST PROD/BLDG MAT/PACKAGING	Mercer International Inc.	US$310 mil 9.25% sr nts due 02/15/2013	B	B	3
FOREST PROD/BLDG MAT/PACKAGING	Millar Western Forest Products Ltd.	US$190 mil 7.75% sr unsecd nts due 11/15/2013	B-	CCC+	5
FOREST PROD/BLDG MAT/PACKAGING	Neenah Paper Inc.	US$225 mil 7.375% sr nts due 11/15/2014	B+	B+	4
FOREST PROD/BLDG MAT/PACKAGING	Newark Group Inc. (The)	US$175 mil 9.75% sr sub nts due 03/15/2014	B-	B-	6
FOREST PROD/BLDG MAT/PACKAGING	NewPage Corp.	US$200 mil 12% sr sub nts due 05/01/2013	CCC+	CCC+	6
FOREST PROD/BLDG MAT/PACKAGING	Norampac Inc.	US$250 mil 6.75% sr nts due 06/01/2013	BB-	BB-	5
FOREST PROD/BLDG MAT/PACKAGING	Norbord (Delaware) GP I	US$200 mil 6.7% sr nts due 2017	BB	BB	3
FOREST PROD/BLDG MAT/PACKAGING	Norbord Inc.	US$250 mil 7.25% sr unsecured nts due 2012	BB	BB	3
FOREST PROD/BLDG MAT/PACKAGING	Norbord Inc.	US$200 mil 8.125% deb due 2008	BB	BB	3
FOREST PROD/BLDG MAT/PACKAGING	Norcraft Cos. LP	US$150 mil 9% sr sub nts due 11/01/2011	B-	B+	3

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
FOREST PROD/BLDG MAT/PACKAGING	Norcraft Holdings LP	US$118 mil step up sr discount nts due 09/01/2012	B-	B-	6
FOREST PROD/BLDG MAT/PACKAGING	Nortek Inc.	US$625 mil 8.5% sr sub nts due 09/01/2014	CCC+	CCC+	6
FOREST PROD/BLDG MAT/PACKAGING	NTK Holdings Inc.	US$400.5 mil 10.75% sr disc nts due 03/01/2014	CCC+	CCC+	6
FOREST PROD/BLDG MAT/PACKAGING	Panolam Industries International Inc.	US$151 mil 10.75% sr sub nts due 10/01/2013	CCC+	CCC+	6
FOREST PROD/BLDG MAT/PACKAGING	Ply Gem Industries Inc.	US$360 mil 9% sr sub nts due 02/15/2012	CCC+	CCC+	6
FOREST PROD/BLDG MAT/PACKAGING	Potlatch Corp.	US$100 mil 12.5% deb due 12/01/2009	BB	BB	3
FOREST PROD/BLDG MAT/PACKAGING	Potlatch Corp.	US$100 mil 6.95% deb due 12/15/2015	BB	BB	3
FOREST PROD/BLDG MAT/PACKAGING	Potlatch Corp.	US$100 mil med-term notes due 9 mos to 30 yrs	BB	BB	3
FOREST PROD/BLDG MAT/PACKAGING	Potlatch Corp.	US$150 mil med-term notes due 9 mos to 30 yrs	BB	BB	3
FOREST PROD/BLDG MAT/PACKAGING	Rock-Tenn Co.	US $200 mil sr unsecd notes due 2016	BB-	BB-	6
FOREST PROD/BLDG MAT/PACKAGING	Smurfit-Stone Container Enterprises Inc.	US$125 mil rating adjustable sr nts due 08/01/2016	B-	B-	6
FOREST PROD/BLDG MAT/PACKAGING	Smurfit-Stone Container Enterprises Inc.	US$750 mil 9.75% sr nts due 02/01/2011	B-	B-	6
FOREST PROD/BLDG MAT/PACKAGING	Smurfit-Stone Container Enterprises Inc.	US$400 mil 8.375% sr nts due 07/01/2012	B-	B-	6
FOREST PROD/BLDG MAT/PACKAGING	Smurfit-Stone Container Enterprises Inc.	US$700 mil 8.25% sr nts due 10/01/2012	B-	B-	6
FOREST PROD/BLDG MAT/PACKAGING	Smurfit-Stone Container Enterprises Inc.	US$300 mil 7.5% sr bnds due 06/01/2013	B-	B-	6
FOREST PROD/BLDG MAT/PACKAGING	Smurfit-Stone Container Enterprises Inc.	US$675 mil 8% sr nts due 03/15/2017	B-	B-	6
FOREST PROD/BLDG MAT/PACKAGING	Stone Container Finance Co. of Canada II	US$200 mil 7.375% nts due 07/15/2014	B-	B-	6
FOREST PROD/BLDG MAT/PACKAGING	Texas Industries Inc.	US$250 mil 7.25% sr nts due 07/15/2013	BB-	BB-	3
FOREST PROD/BLDG MAT/PACKAGING	Texas Industries Inc.	US$200 mil sr unsecd revolving credit fac bank ln due 2012	BB-	BB-	3
FOREST PROD/BLDG MAT/PACKAGING	U.S. Concrete Inc.	US$275 mil 8.375% sr sub nts due 04/01/2014	B-	B	5
FOREST PROD/BLDG MAT/PACKAGING	USG Corp.	US$650 mil revolv credit fac bank ln due 08/02/2012	BB+	BB+	4
FOREST PROD/BLDG MAT/PACKAGING	USG Corp.	US$500 mil 6.75% sr nts due 11/15/2016	BB+	BB+	4
FOREST PROD/BLDG MAT/PACKAGING	USG Corp.	US$500 mil 7.75 sr nts due 01/15/2018	BB+	BB+	4
FOREST PROD/BLDG MAT/PACKAGING	Valmont Industries Inc.	US$150 mil revolv bank ln due 2009	BB	BB+	3
FOREST PROD/BLDG MAT/PACKAGING	Verso Paper Finance Holdings LLC	US$250 mil term loan bank ln	CCC+	CCC+	6
FOREST PROD/BLDG MAT/PACKAGING	Verso Paper Holdings LLC	US$300 mil 11.375% sr sub nts due 08/01/2016	CCC+	CCC+	6

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FOREST PROD/BLDG MAT/PACKAGING	WII Components Inc.	US$120 mil 10% sr unsecd nts due 02/15/2012	B-	B	3
FOREST PROD/BLDG MAT/PACKAGING	Wolverine Tube Inc.	US$150 mil 7.375% sr nts due 08/01/2008	C	C	5
FOREST PROD/BLDG MAT/PACKAGING	Wolverine Tube Inc.	US$120 mil sr unsecd nts due 04/01/2009	C	C	5
HEALTHCARE	Advanced Medical Optics Inc.	US$350 mil 2.5% sr sub nts Convertible due 07/15/2024	B-	B-	6
HEALTHCARE	Advanced Medical Optics Inc.	US$150 mil 1.375% sr sub nts Convertible due 07/01/2025	B-	B-	6
HEALTHCARE	Advanced Medical Optics Inc.	US$500 mil 3.25% sr sub debt Convertible due 08/01/2026	B-	B-	6
HEALTHCARE	Advanced Medical Optics Inc.	US$250 mil 7.5% sr nts due 05/01/2017	B-	B-	6
HEALTHCARE	Alliance Imaging Inc.	US$300 mil 7.25% sr sub nts due 12/15/2012	B-	B-	6
HEALTHCARE	Alpharma Inc.	US$300 mil 2.125% nts Convertible due 03/15/2027	B+	B+	4
HEALTHCARE	American Medical Systems Inc.	US$325 mil 3.25% sr sub nts Convertible due 07/01/2036	B	B	6
HEALTHCARE	AMR Holdings, EmCare Holdings	US$250 mil 10% sr sub nts due 02/15/2015	B-	B-	6
HEALTHCARE	Angiotech Pharmaceuticals Inc.	US$325 mil fltg rate sr unsecd nts due 12/01/2013	B-	B-	3
HEALTHCARE	Angiotech Pharmaceuticals Inc.	US$250 mil 7.75% sr sub nts due 04/01/2014	CCC	CCC	6
HEALTHCARE	Apria Healthcare Group Inc.	US$250 mil 3.375% conv sr nts due 09/01/2033	BB-	BB	5
HEALTHCARE	Axcan Intermediate Holdings Inc.	US$235 mil sr unsecured nts due 2016	B-	B-	6
HEALTHCARE	BioMarin Pharmaceutical Inc.	US$172.5 mil 2.5% sr sub nts Convertible due 03/29/2013	CCC	CCC	6
HEALTHCARE	BioMarin Pharmaceutical Inc.	US$325 mil 1.875% sr sub nts Convertible due 04/23/2017	CCC	CCC	6
HEALTHCARE	Biomet Inc.	US$775 mil nts	B-	B-	6
HEALTHCARE	Biomet Inc.	US$775 mil PIK Toggle nts	B-	B-	6
HEALTHCARE	Biomet Inc.	US$1.015 bil sub nts	B-	B-	6
HEALTHCARE	Boston Scientific Corp.	US$250 mil 4.25% sr nts due 1/12/2011	BB+	BB+	4
HEALTHCARE	Boston Scientific Corp.	US$600 mil 6.4% sr nts due 6/15/2016	BB+	BB+	4
HEALTHCARE	Boston Scientific Corp.	US$400 mil 5.5% nts due 11/15/2015	BB+	BB+	4
HEALTHCARE	Boston Scientific Corp.	US$350 mil 6.25% nts due 11/15/2035	BB+	BB+	4
HEALTHCARE	Boston Scientific Corp.	US$600 mil 6% sr nts due 6/15/2011	BB+	BB+	4
HEALTHCARE	Boston Scientific Corp.	US$600 mil 5.45% nts cue 6/15/2014	BB+	BB+	4
HEALTHCARE	Boston Scientific Corp.	US$250 mil 5.125% sr nts cue 1/12/2017	BB+	BB+	4
HEALTHCARE	Carriage Services Inc.	US$130 mil sr nts due 2015	B-	B-	5
HEALTHCARE	Catalent Pharma Solutions	US$565 mil PIK toggle nts due 04/15/2015	B-	B	5
HEALTHCARE	Catalent Pharma Solutions	US$300 mil sr sub nts due 2017	B-	B-	6

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
HEALTHCARE	CHS/Community Health Systems Inc.	US$3 bil 8.875% sr nts due 07/15/2015	B-	B	5
HEALTHCARE	ConMed Corp.	US$150 mil 2.5% sr sub nts Convertible due 11/15/2024	B	B	6
HEALTHCARE	Cooper Companies Inc.	US$350 mil 7.125% sr nts due 02/15/2015	BB-	BB-	3
HEALTHCARE	CRC Health Corp.	US$200 mil 10.75% sr sub nts due 02/01/2016	CCC+	CCC+	6
HEALTHCARE	DaVita Inc.	US$850 mil 7.25% sr sub nts due 03/15/2015	B	B	6
HEALTHCARE	DaVita Inc.	US$900 mil 6.625% sr nts due 03/15/2013	B	B+	5
HEALTHCARE	DJO Finance LLC; DJO Finance Corp.	US$575 mil 10.875% sr nts due 11/15/2014	CCC+	B-	5
HEALTHCARE	DJO Finance LLC; DJO Finance Corp.	US$200 mil 11.75% sr sub nts due 11/15/2014	CCC+	CCC+	6
HEALTHCARE	Elan Finance PLC	US$850 mil 7.75% sr nts due 11/15/2011	B	B	3
HEALTHCARE	Elan Finance PLC	US$300 mil fltg rate sr nts due 11/15/2011	B	B	3
HEALTHCARE	Elan Finance PLC	US$465 mil 8.875% sr fixed rate nts due 12/01/2013	B	B	3
HEALTHCARE	Elan Finance PLC	US$150 mil fltg rate nts due 12/01/2013	B	B	3
HEALTHCARE	Hanger Orthopedic Group Inc.	US$175 mil 10.25% sr nts due 06/01/2014	CCC+	CCC+	6
HEALTHCARE	HCA Inc.	US$150 mil 7.5% deb due 12/15/2023	B-	B-	6
HEALTHCARE	HCA Inc.	US$150 mil 8.36% deb due 04/15/2024	B-	B-	6
HEALTHCARE	HCA Inc.	US$150 mil 9% med-term nts due 12/15/2014	B-	B-	6
HEALTHCARE	HCA Inc.	US$291 mil 7.69% nts due 06/15/2025	B-	B-	6
HEALTHCARE	HCA Inc.	US$125 mil 7.58% med-term nts due 09/15/2025	B-	B-	6
HEALTHCARE	HCA Inc.	US$150 mil 7.19% deb due 11/15/2015	B-	B-	6
HEALTHCARE	HCA Inc.	US$200 mil 7.5% deb due 11/15/2095	B-	B-	6
HEALTHCARE	HCA Inc.	US$150 mil 7.05% deb due 12/01/2027	B-	B-	6
HEALTHCARE	HCA Inc.	US$200 mil 7.25% nts due 05/20/2008	B-	B-	6
HEALTHCARE	HCA Inc.	US$100 mil 7.75% deb due 07/15/2036	B-	B-	6
HEALTHCARE	HCA Inc.	US$750 mil 8.75% sr nts due 09/01/2010	B-	B-	6
HEALTHCARE	HCA Inc.	£150 mil 8.75% sr unsecd nts due 11/01/2010	B-	B-	6
HEALTHCARE	HCA Inc.	US$500 mil 7.875% sr nts due 02/01/2011	B-	B-	6
HEALTHCARE	HCA Inc.	US$500 mil 6.95% sr nts due 05/01/2012	B-	B-	6

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HEALTHCARE	HCA Inc.	US$500 mil 6.3% sr unsecd nts due 10/01/2012	B-	B-	6
HEALTHCARE	HCA Inc.	US$150 mil 8.7% med-term nts due 02/10/2010	B-	B-	6
HEALTHCARE	HCA Inc.	US$500 mil 6.25% sr nts due 02/15/2013	B-	B-	6
HEALTHCARE	HCA Inc.	US$500 mil 6.75% sr nts due 07/15/2013	B-	B-	6
HEALTHCARE	HCA Inc.	US$350 mil 5.25% nts due 11/06/2008	B-	B-	6
HEALTHCARE	HCA Inc.	US$250 mil 7.5% nts due 11/06/2033	B-	B-	6
HEALTHCARE	HCA Inc.	US$500 mil 5.75% sr nts due 03/15/2014	B-	B-	6
HEALTHCARE	HCA Inc.	US$500 mil 5.5% sr nts due 12/01/2009	B-	B-	6
HEALTHCARE	HCA Inc.	US$750 mil 6.375% sr nts due 01/15/2015	B-	B-	6
HEALTHCARE	HCA Inc.	US$100 mil 6.73% med-term nts due 07/15/2045	B-	B-	6
HEALTHCARE	HCA Inc.	US$1 bil 6.5% nts due 02/15/2016	B-	B-	6
HEALTHCARE	Health Management Associates Inc.	US$575 mil 1.5% conv sr sub nts due 08/01/2023	B-	B-	6
HEALTHCARE	HealthSouth Corp.	US$375 mil fltg rate sr nts due 06/15/2014	CCC+	CCC+	6
HEALTHCARE	HealthSouth Corp.	US$625 mil 10.75% sr nts due 06/15/2016	CCC+	CCC+	6
HEALTHCARE	Hologic Inc.	US$1.725 bil step up sr nts convertible due 12/15/2037	B	B	6
HEALTHCARE	IASIS Healthcare Corp.	US$300 mil sr pik bank ln due 06/15/2014	CCC+	CCC+	6
HEALTHCARE	IASIS Healthcare LLC	US$475 mil 8.75% sr sub nts due 06/15/2014	CCC+	CCC+	6
HEALTHCARE	Invacare Corporation	US$175 mil 9.75% sr nts due 02/15/2015	B-	B	4
HEALTHCARE	Invacare Corporation	US$135 mil 4.125% sr sub Convertible due 02/01/2027	CCC+	CCC+	6
HEALTHCARE	Kendle International Inc.	US$200 mil 3.375% sr nts Convertible due 07/15/2012	NR	B	5
HEALTHCARE	Knowledge Learning Corp	US$260 mil 7.75% sr sub nts due 02/01/2015	B-	B	5
HEALTHCARE	LifeCare Holdings Inc.	US$150 mil 9.25% sr sub nts due 08/15/2013	CCC-	CCC-	6
HEALTHCARE	LifePoint Hospitals Inc.	US$225 mil 3.25% sr sub nts Convertible due 08/15/2025	B	B	6
HEALTHCARE	LifePoint Hospitals Inc.	US$575 mil 3.5% sr sub nts Convertible due 05/15/2014	B	B	6
HEALTHCARE	MedCath Holdings Corp.	US$150 mil 9.875% sr nts due 07/15/2012	B-	B-	6
HEALTHCARE	Millipore Corp.	US$565 mil 3.75% sr nts Convertible due 06/01/2026	BB-	BB-	6
HEALTHCARE	Millipore Corp.	EUR250 mil 5.875% sr unsecd nts due 06/30/2016	BBB	BBB	1

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
HEALTHCARE	Mylan Laboratories Inc.	US$600 mil 1.25% sr nts Convertible due 03/15/2012	B	B+	5
HEALTHCARE	Nabi Biopharmaceuticals	US$112.4 mil 2.875% sr nts Convertible due 04/15/2025	B-	B-	4
HEALTHCARE	National Mentor Inc.	US$150 mil sr sub nts due 2012	CCC+	CCC+	6
HEALTHCARE	National Mentor Inc.	US$180 mil 11.25% sr sub nts due 07/01/2014	CCC+	CCC+	6
HEALTHCARE	NMH Holdings, Inc.	US$175 mil var rate PIK Toggle nts due 06/15/2014	CCC+	CCC+	6
HEALTHCARE	Omnicare Inc.	US$977.5 mil 3.25% sr deb Convertible due 12/15/2035	B+	B+	6
HEALTHCARE	Omnicare Inc.	US$250 mil 6.125% sr sub nts due 06/01/2013	B+	B+	6
HEALTHCARE	Omnicare Inc.	US$225 mil 6.75% sr sub nts due 12/15/2013	B+	B+	6
HEALTHCARE	Omnicare Inc.	US$525 mil 6.875% sr sub nts due 12/15/2015	B+	B+	6
HEALTHCARE	PharmaNet Development Group Inc	US$143.75 mil 2.25% sr nts Convertible due 08/15/2024	B-	B-	6
HEALTHCARE	Phibro Animal Health Corp.	US$160 mil 10% sr unsecd nts due 08/01/2013	B-	B	4
HEALTHCARE	Phibro Animal Health Corp.	US$80 mil 13% sr sub nts due 08/01/2014	CCC+	CCC+	6
HEALTHCARE	PRA International Inc.	US$170 sr sub nts due 2015	CCC+	CCC+	6
HEALTHCARE	PSS World Medical Inc.	US$150 mil 2.25% sr nts Convertible due 03/15/2024	B+	BB-	5
HEALTHCARE	Psychiatric Solutions Inc.	US$470 mil 7.75% sr sub nts due 07/15/2015	B-	B-	6
HEALTHCARE	Res-Care Inc.	US$150 mil 7.75% sr nts due 10/15/2013	B+	B	6
HEALTHCARE	Rotech Healthcare Inc.	US$300 mil 9.5% sr sub nts due 04/01/2012	CCC	CCC	6
HEALTHCARE	Rural/Metro Corp.	US$50 mil pik nts due 2016	CCC+	CCC+	6
HEALTHCARE	Rural/Metro LLC	US$125 mil 9.875% sr sub nts due 03/15/2015	CCC+	B-	5
HEALTHCARE	Select Medical Corp.	US$660 mil 7.625% sr sub nts due 02/01/2015	CCC+	CCC+	6
HEALTHCARE	Select Medical Holdings Corp.	US$175 mil fltg rate sr nts due 09/15/2015	CCC+	CCC+	6
HEALTHCARE	Service Corp. International	US$150 mil 7.875% sr deb due 02/01/2013	BB-	BB-	5
HEALTHCARE	Service Corp. International	US$150 mil 6.875% sr nts due 10/01/2007	BB-	BB-	5
HEALTHCARE	Service Corp. International	US$372 mil 7.7% nts due 04/15/2009	BB-	BB-	5
HEALTHCARE	Service Corp. International	US$200 mil 6.5% nts due 03/15/2008	BB-	BB-	5
HEALTHCARE	Service Corp. International	US$250 mil 6.75% sr nts due 04/01/2016	BB-	BB-	5
HEALTHCARE	Service Corp. International	US$300 mil 7% sr nts due 06/15/2017	BB-	BB-	5
HEALTHCARE	Service Corp. International	US$250 mil 7.375% sr nts due 10/01/2014	BB-	BB-	5

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
HEALTHCARE	Service Corp. International	US$250 mil 7.625% sr nts due 12/31/2018	BB-	BB-	5
HEALTHCARE	Service Corp. International	US$200 mil 6.75% nts due 04/01/2015	BB-	BB-	5
HEALTHCARE	Service Corp. International	US$200 mil 7.5% nts due 04/01/2027	BB-	BB-	5
HEALTHCARE	Skilled Healthcare Group Inc.	US$200 mil 11% sr sub nts due 01/15/2014	B-	B-	6
HEALTHCARE	Spheris Inc.	US$125 mil 11% sr sub nts due 12/15/2012	CCC	CCC	6
HEALTHCARE	Stewart Enterprises Inc.	US$200 mil 6.25% sr nts due 02/15/2013	BB-	BB-	4
HEALTHCARE	Stewart Enterprises Inc.	US$125 mil 3.125% sr nts Convertible due 07/15/2014	BB-	BB-	4
HEALTHCARE	Stewart Enterprises Inc.	US$125 mil 3.375% sr nts Convertible due 07/15/2016	BB-	BB-	4
HEALTHCARE	Sun Healthcare Group, Inc.	US$200 mil 9.125% sr sub nts due 04/15/2015	CCC+	CCC+	6
HEALTHCARE	Surgical Care Affiliates	US$150 mil var rate PIK-election nts due 07/15/2015	CCC+	B-	5
HEALTHCARE	Surgical Care Affiliates	US$150 mil 10% nts due 07/15/2017	CCC+	CCC+	6
HEALTHCARE	Team Health Inc.	US$215 mil 11.25% sr sub nts due 12/01/2013	B-	B-	6
HEALTHCARE	Tenet Healthcare Corp.	US$1 bil 6.375% sr nts due 12/01/2011	CCC+	B	4
HEALTHCARE	Tenet Healthcare Corp.	US$450 mil 6.875% sr nts due 11/15/2031	CCC+	B	4
HEALTHCARE	Tenet Healthcare Corp.	US$600 mil 6.5% sr unsecd nts due 06/01/2012	CCC+	B	4
HEALTHCARE	Tenet Healthcare Corp.	US$1 bil 7.375% sr unsecd nts due 02/01/2013	CCC+	B	4
HEALTHCARE	Tenet Healthcare Corp.	US$1 bil 9.875% nts due 07/01/2014	CCC+	B	4
HEALTHCARE	Tenet Healthcare Corp.	US$800 mil 9.25% sr nts due 02/01/2015	CCC+	B	4
HEALTHCARE	United Surgical Partners International Inc.	US$240 mil 8.875% sr sub nts due 05/01/2017	CCC+	CCC+	6
HEALTHCARE	United Surgical Partners International Inc.	US$200 mil sr sub toggle nts due 05/01/2017	CCC+	CCC+	6
HEALTHCARE	US Oncology Holdings Inc.	US$425 mil fltg rate pik toggle nts due 03/15/2012	CCC+	CCC+	6
HEALTHCARE	US Oncology Inc.	US$300 mil 9% sr nts due 08/15/2012	CCC+	B-	5
HEALTHCARE	US Oncology Inc.	US$275 mil 10.75% sr sub nts due 08/15/2014	CCC+	CCC+	6
HEALTHCARE	Valeant Pharmaceuticals Intl	US$240 mil 3% conv sub nts due 08/16/2010	B-	B-	6
HEALTHCARE	Valeant Pharmaceuticals Intl	US$240 mil 4% conv sub nts due 12/31/2013	B-	B-	6
HEALTHCARE	Valeant Pharmaceuticals Intl	US$ 300 mil 7% sr nts due 12/15/2011	B+	B+	3
HEALTHCARE	Vanguard Health Holding Co. II LLC	US$575 mil 9% sr sub nts due 10/01/2014	CCC+	CCC+	6
HEALTHCARE	Vanguard Holding Co. I Inc.	US$216 mil 11.25% sr discount nts due 10/01/2015	CCC+	CCC+	6

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
HEALTHCARE	VWR Funding Inc.	US$675 mil nts due 07/15/2015	CCC+	B-	5
HEALTHCARE	Warner Chilcott Corp.	US$600 mil 8.75% sr sub nts due 02/01/2015	B-	B-	6
HIGH TECHNOLOGY	Activant Solutions Inc.	US$175 mil 9.5% sr sub nts due 05/01/2016	CCC+	CCC+	6
HIGH TECHNOLOGY	Advanced Micro Devices Inc.	US$600 mil 7.75% sr nts due 11/01/2012	B	B	3
HIGH TECHNOLOGY	Advanced Micro Devices Inc.	US$2.2 mil 6% Convertible nts due 05/01/2015	B	B	3
HIGH TECHNOLOGY	Advanced Micro Devices Inc.	US$1.5 bil 5.75% Convertible nts due 08/15/2012	B	B	3
HIGH TECHNOLOGY	Amkor Technology Inc.	US$425 mil 7.75% sr nts due 05/15/2013	B	B+	4
HIGH TECHNOLOGY	Amkor Technology Inc.	US$250 mil 7.125% sr nts due 03/15/2011	B	B+	4
HIGH TECHNOLOGY	Amkor Technology Inc.	US$400 mil 9.25% sr nts due 06/01/2016	B	B+	4
HIGH TECHNOLOGY	Amkor Technology Inc.	US$190 mil 2.5% sr sub nts Convertible due 05/15/2011	B-	B-	6
HIGH TECHNOLOGY	Anixter Inc.	US$200 mil 5.95% sr nts due 03/01/2015	BB+	BB+	4
HIGH TECHNOLOGY	Anixter International Inc.	US$378.135 mil zero cpn Liquid Yield Option nts due 07/07/2033	BB-	BB-	6
HIGH TECHNOLOGY	Anixter International Inc.	US$300 mil 1% sr nts Convertible due 02/15/2013	BB-	BB-	6
HIGH TECHNOLOGY	Avago Technologies Finance Pte. Ltd.	US$250 mil 11.875% sr sub nts due 12/01/2015	B	B	6
HIGH TECHNOLOGY	Avago Technologies Finance Pte. Ltd.	US$250 mil fltg rate sr nts due 06/01/2013	BB-	BB-	3
HIGH TECHNOLOGY	Avago Technologies Finance Pte. Ltd.	US$500 mil 10.125% sr nts due 2013	BB-	BB-	3
HIGH TECHNOLOGY	Avaya Inc.	US$750 mil sr unsecd PIK toggle nts due 2015	CCC+	B-	5
HIGH TECHNOLOGY	Avaya Inc.	US$700 mil sr unsecd cash pay nts due 2015	CCC+	B-	5
HIGH TECHNOLOGY	Belden Inc.	US$110 mil 4% conv sub deb due 07/15/2023	BB-	BB-	6
HIGH TECHNOLOGY	Belden Inc.	US$350 mil 7% sr sub nts due 03/15/2017	BB-	BB-	6
HIGH TECHNOLOGY	BMS Holdings Inc.	US$150 mil 12.4% sr unsed PIK nts due 02/15/2012	CCC	CCC	6
HIGH TECHNOLOGY	CA Inc.	US$350 mil 6.5% sr nts due 04/15/2008	BB	BB	3
HIGH TECHNOLOGY	CA Inc.	US$400 mil 1.625% conv sr nts due 12/15/2009	BB	BB	3
HIGH TECHNOLOGY	CA Inc.	US$500 mil 4.75% sr nts due 12/01/2009	BB	BB	3
HIGH TECHNOLOGY	CA Inc.	US$500 mil 5.625% sr nts due 12/01/2014	BB	BB	3
HIGH TECHNOLOGY	Cardtronics Inc.	US$300 mil 9.25% sr sub nts due 08/15/2013	B-	B	5

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HIGH TECHNOLOGY	CDW Corp.	US$520 mil sr unsecd PIK toggle nts due 2015	CCC+	CCC+	6
HIGH TECHNOLOGY	CDW Corp.	US$520 mil sr unsecd cash pay nts due 2015	CCC+	CCC+	6
HIGH TECHNOLOGY	CDW Corp.	US$940 mil sr sub nts due 2017	CCC+	CCC+	6
HIGH TECHNOLOGY	Celestica Inc.	US$500 mil 7.875% sr sub nts due 07/01/2011	B-	B	5
HIGH TECHNOLOGY	Celestica Inc.	US$250 mil 7.625% sr sub nts due 07/01/2013	B-	B	5
HIGH TECHNOLOGY	Ceridian Corp.	US$825 mil 11.25% sr nts due 11/15/2015	CCC+	CCC+	6
HIGH TECHNOLOGY	Ceridian Corp.	US$475 mil sr PIK toggle nts due 11/15/2015	CCC+	CCC+	6
HIGH TECHNOLOGY	Ciena Corp.	US$300 mil 0.25% sr nts Convertible due 05/01/2013	B	B	4
HIGH TECHNOLOGY	Ciena Corp.	US$500 mil 0.875% sr nts Convertible due 06/15/2017	B	B	4
HIGH TECHNOLOGY	Coleman Cable Inc.	US$220 mil 9.875% nts due 10/01/2012	B	B+	5
HIGH TECHNOLOGY	CommScope Inc.	US$225 mil 1% sr sub nts Convertible due 03/15/2024	B	B	6
HIGH TECHNOLOGY	CompuCom Systems Inc.	US$210 mil 10.5% nts due 2015	B-	B	5
HIGH TECHNOLOGY	Comverse Technology Inc.	US$420 mil zero cpn yield puttable sec due 05/15/2023	B+	B+	3
HIGH TECHNOLOGY	Corpsource Finance Holdings, LLC	US$125 mil PIK loan nts due 2013	CCC+	CCC+	6
HIGH TECHNOLOGY	Fairchild Semiconductor Corp.	US$200 mil 5% sr conv sub nts due 11/01/2008	B	B	6
HIGH TECHNOLOGY	First Data Corp.	US$2.2 bil 9.875% sr unsecd nts due 9/24/2015	B-	B	5
HIGH TECHNOLOGY	Flextronics International Ltd.	US$400 mil 6.5% sr sub nts due 05/15/2013	BB-	BB-	6
HIGH TECHNOLOGY	Flextronics International Ltd.	US$500 mil 1% conv sr sub nts due 2010	BB-	BB-	6
HIGH TECHNOLOGY	Flextronics International Ltd.	US$500 mil 6.25% sr sub nts due 11/15/2014	BB-	BB-	6
HIGH TECHNOLOGY	Freescale Semiconductor Inc.	US$500 mil fltg rate sr nts due 12/15/2014	B-	B-	6
HIGH TECHNOLOGY	Freescale Semiconductor Inc.	US$1.5 bil 9.125% sr PIK-election nts due 12/15/2014	B-	B-	6
HIGH TECHNOLOGY	Freescale Semiconductor Inc.	US$2.35 bil 8.875% sr nts due 12/15/2014	B-	B-	6
HIGH TECHNOLOGY	Freescale Semiconductor Inc.	US$1.6 bil 10.125% sr sub nts due 12/15/2016	B-	B-	6
HIGH TECHNOLOGY	General Cable Corp.	US$475 mil 1% Convertible due 10/15/2012	B+	B+	5
HIGH TECHNOLOGY	General Cable Corp.	US$355 mil 0.875% sr nts Convertible due 11/15/2013	B+	B+	5
HIGH TECHNOLOGY	General Cable Corp.	US$200 mil 7.125% fixed unsecd nts due 04/01/2017	B+	B+	5

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HIGH TECHNOLOGY	General Cable Corp.	US $125 mil fltg rate sr notes due 04/01/2015	B+	B+	5
HIGH TECHNOLOGY	Global Cash Access Inc.	US$235 mil 8.75% sr sub nts due 03/15/2012	B	B	6
HIGH TECHNOLOGY	IKON Office Solutions Inc.	US$300 mil 6.75% sr bnds due 12/01/2025	BB-	BB-	4
HIGH TECHNOLOGY	IKON Office Solutions Inc.	US$125 mil 7.3% sr nts due 11/01/2027	BB-	BB-	4
HIGH TECHNOLOGY	IKON Office Solutions Inc.	US$225 mil 7.75% sr nts due 09/15/2015	BB-	BB-	4
HIGH TECHNOLOGY	IKON Office Solutions Inc.	US$150 mil fltg rate sr unsecd nts due 01/01/2012	BB-	BB-	4
HIGH TECHNOLOGY	iPayment Inc.	US$205 mil 9.75% sr sub nts due 2014	CCC+	CCC+	6
HIGH TECHNOLOGY	Juniper Networks Inc.	US$400 mil zero cpn zero cpn conv nts due 06/15/2008	BB	BB	3
HIGH TECHNOLOGY	Kulicke & Soffa Industries Inc.	US$205 mil Convertible due 11/30/2008	B-	B+	4
HIGH TECHNOLOGY	Kulicke & Soffa Industries Inc.	US$65 mil 1% sub nts Convertible due 06/30/2010	B-	B+	4
HIGH TECHNOLOGY	LSI Corp.	US$410 mil 6.5% conv sub nts due 12/15/2009	B+	BB	3
HIGH TECHNOLOGY	LSI Corp.	US$350 mil 4% conv sub nts due 05/15/2010	B+	BB	3
HIGH TECHNOLOGY	Maxtor Corp.	US$326 mil 2.375% sr nts Convertible due 08/15/2012	BB+	BB+	4
HIGH TECHNOLOGY	Nuance Communications Inc.	US$250 mil 2.75% sr convertible deb due 08/15/2027	B-	B-	6
HIGH TECHNOLOGY	ON Semiconductor Corp.	US$95 mil 1.875% sub nts Convertible due 12/15/2025	B	B+	5
HIGH TECHNOLOGY	ON Semiconductor Corp.	US$259.5 mil zero cpn sr sub nts Convertible ser B due 04/15/2024	B	B+	5
HIGH TECHNOLOGY	ON Semiconductor Corp.	US$484 mil 2.625% sr sub nts Convertible due 12/15/2026	B	B+	5
HIGH TECHNOLOGY	ON Semiconductor Corp.	US$95 mil 1.875% sub nts Convertible due 12/15/2025	B	B+	5
HIGH TECHNOLOGY	Open Solutions Inc.	US$325 mil 9.75% sr sub nts due 02/01/2015	CCC+	CCC+	6
HIGH TECHNOLOGY	Pegasus Solutions Inc.	US$105 mil nts due 04/15/2015	CCC+	B-	5
HIGH TECHNOLOGY	Quantum Corp.	US$160 mil 4.375% conv nts due 08/01/2010	CCC+	CCC+	6
HIGH TECHNOLOGY	Red Hat Inc.	US$600 mil sr deb Convertible due 01/15/2024	B+	B+	3
HIGH TECHNOLOGY	SanDisk Corp.	US$1.15 bil 1% sr unsecd nts Convertible due 05/15/2013	BB-	BB-	3
HIGH TECHNOLOGY	Sanmina-SCI Corp.	US$400 mil 6.75% sr sub nts due 03/01/2013	B-	B-	6
HIGH TECHNOLOGY	Sanmina-SCI Corp.	US$600 mil 8.125% sr sub nts due 03/01/2016	B-	B-	6
HIGH TECHNOLOGY	Sanmina-SCI Corp.	US$300 mil sr nts due 06/15/2010	B+	B+	4
HIGH TECHNOLOGY	Sanmina-SCI Corp.	US$300 mil sr nts due 06/15/2014	B+	B+	4

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HIGH TECHNOLOGY	Seagate Technology HDD Holdings	US$300 mil fltg rate nts due 10/01/2009	BB+	BB+	4
HIGH TECHNOLOGY	Seagate Technology HDD Holdings	US$600 mil 6.375% sr nts due 10/01/2011	BB+	BB+	4
HIGH TECHNOLOGY	Seagate Technology HDD Holdings	US$600 mil 6.8% sr nts due 10/01/2016	BB+	BB+	4
HIGH TECHNOLOGY	Serena Software Inc.	US$200 mil 10.375% sr sub nts due 03/15/2016	CCC+	CCC+	6
HIGH TECHNOLOGY	Spansion Inc.	US$250 mil 11.25% sr nts due 01/15/2016	B	B	4
HIGH TECHNOLOGY	Spansion LLC	US$207 mil 2.25% exch sr sub deb due 06/15/2016	CCC+	CCC+	6
HIGH TECHNOLOGY	SS&C Technologies Inc.	US$205 mil 11.75% sr sub nts due 12/01/2013	CCC+	CCC+	6
HIGH TECHNOLOGY	Sun Microsystems Inc.	US$550 mil 7.65% sr nts due 08/15/2009	BB+	BB+	3
HIGH TECHNOLOGY	Sun Microsystems Inc.	US$350 mil 0.625% sr nts Convertible due 02/01/2012	BB+	BB+	3
HIGH TECHNOLOGY	Sun Microsystems Inc.	US$350 mil 0.75% sr nts Convertible due 02/01/2014	BB+	BB+	3
HIGH TECHNOLOGY	SunGard Data Systems Inc.	US$1 bil 10.25% sr nts due 08/15/2015	B-	B-	6
HIGH TECHNOLOGY	SunGard Data Systems Inc.	US$1.6 bil 9.125% sr nts due 08/15/2013	B-	B+	4
HIGH TECHNOLOGY	Superior Essex Communications LLC, Essex Group Inc.	US$257 mil 9% sr nts due 04/15/2012	B+	B+	5
HIGH TECHNOLOGY	Syniverse Technologies Inc.	US$175 mil 7.75% sr sub nts due 08/15/2013	B	B	6
HIGH TECHNOLOGY	Telcordia Technologies Inc.	US$300 mil 10% sr sub nts due 03/15/2013	CCC+	CCC+	6
HIGH TECHNOLOGY	Unisys Corp.	US$300 mil 6.875% sr nts due 03/15/2010	B+	B+	3
HIGH TECHNOLOGY	Unisys Corp.	US$400 mil 8% sr nts due 10/15/2012	B+	B+	3
HIGH TECHNOLOGY	Unisys Corp.	US$150 mil 8.5% sr nts due 10/15/2015	B+	B+	3
HIGH TECHNOLOGY	Unisys Corp.	US$210 mil 12.5% sr nts due 01/15/2016	B+	B+	3
HIGH TECHNOLOGY	Vangent Inc.	US$190 mil 9.625% sr sub nts due 02/15/2015	B-	B-	6
HIGH TECHNOLOGY	Viasystems Inc.	US$ 200 mil 10.5% sr sub nts due 01/15/2011	B-	B+	4
HIGH TECHNOLOGY	Vishay Intertechnology Inc.	US$500 mil 3.625% conv sub nts due 08/01/2023	B+	B+	6
INTEGRATED	Tucson Electric Power Co.(Obligor) Apache Cnty Indl Dev Auth (Issuer)	US$83.7 mil poll cntl rev bnds ser 1998A due 03/01/2028	BB-	BB+	2
INTEGRATED	Tucson Electric Power Co.(Obligor) Apache Cnty Indl Dev Auth (Issuer)	US$99.8 mil poll cntl rev bnds ser 1998B due 03/01/2033	BB-	BB+	2
INTEGRATED	Tucson Electric Power Co.(Obligor) Apache Cnty Indl Dev Auth (Issuer)	US$16.5 mil indl dev rev bnds ser 1998C due 03/01/2026	BB-	BB+	2

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Table 3

Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
INTEGRATED	CILCORP Inc.	US$250 mil nts due 10/15/2029	B+	BB	3
INTEGRATED	CILCORP Inc.	US$225 mil 8.7% sr nts due 10/15/2009	B+	BB	3
INTEGRATED	Nevada Power (Obligor) Clark Cnty (Issuer)	US$52.285 mil Indl dev rev bnds ser 1997A due 11/01/2032	B	BB	2
INTEGRATED	Nevada Power (Obligor) Clark Cnty (Issuer)	US$85 mil 5.9% indl dev rfdg bnds ser 1995 due 10/01/2030	B	BB	2
INTEGRATED	Nevada Power (Obligor) Clark Cnty (Issuer)	US$14 mil poll cntl rfdg rev bnds ser 1995D due 10/01/2011	B	BB	2
INTEGRATED	Nevada Power (Obligor) Clark Cnty (Issuer)	US$6.3 mil poll cntl rfdg rev bnds ser 1995D due 10/01/2023	B	BB	2
INTEGRATED	Nevada Power (Obligor) Clark Cnty (Issuer)	US$44 mil indl dev rev bnds (Nevada Pwr Co. proj) ser 1995C due 10/01/2030	B	BB	2
INTEGRATED	Nevada Power (Obligor) Clark Cnty (Issuer)	US$76.75 mil indl dev rev bnds (Nevada Pwr Co. proj) ser 1995A due 10/01/2030	B	BB	2
INTEGRATED	Nevada Power (Obligor) Coconino Cnty Poll Ctl Corp (Issuer)	US$36.7 mil 7.125% Poll cntrl rev bnds 1997 ser A due 10/01/2032	BB-	BB+	2
INTEGRATED	Nevada Power (Obligor) Coconino Cnty Poll Ctl Corp (Issuer)	US$14.7 mil Poll cntrl rev bnds 1997 ser B due 10/01/2032	BB-	BB+	2
INTEGRATED	El Paso Corp.	US$500 mil 6.75% sr nts due 05/15/2009	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$600 mil 7.625% nts due 07/15/2011	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$922 mil zero cpn conv deb due 02/28/2021	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$300 mil 7.375% med-term nts due 12/15/2012	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$500 mil 7% sr nts due 05/15/2011	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$700 mil 7.8% global med-term nts due 08/01/2031	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$1.1 bil 7.75% sr med-term nts due 01/15/2032	BB-	BB-	5
INTEGRATED	El Paso Corp.	EUR500 mil 7.125% euro bnds due 05/06/2009	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$500 mil 7.875% sr bnds due 06/15/2012	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$272 mil 7.625% sr (equity sec units) nts due 08/16/2007	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$300 mil 8.05% sr med-term nts due 10/15/2030	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$191.206 mil 6.5% sr nts due 06/01/2008	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$206.911 mil 7.625% sr nts due 09/01/2008	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$192.777 mil 6.375% sr nts due 02/01/2009	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$378.728 mil 7.75% sr nts due 06/15/2010	BB-	BB-	5

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)

INTEGRATED	El Paso Corp.	US$41.685 mil 10.75% sr nts due 10/01/2010	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$136.118 mil 9.625% sr nts due 2012	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$182.763 mil 6.7% ar nts due 02/15/2027	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$197.1 mil 6.95% sr nts due 06/01/2028	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$149.125 mil 7.75% sr nts due 01/15/2032	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$198.907 mil 7.42% sr nts due 02/15/2037	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$375 mil 6.875% sr nts due 06/15/2014	BB-	BB-	5
INTEGRATED	El Paso Corp.	US$900 mil 7% sr nts due 06/15/2017	BB-	BB-	5
INTEGRATED	Tucson Electric Power Co. (Obligor) Farmington (Issuer)	US$80.41 mil Poll cntrl rev bnds 1997 ser A due 10/01/2020	B+	BB+	2
INTEGRATED	IPALCO Enterprises Inc.	US$750 mil nts due 11/14/2011	BB-	BB	5
INTEGRATED	Indianapolis Power & Light (Obligor) Petersburg (Issuer)	US$20 mil solid waste disp rev bnds (Indianapolis pwr & light co proj) ser 1996 due 11/01/2029	BB-	BBB	1
INTEGRATED	Tucson Electric Power Co. (Obligor) Pima Cnty Indl Dev Auth (Issuer)	US$22.46 mil Indl dev rev bnds 1997 ser A due 09/01/2025	BB-	BB+	2
INTEGRATED	Tucson Electric Power Co. (Obligor) Pima Cnty Indl Dev Auth (Issuer)	US$120.745 mil ind dev rev bnds (Tucson Electric Power Co) ser 2008 A due 09/01/2029	BB-	BB+	2
INTEGRATED	Regency Energy Partners LP, Regency Energy Finance Corp	US$550 mil 8.375% sr nts due 12/15/2013	B	B	6
INTEGRATED	Sierra Pacific Resources	US$335 mil 8.625% sr nts due 03/15/2014	B	BB-	4
INTEGRATED	Sierra Pacific Resources	US$99.142 mil 7.803% sr nts due 06/15/2012	B	BB-	4
INTEGRATED	Sierra Pacific Resources	US$225 mil 6.75% sr nts due 08/15/2017	B	BB-	4
INTEGRATED	Targa Resources Inc	US$250 mil 8.5% sr nts due 11/01/2013	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	AAC Group Holding Corp.	US$125 mil step up sr disc nts due 10/01/2012	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Affinion Group Holdings Inc.	US$350 mil term bank ln due 01/15/2012	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Affinion Group Inc.	US$304 mil 10.125% sr nts due 10/15/2013	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Affinion Group Inc.	US$355.5 mil 11.5% sr sub nts due 10/15/2015	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Affinity Group Holdings Inc.	US$88.2 mil 10.875% sr nts due 02/15/2012	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Affinity Group Inc.	US$200 mil 9% sr sub nts due 02/15/2012	CCC+	B-	5
MEDIA, ENTERTAINMENT & LEISURE	Allbritton Communications Co.	US$455 mil 7.75% sr sub nts due 12/15/2012	B-	B+	4

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
MEDIA, ENTERTAINMENT & LEISURE	AMC Entertainment Holdings Inc.	US$400 mil PIK term bank ln due 2012	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	AMC Entertainment Inc.	US$250 mil 8.625% sr unsecd nts due 08/15/2012	B-	B-	5
MEDIA, ENTERTAINMENT & LEISURE	AMC Entertainment Inc.	US$300 mil 8% sr sub nts due 03/01/2014	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	AMC Entertainment Inc.	US$325 mil 11% sr sub nts due 02/01/2016	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	American Achievement Corp.	US$150 mil 8.25% sr sub nts due 04/01/2012	CCC+	B	4
MEDIA, ENTERTAINMENT & LEISURE	American Achievement Group Holding Corp.	US$150 mil var rate sr disc nts due 10/12/2012	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	American Media Operations Inc.	US$250 mil 10.25% sr sub nts due 05/01/2009	CCC-	CCC-	6
MEDIA, ENTERTAINMENT & LEISURE	American Media Operations Inc.	US$150 mil 10.25% nts ser B due 05/01/2009	CCC-	CCC-	6
MEDIA, ENTERTAINMENT & LEISURE	American Media Operations Inc.	US$155.454 mil 8.875% sr sub nts due 01/15/2011	CCC-	CCC-	6
MEDIA, ENTERTAINMENT & LEISURE	Barrington Broadcasting Group LLC, Barrington Broadcasting Capital Corp.	US$125 mil 10.5% sr sub nts due 08/15/2014	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Belo Corp	$250 million 6.75% sr nts due 05/30/2013	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Belo Corp	$350 million 8% nts due 11/01/2008	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Belo Corp	$200 million 7.75% sr nts due 06/01/2027	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Belo Corp	$250 million 7.25% sr nts due 09/15/2027	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Bonten Media Group Inc.	US$125 mil 9% toggle nts due 06/01/2015	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Bowne & Co. Inc.	US$75 mil 5% conv sub deb due 10/01/2033	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Boyd Gaming Corp.	US$300 mil 7.75% sr sub nts due 12/15/2012	B+	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Boyd Gaming Corp.	US$350 mil 6.75% sr sub nts due 04/15/2014	B+	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Boyd Gaming Corp.	US$250 mil 7.125% sr sub nts due 02/01/2016	B+	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Caesars Entertainment Inc.	US$375 mil 7.875% sr sub nts due 03/15/2010	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Caesars Entertainment Inc.	US$350 mil 8.125% sr sub nts due 05/15/2011	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Canwest Limited Partnership	US$400 mil 9.25% sr sub nts due 08/01/2015	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Canwest Limited Partnership	CAD75 mil term C bank ln due 2015	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Canwest Media Inc	US$751.5 mil 8% sr sub nts due 09/15/2012	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Catalina Marketing Corp.	US$330 mil sr unsecured PIK Toggle bridge bank ln	B-	B-	6

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
MEDIA, ENTERTAINMENT & LEISURE	Catalina Marketing Corp.	US$160 mil sr sub bridge bank ln	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	CCM Merger Inc.	US$300 mil 8% nts due 08/01/2013	CCC+	B-	5
MEDIA, ENTERTAINMENT & LEISURE	Cengage Learning Acquisitions Inc.	US$1.2156 bil 10.5% sr nts due 01/15/2015	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Cengage Learning Acquisitions Inc.	US$519 mil step up (amt at maturity) sr sub discount nts due 07/15/2015	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Cengage Learning Holdco Inc	US$540 mil sr PIK nts due 2017	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Cenveo Corp.	US$125 mil 8.375% sr sub nts due 2014	B	B	6
MEDIA, ENTERTAINMENT & LEISURE	Cenveo Corp.	US$320 mil 7.875% sr sub nts due 2013	B	B	6
MEDIA, ENTERTAINMENT & LEISURE	Cinemark Inc.	US$360 mil step up sr disc nts due 03/15/2014	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	CMP Susquehanna Corp.	US$275 mil sr sub nts	CCC	CCC	6
MEDIA, ENTERTAINMENT & LEISURE	CW Media Holdings Inc.	CAD$298.645 million senior discount notes	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Deluxe Corp.	US$300 mil 5% sr nts due 12/15/2012	BB-	BB-	4
MEDIA, ENTERTAINMENT & LEISURE	Deluxe Corp.	US$275 mil 5.125% sr nts due 10/01/2014	BB-	BB-	4
MEDIA, ENTERTAINMENT & LEISURE	Deluxe Corp.	US$200 mil 7.375% sr unsecd nts due 06/01/2015	BB-	BB-	4
MEDIA, ENTERTAINMENT & LEISURE	Dex Media Inc.	US$500 mil 8% nts due 11/15/2013	B	B	6
MEDIA, ENTERTAINMENT & LEISURE	Dex Media Inc.	US$500 mil (gross proceeds) disc nts due 11/15/2013	B	B	6
MEDIA, ENTERTAINMENT & LEISURE	Dex Media West LLC	US$385 mil 8.5% sr nts due 08/15/2010	B	BB-	3
MEDIA, ENTERTAINMENT & LEISURE	Dex Media West LLC	US$780 mil 9.875% sr sub nts due 08/15/2013	B	BB-	3
MEDIA, ENTERTAINMENT & LEISURE	Donnelley (R.H.) Corp.	US$300 mil 6.875% sr nts due 01/15/2013	B	B	6
MEDIA, ENTERTAINMENT & LEISURE	Donnelley (R.H.) Corp.	US$365 mil 6.875% sr disc nts due 01/15/2013	B	B	6
MEDIA, ENTERTAINMENT & LEISURE	Donnelley (R.H.) Corp.	US$660 mil 6.875% sr disc nts due 01/15/2013	B	B	6
MEDIA, ENTERTAINMENT & LEISURE	Donnelley (R.H.) Corp.	US$1.21 bil 8.875% sr nts due 01/15/2016	B	B	6
MEDIA, ENTERTAINMENT & LEISURE	Donnelley (R.H.) Corp.	US$1.5 bil 8.875% sr nts ser A-4 due 10/15/2017	B	B	6
MEDIA, ENTERTAINMENT & LEISURE	Eastman Kodak Co.	US$125 mil 9.95% deb due 07/01/2018	B	B	5
MEDIA, ENTERTAINMENT & LEISURE	Eastman Kodak Co.	US$200 mil 9.2% nts due 06/01/2021	B	B	5
MEDIA, ENTERTAINMENT & LEISURE	Eastman Kodak Co.	US$250 mil 3.625% med-term nts ser A due 05/15/2008	B	B	5
MEDIA, ENTERTAINMENT & LEISURE	Eastman Kodak Co.	US$500 mil 7.25% sr nts due 11/15/2013	B	B	5

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
MEDIA, ENTERTAINMENT & LEISURE	Eastman Kodak Co.	US$575 mil 3.375% sr nts Convertible due 10/15/2033	B	B	5
MEDIA, ENTERTAINMENT & LEISURE	Education Management LLC	US$375 mil 8.75% sr nts due 06/01/2014	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Education Management LLC	US$385 mil 10.25% sr sub nts due 06/01/2016	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Eldorado Resorts LLC	US$64.7 mil 9% sr nts due 2014	B	B+	2
MEDIA, ENTERTAINMENT & LEISURE	Equinox Holdings Inc.	US$290 mil 9.25% sr nts due 02/15/2012	B-	B-	4
MEDIA, ENTERTAINMENT & LEISURE	Expedia Inc.	US$500 mil 7.456% sr nts due 08/15/2018	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Fisher Communications Inc.	US$150 mil 8.625% nts due 09/15/2014	B	B	3
MEDIA, ENTERTAINMENT & LEISURE	Gaylord Entertainment Co.	US$350 mil 8% sr nts due 11/15/2013	B-	B+	4
MEDIA, ENTERTAINMENT & LEISURE	Gaylord Entertainment Co.	US$225 mil 6.75% sr nts due 11/15/2014	B-	B+	4
MEDIA, ENTERTAINMENT & LEISURE	Great Canadian Gaming Corp.	US$170 mil 7.25% sr sub nts due 02/15/2015	B+	BB	4
MEDIA, ENTERTAINMENT & LEISURE	Haights Cross Communications Inc.	US$135 mil step up sr disc nts due 08/15/2011	CCC-	CCC-	6
MEDIA, ENTERTAINMENT & LEISURE	Haights Cross Operating Co	US$170 mil 11.75% sr nts due 08/15/2011	CCC-	CCC-	6
MEDIA, ENTERTAINMENT & LEISURE	Harlan Clarke Holdings Corp.	US$310 mil 9.5% Fixed nts due 05/15/2015	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Harlan Clarke Holdings Corp.	US$305 mil fltg rate Floating nts due 05/15/2015	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Harrah's Operating Co. Inc.	US$750 mil 5.5% sr nts due 07/01/2010	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Harrah's Operating Co. Inc.	US$500 mil 8% sr nts due 02/01/2011	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Harrah's Operating Co. Inc.	US$500 mil 5.375% sr nts due 12/15/2013	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Harrah's Operating Co. Inc.	US$1 bil 5.625% sr nts due 06/01/2015	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Harrah's Operating Co. Inc.	US$750 mil 6.5% sr nts due 06/01/2016	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Harrah's Operating Co. Inc.	US$750 mil 5.75% sr nts due 10/01/2017	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Harrah's Operating Co. Inc.	US$4.932417 bil 10.75% sr nts due 02/01/2016	B-	B+	3
MEDIA, ENTERTAINMENT & LEISURE	Harrah's Operating Co. Inc.	US$1.402583 bil var rate sr toggle nts due 02/01/2018	B-	B+	3
MEDIA, ENTERTAINMENT & LEISURE	Idearc Inc.	US$2.85 bil 8% sr unsecd nts due 11/15/2016	B+	BB-	5
MEDIA, ENTERTAINMENT & LEISURE	IMAX Corp.	US$ 160 mil 9.625% sr nts due 12/01/2010	CCC+	CCC+	5
MEDIA, ENTERTAINMENT & LEISURE	Interpublic Group of Cos. Inc.	US$500 mil 7.25% sr unsec nts due 08/15/2011	B+	B+	4
MEDIA, ENTERTAINMENT & LEISURE	Interpublic Group of Cos. Inc.	US$400 mil 4.25% conv sr nts due 03/15/2023	B+	B+	4

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
MEDIA, ENTERTAINMENT & LEISURE	Interpublic Group of Cos. Inc.	US$250 mil 5.4% nts due 11/15/2009	B+	B+	4
MEDIA, ENTERTAINMENT & LEISURE	Interpublic Group of Cos. Inc.	US$350 mil 6.25% nts due 11/15/2014	B+	B+	4
MEDIA, ENTERTAINMENT & LEISURE	Interpublic Group of Cos. Inc.	US$200 mil 4.75% sr unsecd Convertible due 03/15/2023	B+	B+	4
MEDIA, ENTERTAINMENT & LEISURE	Interpublic Group of Cos. Inc.	US$250 mil fltg rate sr nts due 11/15/2010	B+	B+	4
MEDIA, ENTERTAINMENT & LEISURE	Interpublic Group of Cos. Inc.	US$200 mil 4.5% conv sr nts due 03/15/2023	B+	B+	4
MEDIA, ENTERTAINMENT & LEISURE	Iron Mountain Inc.	US$150 mil 8.25% sr sub nts due 07/01/2011	B	B+	5
MEDIA, ENTERTAINMENT & LEISURE	Iron Mountain Inc.	US$400 mil 7.75% sr sub nts due 01/15/2015	B	B+	5
MEDIA, ENTERTAINMENT & LEISURE	Iron Mountain Inc.	US$320 mil 6.625% sr sub nts due 01/01/2016	B	B+	5
MEDIA, ENTERTAINMENT & LEISURE	Iron Mountain Inc.	US$435 mil 8.625% nts due 04/01/2013	B	B+	5
MEDIA, ENTERTAINMENT & LEISURE	Iron Mountain Inc.	£ 150 mil 7.25% sr sub nts due 04/15/2014	B	B+	5
MEDIA, ENTERTAINMENT & LEISURE	Iron Mountain Inc.	US$200 mil 8.75% sr sub nts due 07/05/2018	B	B+	5
MEDIA, ENTERTAINMENT & LEISURE	Iron Mountain Inc.	EUR225 mil 6.75% Euro sr sub nts due 10/15/2018	B	B+	5
MEDIA, ENTERTAINMENT & LEISURE	Iron Mountain Inc.	US$50 mil 8% sr sub nt due 2018	B	B+	5
MEDIA, ENTERTAINMENT & LEISURE	IWCO Direct Inc.	US$25 mil revolv bank ln due 08/07/2015	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Jacobs Entertainment Inc.	US$210 mil 9.75% sr nts due 06/15/2014	B-	B	3
MEDIA, ENTERTAINMENT & LEISURE	Knight Ridder Inc.	US$200 mil 9.875% deb due 04/15/2009	B+	B+	6
MEDIA, ENTERTAINMENT & LEISURE	Knight Ridder Inc.	US$300 mil 7.125% nts due 06/01/2011	B+	B+	6
MEDIA, ENTERTAINMENT & LEISURE	Knight Ridder Inc.	US$200 mil 4.625% nts due 11/01/2014	B+	B+	6
MEDIA, ENTERTAINMENT & LEISURE	Knight Ridder Inc.	US$400 mil 5.75% nts due 09/01/2017	B+	B+	6
MEDIA, ENTERTAINMENT & LEISURE	Knight Ridder Inc.	US$100 mil 7.15% deb due 11/01/2027	B+	B+	6
MEDIA, ENTERTAINMENT & LEISURE	Knight Ridder Inc.	US$300 mil 6.875% deb due 03/15/2029	B+	B+	6
MEDIA, ENTERTAINMENT & LEISURE	Lamar Advertising Co.	US$287.5 mil 2.875% conv nts due 12/31/2010	B	B	6
MEDIA, ENTERTAINMENT & LEISURE	Lamar Media Corp.	US$385 mil 7.25% sr sub nts due 01/01/2013	B	BB-	3
MEDIA, ENTERTAINMENT & LEISURE	Lamar Media Corp.	US$400 mil 6.625% sr sub nts due 08/15/2015	B	BB-	3
MEDIA, ENTERTAINMENT & LEISURE	Lamar Media Corp.	US$216 mil sr. nts ser B due 08/15/2015	B	BB-	3
MEDIA, ENTERTAINMENT & LEISURE	Lamar Media Corp.	US$275 mil 6.625% sr sub nts ser C due 08/15/2015	B	BB-	3

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Table 3

Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
MEDIA, ENTERTAINMENT & LEISURE	Language Line Holdings Inc.	US$108.993 mil step up sr disc nts due 06/30/2013	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Language Line Inc.	US$165 mil 11.125% sr sub nts due 06/15/2012	B-	B-	5
MEDIA, ENTERTAINMENT & LEISURE	Laureate Education Inc.	US$685 mil sr nts due 2015	B-	B-	5
MEDIA, ENTERTAINMENT & LEISURE	Laureate Education Inc.	US$310 mil sr sub nt due 2017	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	LBI Media Inc.	US$225 mil 8.5% nts due 08/01/2017	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Liberty Media Corp.	US$990 mil 7.875% sr unsec nts due 07/15/2009	BB+	BB+	3
MEDIA, ENTERTAINMENT & LEISURE	Liberty Media Corp.	US$500 mil 8.5% nts due 07/15/2029	BB+	BB+	3
MEDIA, ENTERTAINMENT & LEISURE	Liberty Media Corp.	US$750 mil 4% sr exchgble deb due 11/15/2029	BB+	BB+	3
MEDIA, ENTERTAINMENT & LEISURE	Liberty Media Corp.	US$1 bil 8.25% sr unsecd deb due 02/01/2030	BB+	BB+	3
MEDIA, ENTERTAINMENT & LEISURE	Liberty Media Corp.	US$750 mil 3.75% sr exchangeable deb due 02/15/2030	BB+	BB+	3
MEDIA, ENTERTAINMENT & LEISURE	Liberty Media Corp.	US$600 mil 3.5% exch sr nts due 01/15/2031	BB+	BB+	3
MEDIA, ENTERTAINMENT & LEISURE	Liberty Media Corp.	US$817 mil 3.25% exch sr nts nts due 03/15/2031	BB+	BB+	3
MEDIA, ENTERTAINMENT & LEISURE	Liberty Media Corp.	US$1.75 bil exchangeable sr deb due 03/30/2023	BB+	BB+	3
MEDIA, ENTERTAINMENT & LEISURE	Liberty Media Corp.	US$1 bil 5.7% sr nts due 05/15/2013	BB+	BB+	3
MEDIA, ENTERTAINMENT & LEISURE	Liberty Media Corp.	US$237.8 mil 7.75% sr nts due 07/15/2009	BB+	BB+	3
MEDIA, ENTERTAINMENT & LEISURE	LIN Television Corp.	US$375 mil 6.5% sr sub nts due 05/15/2013	B-	B+	4
MEDIA, ENTERTAINMENT & LEISURE	LIN Television Corp.	US$100 mil 2.5% exch sr sub nts due 05/15/2033	B-	B+	4
MEDIA, ENTERTAINMENT & LEISURE	LIN Television Corp.	US$190 mil 6.5% sr sub nts due 05/15/2013	B-	B+	4
MEDIA, ENTERTAINMENT & LEISURE	Live Nation Inc.	US$200 mil 2.875% convertible notes due 07/15/2027	B-	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Local TV Finance LLC	US$190 mil 9.25% sr nts due 06/15/2015	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Mandalay Resort Group	US$300 mil 9.375% sr sub nts due 02/15/2010	B+	B+	6
MEDIA, ENTERTAINMENT & LEISURE	Mandalay Resort Group	US$200 mil 7.625% sr sub nts due 07/15/2013	B+	B+	6
MEDIA, ENTERTAINMENT & LEISURE	Mandalay Resort Group	US$250 mil 6.5% sr nts due 07/31/2009	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Mandalay Resort Group	US$250 mil 6.375% sr nts due 12/15/2011	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Mandalay Resort Group	US$400 mil fltg rate conv sr deb due 03/21/2033	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Mandalay Resort Group	US$150 mil 7% sr debt due 11/15/2036	BB	BB	3

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
MEDIA, ENTERTAINMENT & LEISURE	Mandalay Resort Group	US$150 mil 6.7% sr deb due 11/15/2096	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Mandalay Resort Group	US$200 mil 9.5% sr nts due 08/01/2008	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Marquee Holdings Inc.	US$304 mil sr disc nts due 08/15/2014	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	McClatchy Co. (The)	US$1 bil revolv cred fac bank ln due 06/27/2011	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	McClatchy Co. (The)	US$2.2 bil term A bank ln due 06/27/2011	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	MediMedia USA Inc.	US$150 mil 11.375% sr sub nts due 11/15/2014	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	MGM MIRAGE	US$400 mil 8.375% sub nts due 02/01/2011	B+	B+	6
MEDIA, ENTERTAINMENT & LEISURE	MGM MIRAGE	US$1.05 bil 6% sr nts due 10/01/2009	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	MGM MIRAGE	US$850 mil 8.5% sr nts due 09/15/2010	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	MGM MIRAGE	US$550 mil 6.75% sr nts due 09/01/2012	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	MGM MIRAGE	US$500 mil 6.75% sr nts due 04/01/2013	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	MGM MIRAGE	US$225 mil 5.875% sr nts due 02/27/2014	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	MGM MIRAGE	US$300 mil 5.875% sr nts due 02/27/2014	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	MGM MIRAGE	US$875 mil 6.625% sr nts due 07/15/2015	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	MGM MIRAGE	US$250 mil 6.875% sr nts due 04/01/2016	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	MGM MIRAGE	US$750 mil 7.5% sr nts due 06/01/2016	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	MGM MIRAGE	US$750 mil 7.625% sr nts nts due 01/15/2017	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Mirage Resorts Inc.	US$100 mil 7.25% sr deb due 08/01/2017	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Morris Publishing Group LLC	US$300 mil 7% sr sub nts due 08/01/2013	CCC+	B-	5
MEDIA, ENTERTAINMENT & LEISURE	MTR Gaming Group Inc.	US$130 mil 9.75% sr nts due 04/01/2010	B	BB-	2
MEDIA, ENTERTAINMENT & LEISURE	MTR Gaming Group Inc.	US$125 mil sr sub nts due 2012	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Muzak Holdings LLC	US$40 mil 13% sr disc nts due 03/15/2010	CCC-	CCC-	6
MEDIA, ENTERTAINMENT & LEISURE	Muzak LLC	US$115 mil 9.875% sr sub nts due 03/15/2009	CCC-	CCC-	6
MEDIA, ENTERTAINMENT & LEISURE	Muzak LLC	US$220 mil 10% sr nts due 02/15/2009	CCC-	CCC+	3
MEDIA, ENTERTAINMENT & LEISURE	Network Communications Inc.	US$175 mil 10.75% sr nts due 12/01/2013	B-	B-	5
MEDIA, ENTERTAINMENT & LEISURE	Nexstar Broadcasting Group Inc.	US$130 mil 11.375% sr disc nts due 04/01/2013	CCC+	CCC+	6

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
MEDIA, ENTERTAINMENT & LEISURE	Nexstar Broadcasting Inc.	US$200 mil 7% sr sub nts due 01/15/2014	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Nielsen Co. B.V. (The)	EUR343 million step up senior discounted notes	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Nielsen Co. B.V. (The)	¥4 billion 2.5% med-term notes	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Nielsen Co. B.V. (The)	EUR50 million floating rate med-term notes series 12	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Nielsen Co. B.V. (The)	EUR30 million 6.75% med-term notes	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Nielsen Co. B.V. (The)	EUR50 million floating rate med-term notes series 9	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Nielsen Co. B.V. (The)	£250 million 5.625% notes	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Nielsen Finance LLC	US$650 mil 10% nts due 08/01/2014	CCC+	B-	5
MEDIA, ENTERTAINMENT & LEISURE	Nielsen Finance LLC	EUR150 mil 9% nts due 08/01/2014	CCC+	B-	5
MEDIA, ENTERTAINMENT & LEISURE	Nielsen Finance LLC	US$1.07 bil step up /zero coupon sub PIK nts due 08/01/2016	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	NV Television LLC	US$30 mil bank ln due 2015	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Pinnacle Entertainment Inc.	US$135 mil 8.75% sr sub nts due 10/01/2013	B-	B+	3
MEDIA, ENTERTAINMENT & LEISURE	Pinnacle Entertainment Inc.	US$300 mil 8.25% sr sub nts due 03/15/2012	B-	B+	3
MEDIA, ENTERTAINMENT & LEISURE	Pinnacle Entertainment Inc.	US$385 mil 7.5% sub nts due 06/15/2015	B-	B+	3
MEDIA, ENTERTAINMENT & LEISURE	RBG, LLC, Virgin River Casino Corporation, B&BB Inc.	US$66 mil step up nts due 01/15/2013	CCC	CCC	6
MEDIA, ENTERTAINMENT & LEISURE	Realogy Corp.	US$1.7 bil 10.5% sr unsecd nts due 04/15/2014	CCC+	B	3
MEDIA, ENTERTAINMENT & LEISURE	Realogy Corp.	US$550 mil 11% sr pik toggle nts due 04/15/2014	CCC+	B	3
MEDIA, ENTERTAINMENT & LEISURE	Realogy Corp.	US$875 mil 12.375% sr sub nts due 04/15/2015	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Regal Cinemas Corp.	US$350 mil 9.375% sr sub nts due 02/01/2012	B	B	6
MEDIA, ENTERTAINMENT & LEISURE	Regal Entertainment Group	US$240 mil 3.75% conv sr nts due 05/15/2008	B	B	6
MEDIA, ENTERTAINMENT & LEISURE	Remington Arms Co. Inc.	US$200 mil 10.5% sr nts due 02/01/2011	CCC	CCC	6
MEDIA, ENTERTAINMENT & LEISURE	Salem Communications Holding Corp.	US$100 mil 7.75% sr sub nts due 12/15/2010	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Scholastic Corp.	US$175 mil nts due 04/15/2013	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	SGS International Inc.	US$200 mil 12% sr sub nts due 12/31/2013	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Sinclair Broadcast Group Inc.	US$345 mil 3% Convertible due 05/15/2027	B	B	6
MEDIA, ENTERTAINMENT & LEISURE	Sinclair Broadcast Group Inc.	US$150 mil step down conv sr sub nts due 07/15/2018	B	B	6

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
MEDIA, ENTERTAINMENT & LEISURE	Sinclair Television Group Inc.	US$675 mil 8% sr sub nts due 03/15/2012	B	BB-	3
MEDIA, ENTERTAINMENT & LEISURE	Six Flags Inc.	US$480 mil 8.875% nts due 02/01/2010	CCC	CCC-	6
MEDIA, ENTERTAINMENT & LEISURE	Six Flags Inc.	US$430 mil 9.75% sr nts due 04/15/2013	CCC	CCC-	6
MEDIA, ENTERTAINMENT & LEISURE	Six Flags Inc.	US$520 mil 9.625% sr nts due 06/01/2014	CCC	CCC-	6
MEDIA, ENTERTAINMENT & LEISURE	Six Flags Inc.	US$260 mil 4.5% sr nts Convertible due 05/15/2015	CCC	CCC-	6
MEDIA, ENTERTAINMENT & LEISURE	Source Interlink Cos. Inc.	US$465 mil sr sub bridge fac bank ln due 2017	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Speedway Motorsports Inc.	US$330 mil 6.75% sr sub nts due 06/01/2013	BB-	BB+	4
MEDIA, ENTERTAINMENT & LEISURE	Station Casinos Inc.	US$450 mil 6% sr nts due 04/01/2012	B	B+	3
MEDIA, ENTERTAINMENT & LEISURE	Station Casinos Inc.	US$400 mil 7.75% sr nts due 08/15/2016	B	B+	3
MEDIA, ENTERTAINMENT & LEISURE	Station Casinos Inc.	US$450 mil 6.5% sr sub nts due 02/01/2014	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Station Casinos Inc.	US$700 mil 6.875% sr sub nts due 03/01/2016	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Station Casinos Inc.	US$300 mil 6.625% sr sub nts due 03/15/2018	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Sun Media Corp.	US$205 mil 7.625% sr unsecd nts due 02/15/2013	B	B+	5
MEDIA, ENTERTAINMENT & LEISURE	Town Sports International Holdings Inc.	US$213 mil step up sr nts due 02/01/2014	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Universal City Development Partners Ltd.	US$500 mil 11.75% sr nts due 04/01/2010	B-	B+	3
MEDIA, ENTERTAINMENT & LEISURE	Universal City Florida Holding Co. I	US$300 mil fltg rate sr nts due 05/01/2010	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Universal City Florida Holding Co. I	US$150 mil 8.375% sr nts due 05/01/2010	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Univision Communications Inc.	US$1.5 bil 9.75% sr nts due 03/15/2015	CCC	CCC	6
MEDIA, ENTERTAINMENT & LEISURE	Vail Resorts Inc.	US$390 mil 6.75% sr sub nts due 02/15/2014	B	BB-	4
MEDIA, ENTERTAINMENT & LEISURE	Valassis Communications Inc.	US$540 mil 8.25% sr unsecd nts due 03/01/2015	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Visant Corp	US$500 mil. 7.625% sr sub nts due 10/01/2012	B-	B+	4
MEDIA, ENTERTAINMENT & LEISURE	Visant Holding Corp	US$247.2 mil 10.25% sr nts due 12/01/2013	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Visant Holding Corp	US$350 mil 8.75% sr unsecd nts due 12/01/2013	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	West Corp.	US$650 mil 9.5% sr nts due 10/15/2014	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	West Corp.	US$450 mil 11% sr sub nts due 10/15/2016	B-	B-	6
MEDIA, ENTERTAINMENT & LEISURE	Wynn Resorts Ltd.	US$1 bil sr unsecd bank ln due 06/21/2010	B+	BB	3

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
MEDIA, ENTERTAINMENT & LEISURE	Young Broadcasting Inc.	US$500 mil 10% sr sub nts due 03/01/2011	CCC-	CCC-	6
MEDIA, ENTERTAINMENT & LEISURE	Young Broadcasting Inc.	US$140 mil 8.75% sr sub nts due 01/15/2014	CCC-	CCC-	6
MINING AND MINERALS	AK Steel Corp.	US$550 mil 7.75% sr unsec nts due 06/15/2012	BB-	BB-	4
MINING AND MINERALS	Aleris International Inc.	US$705 mil 10% sr nts due 12/15/2014	B-	B-	6
MINING AND MINERALS	Aleris International Inc.	US$500 mil sr sub nts due 2016	B-	B-	6
MINING AND MINERALS	Alpha Natural Resources Inc.	US$175 mil 10% sr nts due 06/01/2012	B-	B	5
MINING AND MINERALS	California Steel Industries Inc.	US$150 mil 6.125% sr nts ser B due 03/15/2014	BB-	BB-	4
MINING AND MINERALS	Century Aluminum Co.	US$250 mil 7.5% sr nts due 08/15/2014	BB-	BB-	3
MINING AND MINERALS	Century Aluminum Co.	US$175 mil 1.75% sr Convertible due 08/01/2024	BB-	BB-	3
MINING AND MINERALS	CII Carbon Corp.	US$235 mil nts due 2015	CCC+	CCC+	6
MINING AND MINERALS	Coeur D'Alene Mines Corp.	US$180 mil 1.25% sr nts Convertible due 01/15/2024	B-	B-	4
MINING AND MINERALS	Coeur D'Alene Mines Corp.	US$150 mil 3.25% sr nts Convertible due 03/15/2028	B-	B-	4
MINING AND MINERALS	Compass Minerals International Inc.	US$179.6 mil 12% sr sub discount nts due 06/01/2013	B	B	6
MINING AND MINERALS	Drummond Co. Inc.	US$400 mil 7.375% sr nts due 02/15/2016	BB-	BB-	3
MINING AND MINERALS	Foundation PA Coal Co.	US$300 mil 7.25% sr nts due 08/01/2014	B	B	6
MINING AND MINERALS	Gerdau Ameristeel Corp.	US$400 mil 10.375% sr nts due 07/15/2011	BB+	BB+	4
MINING AND MINERALS	GrafTech Finance Inc.	US$550 mil 10.25% sr nts due 02/15/2012	B	B+	4
MINING AND MINERALS	GrafTech International Ltd.	US$225 mil 1.625% sr deb Convertible due 01/15/2024	B-	B-	6
MINING AND MINERALS	International Coal Group Inc.	US$175 mil 10.25% sr nts due 07/15/2014	B-	CCC	6
MINING AND MINERALS	International Coal Group Inc.	US$225 mil 9% convertible nts due 2012	B-	CCC	6
MINING AND MINERALS	James River Coal Co.	US$150 mil 9.375% sr nts due 06/01/2012	CC	CC	6
MINING AND MINERALS	Massey Energy Co.	US$335 mil 6.625% sr nts due 11/15/2010	B+	B+	3
MINING AND MINERALS	Massey Energy Co.	US$150 mil 2.25% sr nts Convertible due 04/01/2024	B+	B+	3
MINING AND MINERALS	Massey Energy Co.	US$755 mil 6.875% sr unsecd nts due 12/15/2013	B+	B+	3
MINING AND MINERALS	Metals USA Holdings Corp.	US$300 mil fltg rate sr PIK toggle nts due 07/01/2012	CCC	CCC	6
MINING AND MINERALS	Noranda Aluminum Acquisition Corp.	US$510 mil var rate nts due 05/15/2015	CCC+	B-	5

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
MINING AND MINERALS	Noranda Aluminum Holding Corp.	US$220 mil var rate nts due 11/15/2014	CCC+	CCC+	6
MINING AND MINERALS	Peabody Energy Corp.	US$650 mil 6.875% sr nts due 03/15/2013	BB	BB	3
MINING AND MINERALS	Peabody Energy Corp.	US$220 mil 5.875% sr nts due 04/15/2016	BB	BB	3
MINING AND MINERALS	Peabody Energy Corp.	US$1.8 bil revolving credit fac bank ln due 2011	BB	BB	3
MINING AND MINERALS	Peabody Energy Corp.	US$510 mil delayed draw term loan bank ln	BB	BB	3
MINING AND MINERALS	Peabody Energy Corp.	US$440 mil term A fac bank ln due 2011	BB	BB	3
MINING AND MINERALS	Peabody Energy Corp.	US$650 mil 7.375% sr nts due 11/01/2016	BB	BB	3
MINING AND MINERALS	Peabody Energy Corp.	US$250 mil 7.875% sr nts due 11/01/2026	BB	BB	3
MINING AND MINERALS	PNA Group Inc.	US$250 mil 10.75% sr nts due 09/01/2016	B-	B-	6
MINING AND MINERALS	PNA Intermediate Holding Corp.	US$170 mil fltg rate sr toggle nts due 02/15/2013	B-	B-	6
MINING AND MINERALS	Russel Metals Inc.	US$175 mil 6.375% sr nts due 03/01/2014	BB	BB	5
MINING AND MINERALS	Steel Dynamics Inc.	US$115 mil 4% conv sub nts due 12/15/2012	BB-	BB-	6
MINING AND MINERALS	Steel Dynamics Inc.	US$700 mil 7.38% sr nts due 2012	BB+	BB+	3
MINING AND MINERALS	Steel Dynamics Inc.	US$500 mil 6.75% sr nts due 04/01/2015	BB+	BB+	3
MINING AND MINERALS	Stillwater Mining Co.	US$181.5 mil (original $165 mil) conv sr nts due 3/15/28	B+	B+	2
MINING AND MINERALS	Tube City IMS Corp.	US$225 mil 9.75% sr sub nts due 02/01/2015	B-	B-	6
MINING AND MINERALS	United States Steel Corp.	US$300 mil 5.65% sr nts due 06/01/2013	BB+	BB+	3
MINING AND MINERALS	United States Steel Corp.	US$450 mil 6.05% sr nts due 06/01/2017	BB+	BB+	3
MINING AND MINERALS	United States Steel Corp.	US$350 mil 6.65% sr nts due 06/01/2037	BB+	BB+	3
MINING AND MINERALS	United States Steel LLC	US$500 mil 7% sr nts due 2018	BB+	BB+	3
MINING AND MINERALS	USEC Inc.	US$150 mil 6.75% sr nts due 01/20/2009	CCC	CCC	6
MINING AND MINERALS	USEC Inc.	US$500 mil 3% sr conv nts due 10/01/2014	CCC	CCC	6
MINING AND MINERALS	Valmont Industries Inc.	US$150 mil 6.875% sr sub nts due 05/01/2014	BB-	BB	5
MINING AND MINERALS	Valmont Industries Inc.	US$75 mil term loan bank ln due 2009	BB+	BB+	3
OIL	Allis-Chalmers Energy Inc.	US$240 mil 9% sr nts due 01/15/2014	B	B	3
OIL	Allis-Chalmers Energy Inc.	US$250 mil 8.5% sr nts due 03/01/2017	B	B	3

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OIL	Atlas Energy Operating Company LLC	US$250 mil 10.75% sr nts due 02/01/2018(Co-Issuer: Atlas Energy Finance Corp.,Guarantor: Atlas Energy Resources LLC)	B	B	5
OIL	Basic Energy Services Inc.	US$225 mil 7.125% sr nts due 04/15/2016	B+	BB-	4
OIL	Baytex Energy Trust	US$180 mil 9.625% due 07/15/2010	B-	B	5
OIL	Berry Petroleum Company	US$200 mil 8.25% sr sub nts due 11/01/2016	B	B	6
OIL	Brigham Exploration Co.	US$150 mil 9.625% sr nts due 05/01/2014	CCC+	CCC+	5
OIL	Bristow Group Inc.	US$230 mil 6.125% sr nts due 06/15/2013	BB	BB	4
OIL	Bristow Group Inc.	US$300 mil 7.5% nts due 09/15/2017	BB	BB	4
OIL	Calfrac Holdings LP	US$135 mil 7.75% nts due 02/15/2015	B	B+	3
OIL	CCS Inc.	US$612 mil 10% Senior Notes due 2015	B-	B-	6
OIL	Chaparral Energy Inc.	US$325 mil 8.5% sr nts due 12/01/2015	CCC+	CCC+	6
OIL	Chaparral Energy Inc.	US$325 mil 8.875% sr nts due 02/01/2017	CCC+	CCC+	6
OIL	Chart Industries Inc.	US$170 mil 9.125% sr sub nts due 10/15/2015	B-	B	5
OIL	Chesapeake Energy Corp.	US$245 mil 8.125% sr nts due 04/01/2011	BB	BB	4
OIL	Chesapeake Energy Corp.	US$209.8 mil 8.375% sr unsecd nts due 11/01/2008	BB	BB	4
OIL	Chesapeake Energy Corp.	US$300 mil 9% sr unsecd nts due 08/15/2012	BB	BB	4
OIL	Chesapeake Energy Corp.	US$364 mil 7.75% sr nts due 01/15/2015	BB	BB	4
OIL	Chesapeake Energy Corp.	US$363 mil 7.5% sr unsecd nts due 09/15/2013	BB	BB	4
OIL	Chesapeake Energy Corp.	US$670 mil 6.875% sr nts due 01/15/2016	BB	BB	4
OIL	Chesapeake Energy Corp.	US$300 mil 7.5% sr nts due 06/15/2014	BB	BB	4
OIL	Chesapeake Energy Corp.	US$300 mil 7% sr nts due 08/15/2014	BB	BB	4
OIL	Chesapeake Energy Corp.	US$600 mil 6.375% sr nts due 06/15/2015	BB	BB	4
OIL	Chesapeake Energy Corp.	US$600 mil 6.625% sr nts due 01/15/2016	BB	BB	4
OIL	Chesapeake Energy Corp.	US$600 mil 6.25% sr unsecd nts due 01/15/2018	BB	BB	4
OIL	Chesapeake Energy Corp.	US$500 mil sr nts due 08/15/2017	BB	BB	4
OIL	Chesapeake Energy Corp.	US$500 mil 6.875% sr nts due 11/15/2020	BB	BB	4
OIL	Chesapeake Energy Corp.	US$600 mil 2.75% contigent sr nts Convertible due 11/15/2035	BB	BB	4
OIL	Chesapeake Energy Corp.	US$500 mil 6.5% sr nts due 08/15/2017	BB	BB	4

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
OIL	Chesapeake Energy Corp.	US$500 mil 7.625% sr nts due 07/15/2013	BB	BB	4
OIL	Chesapeake Energy Corp.	EUR600 mil 6.25% sr nts due 01/15/2017	BB	BB	4
OIL	Chesapeake Energy Corp.	US$1 bil 2.5% contingent nts Convertible due 05/15/2037	BB	BB	4
OIL	Cimarex Energy Co.	US$350 mil 7.125% sr nts due 05/01/2017	BB-	BB-	3
OIL	Clayton Williams Energy Inc	US$250 mil 7.75% sr nts due 08/01/2013	B-	B	3
OIL	Complete Production Services	US$650 mil 8% sr nts due 12/15/2016	B+	BB-	3
OIL	Compton Petroleum Finance Corp.	US$450 mil 7.625% sr nts due 12/01/2013	B	B	5
OIL	Comstock Resources Inc.	US$175 mil 6.875% sr nts due 03/01/2012	B	B+	5
OIL	Denbury Resources Inc.	US$225 mil 7.5% sr sub nts due 04/01/2013	B+	BB	3
OIL	Denbury Resources Inc.	US$300 mil 7.5% sr sub nts due 12/15/2015	B+	BB	3
OIL	Dresser-Rand Group Inc.	US$420 mil 7.375% sr sub nts due 11/01/2014	B	B+	5
OIL	Encore Acquisition Co.	US$150 mil 6.25% sr sub nts due 04/15/2014	B	B	6
OIL	Encore Acquisition Co.	US$300 mil sr sub nts due 07/15/2015	B	B	6
OIL	Encore Acquisition Co.	US$150 mil 7.25% sr sub nts due 12/01/2017	B	B	6
OIL	Energy Partners Ltd	US$150 mil 8.75% sr nts due 08/01/2010	B-	B-	5
OIL	Energy Partners Ltd	US$150 mil fltg rate nts due 04/15/2013	B-	B-	5
OIL	Energy Partners Ltd	US$300 mil 9.75% nts due 04/15/2014	B-	B-	5
OIL	Energy XXI Gulf Coast Inc.	US$750 mil 10% sr nts due 06/15/2013	CCC	CCC	5
OIL	Exterran Holdings Inc.	US$143.75 mil 4.75% sr nts Convertible due 01/15/2014	B+	BB	3
OIL	Forest Oil Corp.	US$265 mil 8% sr unsecd nts due 06/15/2008	B+	BB-	4
OIL	Forest Oil Corp.	US$285 mil 8% sr nts due 12/15/2011	B+	BB-	4
OIL	Forest Oil Corp.	US$150 mil 7.75% sr nts due 05/01/2014	B+	BB-	4
OIL	Forest Oil Corp.	US$750 mil 7.25% sr nts due 06/15/2019	B+	BB-	4
OIL	Frontier Oil Corp.	US$150 mil 6.625% sr nts due 10/01/2011	B+	BB-	3
OIL	Grey Wolf Inc.	US$150 mil 3.75% contigent conv sr nts due 05/07/2023	BB-	BB-	3
OIL	GulfMark Offshore Inc.	US$160 mil 7.75% sr nts due 07/25/2014	B+	BB-	3
OIL	Harvest Operations Corp.	US$250 mil 7.875% sr nts due 10/15/2011	CCC+	CCC+	6

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OIL	Helix Energy Solutions Group Inc.	US$550 mil 9.5% sr unsecd fixed nts due 01/15/2016	B+	BB-	3
OIL	Hilcorp Energy I LP	US$600 mil 7.75% sr nts due 11/01/2015	B	B+	3
OIL	Hilcorp Energy I LP	US$200 mil sr nts due 2018	B	B+	3
OIL	Holly Energy Partners LP	US$185 mil 6.25% sr nts due 03/01/2015	B+	B+	5
OIL	Hornbeck Offshore Services Inc.	US$300 mil 6.125% sr nts due 12/01/2014	BB-	BB-	3
OIL	Hornbeck Offshore Services Inc.	US$250 mil step up sr nts Convertible due 11/15/2026	BB-	BB-	3
OIL	Key Energy Services Inc.	US$425 mil 8.375% sr nts due 12/01/2014	B	B+	3
OIL	Mariner Energy Inc.	US$300 mil 7.5% sr nts due 04/15/2013	B	B	5
OIL	Mariner Energy Inc.	US$300 mil 8% nts due 05/15/2017	B	B	5
OIL	Newfield Exploration Co.	US$325 mil 6.625% sr sub nts due 09/01/2014	BB-	BB-	6
OIL	Newfield Exploration Co.	US$550 mil 6.625% sr sub nts due 04/15/2016	BB-	BB-	6
OIL	Newfield Exploration Co.	US$175 mil 7.625% sr nts due 03/01/2011	BB+	BB+	3
OIL	Parallel Petroleum Corp.	US$150 mil nts due 2014	B-	CCC+	6
OIL	Paramount Resources Ltd.	US$213.593 mil 8.5% sr nts due 01/31/2013	B	B	4
OIL	Parker Drilling Co.	US$225 mil 9.625% sr nts due 10/01/2013	B+	B+	3
OIL	Parker Drilling Co.	US$125 mil 2.125% Convertible nts due 07/15/2012	B+	B+	3
OIL	Petrohawk Energy Corp	US$130 mil 9.874% sr nts due 04/01/2011	B	B	5
OIL	Petrohawk Energy Corp	US$775 mil 9.125% sr nts due 07/15/2013	B	B	5
OIL	Petroleum Development Corp	US$203 mil 12% sr nts due 02/15/2018	B-	B+	2
OIL	PetroQuest Energy Inc	US$150 mil 10.375% sr nts due 05/15/2012	B-	B-	3
OIL	PHI Inc.	US$200 mil 7.125% sr nts due 04/15/2013	BB-	BB-	4
OIL	Pioneer Natural Resources Co.	US$350 mil 6.5% nts due 11/15/2008	BB+	BB+	3
OIL	Pioneer Natural Resources Co.	US$250 mil 7.2% sr nts due 01/15/2028	BB+	BB+	3
OIL	Pioneer Natural Resources Co.	US$150 mil sr unsecd nts due 04/15/2012	BB+	BB+	3
OIL	Pioneer Natural Resources Co.	US$526.875 mil 5.875% sr nts due 07/15/2016	BB+	BB+	3
OIL	Pioneer Natural Resources Co.	US$450 mil 6.875% sr nts due 05/01/2018	BB+	BB+	3
OIL	Pioneer Natural Resources Co.	US$500 mil 6.65% sr nts due 03/15/2017	BB+	BB+	3

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
OIL	Pioneer Natural Resources Co.	US$440 mil 2.875% sr nts Convertible due 01/15/2038	BB+	BB+	3
OIL	Plains Exploration & Production Co.	US$500 mil 7% sr nts due 03/15/2017	BB-	BB-	5
OIL	Plains Exploration & Production Co.	US$600 mil 7.75% nts due 06/15/2015	BB-	BB-	5
OIL	Pride International Inc.	US$300 mil 3.25% nts Convertible due 05/01/2033	BB-	BB+	3
OIL	Pride International Inc.	US$500 mil 7.375% sr nts due 07/15/2014	BB-	BB+	3
OIL	Quicksilver Resources Inc.	US$350 mil 7.125% sr sub nts due 04/01/2016	B	B+	5
OIL	Range Resources Corp.	US$200 mil 7.375% sr sub nts due 07/15/2013	B+	BB	4
OIL	Range Resources Corp.	US$150 mil 6.375% sr sub nts due 03/15/2015	B+	BB	4
OIL	Range Resources Corp.	US$250 mil 7.5% sr sub nts due 05/15/2016	B+	BB	4
OIL	Range Resources Corp.	US$250 mil 7.5% sr sub nts due 10/01/2017	B+	BB	4
OIL	SandRidge Energy Inc.	US$650 mil fixed rate term bank ln due 2015	B	B	3
OIL	SandRidge Energy Inc.	US$350 mil fltg rate term bank ln due 2014	B	B	3
OIL	Seitel Inc	US$190 mil sr nts due 2011	B-	B-	3
OIL	Seitel Inc	US$400 mil 9.75% sr nts due 02/15/2014	B-	B-	3
OIL	SESI LLC	US$300 mil sr nts due 2014	BB-	BB	4
OIL	SESI LLC	US$400 mil step up sr exchangeable nts due 12/15/2026	BB-	BB	4
OIL	Southwestern Energy Co.	US$600 mil 7.5% sr unsecd nts due 02/01/2018	BB+	BB+	3
OIL	Stallion Oilfield Services Ltd.	US$300 mil 9.75% sr nts due 02/01/2015	CCC+	B	4
OIL	Stallion Oilfield Services Ltd.	US$250 mil bridge bank ln due 08/01/2014	CCC+	B	4
OIL	Stewart & Stevenson LLC	US$150 mil 10% sr nts due 07/15/2014	B-	B-	5
OIL	Stone Energy Corp.	US$200 mil 8.25% sr nts due 12/15/2011	B-	B+	3
OIL	Stone Energy Corp.	US$200 mil 6.75% sr sub nts due 12/15/2014	B-	B+	3
OIL	Swift Energy Co.	US$150 mil 7.625% sr nts due 07/15/2011	BB-	BB-	3
OIL	Swift Energy Co.	US$250 mil 7.125% sr nts due 06/01/2017	BB-	BB-	3
OIL	Tesoro Corp	US$450 mil 6.25% sr nts due 11/01/2012	BB+	BB+	3
OIL	Tesoro Corp	US$450 mil 6.625% sr nts due 11/01/2015	BB+	BB+	3

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
OIL	Tesoro Corp	US$500 mil 6.5% sr nts due 06/01/2017	BB+	BB+	3
OIL	United Refining Co.	US$350 mil 10.5% sr nts due 08/15/2012	B	B	3
OIL	W&T Offshore Inc	US$450 mil 8.25% sr nts due 06/15/2014	B-	B	4
OIL	Whiting Petroleum Corp.	US$150 mil 7.25% sr sub nts due 05/01/2012	B	B	6
OIL	Whiting Petroleum Corp.	US$220 mil 7.25% sr nts due 05/01/2013	B	B	6
OIL	Whiting Petroleum Corp.	US$250 mil 7% sr sub nts due 02/01/2014	B	B	6
Project	Connecticut Resources Recov Auth	US$30 mil corp credit bnds/tax exempt int ser 1992A due 11/15/2022	BB+	BB+	1
REAL ESTATE COMPANIES	Centex Corp.	US$350 mil Sr Unsecd med-term note prog 12/07/2000: sr unsecd	BB+	BB+	4
REAL ESTATE COMPANIES	Centex Corp.	US$350 mil 5.70% sr unsecd notes due 5/15/2014	BB+	BB+	4
REAL ESTATE COMPANIES	Centex Corp.	US$500 million 6.5% Sr Unsecd Notes due 5/1/2016	BB+	BB+	4
REAL ESTATE COMPANIES	Centex Corp.	US$350 million 5.45% sr unsecd notes due 8/15/2012	BB+	BB+	4
REAL ESTATE COMPANIES	Centex Corp.	US$150 million 4.875% sr unsecd notes due 8/15/2008	BB+	BB+	4
REAL ESTATE COMPANIES	Centex Corp.	US$350 million 7.5% Sr Unsecd notes due 2012	BB+	BB+	4
REAL ESTATE COMPANIES	Centex Corp.	US$225 million 5.8% Sr Unsecd notes due 2009	BB+	BB+	4
REAL ESTATE COMPANIES	Centex Corp.	US$300 million 5.125% sr unsecd notes due 2013	BB+	BB+	4
REAL ESTATE COMPANIES	Centex Corp.	US$300 million 4.55% sr unsecd notes due 11/1/2010	BB+	BB+	4
REAL ESTATE COMPANIES	Centex Corp.	US$450 million 5.25% sr unsecd notes due 6/15/2015	BB+	BB+	4
REAL ESTATE COMPANIES	Centex Corp.	US$400 million 7.78% senior unsecured notes due 2/01/11	BB+	BB+	4
REAL ESTATE COMPANIES	Champion Enterprises Inc.	US$180 mil 2.75% conv deb due 11/01/2037	B-	B-	6
REAL ESTATE COMPANIES	Champion Enterprises Inc.	US$82 mil 7.625% unsecd nts due 05/15/2009	B+	B+	3
REAL ESTATE COMPANIES	D.R. Horton Inc.	US$150 million 9.75% subordinated notes due 2010	BB-	BB-	6
REAL ESTATE COMPANIES	D.R. Horton Inc.	US$200 million 6.875% sr unsecd nts due 5/1/2013	BB+	BB+	3
REAL ESTATE COMPANIES	D.R. Horton Inc.	US$100 million 5.875% Sr Unsecd notes due 2013	BB+	BB+	3
REAL ESTATE COMPANIES	D.R. Horton Inc.	US$200 million 5.00% sr unsecd notes due 1/15/2009	BB+	BB+	3
REAL ESTATE COMPANIES	D.R. Horton Inc.	US$500 million 6.5% sr unsecd notes due 4/15/2016	BB+	BB+	3
REAL ESTATE COMPANIES	D.R. Horton Inc.	US$250 million 5.625% sr unsecd notes due 2014	BB+	BB+	3

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
REAL ESTATE COMPANIES	D.R. Horton Inc.	US$250 million 4.875% sr unsecd notes due 1/15/2010	BB+	BB+	3
REAL ESTATE COMPANIES	D.R. Horton Inc.	US$300 million 5.625% sr unsecd notes due 1/15/2016	BB+	BB+	3
REAL ESTATE COMPANIES	D.R. Horton Inc.	US$300 mil 5.35% sr unsecd notes due 2/15/2015	BB+	BB+	3
REAL ESTATE COMPANIES	D.R. Horton Inc.	US$300 million 5.375% sr unsecd notes due 6/15/2012	BB+	BB+	3
REAL ESTATE COMPANIES	D.R. Horton Inc.	US$250 million 6.0% sr unsecd notes due 4/15/2011	BB+	BB+	3
REAL ESTATE COMPANIES	D.R. Horton Inc.	US$200 mil 7.875% Sr Unsecd nts due 8/2011	BB+	BB+	3
REAL ESTATE COMPANIES	D.R. Horton Inc.	US$385 mil 8.0% sr unsecd nts due 2009	BB+	BB+	3
REAL ESTATE COMPANIES	D.R. Horton Inc.	US$200 million 6.125% sr unsecd notes due 1/15/2014	BB+	BB+	3
REAL ESTATE COMPANIES	Fleetwood Enterprises Inc.	US$100 million 5% convertible sr sub debentures due 2023	CCC+	CCC+	6
REAL ESTATE COMPANIES	Forest City Enterprises, Inc.	US$300 million 7.625% Senior Unsecured notes due 2015	BB-	BB-	6
REAL ESTATE COMPANIES	Forest City Enterprises, Inc.	US$100 million 7.375% sr unsecd notes due 2034	BB-	BB-	6
REAL ESTATE COMPANIES	Forest City Enterprises, Inc.	US$150 million 6.50% sr unsecd notes due 2/1/2017	BB-	BB-	6
REAL ESTATE COMPANIES	Forest City Enterprises, Inc.	US$250 million 3.625% puttable equity linked sr unsecd notes due 10/15/2011	BB-	BB-	6
REAL ESTATE COMPANIES	Hovnanian Enterprises Inc.	US$300 million 7.5% sr unsecd notes due 5/15/2016	B-	B-	4
REAL ESTATE COMPANIES	Hovnanian Enterprises Inc.	US$250 million 8.625% sr unsecd notes due 1/15/2017	B-	B-	4
REAL ESTATE COMPANIES	K. Hovnanian Enterprises Inc.	US$100 mil 8.0% Sr Unsecd nts due 2012	B-	B-	4
REAL ESTATE COMPANIES	K. Hovnanian Enterprises Inc.	US$215 million 6.50% sr unsecd notes due 1/15/2014	B-	B-	4
REAL ESTATE COMPANIES	K. Hovnanian Enterprises Inc.	US$150 million 6.375% sr unsecd notes due 12/15/2014	B-	B-	4
REAL ESTATE COMPANIES	K. Hovnanian Enterprises Inc.	US$200 million 6.25% Sr Unsecd notes due 01/15/2015	B-	B-	4
REAL ESTATE COMPANIES	K. Hovnanian Enterprises Inc.	US$300 mil 6.25% sr unsecd notes due 1/15/2016	B-	B-	4
REAL ESTATE COMPANIES	K. Hovnanian Enterprises Inc.	US$150 mil 8.875% Sr Sub nts due 2012	CCC	CCC	6
REAL ESTATE COMPANIES	K. Hovnanian Enterprises Inc.	US$100 million 6% sr subordinated notes due 2010	CCC	CCC	6
REAL ESTATE COMPANIES	K. Hovnanian Enterprises Inc.	US$150 million 7.75% Sr Sub notes due 2013	CCC	CCC	6
REAL ESTATE COMPANIES	KB Home	US$200 mil 8.265% sr sub notes due 12/15/2008	BB-	BB-	6
REAL ESTATE COMPANIES	KB Home	US$300 million 7.75% senior subordinated notes due 2/1/2010	BB-	BB-	6

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REAL ESTATE COMPANIES	KB Home	US$250 mil 5.75% sr unsecd notes due 2/15/2014	BB+	BB+	4
REAL ESTATE COMPANIES	KB Home	US$350 million 6.375% sr unsecd notes due 8/15/2011	BB+	BB+	4
REAL ESTATE COMPANIES	KB Home	US$300 million 5.875% sr unsecd notes due 2015	BB+	BB+	4
REAL ESTATE COMPANIES	KB Home	US$450 million 6.25% sr unsecd notes due 6/15/2015	BB+	BB+	4
REAL ESTATE COMPANIES	KB Home	US$300 million 7.25% sr unsecd notes due 6/15/2018	BB+	BB+	4
REAL ESTATE COMPANIES	Kimball Hill Inc.	US$200 mil sr subordinated notes due 12/15/2012	C	C	6
REAL ESTATE COMPANIES	Lennar Corp.	US$282 mil 7 5/8% sr unsecd nts due 03/01/2009	BB+	BB+	4
REAL ESTATE COMPANIES	Lennar Corp.	US$300 million 5.125% sr unsecd notes due 10/1/2010	BB+	BB+	4
REAL ESTATE COMPANIES	Lennar Corp.	US$250 million 5.95% sr unsecd notes due 10/17/2011	BB+	BB+	4
REAL ESTATE COMPANIES	Lennar Corp.	US$350 million 5.95% sr unsecured due 3/01/2013	BB+	BB+	4
REAL ESTATE COMPANIES	Lennar Corp.	US$250 million 5.50% sr unsecd notes due 9/1/2014	BB+	BB+	4
REAL ESTATE COMPANIES	Lennar Corp.	US$500 million 5.60% sr unsecd notes due 5/31/2015	BB+	BB+	4
REAL ESTATE COMPANIES	Lennar Corp.	US$250 million 6.50% sr unsecd notes due 4/15/2016	BB+	BB+	4
REAL ESTATE COMPANIES	Lennar Corp.	US$712.250 million senior unsecured revolver	BB+	BB+	4
REAL ESTATE COMPANIES	Lennar Corp.	US$315.250 million senior unsecured 364 day revolving facility	BB+	BB+	4
REAL ESTATE COMPANIES	M/I Homes, Inc.	US$200 million 6.875% sr unsecd notes due 4/1/2012	B+	B+	4
REAL ESTATE COMPANIES	Meritage Homes Corporation	US$150 million 7.73% sr subordinated notes due 4/30/2017	B	B	6
REAL ESTATE COMPANIES	Meritage Homes Corporation	US$280 mil 9.75% Sr Unsecd nts due 2011	BB-	BB-	4
REAL ESTATE COMPANIES	Meritage Homes Corporation	US$130 million 6.875% sr unsecd notes due 5/1/2014	BB-	BB-	4
REAL ESTATE COMPANIES	Meritage Homes Corporation	US$ 350 million 6.25% senior unsecured notes due 2015	BB-	BB-	4
REAL ESTATE COMPANIES	Omega Healthcare Investors, Inc.	US$310 million 7% sr unsecd nts due 2014	BB	BB+	2
REAL ESTATE COMPANIES	Omega Healthcare Investors, Inc.	US$175 mil 7% sr unsecd notes due 2016	BB	BB+	2
REAL ESTATE COMPANIES	Pulte Homes Inc.	US$200 million 8.125% senior unsecured notes due 2011	BB+	BB+	3
REAL ESTATE COMPANIES	Pulte Homes Inc.	US$500 mil 7.875% Sr Unsecd nts due 2011	BB+	BB+	3
REAL ESTATE COMPANIES	Pulte Homes Inc.	US$300 mil 7.875% Sr Unsecd nts due 2/15/2032	BB+	BB+	3
REAL ESTATE COMPANIES	Pulte Homes Inc.	US$150 million 7.375% sr unsecd notes due 6/1/2046	BB+	BB+	3

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REAL ESTATE COMPANIES	Pulte Homes Inc.	US$400 million 6.375% Sr Unsecd notes due 2033	BB+	BB+	3
REAL ESTATE COMPANIES	Pulte Homes Inc.	US$500 mil 5.25% sr unsecd notes due 2014	BB+	BB+	3
REAL ESTATE COMPANIES	Pulte Homes Inc.	US$400 million 4.875% sr unsecd notes due 7/15/2009	BB+	BB+	3
REAL ESTATE COMPANIES	Pulte Homes Inc.	US$350 million 5.2% sr unsecd notes due 2/15/2015	BB+	BB+	3
REAL ESTATE COMPANIES	Pulte Homes Inc.	US$300 million 6.0% sr unsecd notes due 2/15/2035	BB+	BB+	3
REAL ESTATE COMPANIES	Pulte Homes Inc.	US$150 mil 7.625% sr unsecd nts due 2017	BB+	BB+	3
REAL ESTATE COMPANIES	Pulte Homes Inc.	US$300 million 6.25% senior unsecured notes due 2013	BB+	BB+	3
REAL ESTATE COMPANIES	Standard Pacific Corp.	US$100 mil 6% conv sr sub nts due 10/01/2012	B-	B-	6
REAL ESTATE COMPANIES	Standard Pacific Corp.	US$150 mil sr subordinated nts due 4/15/2012	B-	B-	6
REAL ESTATE COMPANIES	Standard Pacific Corp.	US$125 million 7.75% sr unsecd nts due 3/15/2013	B+	B+	4
REAL ESTATE COMPANIES	Standard Pacific Corp.	US$175 million 6.875% Sr Unsecd notes due 2011	B+	B+	4
REAL ESTATE COMPANIES	Standard Pacific Corp.	US$150 million 6.50% sr unsecd notes due 10/01/2008	B+	B+	4
REAL ESTATE COMPANIES	Standard Pacific Corp.	US$150 million 5.125% sr unsecd notes due 2009	B+	B+	4
REAL ESTATE COMPANIES	Standard Pacific Corp.	US$150 million 6.25% sr unsecd notes due 2014	B+	B+	4
REAL ESTATE COMPANIES	Standard Pacific Corp.	US$175 mil 6.5% sr unsecd notes due 2010	B+	B+	4
REAL ESTATE COMPANIES	Standard Pacific Corp.	US$175 million 7.0% sr unsecd notes due 2015	B+	B+	4
REAL ESTATE COMPANIES	Stanley-Martin Communities LLC	US$150 million 9.75% sr subordinated notes due 2015	CCC+	CCC+	6
REAL ESTATE COMPANIES	WCI Communities Inc.	US$200 mil 9.125% Sr Sub notes due 2012	CC	CC	6
REAL ESTATE COMPANIES	WCI Communities Inc.	US$125 million 4.0% Contingent Convertible Sr Sub notes due 2023	CC	CC	6
REAL ESTATE COMPANIES	WCI Communities Inc.	US$125 million 7.875% sr sub notes due 2013	CC	CC	6
REAL ESTATE COMPANIES	WCI Communities Inc.	US$200 million 6.625% sr subordinated notes due 3/15/2015	CC	CC	6
REAL ESTATE COMPANIES	William Lyon Homes	US$250 million 10.75% senior unsecd nts due 2013	B-	B-	5
REAL ESTATE COMPANIES	William Lyon Homes	US$150 million 7.5% sr unsecd nts due 2/15/2014	B-	B-	5
REAL ESTATE COMPANIES	William Lyon Homes	US$150 million 7.625% Sr Unsecd notes due 2012	B-	B-	5
REGULATED T&D	Commonwealth Edison Co.	US$20 mil 4.625% deb due 01/01/2009	B+	BBB-	1
REGULATED T&D	Commonwealth Edison Co.	US$40 mil 4.75% deb due 12/01/2011	B+	BBB-	1

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REGULATED T&D	Commonwealth Edison Co.	US$225 mil 6.95% nts due 07/15/2018	B+	BBB-	1
REGULATED T&D	Commonwealth Edison (Obligor) Hammond (Issuer)	US$20 mil 9.125% poll cntl rev bnds ser 1980 due 06/15/2010	B+	BBB-	1
REGULATED T&D	Commonwealth Edison (Obligor) Illinois Envir Fac Fin Auth (Issuer)	US$40 mil 8.5% poll cntl rev bnds ser 1979 due 11/01/2009	B+	BBB-	1
REGULATED T&D	Central Illinois Public Service (Obligor) Illinois Fin Auth (Issuer)	US$25 mil 5.7% poll cntl rev rfdg bnds 1993 ser C-2 due 08/15/2026	B+	BBB-	1
REGULATED T&D	Central Illinois Public Service (Obligor) Illinois Fin Auth (Issuer)	US$17.5 mil Illinois Dev Fin Agy poll cntl rfdg bnds (Central Illinois Pub Svc Co Proj) ser 1993B-1 due 06/01/2028	B+	BBB-	1
REGULATED T&D	Central Illinois Public Service (Obligor) Illinois Fin Auth (Issuer)	US$51.1 mil Illinois Dev Fin Agy poll cntl rev rfdg bnds (AmerenCIPS Proj) ser 2000A due 03/01/2014	B+	BBB-	1
REGULATED T&D	Central Illinois Public Service (Obligor) Illinois Fin Auth (Issuer)	US$35 mil Illinois Dev Fin Agy poll cntl rfdg bnds (Central Illinois Pub Svc Co Proj) ser 1993 C-1 due 08/15/2026	B+	BBB-	1
REGULATED T&D	Commonwealth Edison (Obligor) Pekin (Issuer)	US$15 mil 6.875% poll cntl rev bnds ser 1979 due 01/15/2009	B+	BBB-	1
REGULATED T&D	Star Gas Partners L.P.	US$200 mil 10.25% sr nts due 02/15/2013	CCC	CCC	6
REGULATED TRANSMISSION/TRANSPORT	Aventine Renewable Energy Holdings Inc.	US$300 mil 10% sr nts due 04/01/2017	B-	B+	4
REGULATED TRANSMISSION/TRANSPORT	Colorado Interstate Gas Co.	US$100 mil 6.85% nts due 06/15/2037	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	Colorado Interstate Gas Co.	US$200 mil 5.95% sr nts due 03/15/2015	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	Colorado Interstate Gas Co.	US$400 mil 6.8% sr nts due 11/15/2015	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	El Paso Natural Gas Co.	US$260 mil 8.625% deb due 01/15/2022	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	El Paso Natural Gas Co.	US$200 mil 7.5% deb due 11/15/2026	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	El Paso Natural Gas Co.	US$300 mil 8.375% sr unsecd bnds due 06/15/2032	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	El Paso Natural Gas Co.	US$355 mil 7.625% sr nts due 08/01/2010	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	El Paso Natural Gas Co.	US$355 mil 5.95% sr nts due 04/15/2017	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	El Paso Tennessee Pipeline Co.	US$250 mil 10% deb due 03/15/2008	BB-	BB-	5
REGULATED TRANSMISSION/TRANSPORT	El Paso Tennessee Pipeline Co.	US$150 mil 9% deb due 11/15/2012	BB-	BB-	5
REGULATED TRANSMISSION/TRANSPORT	El Paso Tennessee Pipeline Co.	US$300 mil 7.25% deb due 12/15/2025	BB-	BB-	5
REGULATED TRANSMISSION/TRANSPORT	MarkWest Energy Partners LP	US$275 mil 8.5% sr nts due 07/15/2016	B	B	5
REGULATED TRANSMISSION/TRANSPORT	Southern Natural Gas Co.	US$100 mil 6.7% nts due 10/01/2007	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	Southern Natural Gas Co.	US$100 mil 6.125% nts due 09/15/2008	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	Southern Natural Gas Co.	US$300 mil 7.35% nts due 02/15/2031	BB	BB	3

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REGULATED TRANSMISSION/TRANSPORT	Southern Natural Gas Co.	US$300 mil 8% sr unsecd nts due 03/01/2032	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	Southern Natural Gas Co.	US$400 mil 8.875% sr nts due 03/15/2010	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	Southern Natural Gas Co.	US$500 mil 5.9% sr nts due 04/01/2017	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	Tennessee Gas Pipeline Co.	US$85.8 mil 6% deb due 12/15/2011	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	Tennessee Gas Pipeline Co.	US$300 mil 7.5% deb due 04/01/2017	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	Tennessee Gas Pipeline Co.	US$300 mil 7.625% deb due 04/01/2037	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	Tennessee Gas Pipeline Co.	US$300 mil 7% deb due 03/15/2027	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	Tennessee Gas Pipeline Co.	US$400 mil 7% deb due 10/15/2028	BB	BB	3
REGULATED TRANSMISSION/TRANSPORT	Tennessee Gas Pipeline Co.	US$240 mil 8.375% sr unsecd bnds due 06/15/2032	BB	BB	3
RESTAURANTS/RETAILING	Albertson's Inc.	US$225 mil 8.7% bnds due 05/01/2030	B	B+	5
RESTAURANTS/RETAILING	Albertson's Inc.	US$200 mil 7.75% deb due 06/15/2026	B	B+	5
RESTAURANTS/RETAILING	Albertson's Inc.	US$650 mil 7.45% sr deb due 08/01/2029	B	B+	5
RESTAURANTS/RETAILING	Albertson's Inc.	US$400 mil 8% deb due 05/01/2031	B	B+	5
RESTAURANTS/RETAILING	Albertson's Inc.	US$60 mil 6.77% med-term nts ser B due 07/21/2009	B	B+	5
RESTAURANTS/RETAILING	Albertson's Inc.	US$30 mil 6.56% med-term nts ser B due 07/26/2027	B	B+	5
RESTAURANTS/RETAILING	Albertson's Inc.	US$43.5 mil 6.57% med-term nts ser C due 02/23/2028	B	B+	5
RESTAURANTS/RETAILING	Albertson's Inc.	US$50 mil 6.1% med-term nts ser C due 04/10/2028	B	B+	5
RESTAURANTS/RETAILING	Albertson's Inc.	US$150 mil 6.625% med-term nts ser C due 06/01/2028	B	B+	5
RESTAURANTS/RETAILING	Albertson's Inc.	US$350 mil 6.95% sr nts due 08/01/2009	B	B+	5
RESTAURANTS/RETAILING	Albertson's Inc.	US$275 mil 8.35% nts due 05/01/2010	B	B+	5
RESTAURANTS/RETAILING	Albertson's Inc.	US$700 mil 7.5% sr unsecd nts due 02/15/2011	B	B+	5
RESTAURANTS/RETAILING	Albertson's Inc.	US$200 mil 7.25% nts due 05/01/2013	B	B+	5
RESTAURANTS/RETAILING	Alimentation Couche-Tard Inc.	US$350 mil 7.5% sr sub nts due 12/15/2013	B+	B+	6
RESTAURANTS/RETAILING	American & Foreign Power Inc.	US$42.2 mil 5% deb due 03/01/2030	BB-	BB-	4
RESTAURANTS/RETAILING	American Stores Co.	US$350 mil 8% deb due 06/01/2026	B	B+	5
RESTAURANTS/RETAILING	American Stores Co.	US$100 mil 7.9% deb due 05/01/2017	B	B+	5
RESTAURANTS/RETAILING	American Stores Co.	US$200 mil 7.5% deb due 05/01/2037	B	B+	5
RESTAURANTS/RETAILING	American Stores Co.	US$45 mil 6.5% med-term nts ser B due 03/20/2008	B	B+	5

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)

RESTAURANTS/RETAILING	American Stores Co.	US$100 mil 7.1% med-term nts ser B due 03/20/2028	B	B+	5
RESTAURANTS/RETAILING	Blockbuster Inc.	US$300 mil 9% sr sub nts due 09/01/2012	CCC	CCC	6
RESTAURANTS/RETAILING	Bon-Ton Department Stores (The)	US$510 mil 10.25% sr unsecd nts due 03/15/2014	CCC+	CCC+	6
RESTAURANTS/RETAILING	Brown Shoe Co. Inc.	US$150 mil 8.75% sr nts due 05/01/2012	BB-	BB-	5
RESTAURANTS/RETAILING	Burlington Coat Factory Investment Holdings Inc.	US$99.309 mil step up sr disc nts due 10/15/2014	CCC+	CCC+	6
RESTAURANTS/RETAILING	Burlington Coat Factory Warehouse Corp.	US$305 mil 11.125% sr nts due 04/15/2014	CCC+	CCC+	6
RESTAURANTS/RETAILING	Carrols Corp.	US$180 mil 9% sr sub nts due 01/15/2013	B-	B	5
RESTAURANTS/RETAILING	Charming Shoppes Inc.	US$275 mil 1.125% sr nts Convertible due 05/01/2014	BB-	B+	5
RESTAURANTS/RETAILING	Claire's Stores Inc.	US$350 mil var rate sr PIK toggle nts due 06/01/2015	CCC+	B-	5
RESTAURANTS/RETAILING	Claire's Stores Inc.	US$250 mil 9.25% sr nts due 06/01/2015	CCC+	B-	5
RESTAURANTS/RETAILING	Claire's Stores Inc.	US$335 mil 10.5% sr sub nts due 06/01/2017	CCC+	CCC+	6
RESTAURANTS/RETAILING	Collective Brands Inc.	US$200 mil 8.25% sr sub nts due 08/01/2013	B-	B-	6
RESTAURANTS/RETAILING	Dave & Buster's Inc.	US$175 mil 11.25% sr nts due 03/15/2014	CCC+	CCC+	5
RESTAURANTS/RETAILING	Denny's Holdings Inc.	US$175 mil 10% sr nts due 10/01/2012	B-	B	5
RESTAURANTS/RETAILING	Dillard's Inc.	US$50 mil 9.5% deb due 09/01/2009	BB	BB	4
RESTAURANTS/RETAILING	Dillard's Inc.	US$100 mil 9.125% nts due 08/01/2011	BB	BB	4
RESTAURANTS/RETAILING	Dillard's Inc.	US$100 mil 7.85% nts due 10/01/2012	BB	BB	4
RESTAURANTS/RETAILING	Dillard's Inc.	US$100 mil 7.875% deb due 01/01/2023	BB	BB	4
RESTAURANTS/RETAILING	Dillard's Inc.	US$100 mil 7.75% deb due 07/15/2026	BB	BB	4
RESTAURANTS/RETAILING	Dillard's Inc.	US$100 mil 7.75% nts due 05/15/2027	BB	BB	4
RESTAURANTS/RETAILING	Dillard's Inc.	US$100 mil 6.625% nts due 01/15/2018	BB	BB	4
RESTAURANTS/RETAILING	Dillard's Inc.	US$100 mil 6.3% nts due 02/15/2008	BB	BB	4
RESTAURANTS/RETAILING	Dillard's Inc.	US$100 mil 6.69% nts due 08/01/2007	BB	BB	4
RESTAURANTS/RETAILING	Dillard's Inc.	US$200 mil 7.13% deb due 08/01/2018	BB	BB	4
RESTAURANTS/RETAILING	Dillard's Inc.	US$100 mil 6.625% nts due 11/15/2008	BB	BB	4
RESTAURANTS/RETAILING	Dillard's Inc.	US$150 mil 7% nts due 12/01/2028	BB	BB	4
RESTAURANTS/RETAILING	Dollar General Corp.	US$200 mil 8.625% sr nts due 06/15/2010	CCC+	CCC+	6
RESTAURANTS/RETAILING	Dollar General Corp.	US$1.175 bil 10.625% unsecd PIK toggle nts due 07/15/2015	CCC+	CCC+	6

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
RESTAURANTS/RETAILING	Dollar General Corp.	US$725 mil var rate sr sub nts due 07/15/2017	CCC+	CCC+	6
RESTAURANTS/RETAILING	Dollarama Group LP	US$200 mil step up sr deferred interest nts due 08/15/2012	B-	B-	6
RESTAURANTS/RETAILING	Dollarama Group LP	US$200 mil 8.875% sr sub nts due 08/15/2012	B-	B-	6
RESTAURANTS/RETAILING	Duane Reade Inc.	US$195 mil 9.75% sr sub nts due 08/01/2011	CC	CC	6
RESTAURANTS/RETAILING	El Pollo Loco Inc.	US$125 mil 11.75% sr nts due 11/15/2013	CCC	CCC+	5
RESTAURANTS/RETAILING	Eye Care Centers of America Inc.	US$150 mil 10.75% sr sub nts due 02/15/2015	CCC+	CCC+	6
RESTAURANTS/RETAILING	Finlay Fine Jewelry Corp.	US$200 mil 8.375% sr nts due 06/01/2012	CCC+	CCC+	5
RESTAURANTS/RETAILING	Foot Locker Inc.	US$200 mil 8.5% debs due 01/15/2022	BB	BB	4
RESTAURANTS/RETAILING	FTD Inc.	US$175 mil 7.75% sr sub nts due 02/15/2014	B-	B-	6
RESTAURANTS/RETAILING	GameStop Corp.	US$475 mil 8% nts due 10/01/2012	BB	BB	4
RESTAURANTS/RETAILING	Gap Inc. (The)	US$500 mil 8.8% sr unsecd nts due 12/15/2008	BB+	BB+	3
RESTAURANTS/RETAILING	General Nutrition Centers Inc.	US$300 mil fltg rate sr PIK Toggle nts due 03/15/2014	CCC	CCC	6
RESTAURANTS/RETAILING	General Nutrition Centers Inc.	US$110 mil 10.75% sr sub nts due 03/15/2015	CCC	CCC	6
RESTAURANTS/RETAILING	Genesco Inc.	US$ 86.25 mil 4.125% conv sub deb due 06/15/2023	B-	B-	6
RESTAURANTS/RETAILING	Great Atlantic & Pacific Tea Co. Inc. (The)	US$230 mil 6.75% sr nts Convertible due 2012	B-	CCC+	6
RESTAURANTS/RETAILING	Great Atlantic & Pacific Tea Co. Inc. (The)	US$150 mil 5.125% sr nts Convertible due 2011	B-	CCC+	6
RESTAURANTS/RETAILING	Great Atlantic & Pacific Tea Co. Inc. (The)	US$200 mil 9.375% sr nts due 08/01/2039	B-	CCC+	6
RESTAURANTS/RETAILING	Harry & David Operations Corp.	US$175 mil 9% sr nts due 03/01/2013	B-	B-	5
RESTAURANTS/RETAILING	Harry & David Operations Corp.	US$70 mil sr nts due 03/01/2012	B-	B-	5
RESTAURANTS/RETAILING	Ingles Markets Inc.	US$250 mil sub nts due 12/01/2011	B	B+	5
RESTAURANTS/RETAILING	Ingles Markets Inc.	US$100 mil 8.875% sr sub nts due 12/01/2011	B	B+	5
RESTAURANTS/RETAILING	Jo-Ann Stores Inc.	US$100 mil sr sub nts due 03/01/2012	CCC	CCC	6
RESTAURANTS/RETAILING	Keystone Automotive Operations Inc.	US$ 175 mil 9.75% sr sub nts due 11/01/2013	CCC+	CCC+	6
RESTAURANTS/RETAILING	Leslie's Poolmart Inc.	US$170 mil 7.75% sr nts due 02/01/2013	B-	B-	5
RESTAURANTS/RETAILING	Michaels Stores Inc.	US$750 mil 10% sr nts due 11/01/2014	CCC	CCC	6
RESTAURANTS/RETAILING	Michaels Stores Inc.	US$400 mil 11.375% sr sub nts due 11/01/2016	CCC	CCC	6
RESTAURANTS/RETAILING	Michaels Stores Inc.	US$250 mil 13% sub disc nts ($468.449 mil accreted value at maturity) due 11/01/2016	CCC	CCC	6

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RESTAURANTS/RETAILING	Nash Finch Co.	US$322 mil step down sr sub nts Convertible due 03/15/2035	B-	B-	6
RESTAURANTS/RETAILING	NBC Acquisition Corp.	US$50 mil 11% sr disc nts due 03/15/2013	CCC	CCC	6
RESTAURANTS/RETAILING	Nebraska Book Co. Inc.	US$175 mil 8.625% sr sub nts due 03/15/2012	CCC	CCC	6
RESTAURANTS/RETAILING	Neiman Marcus Group Inc. (The)	US$500 mil 10.375% sr sub nts due 10/15/2015	B	B	6
RESTAURANTS/RETAILING	Neiman Marcus Group Inc. (The)	US$700 mil 9% sr nts due 10/15/2015	B	B+	5
RESTAURANTS/RETAILING	NPC International Inc.	US$175 mil 9.5% sub nts due 05/01/2014	B-	B-	6
RESTAURANTS/RETAILING	O'Charley's Inc.	US$125 mil 9% nts due 11/01/2013	B	B	6
RESTAURANTS/RETAILING	OfficeMax Inc.	US$150 mil 9.45% deb due 11/01/2009	BB-	BB-	4
RESTAURANTS/RETAILING	OfficeMax Inc.	US$125 mil 7.35% deb due 02/01/2016	BB-	BB-	4
RESTAURANTS/RETAILING	OfficeMax Inc.	US$172.5 mil 7.5% adjustable conversion rate equity security (ACES) units	BB-	BB-	4
RESTAURANTS/RETAILING	OfficeMax Inc.	US$150 mil 7.5% sr unsecd nts due 02/01/2008	BB-	BB-	4
RESTAURANTS/RETAILING	OfficeMax Inc.	US$300 mil 6.5% sr nts due 11/01/2010	BB-	BB-	4
RESTAURANTS/RETAILING	OfficeMax Inc.	US$50 mil 7.45% med-term nts ser A due 08/10/2011	BB-	BB-	4
RESTAURANTS/RETAILING	OfficeMax Inc.	US$52 mil 7.9% med-term nts ser A due 06/15/2012	BB-	BB-	4
RESTAURANTS/RETAILING	OfficeMax Inc.	US$200 mil 7% sr nts due 11/01/2013	BB+	BB+	1
RESTAURANTS/RETAILING	OSI Restaurant Partners Inc.	US$550 mil 9.625% nts due 05/15/2015	CCC+	CCC+	6
RESTAURANTS/RETAILING	Pantry Inc. (The)	US$250 mil 7.75% sr sub nts due 02/15/2014	B-	B-	6
RESTAURANTS/RETAILING	Pantry Inc. (The)	US$150 mil 3% sr sub nts Convertible due 2012	B-	B-	6
RESTAURANTS/RETAILING	Pep Boys-Manny, Moe & Jack	US$200 mil 7.5% sr sub nts due 12/15/2014	CCC	B-	3
RESTAURANTS/RETAILING	Perkins & Marie Callender's Inc.	US$190 mil 10% sr nts due 10/01/2013	CCC-	CCC	5
RESTAURANTS/RETAILING	RadioShack Corp.	US$350 mil 7.375% nts due 05/15/2011	BB	BB	4
RESTAURANTS/RETAILING	RadioShack Corp.	US$300 mil revolv cred fac bank ln due 06/16/2009	BB	BB	4
RESTAURANTS/RETAILING	Rent-A-Center Inc.	US$300 mil 7.5% sr sub nts due 12/31/2010	B+	B+	6
RESTAURANTS/RETAILING	Rite Aid Corp.	US$200 mil 6.875% deb due 08/15/2013	CCC+	CCC+	6
RESTAURANTS/RETAILING	Rite Aid Corp.	US$300 mil 7.7% deb due 02/15/2027	CCC+	CCC+	6
RESTAURANTS/RETAILING	Rite Aid Corp.	US$200 mil dealer remarketable secs due 10/01/2013	CCC+	CCC+	6
RESTAURANTS/RETAILING	Rite Aid Corp.	US$150 mil 6.125% sr nts due 12/15/2008	CCC+	CCC+	6

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RESTAURANTS/RETAILING	Rite Aid Corp.	US$150 mil 6.875% deb due 12/15/2028	CCC+	CCC+	6
RESTAURANTS/RETAILING	Rite Aid Corp.	US$150 mil 9.25% sr nts due 06/15/2013	CCC+	CCC+	6
RESTAURANTS/RETAILING	Rite Aid Corp.	US$500 mil 8.625% nts due 03/01/2015	CCC+	CCC+	6
RESTAURANTS/RETAILING	Rite Aid Corp.	US$810 mil 9.5% sr nts due 06/15/2017	CCC+	CCC+	6
RESTAURANTS/RETAILING	Rite Aid Corp.	US$410 mil 9.375% sr nts due 12/15/2015	CCC+	CCC+	6
RESTAURANTS/RETAILING	Sally Holdings LLC	US$430 mil sr unsecd nts due 11/15/2014	CCC+	B-	5
RESTAURANTS/RETAILING	Sally Holdings LLC	US$280 mil sr sub nts due 11/15/2016	CCC+	CCC+	6
RESTAURANTS/RETAILING	Sbarro Inc.	US$150 mil 10.375% sr nts due 02/01/2015	CCC	CCC	6
RESTAURANTS/RETAILING	Sears DC Corp.	US$10 mil 9.2% med-term nts due 02/27/2012	BB	BB	3
RESTAURANTS/RETAILING	Sears DC Corp.	US$10 mil 9.14% med-term nts ser II due 03/13/2012	BB	BB	3
RESTAURANTS/RETAILING	Sears DC Corp.	US$7 mil 9.07% med-term nts ser II due 03/16/2012	BB	BB	3
RESTAURANTS/RETAILING	Sears DC Corp.	US$4.3 mil 9.14% med-term nts ser III due 03/19/2012	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$250 mil 7.5% nts due 10/15/2027	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$300 mil 6.875% nts due 10/15/2017	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$150 mil 6.7% nts due 09/18/2007	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$200 mil 6.75% sr nts due 01/15/2028	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$300 mil 6.5% nts due 12/01/2028	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$750 mil 6.25% nts due 05/01/2009	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$1 bil 7% sr unsecd nts due 02/01/2011	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$750 mil 6.75% global nts due 08/15/2011	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$600 mil 6.7% nts due 04/15/2012	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$1 bil 7% nts due 06/01/2032	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$250 mil 7% nts due 07/15/2042	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$250 mil 7.4% sr unsecd nts due 02/01/2043	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$46.362 mil 6.65% InterNotes due 02/15/2008	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$24 mil 6.25% InterNotes due 02/15/2008	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$27.3 mil 6.1% InterNotes due 02/15/2008	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$39.9 mil 6.2% InterNotes due 02/15/2008	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$43.6 mil 6.15% InterNotes due 01/15/2008	BB	BB	3

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RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$56.3 mil 6.75% InterNotes due 01/15/2008	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$36.38 mil 7.5% InterNotes due 01/15/2013	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$24.3 mil 6.2% InterNotes due 03/15/2008	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$13.8 mil 7.15% InterNotes due 03/15/2013	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$15.595 mil 6% InterNotes due 03/15/2008	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$8.358 mil 7.05% InterNotes due 03/15/2013	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$21.498 mil 7.5% InterNotes due 01/15/2013	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$17.834 mil 7% InterNotes due 01/15/2008	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$19.777 mil 6.9% InterNotes due 01/15/2008	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$10.459 mil 7.4% InterNotes due 01/15/2010	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$19.068 mil 7.4% InterNotes due 01/15/2010	BB	BB	3
RESTAURANTS/RETAILING	Sears Roebuck Acceptance Corp.	US$14.229 mil 7.5% InterNotes due 01/15/2013	BB	BB	3
RESTAURANTS/RETAILING	Sotheby's	US$100 mil 6.875% nts due 02/01/2009	BB+	BB+	4
RESTAURANTS/RETAILING	Stater Bros. Holdings Inc.	US$525 mil 8.125% sr nts due 06/15/2012	B+	B+	4
RESTAURANTS/RETAILING	Stater Bros. Holdings Inc.	US$285 mil 7.75% sr nts due 04/15/2015	B+	B+	4
RESTAURANTS/RETAILING	SuperValu Inc.	US$350 mil 7.875% sr nts due 08/01/2009	B	B+	5
RESTAURANTS/RETAILING	SuperValu Inc.	US$185 mil zero cpn LYONs nts due 11/02/2031	B	B+	5
RESTAURANTS/RETAILING	SuperValu Inc.	US$300 mil 7.5% nts due 05/15/2012	B	B+	5
RESTAURANTS/RETAILING	SuperValu Inc.	US$500 mil 7.5% sr nts due 11/15/2014	B	B+	5
RESTAURANTS/RETAILING	Susser Holdings LLC	US$320 mil sr nts due 2013	B	B+	4
RESTAURANTS/RETAILING	Toys "R" Us Delaware Inc.	US$200 mil 8.75% deb due 09/01/2021	CCC+	B	3
RESTAURANTS/RETAILING	Toys "R" Us Inc.	US$500 mil 7.625% sr nts due 08/01/2011	CCC+	CCC+	6
RESTAURANTS/RETAILING	Toys "R" Us Inc.	US$400 mil 7.875% sr nts due 04/15/2013	CCC+	CCC+	6
RESTAURANTS/RETAILING	Toys "R" Us Inc.	US$400 mil 7.375% nts due 10/15/2018	CCC+	CCC+	6
RESTAURANTS/RETAILING	U.S. Propco	$1.3 bil credit facility	B	B+	2
TELECOMMUNICATIONS	ALLTEL Communications Inc.	US$1 bil PIK toggle nts due 2017	B-	B-	6
TELECOMMUNICATIONS	ALLTEL Corp.	US$200 mil 6.5% deb due 11/01/2013	B-	B-	6
TELECOMMUNICATIONS	ALLTEL Corp.	US$300 mil 7% deb due 03/15/2016	B-	B-	6

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
TELECOMMUNICATIONS	ALLTEL Corp.	US$300 mil 6.8% deb due 05/01/2029	B-	B-	6
TELECOMMUNICATIONS	ALLTEL Corp.	US$700 mil 7.875% sr nts due 07/01/2032	B-	B-	6
TELECOMMUNICATIONS	ALLTEL Corp.	US$800 mil 7% sr nts due 07/01/2012	B-	B-	6
TELECOMMUNICATIONS	ALLTEL Georgia Communications Corp. (changed to Windstream Georgia Communications Corp.)	US$200 mil 6.5% deb due 11/15/2013	BBB	BBB	1
TELECOMMUNICATIONS	American Tower Corp.	US$ 450 mil 5% nts Convertible due 02/15/2010	BB+	BB+	3
TELECOMMUNICATIONS	American Tower Corp.	US$175 mil 3.25% nts Convertible due 08/01/2010	BB+	BB+	3
TELECOMMUNICATIONS	American Tower Corp.	US$225 mil 7.5% sr nts due 05/01/2012	BB+	BB+	3
TELECOMMUNICATIONS	American Tower Corp.	US$500 mil 7.125% sr nts due 10/15/2012	BB+	BB+	3
TELECOMMUNICATIONS	American Tower Corp.	US$345 mil 3% nts Convertible due 08/15/2012	BB+	BB+	3
TELECOMMUNICATIONS	American Tower Corp.	US$1.25 bil revolver bank ln due 2015	BB+	BB+	3
TELECOMMUNICATIONS	American Tower Corp.	US$500 mil 7% sr nts due 10/15/2017	BB+	BB+	3
TELECOMMUNICATIONS	Atlantic Broadband Finance LLC	US$150 mil 9.375% sr sub nts due 01/15/2014	CCC+	CCC+	6
TELECOMMUNICATIONS	Block Communications Inc.	US$150 mil 8.25% sr nts due 12/15/2015	B-	B	5
TELECOMMUNICATIONS	Cablevision Systems Corp.	US$1 bil 8% sr nts due 04/15/2012	B+	B+	6
TELECOMMUNICATIONS	Cablevision Systems Corp.	US$500 mil fltg rate sr nts due 04/01/2009	B+	B+	6
TELECOMMUNICATIONS	CCH I Holdings Capital Corp.	US$150.7 mil 11.125% sr accreting nts due 01/15/2014	CCC	CCC	6
TELECOMMUNICATIONS	CCH I Holdings LLC	US$470.9 mil 9.92% sr accreting nts due 04/01/2014	CCC	CCC	6
TELECOMMUNICATIONS	CCH I Holdings LLC	US$299.1 mil 10% sr accreting nts due 05/15/2014	CCC	CCC	6
TELECOMMUNICATIONS	CCH I Holdings LLC	US$814.6 mil 11.75% sr accreting nts due 05/15/2014	CCC	CCC	6
TELECOMMUNICATIONS	CCH I Holdings LLC	US$580.7 mil 13.5% sr accreting nts due 01/15/2014	CCC	CCC	6
TELECOMMUNICATIONS	CCH I Holdings LLC	US$216.7 mil 12.125% sr accreting nts due 01/15/2015	CCC	CCC	6
TELECOMMUNICATIONS	CCH II LLC	US$1.6 bil 10.25% nts due 09/15/2010	CCC	CCC	6
TELECOMMUNICATIONS	CCH II LLC	US$450 mil 10.25% sr nts ser B due 09/15/2013	CCC	CCC	6
TELECOMMUNICATIONS	CCH II LLC, CCH I Capital Corp.	US$450 mil 10.25% nts due 09/15/2010	CCC	CCC	6
TELECOMMUNICATIONS	CCO Holdings Capital Corp.	US$800 mil 8.75% sr nts due 11/15/2013	CCC	CCC	6
TELECOMMUNICATIONS	Centennial Communications Corp.	US$500 mil 10.125% sr nts due 06/15/2013	CCC+	B	3
TELECOMMUNICATIONS	Centennial Communications Corp.	US$325 mil 8.13% sr nts due 02/01/2014	CCC+	B	3

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TELECOMMUNICATIONS	Centennial Communications Corp.	US$200 mil 10% sr nts due 01/01/2013	CCC+	CCC+	6
TELECOMMUNICATIONS	Centennial Communications Corp.	US$350 mil fltg rate sr nts due 01/01/2013	CCC+	CCC+	6
TELECOMMUNICATIONS	Charter Communications Holdings LLC	US$750 mil 9.92% (gross proceeds) sr disc nts due 04/01/2011	CCC	CCC	6
TELECOMMUNICATIONS	Charter Communications Holdings LLC	US$675 mil 10% sr nts due 04/01/2009	CCC	CCC	6
TELECOMMUNICATIONS	Charter Communications Holdings LLC	US$325 mil 10.25% sr nts due 01/15/2010	CCC	CCC	6
TELECOMMUNICATIONS	Charter Communications Holdings LLC	US$532 mil 11.75% sr disc nts due 01/15/2010	CCC	CCC	6
TELECOMMUNICATIONS	Charter Communications Holdings LLC	US$900 mil 10.75% sr nts due 10/01/2009	CCC	CCC	6
TELECOMMUNICATIONS	Charter Communications Holdings LLC	US$500 mil 11.125% sr nts due 01/15/2011	CCC	CCC	6
TELECOMMUNICATIONS	Charter Communications Holdings LLC	US$675 mil 13.5% sr dis nts due 01/15/2011	CCC	CCC	6
TELECOMMUNICATIONS	Charter Communications Holdings LLC, Charter Communications Holdings Capital Corp.	US$350 mil 9.625% sr nts due 11/15/2009	CCC	CCC	6
TELECOMMUNICATIONS	Charter Communications Holdings LLC, Charter Communications Holdings Capital Corp.	US$575 mil 10% sr nts due 05/15/2011	CCC	CCC	6
TELECOMMUNICATIONS	Charter Communications Holdings LLC, Charter Communications Holdings Capital Corp.	US$1.018 bil 11.75% sr disc nts due 05/15/2011	CCC	CCC	6
TELECOMMUNICATIONS	Charter Communications Holdings LLC, Charter Communications Holdings Capital Corp.	US$200 mil 12.125% sr nts due 01/15/2012	CCC	CCC	6
TELECOMMUNICATIONS	Charter Communications Inc.	US$862.5 mil 5.875% sr nts Convertible due 11/16/2009	CCC	CCC	6
TELECOMMUNICATIONS	Charter Communications Inc.	US$479 mil 5.875% sr nts Convertible due 2027	CCC	CCC	6
TELECOMMUNICATIONS	Cincinnati Bell Inc.	US$640 mil 8.375% sr sub nts due 01/15/2014	B-	B-	6
TELECOMMUNICATIONS	Cincinnati Bell Inc.	US$500 mil 7.25% sr nts due 07/15/2013	B-	B+	3
TELECOMMUNICATIONS	Cincinnati Bell Inc.	US$250 mil 7% sr nts due 02/15/2015	B-	B+	3
TELECOMMUNICATIONS	Cincinnati Bell Telephone Co.	US$120 mil 7.2% med-term nts due 11/29/2023	BB	BB	1
TELECOMMUNICATIONS	Cincinnati Bell Telephone Co.	US$150 mil 6.3% gtd deb due 12/01/2028	BB	BB	1
TELECOMMUNICATIONS	Citizens Communications Co.	US$100 mil 7.68% deb due 10/01/2034	BB+	BB+	3
TELECOMMUNICATIONS	Citizens Communications Co.	US$125 mil 7.45% deb due 07/01/2035	BB+	BB+	3
TELECOMMUNICATIONS	Citizens Communications Co.	US$150 mil 7% deb due 11/01/2025	BB+	BB+	3
TELECOMMUNICATIONS	Citizens Communications Co.	US$100 mil 6.8% deb due 08/15/2026	BB+	BB+	3

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
TELECOMMUNICATIONS	Citizens Communications Co.	US$200 mil 7.05% deb due 10/01/2046	BB+	BB+	3
TELECOMMUNICATIONS	Citizens Communications Co.	US$1.05 bil 9.25% sr nts due 05/15/2011	BB+	BB+	3
TELECOMMUNICATIONS	Citizens Communications Co.	US$700 mil 9% sr nts due 08/15/2031	BB+	BB+	3
TELECOMMUNICATIONS	Citizens Communications Co.	US$700 mil 6.25% sr nts due 01/15/2013	BB+	BB+	3
TELECOMMUNICATIONS	Citizens Communications Co.	US$400 mil 7.875% sr nts due 01/15/2027	BB+	BB+	3
TELECOMMUNICATIONS	Citizens Communications Co.	US$300 mil 6.625% sr nts due 03/15/2015	BB+	BB+	3
TELECOMMUNICATIONS	Citizens Communications Co.	US$450 mil 7.125% sr nts due 03/15/2019	BB+	BB+	3
TELECOMMUNICATIONS	Cricket Communications Inc.	US$1.035 bil 9.375% sr unsecd nts due 11/01/2014	CCC	B-	4
TELECOMMUNICATIONS	CSC Holdings Inc.	US$400 mil 8.125% sr deb due 08/15/2009	B+	BB	3
TELECOMMUNICATIONS	CSC Holdings Inc.	US$300 mil 7.875% sr deb due 2018	B+	BB	3
TELECOMMUNICATIONS	CSC Holdings Inc.	US$500 mil 7.25% sr nts due 2008	B+	BB	3
TELECOMMUNICATIONS	CSC Holdings Inc.	US$500 mil 7.625% sr deb due 2018	B+	BB	3
TELECOMMUNICATIONS	CSC Holdings Inc.	US$500 mil 8.125% sr nts due 2009	B+	BB	3
TELECOMMUNICATIONS	CSC Holdings Inc.	US$1 bil 7.625% sr nts due 04/01/2011	B+	BB	3
TELECOMMUNICATIONS	CSC Holdings Inc.	US$500 mil 6.75% sr nts due 04/15/2012	B+	BB	3
TELECOMMUNICATIONS	DIRECTV Holdings LLC	US$1.4 bil 8.375% sr unsecd nts due 2013	BB-	BB-	5
TELECOMMUNICATIONS	DIRECTV Holdings LLC	US$1 bil 6.375% sr nts due 06/15/2015	BB-	BB-	5
TELECOMMUNICATIONS	Echostar DBS Corp.	US$1 bil 5.75% sr nts due 10/01/2008	BB-	BB-	4
TELECOMMUNICATIONS	Echostar DBS Corp.	US$1 bil 6.375% sr nts due 10/01/2011	BB-	BB-	4
TELECOMMUNICATIONS	Echostar DBS Corp.	US$1 bil 6.625% sr nts due 10/01/2014	BB-	BB-	4
TELECOMMUNICATIONS	Echostar DBS Corp.	US$1.5 bil 7.125% sr nts due 02/01/2016	BB-	BB-	4
TELECOMMUNICATIONS	Echostar DBS Corp.	US$500 mil 7% sr nts due 10/01/2013	BB-	BB-	4
TELECOMMUNICATIONS	Equinix Inc.	US$396 mil 3% sub nts convertible due 10/15/2014	CCC+	CCC+	6
TELECOMMUNICATIONS	Equinix Inc.	US$250 mil 2.5% sr nts convertible due 4/12/2012	CCC+	CCC+	6
TELECOMMUNICATIONS	FairPoint Communications Inc.	US$540 mil nts	B+	B+	6
TELECOMMUNICATIONS	GCI Inc.	US$320 mil 7.25% sr nts due 02/15/2014	B	B+	5
TELECOMMUNICATIONS	Hawaiian Telcom Communications Inc.	US$200 mil 9.75% sr nts due 05/01/2013	CCC	CCC	6
TELECOMMUNICATIONS	Hawaiian Telcom Communications Inc.	US$150 mil fltg rate nts due 05/01/2013	CCC	CCC	6
TELECOMMUNICATIONS	Hawaiian Telcom Communications Inc.	US$150 mil 12.5% sr sub nts due 05/01/2015	CCC	CCC	6

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Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
TELECOMMUNICATIONS	Hughes Network Systems LLC	US$450 mil 9.5% sr nts due 2014	B-	B	4
TELECOMMUNICATIONS	Hughes Network Systems LLC	US$115 mil fltg rate term loan bank ln due 2014	B-	B	4
TELECOMMUNICATIONS	Integra Telecom Inc.	US$215 mil PIK term bank ln due 2014	CCC	CCC	6
TELECOMMUNICATIONS	Intelsat Corp.	US$1.01 bil 9% sr nts due 08/15/2014	CCC+	BB-	1
TELECOMMUNICATIONS	Intelsat Corp.	US$575 mil 9% sr nts due 06/15/2016	CCC+	BB-	1
TELECOMMUNICATIONS	Intelsat Intermediate Holding Company Ltd.	US$478.4 mil step up sr disc nts due 02/01/2015	CCC+	B-	5
TELECOMMUNICATIONS	Intelsat Jackson Holdings Ltd.	US$750 mil 9.25% gtd sr nts due 06/15/2016	B-	BB-	1
TELECOMMUNICATIONS	Intelsat Jackson Holdings, Ltd.	US$1 bil sr unsecd term bank ln due 2014	B-	BB-	1
TELECOMMUNICATIONS	Intelsat Jackson Holdings, Ltd. (fka Bermuda)	US$1.33 bil 11.25% fixed rate sr nts due 06/15/2016	CCC+	CCC+	6
TELECOMMUNICATIONS	Intelsat Ltd.	US$600 mil 7.625% nts due 04/15/2012	CCC+	CCC+	6
TELECOMMUNICATIONS	Intelsat Ltd.	US$700 mil 6.5% sr nts due 11/01/2013	CCC+	CCC+	6
TELECOMMUNICATIONS	Intelsat Subsidiary Holding Co. Ltd.	US$875 mil 8.25% sr nts due 01/15/2013	B-	BB-	1
TELECOMMUNICATIONS	Intelsat Subsidiary Holding Co. Ltd.	US$675 mil 8.625% sr nts due 01/15/2015	B-	BB-	1
TELECOMMUNICATIONS	Level 3 Communications Inc.	US$800 mil 11% sr nts due 03/15/2008	CCC	CCC	6
TELECOMMUNICATIONS	Level 3 Communications Inc.	EUR500 mil 10.75% sr nts due 03/15/2008	CCC	CCC	6
TELECOMMUNICATIONS	Level 3 Communications Inc.	EUR300 mil 11.25% sr nts due 2010	CCC	CCC	6
TELECOMMUNICATIONS	Level 3 Communications Inc.	US$325 mil 2.875% conv sr nts due 07/15/2010	CCC	CCC	6
TELECOMMUNICATIONS	Level 3 Communications Inc.	US$345 mil 5.25% sr nts Convertible due 12/15/2011	CCC	CCC	6
TELECOMMUNICATIONS	Level 3 Communications Inc.	US$880 mil 10% sr nts Convertible due 05/01/2011	CCC	CCC	6
TELECOMMUNICATIONS	Level 3 Communications Inc.	US$1.23 bil 11.5% sr nts due 03/01/2010	CCC	CCC	6
TELECOMMUNICATIONS	Level 3 Communications Inc.	US$335 mil 3.5% sr nts Convertible due 06/15/2012	CCC	CCC	6
TELECOMMUNICATIONS	Level 3 Communications Inc.	US$823 mil 6% conv sub nts due 09/15/2009	CCC	CCC	6
TELECOMMUNICATIONS	Level 3 Communications Inc.	US$863 mil 6% conv sub nts due 03/15/2010	CCC	CCC	6
TELECOMMUNICATIONS	Level 3 Financing Inc.	US$500 mil 10.75% nts due 10/15/2011	CCC+	CCC+	5
TELECOMMUNICATIONS	Level 3 Financing Inc.	US$550 mil 12.25% sr nts due 03/15/2013	CCC+	CCC+	5
TELECOMMUNICATIONS	Level 3 Financing Inc.	US$150 mil fltg rate sr nts due 2011	CCC+	CCC+	5
TELECOMMUNICATIONS	Level 3 Financing Inc.	US$650 mil 9.25% sr nts due 11/01/2014	CCC+	CCC+	5
TELECOMMUNICATIONS	Level 3 Financing Inc.	US$300 mil fltg rate sr nts due 02/15/2015	CCC+	CCC+	5

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TELECOMMUNICATIONS	Level 3 Financing Inc.	US$700 mil 8.75% 8.75% sr. nts due 02/15/2017	CCC+	CCC+	5
TELECOMMUNICATIONS	Mediacom Broadband LLC	US$400 mil 8.5% sr nts due 10/15/2015	B-	B-	6
TELECOMMUNICATIONS	Mediacom Communications Corp., Mediacom LLC	US$ 125 mil 7.875% sr nts due 02/15/2011	B-	B-	6
TELECOMMUNICATIONS	Mediacom LLC	US$ 500 mil 9.5% sr nts due 01/15/2013	B-	B-	6
TELECOMMUNICATIONS	MetroPCS Wireless Inc.	US$1.4 bil 9.25% sr nts due 11/01/2014	CCC	B-	4
TELECOMMUNICATIONS	Nortel Networks Capital Corp.	US$150 mil 7.875% deb due 06/15/2026	CCC	CCC	6
TELECOMMUNICATIONS	Nortel Networks Corp.	US$575 mil 1.75% nts Convertible due 04/15/2012	B-	B-	4
TELECOMMUNICATIONS	Nortel Networks Corp.	US$575 mil 2.125% nts Convertible due 04/15/2014	B-	B-	4
TELECOMMUNICATIONS	Nortel Networks Corp.	US$1.8 bil 4.25% sr nts Convertible due 09/01/2008	B-	B-	4
TELECOMMUNICATIONS	Nortel Networks Ltd.	US$1 bil fltg rate sr nts due 07/15/2011	B-	B-	4
TELECOMMUNICATIONS	Nortel Networks Ltd.	US$550 mil 10.125% sr nts due 07/15/2013	B-	B-	4
TELECOMMUNICATIONS	Nortel Networks Ltd.	US$450 mil 10.75% sr nts due 07/15/2016	B-	B-	4
TELECOMMUNICATIONS	Nortel Networks Ltd.	US$200 mil 6.875% nts due 09/01/2023	CCC	CCC	6
TELECOMMUNICATIONS	PAETEC Holding Corp.	US$300 mil 9.5% sr nts due 07/15/2015	CCC+	CCC+	6
TELECOMMUNICATIONS	Quebecor Media Inc.	US$525 mil sr nts due 03/15/2016	B	B	6
TELECOMMUNICATIONS	Quebecor Media Inc.	US$750 mil sr nts consist of two tranches	B	B	6
TELECOMMUNICATIONS	Qwest Capital Funding Inc.	US$887 mil 6.875% deb due 07/15/2028	B+	B+	6
TELECOMMUNICATIONS	Qwest Capital Funding Inc.	US$272 mil 6.5% deb due 11/15/2018	B+	B+	6
TELECOMMUNICATIONS	Qwest Capital Funding Inc.	US$304 mil 6.375% nts due 07/15/2008	B+	B+	6
TELECOMMUNICATIONS	Qwest Capital Funding Inc.	US$745 mil 7.9% nts due 08/15/2010	B+	B+	6
TELECOMMUNICATIONS	Qwest Capital Funding Inc.	US$1.258 bil 7.25% nts due 02/15/2011	B+	B+	6
TELECOMMUNICATIONS	Qwest Capital Funding Inc.	US$748 mil 7.75% nts due 02/15/2031	B+	B+	6
TELECOMMUNICATIONS	Qwest Capital Funding Inc.	US$248 mil 7.625% nts due 08/03/2021	B+	B+	6
TELECOMMUNICATIONS	Qwest Capital Funding Inc.	US$938 mil 7% nts due 08/03/2009	B+	B+	6
TELECOMMUNICATIONS	Qwest Communications Corp.	US$500 mil 6.5% sr nts due 06/01/2017	BBB-	BBB-	1
TELECOMMUNICATIONS	Qwest Communications International Inc.	US$750 mil 7.5% sr nts due 11/01/2008	B+	B+	6
TELECOMMUNICATIONS	Qwest Communications International Inc.	US$300 mil 7.25% sr nts due 11/01/2008	B+	B+	6

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TELECOMMUNICATIONS	Qwest Communications International Inc.	US$522.61 mil 7.25% sr nts due 02/15/2011	B+	B+	6
TELECOMMUNICATIONS	Qwest Communications International Inc.	US$1.1 bil 7.5% sr nts due 02/15/2014	B+	B+	6
TELECOMMUNICATIONS	Qwest Communications International Inc.	US$750 mil fltg rate sr nts due 02/15/2009	B+	B+	6
TELECOMMUNICATIONS	Qwest Communications International Inc.	US$1.1 bil 3.5% sr nts Convertible due 11/15/2025	B+	B+	6
TELECOMMUNICATIONS	Qwest Corp.	US$55.15 mil 7.375% deb due 05/01/2030	BBB-	BBB-	1
TELECOMMUNICATIONS	Qwest Corp.	US$42.883 mil 7.75% deb due 05/01/2030	BBB-	BBB-	1
TELECOMMUNICATIONS	Qwest Corp.	US$484 mil 7.5% debs due 06/15/2023	BBB-	BBB-	1
TELECOMMUNICATIONS	Qwest Corp.	US$1 bil 6.875% debs due 09/15/2033	BBB-	BBB-	1
TELECOMMUNICATIONS	Qwest Corp.	US$250 mil 7.125% debs due 11/15/2043	BBB-	BBB-	1
TELECOMMUNICATIONS	Qwest Corp.	US$250 mil 7.25% deb due 10/15/2035	BBB-	BBB-	1
TELECOMMUNICATIONS	Qwest Corp.	US$250 mil 7.25% deb due 09/15/2025	BBB-	BBB-	1
TELECOMMUNICATIONS	Qwest Corp.	US$250 mil 7.2% deb due 11/10/2026	BBB-	BBB-	1
TELECOMMUNICATIONS	Qwest Corp.	US$320 mil 5.625% nts due 11/15/2008	BBB-	BBB-	1
TELECOMMUNICATIONS	Qwest Corp.	US$1.5 bil 8.875% nts due 03/15/2012	BBB-	BBB-	1
TELECOMMUNICATIONS	Qwest Corp.	US$500 mil term bank ln due 2010	BBB-	BBB-	1
TELECOMMUNICATIONS	Qwest Corp.	US$825 mil 7.875% nts due 09/01/2011	BBB-	BBB-	1
TELECOMMUNICATIONS	Qwest Corp.	US$400 mil 7.625% sr nts due 06/15/2015	BBB-	BBB-	1
TELECOMMUNICATIONS	Qwest Corp.	US$750 mil sr nts due 06/15/2013	BBB-	BBB-	1
TELECOMMUNICATIONS	Qwest Corp.	US$600 mil 7.5% nts due 10/01/2014	BBB-	BBB-	1
TELECOMMUNICATIONS	Rainbow National Services LLC	US$300 mil 8.75% sr nts due 09/01/2012	B+	BB	3
TELECOMMUNICATIONS	Rainbow National Services LLC	US$500 mil 10.375% sr sub nts due 09/01/2014	B+	BB	3
TELECOMMUNICATIONS	Shaw Communications Inc.	US$440 mil 8.25% sr unsec nts due 04/11/2010	BB+	BB+	3
TELECOMMUNICATIONS	Shaw Communications Inc.	US$225 mil 7.25% nts due 04/06/2011	BB+	BB+	3
TELECOMMUNICATIONS	Shaw Communications Inc.	US$300 mil 7.2% sr nts due 12/15/2011	BB+	BB+	3
TELECOMMUNICATIONS	Shaw Communications Inc.	CAD350 mil 7.5% sr nts due 11/20/2013	BB+	BB+	3
TELECOMMUNICATIONS	Shaw Communications Inc.	CAD450 mil 6.1% sr nts due 11/16/2012	BB+	BB+	3
TELECOMMUNICATIONS	Shaw Communications Inc.	CAD300 mil 6.15% sr nts due 05/09/2016	BB+	BB+	3
TELECOMMUNICATIONS	Shaw Communications Inc.	CAD400 mil 5.7% nts due 03/02/2017	BB+	BB+	3
TELECOMMUNICATIONS	Stratos Global Corp.	US$150 mil 9.875% sr nts due 02/15/2013	B-	B-	6

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Table 3

Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
TELECOMMUNICATIONS	Time Warner Telecom Holdings Inc.	US$400 mil 9.25% sr nts due 02/15/2014	CCC+	CCC+	6
TELECOMMUNICATIONS	Time Warner Telecom Inc.	US$325 mil 2.375% sr deb Convertible due 04/01/2026	CCC+	CCC+	6
TELECOMMUNICATIONS	Videon Cablesystems Inc.	CAD130 mil 8.15% sr unsecd nts due 04/26/2010	BB+	BBB	1
TELECOMMUNICATIONS	Videotron Ltee	US$335 mil 6.875% nts due 01/15/2014	B+	BB-	3
TELECOMMUNICATIONS	Videotron Ltee	US$315 mil 6.875% sr nts due 01/15/2014	B+	BB-	3
TELECOMMUNICATIONS	Videotron Ltee	US$175 mil 6.375% sr nts due 12/15/2015	B+	BB-	3
TELECOMMUNICATIONS	Windstream Corp.	US$1.746 bil 8.625% sr nts due 08/01/2016	BB-	BB	5
TELECOMMUNICATIONS	Windstream Corp.	US$800 mil 8.125% sr nts due 08/01/2013	BB-	BB	5
TELECOMMUNICATIONS	Windstream Corp.	US$500 mil 7% sr nts due 03/15/2019	BB-	BB	5
TRANSPORTATION	AirTran Holdings Inc.	US$125 mil 7% conv nts due 07/01/2023	CCC	CCC	6
TRANSPORTATION	AMR Corp.	US$100 mil 9% deb due 09/15/2016	CCC+	B-	5
TRANSPORTATION	AMR Corp.	US$100 mil 8.625% deb due 03/01/2017	CCC+	B-	5
TRANSPORTATION	AMR Corp.	US$200 mil 9.88% nts due 06/15/2020	CCC+	B-	5
TRANSPORTATION	AMR Corp.	US$125 mil 10.2% deb due 03/15/2020	CCC+	B-	5
TRANSPORTATION	AMR Corp.	US$350 mil 10% deb due 04/15/2021	CCC+	B-	5
TRANSPORTATION	AMR Corp.	US$200 mil 9.75% deb due 08/15/2021	CCC+	B-	5
TRANSPORTATION	AMR Corp.	US$100 mil 9.8% deb due 10/01/2021	CCC+	B-	5
TRANSPORTATION	AMR Corp.	US$350 mil 9% deb due 08/01/2012	CCC+	B-	5
TRANSPORTATION	AMR Corp.	US$300 mil 4.25% sr conv Convertible due 09/23/2023	CCC+	B-	5
TRANSPORTATION	AMR Corp.	US$300 mil 4.5% sr conv Convertible due 02/15/2024	CCC+	B-	5
TRANSPORTATION	AMR Corp.	US$35 mil 10.45% med-term nts ser B due 03/10/2011	CCC+	B-	5
TRANSPORTATION	AMR Corp.	US$36 mil 10.4% med-term nts ser B due 03/10/2011	CCC+	B-	5
TRANSPORTATION	AMR Corp.	US$25 mil 10.4% med-term nts ser B due 03/15/2011	CCC+	B-	5
TRANSPORTATION	AMR Corp.	US$30 mil 10.42% med-term nts ser B due 03/15/2011	CCC+	B-	5
TRANSPORTATION	AMR Corp.	US$27 mil 10.5% med-term nts ser B due 03/01/2021	CCC+	B-	5
TRANSPORTATION	AMR Corp.	US$50 mil 10.375% med-term nts ser B due 03/15/2021	CCC+	B-	5
TRANSPORTATION	AMR Corp.	US$40 mil 10.125% med-term nts ser C due 06/01/2021	CCC+	B-	5
TRANSPORTATION	Continental Airlines Inc.	US$175 mil 5% sr conv nts due 06/15/2023	CCC+	B-	5

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Table 3

Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)					
TRANSPORTATION	Continental Airlines Inc.	US$200 mil 8.75% nts due 12/01/2011	CCC+	B-	5
TRANSPORTATION	GWLS Holdings Inc.	US$95 mil sr nts due 2014	CCC	CCC	6
TRANSPORTATION	Hertz Corp.	US$600 mil 10.5% sr sub nts due 01/01/2016	B	B	6
TRANSPORTATION	Hertz Corp.	US$200 mil 6.625% sr nts due 05/15/2008	B	BB-	4
TRANSPORTATION	Hertz Corp.	US$300 mil 6.25% nts due 03/15/2009	B	BB-	4
TRANSPORTATION	Hertz Corp.	US$500 mil 7.625% unsecd nts due 08/15/2007	B	BB-	4
TRANSPORTATION	Hertz Corp.	US$500 mil 7.4% unsecd nts due 03/01/2011	B	BB-	4
TRANSPORTATION	Hertz Corp.	US$800 mil 7.625% sr nts due 06/01/2012	B	BB-	4
TRANSPORTATION	Hertz Corp.	US$1.8 bil 8.875% sr nts due 01/01/2014	B	BB-	4
TRANSPORTATION	Hertz Corp.	EUR225 mil sr nts due 01/01/2014	B	BB-	4
TRANSPORTATION	Horizon Lines Inc.	US$330 mil 4.25% sr nts convertible due 8/15/2012	B	B	6
TRANSPORTATION	JetBlue Airways Corp.	US$ 175 mil 3.5% conv nts due 07/15/2033	CCC+	CCC+	6
TRANSPORTATION	JetBlue Airways Corp.	US$250 mil 3.75% debs Convertible due 03/15/2035	CCC+	CCC+	6
TRANSPORTATION	Kansas City Southern de Mexico S. de R.L. de C.V.	US$230 mil 12.5% sr nts due 06/15/2012	B	BB-	2
TRANSPORTATION	Kansas City Southern de Mexico S. de R.L. de C.V.	US$230 mil sr nts due 2015	B	BB-	2
TRANSPORTATION	Kansas City Southern de Mexico S. de R.L. de C.V.	US$175 mil 7.625% sr nts due 12/01/2013	B	BB-	2
TRANSPORTATION	Kansas City Southern de Mexico S. de R.L. de C.V.	US$165 mil 7.375% sr nts due 06/01/2014	B	BB-	2
TRANSPORTATION	Kansas City Southern Railway Co.	US$200 mil 9.5% sr nts due 10/01/2008	B-	BB-	2
TRANSPORTATION	Kansas City Southern Railway Co.	US$200 mil 7.5% sr nts due 06/15/2009	B-	BB-	2
TRANSPORTATION	Overseas Shipholding Group Inc.	US$100 mil 8.75% deb due 12/01/2013	BB	BB	4
TRANSPORTATION	Overseas Shipholding Group Inc.	US$200 mil 8.25% sr nts due 03/15/2013	BB	BB	4
TRANSPORTATION	Overseas Shipholding Group Inc.	US$150 mil 7.5% sr nts due 02/15/2024	BB	BB	4
TRANSPORTATION	Quality Distribution LLC	US$ 125 mil 9% sr sub nts due 11/15/2010	CCC	CCC	6
TRANSPORTATION	Quality Distribution LLC	US$135 mil fltg rate sr nts due 01/15/2012	CCC	CCC+	5
TRANSPORTATION	Sabre Holdings Corp.	US$400 mil 7.35% sr nts due 08/01/2011	B-	B-	6
TRANSPORTATION	Sabre Holdings Corp.	US$400 mil 6.35% sr nts due 03/15/2016	B-	B-	6
TRANSPORTATION	Teekay Corp.	US$350 mil 8.875% nts due 07/15/2011	BB-	BB+	4

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Table 3

Recovery Ratings Assigned To Speculative-Grade Unsecured Issues (U.S. & Canada)(cont.)

TRANSPORTATION	Travelport Holdings Ltd.	US$1.1 bil sr PIK nts consist of 2 tranches due 2012	CCC+	CCC+	6
TRANSPORTATION	Travelport LLC	US$450 mil 9.875% sr nts due 09/01/2014	CCC+	B	4
TRANSPORTATION	Travelport LLC	US$150 mil fltg rate sr nts due 09/01/2014	CCC+	B	4
TRANSPORTATION	Travelport LLC	EUR235 mil fltg rate sr euro nts due 09/01/2014	CCC+	B	4
TRANSPORTATION	Travelport LLC	US$300 mil 11.875% sr sub nts due 09/01/2016	CCC+	CCC+	6
TRANSPORTATION	Travelport LLC	EUR160 mil 10.875% sr sub nts due 09/01/2016	CCC+	CCC+	6
TRANSPORTATION	UAL Corp.	US$726 mil 4.5% limited-sub Convertible due 06/30/2021	CCC+	CCC+	6
TRANSPORTATION	US Airways Group Inc.	US$143.75 mil 7% sr nts Convertible due 09/30/2020	CCC	CCC	6

Table 4

Recovery Ratings Assigned to Speculative-Grade Unsecured Issues (Europe)

Europe

Sector	Issuer	Issue Description	From Rating	To Rating	Recovery Rating
AEROSPACE/DEFENSE	MTU Aero Engines Finance B.V.	EUR180 mil 2.75% conv bnds due 02/01/2012	BB-	BB+	4
AUTO/TRUCKS	Fiat Finance & Trade Ltd.	EUR1 bil 6.625% bnds due 02/15/2013	BB+	BB+	4
AUTO/TRUCKS	Fiat Finance & Trade Ltd.	EUR1 bil 5.625% med-term nts due 11/15/2011	BB+	BB+	4
AUTO/TRUCKS	Fiat Finance & Trade Ltd.	EUR1.3 bil 6.75% med-term nts ser 077CA due 05/25/2011	BB+	BB+	4
AUTO/TRUCKS	Fiat Finance & Trade Ltd.	EUR617 mil step up med-term nts ser 103UC due 11/07/2011	BB+	BB+	4
AUTO/TRUCKS	Fiat Finance & Trade Ltd.	EUR1 bil 6.25% med-term nts ser 019MS due 02/24/2010	BB+	BB+	4
AUTO/TRUCKS	Fiat Finance North America Inc.	EUR1 bil 5.625% med-term nts due 06/12/2017	BB+	BB+	4
AUTO/TRUCKS	Piaggio Finance S.A.	EUR150 mil 10% nts due 04/30/2012	BB	BB	3
CAP GOODS/MACHINE&EQUIP	Duerr AG	EUR200 mil 9.75% bnds due 07/15/2011	CCC+	CCC+	6
CAP GOODS/MACHINE&EQUIP	Jenoptik AG	EUR62.1 mil 2.5% conv nts due 07/23/2009	B	BB-	4
CAP GOODS/MACHINE&EQUIP	Nexans S.A.	EUR280 mil 1.5% callable bnds Convertible due 01/01/2013	BB	BB+	4
CAP GOODS/MACHINE&EQUIP	Nexans S.A.	EUR350 mil 5.75% nts due 05/02/2017	BB	BB+	4
CHEMICALS	Basell Finance Co. B.V.	US$300 mil 8.1% sub nts due 03/15/2027	B-	B-	6
CHEMICALS	Clondalkin Industries B.V.	EUR170 mil 8% sub bnds due 03/15/2014	B-	B-	6

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Table 4

Recovery Ratings Assigned to Speculative-Grade Unsecured Issues (Europe)(cont.)					
CHEMICALS	Cognis GmbH	EUR345 mil 9.5% nts due 05/15/2014	CCC+	CCC+	6
CHEMICALS	Cognis Holding GmbH	EUR362 mil zero cpn PIK loans ser 2007-3 due 01/15/2015	CCC+	CCC+	6
CHEMICALS	Evonik Degussa GmbH	EUR1.25 bil 5.125% bnds due 12/10/2013	BB	BB	4
CHEMICALS	Ineos Vinyls Finance PLC	EUR 160 mil 9.125% nts due 12/01/2011	B-	B-	6
CHEMICALS	LyondellBasell Industries AF S.C.A.	EUR500 mil 8.375% sub callable high yield bnds due 08/15/2015	B-	B-	6
CHEMICALS	LyondellBasell Industries AF S.C.A.	US$615 mil 8.375% sub callable high yield bnds due 08/15/2015	B-	B-	6
CHEMICALS	Millennium America Inc.	US$241 mil 7.625% sr deb due 11/15/2026	B-	B-	6
CHEMICALS	Rhodia S.A.	EUR1.1 bil fltg rate nts due 10/15/2013	B	BB-	4
CHEMICALS	Rhodia S.A.	EUR595.13 mil 0.5% conv nts due 01/01/2014	B	BB-	4
CHEMICALS	SABIC Innovative Plastics Holding B.V.	US$1.5 bil 9.5% sr unsecd nts due 08/15/2015	B+		6
CHEMICALS	SPCM S.A.	EUR210 mil 8.25% nts due 06/15/2013	B	BB-	3
CONSUMER PRODUCTS	Allied Domecq Financial Services Ltd.	£450 mil 6.625% bnds due 04/18/2011	BB+	BB+	3
CONSUMER PRODUCTS	Allied Domecq Financial Services Ltd.	£250 mil 6.625% bnds due 06/12/2014	BB+	BB+	3
CONSUMER PRODUCTS	Allied Domecq Financial Services Ltd.	EUR600 mil 5.875% nts due 06/12/2009	BB+	BB+	3
CONSUMER PRODUCTS	Barry Callebaut AG, Barry Callebaut Services N.V.	EUR850 mil sr unsecd bank ln due 2010	BB+	BB+	4
CONSUMER PRODUCTS	Barry Callebaut Services N.V.	EUR350 mil 6% nts due 07/13/2017	BB+	BB+	4
CONSUMER PRODUCTS	ESCADA AG	EUR200 mil 7.5% bnds due 04/01/2012	BB-	BB-	3
CONSUMER PRODUCTS	Pernod Ricard S.A.	EUR9.45 bil sr unsecd bank ln due 07/26/2012	BB+	BB+	3
CONSUMER PRODUCTS	Pernod Ricard S.A.	EUR550 mil 4.625% nts due 12/06/2013	BB+	BB+	3
CONSUMER PRODUCTS	Pernod Ricard S.A.	EUR300 mil fltg rate nts due 06/06/2011	BB+	BB+	3
CONSUMER PRODUCTS	Remy Cointreau S.A.	EUR200 mil 5.2% callable bnds due 01/15/2012	BB-	BB-	3
CORPORATE - UNREGULATED GENERATOR	British Energy Holdings PLC	£550 mil 7% amort bnds due 03/31/2022	BB-	BB	4
FOREST PROD/BLDG MAT/PACKAGING	Ardagh Glass B.V.	EUR175 mil 8.875% callable sub bnds due 07/15/2013	CCC+	CCC+	6
FOREST PROD/BLDG MAT/PACKAGING	Ardagh Glass Finance PLC	EUR310 mil 7.125% nts due 06/15/2017	CCC+	CCC+	6
FOREST PROD/BLDG MAT/PACKAGING	Ardagh Glass Group PLC	EUR125 mil 10.75% PIK nts due 03/01/2015	CCC+	CCC+	6
FOREST PROD/BLDG MAT/PACKAGING	Impress Holdings B.V.	EUR250 mil 9.5% callable sub bnds due 09/15/2014	B-	B-	6

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Table 4

Recovery Ratings Assigned to Speculative-Grade Unsecured Issues (Europe)(cont.)

FOREST PROD/BLDG MAT/PACKAGING	Lecta S.A.	EUR150 mil fltg rate nts due 02/15/2014	B-	B-	6
FOREST PROD/BLDG MAT/PACKAGING	M-real Corp.	EUR150 mil fltg rate med-term nts due 12/04/2008	B-	B-	4
FOREST PROD/BLDG MAT/PACKAGING	M-real Corp.	EUR30 mil med-term nts due 06/20/2009	B-	B-	4
FOREST PROD/BLDG MAT/PACKAGING	M-real Corp.	EUR40 mil 5.91% med-term nts due 04/20/2009	B-	B-	4
FOREST PROD/BLDG MAT/PACKAGING	M-real Corp.	EUR500 mil var rate sr unsecd multi-curr revolving credit fac due 12/2009 bank ln	B-	B-	4
FOREST PROD/BLDG MAT/PACKAGING	M-real Corp.	EUR70 mil fltg rate med-term nts due 01/19/2009	B-	B-	4
FOREST PROD/BLDG MAT/PACKAGING	M-real Corp.	EUR500 mil 7.25% nts due 04/01/2013	B-	B-	4
FOREST PROD/BLDG MAT/PACKAGING	M-real Corp.	EUR400 mil fltg rate nts due 12/15/2010	B-	B-	4
FOREST PROD/BLDG MAT/PACKAGING	Norske Skogindustrier ASA	US$600 mil 7.625% nts due 10/15/2011	BB	BB	4
FOREST PROD/BLDG MAT/PACKAGING	Norske Skogindustrier ASA	US$200 mil 7.125% bnds due 10/15/2033	BB	BB	4
FOREST PROD/BLDG MAT/PACKAGING	Norske Skogindustrier ASA	US$200 mil 6.125% bnds due 10/15/2015	BB	BB	4
FOREST PROD/BLDG MAT/PACKAGING	Norske Skogindustrier ASA	EUR500 mil 7% nts due 06/26/2017	BB	BB	4
FOREST PROD/BLDG MAT/PACKAGING	Sappi Papier Holding GmbH	US$500 mil 6.75% nts due 06/15/2012	BB	BB	4
FOREST PROD/BLDG MAT/PACKAGING	Sappi Papier Holding GmbH	US$250 mil 7.5% nts due 06/15/2032	BB	BB	4
FOREST PROD/BLDG MAT/PACKAGING	Sappi Papier Holding GmbH	EUR500 mil Sr Unsecd syndicated bank ln due 12/31/2010	BB	BB	4
FOREST PROD/BLDG MAT/PACKAGING	Sappi Papier Holding GmbH	EUR600 mil sr unsecd multi curr revolving bank ln	BB	BB	4
FOREST PROD/BLDG MAT/PACKAGING	Smurfit Kappa Funding PLC	EUR217.5 mil 7.75% sub nts due 04/01/2015	B	B	6
FOREST PROD/BLDG MAT/PACKAGING	Smurfit Kappa Funding PLC	US$200 mil 7.75% sub nts due 04/01/2015	B	B	6
HEALTHCARE	Fresenius Finance B.V.	EUR100 mil 7.5% nts due 04/30/2009	BB	BB+	2
HEALTHCARE	Fresenius Finance B.V.	EUR500 mil 5.5% nts due 01/31/2016	BB	BB+	2
HEALTHCARE	Fresenius Finance B.V.	EUR500 mil 5% nts due 01/31/2013	BB	BB+	2
HEALTHCARE	Fresenius Medical Care Capital Trust IV	US$225 mil 7.875% trust preferred secs (sr sub nts) due 06/15/2011	B+	BB	3
HEALTHCARE	Fresenius Medical Care Capital Trust V	EUR300 mil 7.375% trust pfd secs due 06/15/2011	B+	BB	3
HEALTHCARE	Fresenius Medical Care Finance III S.A.	US$500 mil 6.875% fxd rate Global bnds due 07/15/2017	BB-	BB+	2
HEALTHCARE	Pipe Holdings PLC	£66 mil 9.75% nts due 11/01/2013	CCC+	CCC+	6

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Table 4

Recovery Ratings Assigned to Speculative-Grade Unsecured Issues (Europe)(cont.)					
HIGH TECHNOLOGY	Alcatel Lucent	EUR805 mil 4.375% bnds due 02/17/2009	BB-	BB-	3
HIGH TECHNOLOGY	Alcatel Lucent	EUR1.02 bil 4.75% conv callable nts due 01/01/2011	BB-	BB-	3
HIGH TECHNOLOGY	Alcatel Lucent	EUR462.01 mil 6.375% Exchange offer med-term nts due 04/07/2014	BB-	BB-	3
HIGH TECHNOLOGY	Alcatel Lucent	EUR1.4 bil sr unsecd multi-curr syndicated revolving fac due 04/2012 bank ln	BB-	BB-	3
HIGH TECHNOLOGY	ASM International N.V.	US$90 mil 5.25% callable conv bnds due 05/15/2010	B	BB	2
HIGH TECHNOLOGY	ASM International N.V.	US$150 mil 4.25% callable conv bnds due 12/06/2011	B	BB	2
HIGH TECHNOLOGY	EPCOS Finance B.V.	EUR126.43 mil 2.5% conv callable bnds due 07/16/2010	BB+	BB+	4
HIGH TECHNOLOGY	Lucent Technologies Inc.	US$300 mil 6.5% sr deb due 01/15/2028	B+	BB-	4
HIGH TECHNOLOGY	Lucent Technologies Inc.	US$202 mil 5.5% sr nts due 11/15/2008	B+	BB-	4
HIGH TECHNOLOGY	Lucent Technologies Inc.	US$1.36 bil 6.45% deb due 03/15/2029	B+	BB-	4
HIGH TECHNOLOGY	Lucent Technologies Inc.	US$881.5 mil 2.875% conv sr deb ser B due 06/15/2025	BB-	BB-	4
HIGH TECHNOLOGY	Lucent Technologies Inc.	US$750 mil 2.875% conv sr deb ser A due 01/15/2023	BB-	BB-	4
HIGH TECHNOLOGY	NXP B.V., NXP Funding LLC	EUR525 mil 8.625% callable bnds due 10/15/2015	B-	B	5
HIGH TECHNOLOGY	NXP B.V., NXP Funding LLC	US$1.25 bil 9.5% callable bnds due 10/15/2015	B-	B	5
HIGH TECHNOLOGY	Vestel Electronics Finance Ltd.	US$225 mil 8.75% nts due 05/09/2012	B	B	4
MEDIA, ENTERTAINMENT & LEISURE	Cirsa Capital Luxembourg S.A.	EUR230 mil 7.875% bnds due 07/15/2012	B-	B+	4
MEDIA, ENTERTAINMENT & LEISURE	Cirsa Finance Luxembourg S.A.	EUR270 mil 8.75% bnds due 05/15/2014	B	B+	4
MEDIA, ENTERTAINMENT & LEISURE	Codere Finance (Luxembourg) S.A.	EUR660 mil bnds due 06/15/2015	B	BB-	3
MEDIA, ENTERTAINMENT & LEISURE	Ladbrokes Group Finance PLC	EUR500 mil 6.5% med-term nts due 07/17/2009	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Ladbrokes Group Finance PLC	£250 mil 7.125% med-term nts due 07/11/2012	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Ladbrokes Group Finance PLC	£175 mil 7.25% med-term nts ser 2 due 07/29/2008	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	Ladbrokes Group Finance PLC	HKD200 mil 9.1% med-term nts ser 7 due 04/12/2010	BB	BB	3
MEDIA, ENTERTAINMENT & LEISURE	ONO Finance II PLC	EUR270 mil 8% fxd- and fltg-rate nts due 05/16/2014	CCC+	CCC+	6
MEDIA, ENTERTAINMENT & LEISURE	Rank Group Finance PLC	US$14.3 mil 7.125% nts due 01/15/2018	B	B	5
MEDIA, ENTERTAINMENT & LEISURE	Rank Group PLC (The)	£167.7 mil 3.875% conv bnds due 01/20/2009	B	B	5

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Recovery Ratings Assigned to Speculative-Grade Unsecured Issues (Europe)(cont.)					
MEDIA, ENTERTAINMENT & LEISURE	TUI AG	EUR694 mil 2.75% nts due 09/01/2012	B	B+	5
MINING AND MINERALS	Eco-Bat Finance PLC	EUR235 mil 10.125% bnds due 01/31/2013	B	B+	3
MINING AND MINERALS	SGL Carbon AG	EUR200 mil 0.75% conv bnds due 05/16/2013	B+	BB	3
OIL	Compagnie Generale de Geophysique - Veritas	US$530 mil 7.5% bnds due 05/15/2015	BB-	BB	3
OIL	Compagnie Generale de Geophysique - Veritas	US$400 mil 7.75% callable nts due 05/15/2017	BB-	BB	3
OIL	Petroleum Geo-Services ASA	US$400 mil 2.7% conv nts due 12/20/2012	B	B	6
OIL	PO Oil Financing Ltd.	US$175 mil 9.75% nts due 07/22/2009	B+	B+	4
REAL ESTATE	Castle HoldCo 4	£170 mil 9.875% nts due 05/15/2015	CCC+	CCC+	6
RESTAURANTS/RETAILING	Edcon Holdings (Proprietary) Ltd.	EUR630 mil fltg rate nts due 06/15/2015	B-	B-	6
RESTAURANTS/RETAILING	Hornbach-Baumarkt-AG	EUR250 mil 6.125% nts due 11/15/2014	BB-	BB	4
TELECOMMUNICATIONS	Cable & Wireless International Finance B.V.	£200 mil 8.625% bnds due 03/25/2019	B	BB-	3
TELECOMMUNICATIONS	Cable & Wireless PLC	£200 mil 8.75% bnds due 08/06/2012	B	BB-	3
TELECOMMUNICATIONS	Cell C (Pty) Ltd.	US$270 mil 11% sub nts due 07/01/2015	CCC	CCC	6
TELECOMMUNICATIONS	COLT Telecom Group Ltd.	EUR262.2 mil 7.625% nts due 12/15/2009	B	B	3
TELECOMMUNICATIONS	Hellas Telecommunications (Luxembourg) II	EUR960 mil callable sub nts due 01/15/2015	CCC+	CCC+	6
TELECOMMUNICATIONS	Hellas Telecommunications (Luxembourg) II	US$275 mil fltg rate callable sub nts due 01/15/2015	CCC+	CCC+	6
TELECOMMUNICATIONS	Hellas Telecommunications (Luxembourg) III	EUR355 mil 8.5% callable nts due 10/15/2013	CCC+	CCC+	6
TELECOMMUNICATIONS	Inmarsat Finance II PLC	US$450 mil step up sub callable disc nts due 11/15/2012	B+	BB-	5
TELECOMMUNICATIONS	Inmarsat Finance PLC	US$218.8 mil 7.625% callable nts due 06/30/2012	B+	BB	3
TELECOMMUNICATIONS	Millicom International Cellular S.A.	US$550 mil 10% nts due 12/01/2013	B+	BB	3
TELECOMMUNICATIONS	Nordic Telephone Co. Holding ApS	EUR750 mil fltg rate callable nts due 05/01/2016	B	B	6
TELECOMMUNICATIONS	Nordic Telephone Co. Holding ApS	EUR800 mil 8.25% callable nts due 05/01/2016	B	B	6
TELECOMMUNICATIONS	Nordic Telephone Co. Holding ApS	US$600 mil 8.875% callable nts due 05/01/2016	B	B	6
TELECOMMUNICATIONS	ONO Finance PLC	EUR180 mil 10.5% callable bnds due 05/17/2014	CCC+	CCC+	6
TELECOMMUNICATIONS	TDC A/S	EUR194 mil 5% nts due 07/08/2008	B	B	6
TELECOMMUNICATIONS	TDC A/S	¥3 bil 1.28% exchangable nts ser 14 due 07/09/2008	B	B	6

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Recovery Ratings Assigned to Speculative-Grade Unsecured Issues (Europe)(cont.)					
TELECOMMUNICATIONS	TDC A/S	EUR345 mil 5.625% nts due 02/06/2009	B	B	6
TELECOMMUNICATIONS	TDC A/S	EUR724 mil 6.5% bnds ser 16 due 04/19/2012	B	B	6
TELECOMMUNICATIONS	UnitedGlobalCom Inc.	EUR500 mil 1.75% sr nts Convertible due 04/15/2024	B-	B-	6
TELECOMMUNICATIONS	Unitymedia GmbH	EUR215 mil 8.75% sub nts due 02/15/2015	B-	B-	6
TELECOMMUNICATIONS	Unitymedia GmbH	EUR235 mil 10.125% sub nts due 02/15/2015	B-	B-	6
TELECOMMUNICATIONS	Unitymedia GmbH	US$151 mil 10.375% sub nts due 02/15/2015	B-	B-	6
TELECOMMUNICATIONS	Virgin Media Finance PLC	£375 mil 9.75% bnds due 04/15/2014	B-	B-	6
TELECOMMUNICATIONS	Virgin Media Finance PLC	US$425 mil 8.75% callable bnds due 04/15/2014	B-	B-	6
TELECOMMUNICATIONS	Virgin Media Finance PLC	EUR225 mil 8.75% bnds due 04/15/2014	B-	B-	6
TELECOMMUNICATIONS	Virgin Media Finance PLC	US$550 mil 9.125% callable bnds due 08/15/2016	B-	B-	6
TELECOMMUNICATIONS	Wind Acquisition Finance S.A.	EUR125 mil 9.75% nts due 12/01/2015	B	B	6
TELECOMMUNICATIONS	Wind Acquisition Finance S.A.	US$150 mil 10.75% nts due 12/01/2015	B	B	6
TELECOMMUNICATIONS	Wind Acquisition Finance S.A.	EUR825 mil 9.75% nts due 12/01/2015	B	B	6
TELECOMMUNICATIONS	Wind Acquisition Finance S.A.	US$500 mil 10.75% nts due 12/01/2015	B	B	6
TRANSPORTATION	CEVA Group PLC	EUR505 mil 8.5% bnds due 12/01/2014	CCC+	B-	5
TRANSPORTATION	CEVA Group PLC	EUR225 mil 10% sub bnds due 12/01/2016	CCC+	CCC+	6
TRANSPORTATION	Europcar Groupe S.A.	EUR375 mil 8.125% sub nts due 05/15/2014	B	B+	5
TRANSPORTATION	Kloeckner & Co. Finance International S.A.	EUR325 mil 1.5% conv bnds bnds due 07/27/2012	B+	B+	6
TRANSPORTATION	Stena AB	US$175 mil 7.5% nts due 11/01/2013	BB-	BB+	3
TRANSPORTATION	Stena AB	US$250 mil 7% callable nts due 12/01/2016	BB-	BB+	3
TRANSPORTATION	Stena AB	EUR300 mil 6.125% bnds due 02/01/2017	BB-	BB+	3
TRANSPORTATION	Stena AB	EUR102 mil 5.875% nts due 02/01/2019	BB-	BB+	3
TRANSPORTATION	Thiel Logistik AG	EUR130 mil 8% nts due 12/15/2012	CCC+	B-	5
TRANSPORTATION	TUI AG	EUR625 mil 6.625% nts ser 144A due 05/16/2011	B	B+	5
TRANSPORTATION	TUI AG	EUR400 mil fltg rate nts due 08/17/2009	B	B+	5
TRANSPORTATION	TUI AG	EUR450 mil 5.125% callable bnds due 12/10/2012	B	B+	5

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Table 4

Recovery Ratings Assigned to Speculative-Grade Unsecured Issues (Europe)(cont.)					
TRANSPORTATION	TUI AG	EUR550 mil fltg rate nts due 12/10/2010	B	B+	5
TRANSPORTATION	TUI AG	EUR300 mil var rate jnr sub perp callable deferrable bnds	B-	B-	6

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EXHIBIT

KPL-6

EEI EDISON ELECTRIC INSTITUTE

Credit Ratings

Q4 2007
FINANCIAL UPDATE

QUARTERLY REPORT
OF THE U.S. SHAREHOLDER-OWNED
ELECTRIC UTILITY INDUSTRY

EDISON ELECTRIC INSTITUTE

About EEI

The Edison Electric Institute is the association of U.S. shareholder-owned electric companies. Our members serve 95% of the ultimate customers in the shareholder-owned segment of the industry, and represent approximately 70% of the U.S. electric power industry. We also have 79 international electric companies as Affiliate members and more than 190 industry suppliers and related organizations as Associate members.

About EEI's Quarterly Financial Updates

EEI's quarterly financial updates present industry trend analyses and financial data covering 70 U.S. shareholder-owned electric utility companies. These 70 companies include 61 electric utility holding companies whose stocks are traded on major U.S. stock exchanges and 9 electric utilities who are subsidiaries of non-utility or foreign companies. Q4 2007 financial updates will be published for the following topics:

- Dividends
- Stock Performance
- Credit Ratings
- Construction
- Rate Case Summary
- Income Statement
- Balance Sheet
- Cash Flow Statement
- Business Segmentation

For EEI Member Companies

The EEI Finance and Accounting Division is developing current year and historical data sets that cover a wide range of industry financial and operating metrics. We look forward to serving as a resource for member companies who wish to produce customized industry financial data and trend analyses for use in:

- Investor relations studies and presentations
- Internal company presentations
- Performance benchmarking
- Peer group analyses
- Annual and quarterly reports to shareholders

We Welcome Your Feedback

EEI is interested in ensuring that our financial publications and industry data sets best address the needs of member companies and the financial community. We welcome your comments, suggestions and inquiries.

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Future EEI Finance Meetings

EEI International Financial Conference
March 9-12, 2008
London Hilton on Park Lane
London, United Kingdom

EEI Annual Finance Committee Meeting
May 21, 2008
Waldorf-Astoria
New York, New York

43rd EEI Financial Conference
November 2-5, 2008
Marriott Desert Ridge
Phoenix, Arizona

For more information about EEI Finance Meetings, please contact Debra Henry, (202) 508-5496, dhenry@eei.org

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The 70 U.S. Shareholder-Owned Electric Utilities

Allegheny Energy, Inc. (AYE)
ALLETE, Inc. (ALE)
Alliant Energy Corporation (LNT)
Ameren Corporation (AEE)
American Electric Power Company, Inc. (AEP)
Aquila, Inc. (ILA)
Avista Corporation (AVA)
Black Hills Corporation (BKH)
CenterPoint Energy, Inc. (CNP)
Central Vermont Public Service Corporation (CV)
CH Energy Group, Inc. (CHG)
Cleco Corporation (CNL)
CMS Energy Corporation (CMS)
Consolidated Edison, Inc. (ED)
Constellation Energy Group, Inc. (CEG)
Dominion Resources, Inc. (D)
DPL, Inc. (DPL)
DTE Energy Company (DTE)
Duke Energy Corporation (DUK)
Duquesne Light Holdings, Inc.
Edison International (EIX)
El Paso Electric Company (EE)
Empire District Electric Company (EDE)
Energy East Corporation (EAS)
Entergy Corporation (ETR)
Exelon Corporation (EXC)
FirstEnergy Corp. (FE)
FPL Group, Inc. (FPL)
Great Plains Energy Incorporated (GXP)
Green Mountain Power Corporation
Hawaiian Electric Industries, Inc. (HE)
IDACORP, Inc. (IDA)
Ipalco Enterprises, Inc.
Integrys Energy Group, Inc. (TEG)
Kentucky Utilities **
KeySpan Corporation (KSE)
Louisville Gas and Electric **
Maine & Maritimes Corporation (MAM)
MDU Resources Group, Inc. (MDU)
MGE Energy, Inc. (MGEE)
MidAmerican Energy Company
Niagra Mohawk Power Corporation
NiSource Inc. (NI)
Northeast Utilities (NU)
NorthWestern Corporation (NWEC)
NSTAR (NST)
OGE Energy Corp. (OGE)
Otter Tail Corporation (OTTR)
Pepco Holdings, Inc. (POM)
PG&E Corporation (PCG)
Pinnacle West Capital Corporation (PNW)
PNM Resources, Inc. (PNM)
Portland General Electric Company (POR)*
PPL Corporation (PPL)
Progress Energy (PGN)
Public Service Enterprise Group Inc. (PEG)
Puget Energy, Inc. (PSD)
SCANA Corporation (SCG)
Sempra Energy (SRE)
Sierra Pacific Resources (SRP)
Southern Company (SO)
TECO Energy, Inc. (TE)
Energy Future Holdings Corp. (formerly TXU Corp.)^
UIL Holdings Corporation (UIL)
UniSource Energy Corporation (UNS)
Unitil Corporation (UTL)
Vectren Corporation (VVC)
Westar Energy, Inc. (WR)
Wisconsin Energy Corporation (WEC)
Xcel Energy, Inc. (XEL)

Note: Includes the 61 shareholder-owned electric utility holding companies plus an additional 9 electric utilities (shown in *italics*) that are not listed on U.S. stock exchanges for one of the following reasons — i. they are a subsidiary of an independent power producer, ii. they are a subsidiary of a foreign-owned company, or iii. they were acquired by an investment firm. Stock symbols are shown in parentheses.

*Portland General transitioned from private ownership to become a publicly traded company on April 3, 2006. The EEI Index includes Portland General beginning on January 1, 2007.

**Kentucky Utilities and Louisville Gas and Electric, both subsidiaries of E.ON AG, were added to the EEI coverage universe effective January 1, 2007. EEI's historical industry financial data now includes their results.

^TXU (now Energy Future Holdings Corp.) was acquired by the Texas Energy Future Holdings Limited Partnership (TEF) on 10/10/2007. TEF was formed by a group of investors led by Kohlberg Kravis Roberts and Texas Pacific Group to facilitate the merger.

Companies Listed by Category
(as of 12/31/06)

Given the diversity of utility holding company corporate strategies, no single company categorization approach will be useful for all EEI members and utility industry analysts. Nevertheless, we believe the following classification provides an informative framework for tracking financial trends and the capital markets' response to business strategies as companies depart from the traditional regulated utility model.

Regulated	80%+ of total assets are regulated
Mostly Regulated	50% to 80% of total assets are regulated
Diversified	Less than 50% of total assets are regulated

Categorization of the 65 publicly traded utility holding companies is based on year-end business segmentation data presented in 10Ks, supplemented by discussions with company IR departments. Categorization of the 5 non-publicly traded companies (*shown in italics*) is based on estimates derived from FERC Form 1 data and information provided by parent company IR departments.

The EEI Finance and Accounting Division continues to evaluate our approach to company categorization and business segmentation. In addition, we can produce customized categorization and peer group analyses in response to member company requests. We welcome comments, suggestions and feedback from EEI member companies and the financial community.

Regulated (42 of 70)

Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
Aquila, Inc.
Central Vermont Public Service Corporation
CH Energy Group, Inc.
Cleco Corporation
CMS Energy Corporation
Consolidated Edison, Inc.
DPL, Inc.
Duquesne Light Holdings, Inc.
El Paso Electric Company
Empire District Electric Company
Energy East Corporation
Entergy Corporation
Great Plains Energy Incorporated
Green Mountain Power Corporation
IDACORP, Inc.
IPALCO Enterprises, Inc.
Kentucky Utilities
KeySpan Corporation
Louisville Gas and Electric
Maine & Maritimes Corporation
MGE Energy, Inc.
Niagara Mohawk Power Corporation
Northeast Utilities
NorthWestern Corporation
NSTAR
PG&E Corporation
Pinnacle West Capital Corporation
Portland General Electric Company
Progress Energy
Puget Energy, Inc.
Sierra Pacific Resources
Southern Company
UIL Holdings Corporation
UniSource Energy Corporation
Unitil Corporation
Vectren Corporation
Westar Energy, Inc.
Wisconsin Energy Corporation
Xcel Energy, Inc.

Mostly Regulated (19 of 70)

ALLETE, Inc.
Avista Corporation
CenterPoint Energy, Inc.
DTE Energy Company
Edison International
Exelon Corporation
First Energy Corp.
FPL Group, Inc.
MidAmerican Energy Holdings
NiSource Inc.
OGE Energy Corp.
Otter Tail Corporation
Pepco Holdings, Inc.
PNM Resources, Inc.
PPL Corporation
Public Service Enterprise Group, Inc.
SCANA Corporation
TECO Energy, Inc.
WPS Resources Corporation*

Diversified (9 of 70)

Allegheny Energy, Inc.
Black Hills Corporation
Constellation Energy Group, Inc.
Dominion Resources, Inc.
Duke Energy Corporation
Hawaiian Electric Industries, Inc.
MDU Resources Group, Inc.
Sempra Energy
TXU Corp.

Note: Based on assets at 12/31/06

**Changed name to Integrys Energy Group, Inc. effective February 21, 2007*

Q4 2007

Credit Ratings

Announcements

1. The charts and tables shown in this publication are available in Excel file format at the EEI website (www.eei.org) on the "Quarterly Financial Updates" page in the Finance section of the website (except where prohibited by copyright law).

2. Are you interested in doing customized industry peer group and financial ratio analysis? We can supply annual and quarterly SEC and FERC financial data for all 70 shareholder-owned electric utilities in easy-to-manipulate Excel format to clients of SNL Financial. Contact Mark Agnew, magnew@eei.org, (202) 508-5049.

HIGHLIGHTS

- Industry credit quality improved for the third consecutive year in 2007 as upgrades outnumbered downgrades by a 3:2 ratio.
- The industry's average credit rating remained at a solid BBB in 2007 for a fourth consecutive year. The year's 121 total ratings actions, just above last year's 110, were also at a consistent level for a fourth year.
- Nearly half of the year's downgrades were tied to regulatory uncertainty in Illinois. TXU received significant downgrades based on its debt-financed acquisition by a group of private equity investors.
- As the year progressed, rising capital expenditures and the accompanying debt were becoming a more frequent concern cited by the ratings agencies.

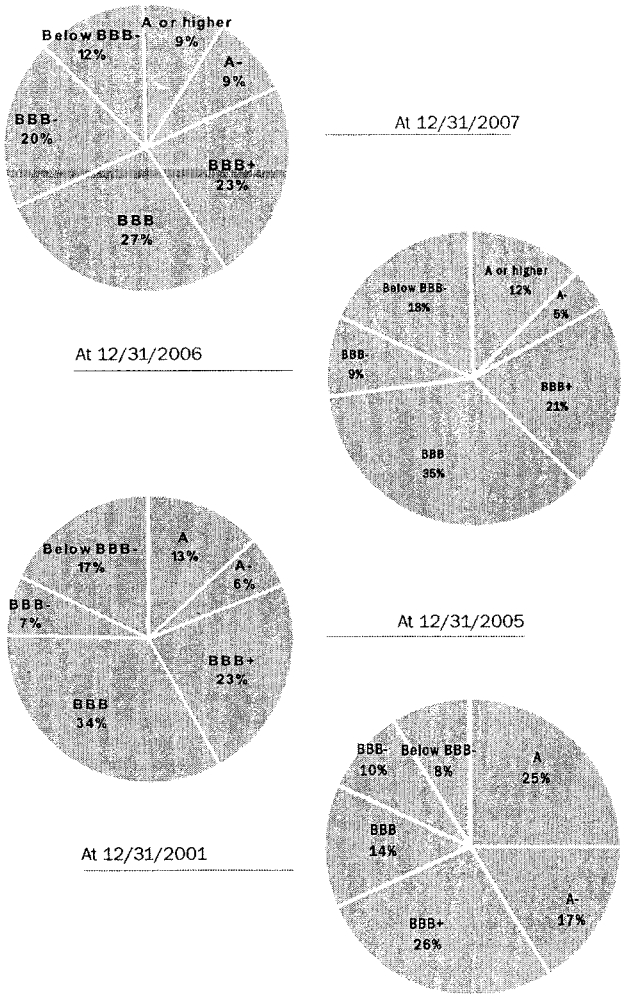
COMMENTARY

Industry credit quality improved for the third consecutive year in 2007 as upgrades outnumbered downgrades by a 3:2 ratio. Two-thirds of the ratings actions occurred during the first half of the year and upgrades outpaced downgrades in all four quarters. Favorable state regulatory relations, a focus on core utility operations and stronger credit metrics were common reasons cited for ratings agency upgrades throughout the year. Nearly half of the year's downgrades were tied to regulatory uncertainty in Illinois and all of these occurred in the year's first half. TXU received significant downgrades, including six notches by S&P, based on its acquisition, announced in late February, by a group of private equity investors. By the fourth quarter, the issue of rising capital expenditures became a topic frequently cited for ratings actions.

The industry's average credit rating remained at a solid

I. S&P Utility Credit Ratings Distribution

U.S. Shareholder-Owned Electric Utilities

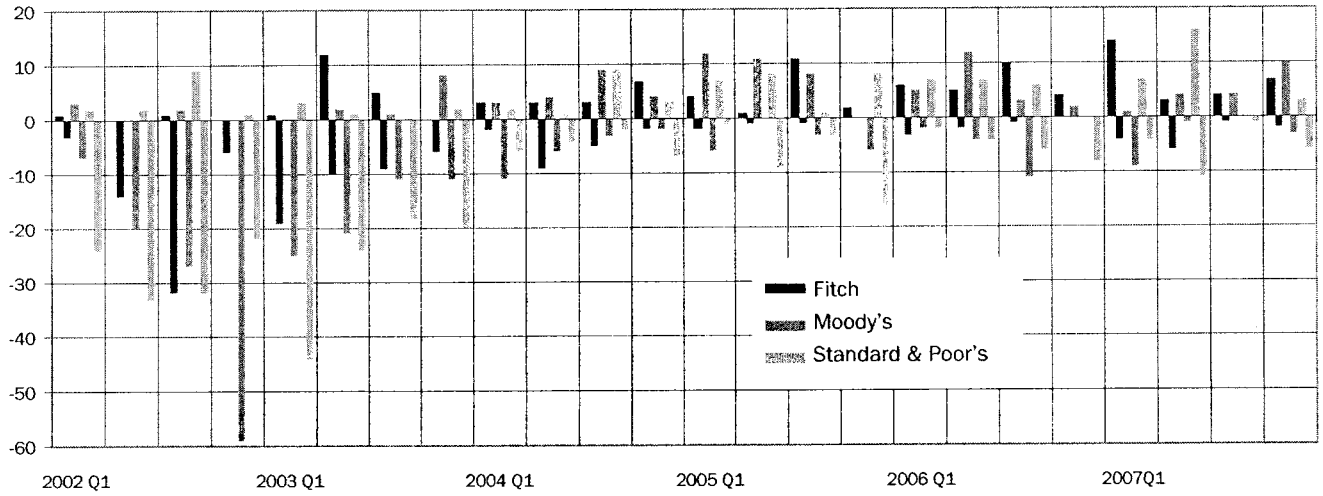


Note: Rating applies to utility holding company entity.
Source: Standard & Poor's, SNL Financial, EEI Finance Department and company annual reports.

II. Credit Rating Agency Upgrades and Downgrades

U.S. Shareholder-Owned Electric Utilities

Positive = upgrades
Negative = downgrades



	2002		2003		2004		2005		2006		2007	
	Up	Down	Up	Down	Up	Down	Up	Down	Up	Down	Up	Down
Fitch												
Q1	1	-3	1	-19	3	-2	4	-2	6	-3	14	-4
Q2	0	-14	12	-10	3	-9	1	-1	5	-2	3	-6
Q3	1	-32	5	-9	3	-5	11	-1	10	-1	4	-1
Q4	0	-6	0	-6	7	-2	2	0	4	0	7	-2
Total	**2**	**-55**	**18**	**-44**	**16**	**-18**	**18**	**-4**	**25**	**-6**	**28**	**13**
Moody's												
Q1	3	-7	0	-25	3	-11	12	-6	5	-2	1	-9
Q2	0	-20	2	-21	4	-6	11	0	12	-4	4	-1
Q3	2	-27	1	-11	9	-3	8	-3	3	-11	4	0
Q4	0	-59	8	-11	4	-2	0	-6	2	0	10	-3
Total	**5**	**-113**	**11**	**-68**	**20**	**-22**	**31**	**-15**	**22**	**-17**	**19**	**13**
S&P												
Q1	2	-24	3	-44	2	-6	7	-1	7	-2	7	-4
Q2	2	-33	1	-24	1	-4	8	-9	7	-4	16	-11
Q3	9	-32	0	-18	9	-2	1	-3	6	-6	0	-1
Q4	1	-22	2	-20	3	-7	8	-16	0	-8	3	-6
Total	**14**	**-111**	**6**	**-106**	**15**	**-19**	**24**	**-29**	**20**	**-20**	**26**	**22**

Note: Data presents the number of occurences and includes each event, even if multiple actions occurred for a single company.
Source: Fitch Ratings, Moody's, Standard & Poor's

III. Total Ratings Actions

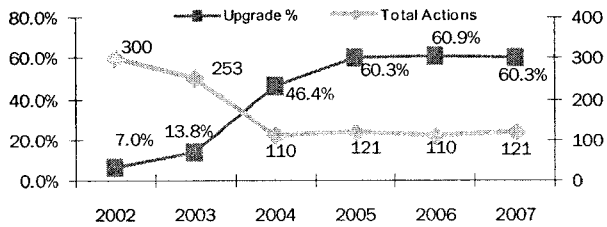
U.S. Shareholder-Owned Electric Utilities

	2002	2003	2004	2005	2006	2007
Fitch	57	62	34	22	31	41
Moody's	118	79	42	46	39	32
Standard & Poor's	125	112	34	53	40	48
Total	**300**	**253**	**110**	**121**	**110**	**121**

Note: Full year, except where noted
Source: Fitch Ratings, Moody's, Standard & Poor's

IV. Direction of Ratings Actions

U.S. Shareholder-Owned Electric Utilities



Note: Full year, except where noted
Source: Fitch Ratings, Moody's, Standard & Poor's

V. S&P Utility Credit Rating Distribution by Company Category (at period end)

U.S. Shareholder-Owned Electric Utilities

	2002		2003		2004		2005		2006		2007	
	#	%	#	%	#	%	#	%	#	%	#	%
Regulated												
A or higher	6	19%	6	17%	7	19%	7	19%	6	19%	5	13%
A-	7	22%	5	14%	4	11%	3	8%	1	3%	2	5%
BBB+	3	9%	6	17%	7	19%	8	22%	7	22%	8	21%
BBB	6	19%	6	17%	8	22%	9	25%	9	28%	10	26%
BBB-	4	13%	5	14%	5	14%	3	8%	3	9%	7	18%
Below BBB-	6	19%	8	22%	5	14%	6	17%	6	19%	6	16%
Total	32	100%	36	100%	36	100%	36	100%	32	100%	38	100%
Mostly Regulated												
A or higher	5	21%	3	15%	2	9%	2	9%	1	4%	1	5%
A-	3	13%	2	10%	1	4%	0	0%	2	9%	3	16%
BBB+	6	25%	5	25%	6	26%	6	27%	3	13%	4	21%
BBB	4	17%	4	20%	7	30%	9	41%	11	48%	6	32%
BBB-	2	8%	2	10%	7	30%	0	0%	1	4%	4	21%
Below BBB-	4	17%	4	20%	0	0%	5	23%	5	22%	1	5%
Total	24	100%	20	100%	23	100%	22	100%	23	100%	19	100%
Diversified												
A or higher	2	14%	0	0%	0	0%	0	0%	1	9%	0	0%
A-	1	7%	2	13%	1	9%	1	9%	0	0%	1	11%
BBB+	2	14%	4	27%	3	27%	2	18%	4	36%	3	33%
BBB	7	50%	5	33%	5	45%	5	45%	3	27%	2	22%
BBB-	0	0%	2	13%	1	9%	2	18%	2	18%	2	22%
Below BBB-	2	14%	2	13%	1	9%	1	9%	1	9%	1	11%
Total	14	100%	15	100%	11	100%	11	100%	11	100%	9	100%

Note: At year-end, unless otherwise noted.
Source: Standard & Poor's, SNL Financial, EEI Finance Department

BBB in 2007 for a fourth consecutive year. The year's 121 total ratings actions, just above last year's 110, were also at a consistent level for a fourth straight year. Ratings outlooks and watches, however, were mostly negative as the year came to a close, outnumbering positive ones by a 2:1 ratio at year-end for the second straight year, although positive outlooks were more in number at the end of Q3.

Constructive Regulatory Relations Prompt Upgrades

Starting in Q1, upgrades were given to three parent companies (FirstEnergy, Westar Energy and PG&E) and four affiliate subsidiaries due to positive regulatory developments. On February 2, Fitch upgraded FirstEnergy from BBB- to BBB, citing constructive regulatory environments in Ohio and Pennsylvania following the adoption of the company's rate certainty plan in 2006, which should result in more predictable earnings and cash flow. Fitch also upgraded FirstEnergy subsidiaries Cleveland Electric Illuminating Company (from BB to BB+), Jersey Central Power & Light (from BBB- to BBB), and Toledo Edison Company (from BB to BB+) given its expectations of reasonable regulatory treatment in future rate proceedings.

A supportive rate-making environment was also noted in S&P's upgrade of Westar Energy and its Kansas Gas & Electric utility (from BB+ to BBB-) on February 27. S&P said the upgrade reflected the reasonable resolution of the December 2005 rate case by the Kansas Corporation Commission, which should improve the company's overall financial condition and reduce its business risk. Favorable regulatory treatment also resulted in the March 30 upgrade of Pacific Gas & Electric (PG&E) by Fitch (from BBB to BBB+), who noted that the resolution of PG&E's 2007 general rate case should lead to improved credit metrics in 2007. Positive regulatory developments in Q2 supported upgrades for Aquila, PG&E and Xcel Energy. On June 12, Fitch raised Aquila's rating from B to BB- citing an improved risk profile due to recent rate increases, the implementation of a fuel adjustment clause for Aquila's Missouri utilities and reduced long-term debt. S&P also upgraded Aquila from B to B+ on May 15, based on Aquila's announcement that it would repurchase another $344 million of debt on June 15, for (at the time) a total of about $1.1 billion since year-end 2005. On June 4, S&P raised PG&E subsidiary Pacific Gas & Electric's rating from BBB to BBB+ based on strengthening financial performance, improved regulatory support and a strategic focus on regulated utility operations.

Fitch upgraded Xcel subsidiary Public Service Company of Colorado on June 27, citing improving credit metrics and a lower-risk business profile due mostly to a favorable outcome in its Colorado gas rate case.

Regulatory-related upgrades continued in Q4, as Moody's upgraded Sierra Pacific Resources and its utility subsidiaries, Nevada Power Company and Sierra Pacific Power Company, from B1 to Ba3 on October 4. Reasons for the upgrades included stronger credit metrics achieved over the last couple of years and a steadily improving regulatory environment for its regulated utility subsidiaries in Nevada. Moody's upgraded PG&E and subsidiary Pacific Gas & Electric on December 27, giving the utility an upgrade from all three ratings agencies in 2007. Moody's jumped the parent company's rating by two notches from Baa3 to Baa1 and the subsidiary by one notch from Baa1 to A3, citing a more constructive regulatory environment in California, which should lead to sustainable and predictable stronger credit metrics.

Credit Ratings Scales

	Moody's	S & P	Fitch
Investment Grade	Aaa	AAA	AAA
	Aa1	AA+	AA+
	Aa2	AA	AA
	Aa3	AA-	AA-
	A1	A+	A+
	A2	A	A
	A3	A-	A-
	Baa1	BBB+	BBB+
	Baa2	BBB	BBB
	Baa3	BBB-	BBB-
Speculative Grade	Ba1	BB+	BB+
	Ba2	BB	BB
	Ba3	BB-	BB-
	B1	B+	B+
	B2	B	B
	B3	B-	B-
	Caa1	CCC+	CCC+
	Caa2	CCC	CCC
	Caa3	CCC-	CCC-
	Ca	CC	CC
	C	C	C
Default	C	D	D

Source: Fitch Ratings, Moody's, Standard & Poor's

Core Utility Focus Supports Upgrades

Even after several years of "back to basics" strategies across the industry, the divestiture of non-core businesses and subsequent reduction of debt continued to be rewarded with upgrades from the ratings agencies in 2007. Fitch referenced an improved, lower-risk business profile resulting from strong regulated operations as the key driver behind its March 23 upgrade of Duke Energy Corp. (from BBB to BBB+) and three of its subsidiaries. The one-notch increases for Duke Energy Indiana (from BBB to BBB+), Duke Energy Ohio (from BBB to BBB+), and Duke Energy Carolinas (from BBB+ to A-) came after the parent company's move to spin-off its natural gas pipeline business (Spectra Energy) in January 2007 and sell its Cinergy subsidiary's commercial marketing and trading business in October 2006. The moves eliminated about $8.6 billion in consolidated debt and provided more than $1 billion in cash. S&P also upgraded Duke Energy and the same three subsidiaries on May 21, from BBB to A-, a two-notch jump.

Debt reduction was noted in S&P's March 15 upgrade of Progress Energy Inc. and its subsidiaries Progress Energy Carolinas and Progress Energy Florida (all from BBB to BBB+). Proceeds from Q1 asset sales significantly helped Progress reduce holding company debt, and its ongoing divestiture of unregulated activities helped moderate the company's business risk. S&P cited similar reasons in its upgrade of holding company DPL Inc. and its utility subsidiary on February 5, as did Fitch in its upgrade of CMS Energy and its utility Consumers Energy on March 12.

On April 19, Moody's upgraded TECO Energy from Ba2 to Ba1 citing reduced business risk and lower cash flow volatility due to its exit from the merchant generation business. Moody's and S&P also upgraded TECO in Q4 based on the closing of the sale of TECO Transport, a subsidiary that provides waterborne transportation services for coal and other commodities. Both ratings agencies gave similar reasons for the upgrade: the sale allows for debt reduction that will improve TECO's financial metrics to investment-grade levels. With the sale, S&P upgraded TECO from BB to BBB- (November 20) and Moody's from Ba1 to Baa3 (December 5), raising TECO to investment grade status in both cases.

On July 13, Fitch upgraded Progress Energy and its two electric utilities from BBB+ to A-. Fitch based the upgrades on the fact that the individual utilities' cash flow coverage and leverage ratios are more consistent with an A rating, along with their sound utility operations and the favorable state regulatory environments in their three states of operation (North Carolina, South Carolina and Florida). Fitch added that Progress Energy's consolidated business risk has improved as a result of the sale or wind-down of non-utility operations and subsequent reduction in parent-company debt, which lowered group linkage risks for its subsidiaries.

Fitch upgraded Avista Corp. on August 9 from BB to BB+, citing reduced business risk from the divestiture of its energy marketing and resource management subsidiary, Avista Energy. The upgrade was also driven by Avista's strategic

focus on its core electric and gas utility businesses in the Pacific Northwest and regulatory mechanisms in Washington and Idaho that allow it to recover certain rising power supply costs. Moody's also upgraded Avista on December 20, primarily reflecting the sale of Avista Energy and the use of sale proceeds to initially reduce debt, in line with Moody's expectations. S&P closed out the year with a two-notch increase (BBB to A-) for Virginia Electric and Power Company (a Dominion Resources' subsidiary). The upgrade relates to the parent company's sale of exploration and production assets, its plans to invest in regulated utility operations and its cash flow stability.

Upgrades of Generation Subsidiaries

On September 10, Moody's upgraded Allegheny Energy subsidiaries Allegheny Energy Supply (from Ba3 to Ba1) and Allegheny Generating (from Ba3 to Baa3), reflecting continued improvement in holding company Allegheny Energy's financial situation. The company has used proceeds from asset sales to reduce debt, and has shown better operating performance along with improved margins. The company cited the upgrades by ratings agencies in 2007 as further confirmation that its financial turnaround is complete.

Exelon and its Exelon Generation subsidiary each received upgrades from Moody's on September 21 — the parent company from Baa2 to Baa1 and the subsidiary from Baa1 to A3. The upgrades reflect strong financial credit metrics at the Chicago-based company as it extends its transition from a largely rate-regulated business to one whose results are driven by Exelon Generation, a wholesale power generator.

Illinois Regulatory Uncertainty Prompts Downgrades

A total of 20 downgrades (42% of all 2007's downgrades) were given to Illinois utilities and their affiliated companies in the first half of 2007 due to the state's regulatory uncertainty. Rate increases of up to 55 percent for Ameren customers and up to 26 percent for Commonwealth Edison (ComEd) customers — resulting from the state's competitive power auction in September 2006 — took effect in January 2007. On March 6, amidst growing public dissent, the Illinois House voted overwhelmingly in favor of rolling back these rate increases (92 to 5), and discussed the possibility of an additional three-year rate freeze. A potential rate freeze was also considered by the Illinois Senate during its March session.

Illinois' regulatory situation was closely scrutinized by the rating agencies during Q1 leading to multiple downgrades for the state's regulated utilities. On March 9, Fitch reacted to the House vote by downgrading Exelon's regulated distribution subsidiary ComEd to junk status (from BBB- to BB), citing increased overall corporate risk due to the uncertain regulatory environment. On March 26, shortly after the Senate bill was proposed, Moody's also downgraded ComEd to junk status (from Baa3 to Ba1), indicating that the regulatory environment was no longer supportive of an investment-grade rating.

Moody's cited similar reasons when it downgraded the other major Illinois utility, Ameren Corp. (from Baa1 to Baa2), and five of its subsidiaries on March 12. Of the five subsidiaries, ratings for Central Illinois Light Company, Illinois Power Company, and Central Illinois Public Service Company all fell into the 'speculative grade' category.

During the second quarter, negotiations continued between Illinois state lawmakers and utilities concerning a rate relief deal. The state requested $1 billion spread over three to five years, along with long-term measures to protect consumers from high prices in the future. This included a proposal to establish a new power authority that would oversee the way Ameren and Commonwealth Edison (ComEd) purchase power and the development of new power plants. The second quarter began with Fitch downgrading Ameren and three of its subsidiaries on April 2, citing an increased corporate risk profile due to the regulatory environment in Illinois. Ameren's rating was reduced one notch from A- to BB+, while its subsidiaries (Central Illinois Light Company, Central Illinois Public Service Company, and CILCORP) were lowered three notches, from BBB+ to BB+, or just below investment grade.

On April 23, S&P downgraded Ameren and seven of its subsidiaries just after the Illinois' Senate passed an Ameren-specific bill that would roll back electricity rates to 2006 levels, freeze them at that level for at least a year, and refund to customers any increases implemented since January 1, 2007. According to S&P, Senate Bill 1592, if signed into law, would result in a significant revenue shortfall and materially affect the liquidity of Ameren's Illinois utilities. S&P lowered Ameren and its Ameren Energy Generating and Union Electric subsidiaries from BBB to BBB- and dropped four subsidiaries (Central Illinois Light Company, Central Illinois Public Service Company, CILCORP Inc., and Illinois Power Company) to a below-investment-grade rating, from BBB- to BB.

On June 5, S&P downgraded Exelon subsidiary Commonwealth Edison (ComEd) from BBB- to BB, due to concern that a rate freeze could go into effect in Illinois. In July, Illinois' utilities and the state's legislative leaders forged a comprehensive rate relief package. Following the July agreement, S&P revised its outlooks for Exelon and Ameren to "stable" from "negative". On August 29, Fitch upgraded Commonwealth Edison from BB to BB+ following the signing of legislation by Illinois Governor Rod Blagojevich that assures Comed's ability to recover future power supply costs.

TXU Buyout Brings Downgrades

On February 26, TXU Corp. announced its entry into a definitive agreement with private equity firms Kohlberg Kravis Roberts & Co. (KKR) and Texas Pacific Group to be acquired for approximately $45 billion. Included in the acquisition plan was the assumption of nearly $25 billion worth of debt by the investment group, an agreement that was vehemently

opposed by bondholders. Fitch immediately reacted to the news by downgrading TXU Corp. to speculative grade (from BBB- to BB+) and its subsidiaries TXU Electric Delivery and TXU Energy to near-speculative grade (from BBB to BBB-). On March 2, S&P downgraded TXU Corp. and its unregulated subsidiary TXU Energy by two notches, from BBB- to BB. S&P subsequently placed the company on watch negative, and indicated that if the acquisition was successful and the capitalization plan defined by the buyers was established, further downgrades were expected.

The LBO merger transaction was completed on October 10, and TXU received downgrades from all three agencies in anticipation of the closing date. On October 8, Fitch downgraded TXU (BB+ to B) and subsidiary TXU Energy Co. (BBB- to B), citing the significant debt leverage and weak cash flow coverage ratios that would result from the merger. On October 9, S&P also cut the ratings of both companies from BB to B-, six levels below investment grade. In addition to the added debt, S&P stated that TXU's rating is further negatively affected by the planned ring-fencing and legal provisions that the deal's sponsors intend to structure around Oncor Electric Delivery, the company's regulated transmission and distribution subsidiary. Moody's also downgraded TXU on October 9 citing concern over its debt leverage. TXU changed its name to Energy Future Holdings Corp. with the completion of the merger on October 10.

A similar scenario unfolded for Duquesne Light Holdings earlier in the year. Moody's, S&P and Fitch all downgraded the company as it neared completion of its acquisition by Macquarie Infrastructure, which closed on April 30, 2007. All three agencies cited the additional debt, estimated by Fitch at $770 million, being taken on by Macquarie to fund the deal. The one-notch downgrades by Fitch (BBB- to BB+) and Moody's (Baa3 to Ba1) placed Duquesne below investment grade at both agencies. S&P lowered Duquesne Light Holdings and subsidiary Duquesne Light Company from BBB to BBB-.

Focus Shifts to Rising Capex

As the year progressed, rising capital expenditures and the accompanying debt were becoming a more frequent concern cited by the ratings agencies. In Q4, a total of four downgrades were issued to two parent companies and two affiliated subsidiaries. On December 4, Moody's lowered the ratings for SCANA Corp. (A3 to Baa1) and subsidiary South Carolina Electric & Gas Co. (A2 to A3). The downgrades primarily reflected Moody's expectation of a weakening financial profile over the intermediate term from a significantly increased capital expenditure program (relative to last year's projections) and management's decision to fund the increase mostly with debt. S&P downgraded NiSource on December 18 from BBB to BBB-, the lowest investment-grade rating. S&P referred to NiSource's newly aggressive capital spending program, which will result in negative free cash flow and increased debt levels, reversing years of deleveraging. Following its March 30 upgrades of PG&E and its Pacific Gas & Electric subsidiary, Moody's said there is limited opportunity for further upgrades in the near term due to PG&E's large capital investment program. The agency said the ratings may be downgraded, however, if PG&E elects to finance its capex with higher leverage, or if there is a significant negative change in the current regulatory environment.

The ratings agencies also took positive actions related to capex programs. In its November 26 upgrade of DPL Inc. (Baa3 to Baa2) and subsidiary Dayton Power and Light Company (Baa1 to A3), Moody's stated that the higher ratings reflect strong and improving consolidated cash flow coverage ratios and financial metrics that compare strongly to peer companies, especially at the utility. Moody's went on to mention that, unlike most other predominantly coal-fired utilities, Dayton Power & Light has completed a large portion of the capital expenditures required to put its plants into compliance with more stringent environmental guidelines. The utility's capital expenditures are projected to decrease from a high of $360 million in 2007 to $200 million in 2008 and to $145 million in 2009, resulting in significant free cash flow generation in both 2008 and 2009. Regarding the previously mentioned upgrade for Sierra Pacific Resources and its subsidiaries, Moody's mentioned that the companies' improved financial and regulatory situation should foster greater predictability for consolidated earnings and cash flow over the intermediate term as management undertakes a large capital program to address significant growth in Nevada.

Industry-wide capex began to rise in 2005, which saw the first significant full-year increase since the industry's competitive generation build-out peaked in 2001 ($56.8 billion was spent on capex in 2001). The $66.7 billion spent during the 12 months ending September 30, 2007 is $26.5 billion, or 65.9%, above the $40.2 billion spent during the 12-month period that ended on September 30, 2004, the cyclical low following the competitive generation build-out.

Companies are now boosting spending on environmental compliance and transmission and distribution upgrades, and are beginning to announce new generation projects in many power markets to ensure adequate reserve margins over the long term. EEI's spring 2007 study of industry capital spending based on 2006 10K data, company presentations, and discussions with companies revealed that:

- The industry is projecting $73.1 billion of capital expenditures in 2007, a 21.1% rise from the $60.3 billion spent in 2006 and 51.1% above the $48.4 billion in 2005.
- Industry capex will reach approximately $75 billion in 2008 and $75.5 billion in 2009.
- 2007's total capital spending is expected to be allocated as follows: Generation, 31%; Distribution, 30%; Environmental, 14%; Transmission, 12%; Natural Gas-related, 6%, Other, 7%.
- All components of capex are growing, with environ-

mental spending growing at the fastest rate. Total dollars spent on environmental capex nearly doubled from 2005 to 2006.

Ratings Analysis by Company Category Table V presents the distribution of credit ratings over time for the shareholder-owned electric utilities, organized into Regulated, Mostly Regulated and Diversified categories. Ratings are based on S&P long-term issuer ratings at the holding company level, with only one rating assigned per company. The average rating within each category is BBB, which reflects the overall industry average. Of particular note in Table V is the decline in credit quality within our Diversified category in 2007, primarily due to TXU's downgrade to below-investment-grade status. The drop in the Regulated category's credit quality was mostly due to the addition of six lower-rated companies to the category since the end of 2006.

Outlooks Mostly Negative at Year End

Thirty-five percent of outlooks/watches were positive on December 31, compared to 53%, 42% and 34% at the end of the first three quarters of 2007. Several negative outlooks were dropped for companies that completed or terminated mergers throughout the year, including TXU (acquired by Energy Future Holdings Limited Partnership) in Q4; KeySpan (acquired by National Grid), Niagara Mohawk Power (a regulated distribution subsidiary of National Grid), and NorthWestern (terminated merger) in Q3; Duquesne Light Holdings (acquired by consortium led by Macquarie Infrastructure Partners) in Q2; and Integrys Energy Group (formerly WPS Resources – merged with People's Energy) in Q1. Negative outlooks remained at year end for companies with mergers still pending, such as Puget Energy (with a consortium of long-term infrastructure investors led by Macquarie Infrastructure Partners) and Energy East (with Iberdrola).

In July, after Illinois utilities and the state's legislative leaders forged a comprehensive rate relief package, S&P revised its outlooks on Exelon and Ameren to "stable" from "negative".

Regulatory uncertainty has kept agencies wary of prolonged revenue deferrals and cost recovery challenges, particularly in volatile regulatory environments. Going forward, timely recovery of elevated fuel costs remains a challenge to cash flow for many utilities, and the impact of industry consolidation continues to be a major influence on ratings outlooks.■

Companies Listed by Category
(as of 12/31/05)

Given the diversity of utility holding company corporate strategies, no single company categorization approach will be useful for all EEI members and utility industry analysts. Never-the-less, we believe the following classification provides an informative framework for tracking financial trends and the capital markets' response to business strategies as companies depart from the traditional regulated utility model.

Regulated	80%+ of total assets are regulated
Mostly Regulated	50% to 80% of total assets are regulated
Diversified	Less than 50% of total assets are regulated

Categorization of the 65 publicly traded utility holding companies is based on year-end business segmentation data presented in 10Ks. Categorization of the 5 non-publicly traded companies (*shown in italics*) is based on estimates derived from FERC Form 1 data and information provided by parent company IR departments.

The EEI Finance and Accounting Division continues to evaluate our approach to company categorization and business segmentation. In addition, we can produce customized categorization and peer group analyses in response to member company requests. We welcome comments, suggestions and feedback from EEI member companies and the financial community.

Regulated (36 of 70)

Alliant Energy Corporation
Ameren Corporation
Central Vermont Public Service Corporation
CH Energy Group, Inc.
Cleco Corporation
Consolidated Edison, Inc.
DPL, Inc.
Duquesne Light Holdings, Inc.
El Paso Electric Company
Empire District Electric Company
Energy East Corporation
Great Plains Energy Incorporated
Green Mountain Power Corporation
IDACORP, Inc.
IPALCO Enterprises, Inc.
Kentucky Utilities
KeySpan Corporation
Louisville Gas and Electric
Maine & Maritimes Corporation
Niagara Mohawk Power Corporation
NorthWestern Corporation
NSTAR
PG&E Corporation
Pinnacle West Capital Corporation
Portland General Electric Company
Progress Energy
Puget Energy, Inc.
SCANA Corporation
Sierra Pacific Resources
Southern Company
UIL Holdings Corporation
UniSource Energy Corporation
Unitil Corporation
Westar Energy, Inc.
Wisconsin Energy Corporation
Xcel Energy, Inc.

Mostly Regulated (23 of 70)

ALLETE, Inc.
American Electric Power Company, Inc.
Aquila, Inc.
Avista Corporation
CenterPoint Energy, Inc.
CMS Energy Corporation
DTE Energy Company
Edison International
Entergy Corporation
Exelon Corporation
First Energy Corp.
FPL Group, Inc.
MGE Energy, Inc.
MidAmerican Energy Holdings
NiSource Inc.
Northeast Utilities
Otter Tail Corporation
Pepco Holdings, Inc.
PNM Resources, Inc.
PPL Corporation
Public Service Enterprise Group, Inc.
TECO Energy, Inc.
Vectren Corporation

Diversified (11 of 70)

Allegheny Energy, Inc.
Black Hills Corporation
Constellation Energy Group, Inc.
Duke Energy Corporation
Dominion Resources, Inc.
Hawaiian Electric Industries, Inc.
MDU Resources Group, Inc.
OGE Energy Corp.
Sempra Energy
TXU Corp.
WPS Resources Corporation

Note: Based on assets at 12/31/05

Companies Listed by Category
(as of 12/31/04)

Given the diversity of utility holding company corporate strategies, no single company categorization approach will be useful for all EEI members and utility industry analysts. Never-theless, we believe the following classification provides an informative framework for tracking financial trends and the capital markets' response to business strategies as companies depart from the traditional regulated utility model.

Regulated	80%+ of total assets are regulated
Mostly Regulated	50% to 80% of total assets are regulated
Diversified	Less than 50% of total assets are regulated

Categorization of the 65 publicly traded utility holding companies is based on year-end business segmentation data presented in 10Ks. Categorization of the 8 non-publicly-traded companies (*shown in italics*) is based on estimates derived from FERC Form 1 data and information provided by parent company IR departments.

The EEI Finance and Accounting Division continues to evaluate our approach to company categorization and business segmentation. In addition, we can produce customized categorization and peer group analyses in response to member company requests. We welcome comments, suggestions and feedback from EEI member companies and the financial community.

Regulated (37 of 73)

Ameren Corporation
Central Vermont Public Service Corporation
Consolidated Edison, Inc.
DPL, Inc.
Duquesne Light Holdings, Inc.
El Paso Electric Company
Empire District Electric Company
Energy East Corporation
FirstEnergy Corp.
Great Plains Energy Incorporated
Green Mountain Power Corporation
IDACORP, Inc.
IPALCO Enterprises, Inc.
Kentucky Utilities
KeySpan Corporation
Louisville Gas and Electric
Maine & Maritimes Corporation
New England Power Company
Niagara Mohawk Power Corporation
NorthWestern Corporation
NSTAR
PacifiCorp
PG&E Corporation
Pinnacle West Capital Corporation
Portland General Electric Company
Progress Energy
Puget Energy, Inc.
SCANA Corporation
Sierra Pacific Resources
Southern Company
UIL Holdings Corporation
UniSource Energy Corporation
Unitil Corporation
Vectren Corporation
Westar Energy, Inc.
Wisconsin Energy Corporation
Xcel Energy, Inc.

Mostly Regulated (26 of 73)

Alliant Energy Corporation
ALLETE, Inc.
American Electric Power Company, Inc.
Aquila, Inc.
Avista Corporation
CenterPoint Energy, Inc.
CH Energy Group, Inc.
Cinergy Corp.
Cleco Corporation
CMS Energy Corporation
DTE Energy Company
Edison International
Entergy Corporation
Exelon Corporation
FPL Group, Inc.
MGE Energy, Inc.
MidAmerican Energy Holdings
NiSource Inc.
Northeast Utilities
Otter Tail Corporation
Pepco Holdings, Inc.
PNM Resources, Inc.
PPL Corporation
Public Service Enterprise Group, Inc.
TECO Energy, Inc.
WPS Resources Corporation

Diversified (10 of 73)

Allegheny Energy, Inc.
Black Hills Corporation
Constellation Energy Group, Inc.
Dominion Resources, Inc.
Duke Energy Corporation
Hawaiian Electric Industries, Inc.
MDU Resources Group, Inc.
OGE Energy Corp.
Sempra Energy
TXU Corp.

Note: Based on assets at 12/31/04

EXHIBIT

KPL-7

FitchRatings
KNOW YOUR RISK

FITCH TO RATE TEP SENIOR UNSECURED INDUSTRIAL REVENUE BONDS 'BB+'; OUTLOOK STABLE

Fitch Ratings-New York-12 March 2008: Fitch Ratings expects to assign a 'BB+' rating to the planned $121 million Industrial Development Revenue Bonds, 2008 Series A issued on behalf of the Tucson Electric Power Company (TEP) by the Industrial Development Authority of the County of Pima (Arizona). Proceeds from the offering will be used by TEP to repay short-term and maturing long-term debt obligations. The Rating Outlook is Stable.

The rating considers TEP's cash flow coverage and debt ratios, which are consistent with the rating category. TEP's rating also reflects the company's utility-focused strategy, solid service territory growth and efforts to reduce debt. Fitch assumes that TEP's pending general rate case (GRC) will result in revenues, earnings and cash flows sufficient to facilitate continued financial de-leveraging.

The primary concern for investors is an outcome in TEP's pending GRC, which was filed in July 2007, that would result in an inability to further reduce debt leverage. In its filing TEP requested a $181 million (23%) revenue increase on a cost-of-service basis and proposed alternative rate adjustments based on market rates for generation, or a hybrid model. The rate increase is based on a 10.75% authorized return on equity. The filing also requests implementation of a fuel adjustment clause. A final order is expected by year-end 2008.

On Feb. 29, 2008, the Arizona Corporation Commission (ACC) staff filed testimony in the proceeding recommending a $14 million-$22 million rate decrease based on a 10.25% return on equity. While the commission is not bound by the staff recommendation, Fitch notes that a final order by the ACC consistent with the staff proposal would likely result in weaker than anticipated credit metrics. Positively, the staff recommends ACC adoption of a fuel adjustment clause.

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Fitch's rating definitions and the terms of use of such ratings are available on the agency's public site, 'www.fitchratings.com'. Published ratings, criteria and methodologies are available from this site, at all times. Fitch's code of conduct, confidentiality, conflicts of interest, affiliate firewall, compliance and other relevant policies and procedures are also available from the 'Code of Conduct' section of this site.

EXHIBIT

KPL-8

EXHIBIT KPL-1

Tucson Electric Power Company
Cost of Long-Term Debt and Short-Term Debt
Test Year Ended December 31, 2006
(Thousands of Dollars)

Line No.	Description	End of Test Period (Actual) - as if on FAS71 Outstanding	Annual Interest	Cost Rate	End of Test Period (Proposed) - as if on FAS71 Outstanding	Annual Interest	Cost Rate	Line No.
	Mortgage Bonds							
1	7.5% Series First Collateral Trust Bonds	$138,300	$10,373		$138,300	$10,373		1
2	Total First Mortgage Bonds	138,300	10,373	7.50%	138,300	10,373	7.50%	2
	Variable Rate-Tax Exempt Bonds							
3	Variable 1982 Pima A Irvington	38,700	1,782		38,700	1,872		3
4	Variable 1982 Pima A Irvington & Four Corners	39,900	1,838		39,900	1,889		4
5	Variable 1983 Apache A Springerville	100,000	4,546		100,000	4,786		5
6	Variable 1983 Apache B Springerville	80,000	3,685		80,000	3,788		6
7	Variable 1983 Apache C Springerville	50,000	2,273		50,000	2,340		7
8	Variable 1985 Apache A Springerville	20,000	909		20,000	956		8
9	Total Variable Rate-Tax Exempt Bonds	328,600	15,033	4.57%	328,600	15,631	4.76%	9
	Fixed Rate-Tax Exempt Bonds							
10	6.1% 1997 Pima A	22,460	1,370		22,460	1,370		10
11	5.85% 1998 Apache C	16,500	965		16,500	965		11
12	6.95% 1997 Farmington A	80,410	5,588		80,410	5,588		12
13	7.125% 1997 Coconino A	36,700	2,615		36,700	2,615		13
14	7.0% 1997 Coconino B	14,700	1,029		14,700	1,029		14
15	5.85% 1998 Apache A	83,700	4,896		83,700	4,896		15
16	5.875% 1998 Apache B	99,800	5,863		99,800	5,863		16
17	Total Fixed Rate Tax-Exempt Bonds	354,270	22,327	6.30%	354,270	22,327	6.30%	17
18	Total Long-Term Debt (a)	821,170	47,733	5.81%	821,170	48,331	5.89%	18
19	Unamortized Debt Discount, Premium and Expense and Loss on Reacquired Debt	(20,460)			(20,460)			19
20	Amortization of Debt Discount and Expense and Loss on Reacquired Debt		5,003			4,286		20
21	Credit Facility Commitment Fees		105			165		21
22	Total Long-Term Debt - Net	$800,710	$52,841	6.60%	$800,710	$52,782	6.59%	22
23	Total Short-Term Debt	$30,000	$1,776	5.92%	$0	$0	N/A	23

Supporting Schedules	Recap Schedules
(a) E-1 (P2)	A-4
E-9	

SCHEDULE D-2 PAGE 1 REFERENCES

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-0402

TUCSON ELECTRIC POWER COMPANY

REBUTTAL TESTIMONY AND EXHIBITS

VOLUME 2 OF 2

April 1, 2008

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-0402

Rebuttal Testimony of

David G. Hutchens

on Behalf of

Tucson Electric Power Company

April 1, 2008

Executive Summary of the Rebuttal Testimony of David G. Hutchens

Mr. Hutchens is the Vice President, Wholesale Energy for Tucson Electric Power Company ("TEP" or the "Company"). Mr. Hutchens' Rebuttal Testimony addresses the following matters:

1. Springerville Unit 1. RUCO and AECC recommend the unit be recovered at test year cost. Staff recommends that a market rate determined 20 years ago still be used today. This unit should be recovered at current market rates for equivalent capacity and energy.

2. Luna Energy Facility. RUCO, Staff and AECC recommend recovery of the Luna facility at Test Year cost. This facility should be recovered at the discounted market rate as offered by the Company in its Direct Testimony.

3. Coal Cost Adjustments. Staff and RUCO agree on the Sundt coal cost adjustment but take different views on the Navajo and San Juan coal cost adjustments. The Company believes that RUCO will agree with the Company and Staff on Navajo adjustment after the provided clarification on some data inconsistencies. The Company further believes that Staff should agree with the Company and RUCO that San Juan adjustment is accurate and valid and should be adopted.

4. Short-Term Sales. Staff and RUCO recommend crediting 100% of wholesale revenue (and margins) to the base rates. The Company objects to crediting this to base rates and proposes crediting to the PPFAC on a going forward basis. The Company also proposes keeping a portion of the revenues (or margins) of short-terms sales to align the interests of the Company and its customers.

5. Purchased Power and Fuel Adjustment Clause ("PPFAC"). The Company is in general agreement with Staff's proposed mechanism. The Company objects to base rate treatment of certain PPFAC credits and recommends those credits be applied to the PPFAC on a going forward basis. The Company rejects RUCO's unclear mechanism. The Company also rejects AECC's positions on the PPFAC and its recommended adjustments thereto.

6. SO2 Allowance Credits. The Company objects to Staff and RUCO's base rate treatment of the excess gain on SO2 allowances. The Company also objects to the Staff and RUCO's position that 100% of the excess allowance gain belong to the customers.

7. Fuel and Purchased Power Audit. The Company generally agrees with Staff's conclusions and recommendations. The few points of disagreement are addressed.

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Exhibits

Exhibit DGH-13 Historical gas and power market prices

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is David G. Hutchens. My business address is One South Church Avenue, Tucson, Arizona 85701.

Q. Are you the same David G. Hutchens that previously submitted Direct Testimony on behalf of Tucson Electric Power Company ("TEP" or "Company") in this Docket?

A. Yes.

Q. Have you reviewed the Direct Testimonies filed by the Arizona Corporation Commission Staff ("Staff"), the Residential Utility Consumer Office ("RUCO"), and Arizonans for Electric Choice and Competition ("AECC")?

A. Yes I have.

Q. Please Summarize your Rebuttal Testimony.

A. My Rebuttal Testimony addresses the following main topics:

1. Springerville Unit 1 – RUCO and AECC recommend the unit be recovered at test year cost. Staff recommends that a market rate determined 20 years ago still be used today. This unit should be recovered at current market rates for equivalent capacity and energy.
2. Luna Energy Facility – RUCO, Staff and AECC recommend recovery of the Luna facility at Test Year cost. This facility should be recovered at the discounted market rate as offered by the Company in its Direct Testimony.
3. Coal Cost Adjustments – Staff and RUCO agree on the Sundt coal cost adjustment but take different views on the Navajo and San Juan coal cost adjustments. The Company believes that RUCO will agree with the Company and Staff on Navajo

adjustment after being provided clarification on some data inconsistencies as set forth in this testimony. The Company further believes that Staff should agree with the Company and RUCO that San Juan adjustment is accurate and valid and should be adopted.

4. Short-Term Sales – Staff and RUCO recommend crediting 100% of wholesale revenue (and margins) to the base rates. The Company objects to crediting this amount to base rates and proposes crediting the amount to the PPFAC on a going forward basis. The Company also proposes keeping a portion of the revenues (or margins) of short-terms sales to align the interests of the Company and its customers.

5. Purchased Power and Fuel Adjustment Clause ("PPFAC") – The Company is in general agreement with Staff's proposed mechanism. The Company objects to base rate treatment of certain PPFAC credits and recommends those credits be applied to the PPFAC on a going forward basis. The Company rejects RUCO's unclear mechanism. The Company also rejects AECC's positions on the PPFAC and its recommended adjustments thereto.

6. SO2 Allowance Credits – The Company objects to Staff and RUCO's base rate treatment of the excess gain on SO2 allowances. The Company also objects to the Staff and RUCO's position that 100% of the excess allowance gain belongs to the customers.

7. Fuel and Purchased Power Audit – The Company generally agrees with Staff's conclusions and recommendations. The few points of disagreement are addressed in my testimony below.

II. SPRINGERVILLE UNIT 1.

A. Overview of Parties' Positions.

Q. Please summarize the Parties' positions on the Springerville Unit 1.

A. In its Direct Testimony, TEP had valued Springerville Unit 1 at $25.67 per kW-month – a low end market rate value for the unit – in determining TEP's revenue requirement. Staff recommends treating Springerville Unit 1 using a twenty year old market based value of $15 per kW-month set in a 1989 rate decision in the calculation of revenue requirement. RUCO recommends the use of the actual test year embedded cost of Springerville Unit 1. According to RUCO, the test year cost for Springerville Unit 1 was approximately $85 million, which equates to $18.63 per kW-month. AECC also recommends the removal of the Company adjustment for Springerville Unit 1; resulting in a recovery rate of $18.63 per kW-month.

Q. What are the reasons for Staff recommending the $15 rate in this proceeding?

A. Staff provides very little information on its reasoning other than what Mr. Ralph D. Smith states is his Direct Testimony at page 52. Staff states "there is no compelling need at this time to revise the $15 per kW fixed monthly rate" and that "the fixed monthly rate should remain at $15 per kW, as established in Decision No. 56659 (October 24, 1989) and used in prior TEP rate cases". Mr. Smith also suggests the possibility of capital lease treatment which is not an option under Arizona law, as described in the rebuttal testimony of Ms. Kissinger. Finally, Mr. Smith believes the $15 value continues to be justified in light of conduct by past TEP management over 20 years ago.

B. History of the $15 per kW rate.

Q. Are you aware of other Commission precedent for the use of market-based rates or market value for assets in rate base?

A. Yes. Besides Decision No. 56659 setting Springerville Unit 1 at a market rate, Decision No. 67744 (April 7, 2005) relied on a market valuation of a power sale agreement between Arizona Public Service Corporation ("APS") and Pinnacle West Energy Corporation ("PWEC").

Q. What was Staff's position on the Springerville Unit 1 fixed monthly rate in TEP's 2004 Rate Review (Docket No. E-01933-04-0408)?

A. In the 2004 Rate Review, Staff recommended a fixed recovery at $20 per kW-month. In short, Staff rejected the Company's recommended recovery rate and eliminated the related pro forma adjustment.

Q. What was the basis for this adjustment in the 2004 Rate Review?

A. Staff indicated that TEP had not presented any compelling reasons to reset the rate to a market level and that the contract TEP used to establish market should be disregarded. According to Staff witness James Dorf in Direct Testimony provided in Docket No. E-0933A-04-0408 (p. 19, lines 17-18), "In effect, Staff's adjustment is approximately half way between TEP's market rate of $25.67 and the Commission adopted $15.00".

Q. Does the Company agree with Staff's position in this docket?

A. No. Mr. Smith provides no evidence that the rate established in 1989 is reasonable for 2008 and beyond. The rate established in Decision No. 56659 was not meant to be set in perpetuity. There is additional information in that Docket that clearly sheds light on that fact. Moreover, there is a subsequent Commission decision that sets a different standard

for treating Springerville Unit 1 (Decision No. 57856 (October 11, 1991). Mr. Smith's position also simply ignores the substantial leasehold improvements made at Springerville Unit 1 since 1989 as addressed in Ms. Kissinger's Rebuttal Testimony. Finally, TEP does not agree with Mr. Smith's position that the Company should continue to be penalized for the 20 year old practices of previous management.

Q. What additional information can the Company provide related to the $15 per kW-month rate that was established in Decision No. 56659?

A. In setting the $15 rate, the Commission stated: "We believe the more reasonable evidence was offered by Staff witness [Robert D Adkins, a Utility Regulatory Consultant with LMSL, Inc.] who testified that a reasonable purchase price for the capacity is $15 per kilowatt-month" (Decision No. 56659 at page 11 lines 12 through 14). Importantly, when Staff Witness Mr. Adkins recommended the $15 per kW-month rate, he also stated – at page 18 of his Direct Testimony in Docket U-1933-88-280 - that it would be unreasonable for TEP to assume "it could purchase replacement capacity beyond 1996 at $18.50/kW-month (effectively equal to San Juan rates in 1988)." Mr. Adkins further stated that "The **market value of replacement capacity** based on projected gas prices in the western U.S. or the cost of new generating capacity is significantly higher than $18.50/kW-month during the 1997-2015 period." – in his Direct Testimony in Nos. Docket U-1933-88-280 et al, at page 13 lines 9 through 12 [emphasis added].

Mr. Adkins' statements - made at the time TEP first requested Springerville Unit 1 inclusion in the revenue requirement – did not indicate that the $15 per kW-month rate should be constant over time. To the contrary, Mr. Adkins expected that the value of capacity for Springerville Unit 1 would increase over time.

Q. What other assumptions does Mr. Adkins make that shed light on his basis for the initial $15 per kW-month rate?

A. On page 18 of his Direct Testimony, Mr. Adkins stated "I assumed that TEP would be able to sell capacity at $15.00/kW-month (1989-1996), $18.50/kW-month (1997-2010), and $22.50/kW-month (2011-2015); and energy at San Juan Unit 3 fuel cost (1989-2010) and Springerville Unit 1 fuel cost (2011-2015), based on **market rates** recently negotiated by TEP in its 1990-2011 power sales agreement with Salt River Project, and the projected cost of service over the 2011-2015 period for Springerville Unit 1." Mr. Adkins' testimony shows that he did not expect the market rate to remain at $15 per kW-month starting as early as 1997. Yet Staff here makes no adjustment to account for the increase in this rate in 2008.

Q. Are there other Commission Decisions related to future Springerville Unit 1 rate treatment?

A. Yes. The Commission subsequently took the step of formally acknowledging that Springerville Unit 1's treatment was not fixed at the $15 rate. In Finding of Fact No. 10.q in Decision No. 57586 (October 11, 1991), the Commission stated "In future rate cases the Commission shall determine the appropriate level of the Century demand charge *based on reasonable market prices*, but in no event will the rate be lower than the rate allowed in Decision No. 56659, or $15 per kW/month." (emphasis added).) Here, the Company is requesting that the Commission determine an appropriate level for this demand charge. The evidence I present shows that the $15 per kW-month is not a reasonable market price going forward. Mr. Smith is ignoring that evidence by blindly adhering to a rate established over 20 years ago. Both Mr. Adkin's testimony from Docket No. U-1933-88-280 and Decision No. 57586 support the market-based rate treatment the Company seeks here.

Q. Was Mr. Smith aware of Decision No. 57586 when he developed his testimony?

A. Apparently not. In his deposition on pages 134 and 135 he was presented with Decision No. 57586 and was required to read the finding of fact 10 q. above. On page 146 of his deposition, he states "This particular finding of fact, I could tell you now that I was not aware of that particular finding when my testimony was prepared."

C. SRP Power Supply Agreement.

Q. Please explain how the SRP power sale agreement relates to Springerville Unit 1 recovery rate.

A. As previously mentioned, Mr. Adkins based his initial recommended recovery rate for Springerville Unit 1 on market rates recently negotiated by TEP in this power sale agreement with SRP. The initial rates of this agreement were $15 per kW-month (from 1990 to 1996) and $18.50 per kW-month (from 1997 through the end of the contract in 2011), the exact numbers recommended for these time periods by Mr. Adkins.

Q. What is the demand charge today for the Salt River Project's power supply agreement?

A. The current demand charge is $18.50 per kW-month.

Q. Is this value directly applicable in determining a current equivalent demand rate for Springerville Unit 1?

A. No. An adjustment must be made to take into account the energy cost differences between the power sales agreement and Springerville unit 1 fuel expense.

Q. Please explain?

A. The power sales agreement computes an energy charge based on average fuel costs. This energy charge is higher than the fuel expense rate of Springerville Unit 1.

Q. What is the equivalent demand charge of the SRP power sales agreement taking this into account?

A. $22.52 per kW-month.

Q. Please explain how this was calculated?

A. Test Year fuel expense for Springerville Unit 1 was 1.65 cents per kWh. The average energy charge for SRP's power sales agreement in 2007 was 2.227 cents per kWh. The difference between these rates is 0.577 cents per kWh. SRP purchased 836,368,000 kWh in 2007 resulting in $4.8 million of higher energy charges compared to Springerville Unit 1. Converting this $4.8 million to a demand rate yields that the SRP power supply agreement would have a $4.02 per kW-month higher demand rate if its energy charge was equivalent to Springerville fuel expense rate ($4.8 million/(100,000 kW)/(12 months)). Adding this $4.02 to the contract demand rate of $18.50 yields a contract demand rate of $22.52 to be equivalent to Springerville Unit 1 at its fuel expense rate.

D. Leasehold Improvements.

Q. Does Mr. Smith express other reservations about the $15 per kW-month rate proposed by Staff for Springerville 1?

A. Yes. Mr. Smith acknowledges that the $15 rate doesn't consider leasehold improvements subsequent to 1989, as is demonstrated in the following exchange on page 144 of his deposition:

"Q. No. I hear that. But if the Staff is going to stick to the $15 per kW, per month, how are those post 1989 leasehold improvements reflected in the rates? How do we recover those expenditures?

A. I'm not sure that you would. And that presents a problem, a legitimate concern, I believe. And one potential solution would be to go to the test year cost basis approaches, just strip off all of the company pro forma adjustments related to Springerville, and then do a further evaluation to make sure that there aren't other things that need to be considered and use that as the ratemaking basis based on recovery of as-recorded costs in the test year. I understand from briefly skimming RUCO's testimony that that's what they may have done. I haven't looked at it in detail. But we will certainly, you know, look at that type of proposal and , if that is more reasonable than continuing to use the $15 per kilowatt hour, we will make—you know, modify our recommendations should we reach that conclusion."

E. Cost Method.

Q. Has the Company provided compelling reasons to reset the rate in this proceeding?

A. Yes. The Company has provided very compelling reasons based on the history of the Springerville Unit 1 rate treatment in prior Decisions and has provided numerous market benchmarks to establish the applicable market value and rates associated with this generating plant.

Q. Has Staff explained the reversal of its position in the 2004 rate review in which it recommended cost basis?

A. Staff has indicated in its Response to Data Request No. 2-22 that "Staff is also willing to consider an alternative to reflect Springerville Unit No. 1 in rates in the current TEP rate case at cost, if the cost amounts can be ascertained with clarity and can be verified."

Q. What amount of Springerville Unit 1 costs do RUCO and AECC propose to include in the revenue requirement?

A. RUCO and AECC are proposing to include the unadjusted Springerville Unit 1-related expenses that TEP booked in the test year. These costs include approximately $81 million of operations and maintenance expenses and approximately $4 million of administrative and general expenses.

Q. Is this a correct measurement of "cost"?

A. No. In Ms. Kissinger's rebuttal testimony she describes the appropriate determination of cost for Springerville Unit 1.

F. Market Costs.

Q. Has any Party refuted the validity of the market costs presented in your Direct Testimony?

A. No. No Party has challenged the $25.67 per kW-month as an inaccurate or unreasonable reflection of market cost. In fact, the evidence shows that this value is lower than market costs going forward. RUCO and AECC challenge using a market cost going forward. Staff merely recommends sticking to an outdated and clearly inappropriate rate per kW-month.

Q. What was the Company's position on the fixed cost recovery rate requested for Springerville Unit 1 in your Direct Testimony?

A. The Company offered to use a discounted market capacity rate as the fixed cost recovery rate based upon the Springerville Unit 3 Purchased Power Agreement with Tri-State Generation and Transmission Association ("Tri-State").

Q. You said this was a "discounted" rate. Please explain.

A. As covered in my Direct Testimony, it was discounted due to the call feature. As I explained, TEP entered into a five-year purchase power agreement ("PPA") with Tri-State. The Tri-State PPA has a provision that gives Tri-State the option to call back capacity with a 90-day written notice. In April, 2007 Tri-State served notice of its option to recall 100% of the energy and capacity effective August 1, 2007 thereby terminating the PPA. This is a call feature that reduces the value of the contract (*i.e.* $25.67 per kW-month), as compared to similar contracts without call features. This value is lower than the three forward market capacity estimates as shown in Exhibit DGH-7. TEP proposed using this value because it is consistent with the relevant timeframe in this case (*i.e.* 2008 through 2011). As I also stated in my Direct Testimony at pages 19 through 20, 2009 market-based coal capacity estimates averaged $29.72 per kW-month. No Party, to my knowledge, challenged these estimates as inaccurate or not reflective of costs going forward.

Q. Was the contract's call feature exercised?

A. Yes. Tri-State called the contract effective August 1, 2007.

Q. What can one infer from the fact that Tri-State exercised its call option?

A. Exercising the call indicates that the contract was under market (i.e. that $25.67 per kW-month is under the current market rate). If Tri-State could have acquired a cheaper source

from the market, it is reasonable to assume that it would have rather than calling the contract with TEP.

Q. How did this contract compare in value to the other market capacity values presented in your Direct Testimony?

A. It was the cheapest. In fact, it was 14% cheaper than the average of the other market values. This is shown on confidential Exhibit DGH-7.

Q. Why did the Company use this contract as a proxy for market value if it was the cheapest option identified?

A. As explained in my Direct Testimony at pages 22 and 23, the Tri-State agreement was a known and measurable coal capacity value and it fit the relevant timeframe. The Company was also offering the lower rate in the spirit of compromise given the breadth of issues in this case.

Q. Has your view of using this contract for the new Springerville Unit 1 rate changed?

A. Yes. First, the contract was called by Tri-State, showing that it was under market. Second, as the timeframe for this case extends, there are fewer years of that contract that will be applicable to this case. Third, due to positions taken by the intervenors in this case, it appears that no party is interested in compromise.

Q. What does the Company propose now?

A. The Company withdraws using the Tri-State contract as a proxy (since that contract is now terminated) and will use the average of the remaining market comparisons. As set for in my Direct Testimony at pages 19-20 and Confidential Exhibit DGH-7 thereto, this results in a $29.72 per kW-month rate

Q. Have expected wholesale power prices for 2009 increased compared to those filed with the case and used for development of the market capacity prices?

A. Yes. The forward wholesale power prices for 2009 have increased approximately 7.5% as of March 7, 2008.

Q. What effect would this have on the market capacity prices calculated in your Direct Testimony?

A. The market capacity prices would be higher than those filed in this case.

Q. Is the Company requesting that these values be recalculated based on the updated, higher power market prices?

A. No. Not at this time.

Q. Do you believe it is appropriate to continue to penalize TEP for acts of past management?

A. No. Current management has taken significant effort to improve the financial condition of TEP over the past 20 years. Mr. Larson, in his Direct and Rebuttal Testimony, explains in detail how the Company's finances have improved under the guidance of new management. For Staff to continue to base its recommendations on a 20 year old market value and to justify that position based on distant historic practices by past management is unreasonable.

III. LUNA ENERGY FACILITY.

Q. Please summarize the positions of the Parties regarding the Luna Energy Facility ("Luna").

A. Staff, RUCO and AECC recommend the reversal of the adjustment the Company proposed to remove Luna from rate base and replace it with a market-based recovery rate. The Parties also propose to reverse the operating income adjustments associated with Luna.

Q. Does any Party dispute the market values presented in your Direct Testimony?

A. No. The Parties do not dispute the market values presented in my Direct Testimony.

Q. Is TEP requesting that Luna be recovered at current market value?

A. No. TEP is requesting that it be recovered at a discount to current market values. As covered in my Direct Testimony, the current market rate is $10.66 per kW-month and the Company requested $7.00 per kW-month. In addition, as explained in Mr. Judah Rose's Rebuttal Testimony, the cost to build a facility like Luna has increased greatly.

Q. Is TEP suggesting that the Luna's price be determined in the future using a market price?

A. No. TEP is willing to commit to the discounted value for the life of Luna if its requested rate treatment is approved.

Q. Is there precedent of the Commission using a market price for the recovery of assets?

A. Yes. As I discussed earlier in my Rebuttal Testimony – Decision Nos. 56659, 57586 and 67744 all approved using a market price for the recovery of assets. For example, in Decision No. 67744, the Commission approved PWEC assets at a non-cost based

valuation. This value was a market based determination of the value of the remaining term of a Track B contract between APS and PWEC.

Q. Will the Company accept cost base treatment for Luna?

A. No. The market based fixed cost recovery rate for Luna Energy Facility of $7.00 per kW-month is reasonable and compares favorably for the customers benefit versus using the present value equivalent of $10.66 per kW-month.

Q. If the Company and the Parties were to agree to a cost-based treatment of Luna, are there other costs that need to be included?

A. Yes. When the Company filed its requested treatment of Luna, it did not include other fixed costs that were covered by the proposed demand charge, such as fixed O&M expenses that are covered in Luna's Long-Term Service Agreement with GE. If Luna receives cost-based treatment then these costs must be included. This adjustment and the other Luna adjustments for cost-based treatment are detailed in Ms. Kissinger's Rebuttal Testimony.

IV. <u>COAL COST ADJUSTMENTS.</u>

Q. Could you summarize the position of the Parties on the Company's three coal cost adjustments?

A. Regarding the three coal cost adjustments used to recognize the known increase from 2006 to 2007:

- all parties agree with the Sundt adjustment;
- regarding the Navajo Station adjustment, RUCO disagrees with the numbers used to calculate the increase while Staff accepts the adjustment as calculated; and

- regarding the San Juan adjustment, Staff disagrees, but RUCO accepts the adjustment.

Q. What is the basis of RUCO's disagreement with the Navajo calculation?

A. RUCO agrees with the methodology but uses incorrect data. RUCO was provided Navajo fuel costs in the middle of 2007 that did not include an amount accrued but not yet invoiced for the Five Year Price Review that is retroactive back to January 1, 2007. Based on that information RUCO applied the proper methodology but used the wrong cost information.

Q. Since 2007 cost information is now known, would it be appropriate to use 2007 actual costs?

A. Yes. The best available information at this time is the 2007 actual fuel costs. These costs are more representative of the Navajo fuel costs that will be in effect in 2009.

Q. What should the Navajo adjustment be?

A. Using the actual cost per ton in the test year of $30.23 and the full year 2007 actual cost of $35.43 the increase is $5.20 per ton. That difference times the number of tons burned in the test year yields an increase of $2.9 million in fuel expense.

Q. Do you have any comments regarding the San Juan adjustment?

A. Yes. This adjustment reflects the increased costs from this underground mine – comparing the actual costs of the coal in the test year on a per ton basis to the miner's forecast of costs in 2007 – with the difference multiplied by the number of tons burned in the test year. This is clear evidence that coal prices are not stable and that a fuel and purchased power adjustment clause that recovers coal costs is appropriate, as I explain later in my Rebuttal Testimony. If the PPFAC recommended by Staff is adopted, then actual costs for San Juan

coal will be recovered through the PPFAC mechanism. Therefore, the Company does not need to include projected costs as part of the base rates, although all of the evidence points to these projections as accurate and reasonable. I note, however, that the PPFAC rate could then increase more than if the 2007 forecasts for San Juan coal are included.

Q. Please summarize the various positions of the Parties regarding the Company's treatment of the coal buy-out costs.

A. All Parties presented different positions regarding coal buyout costs:

- AECC recognizes that the buyouts are both prudent and beneficial. Even so, AECC recommends that the buy-out costs be amortized over ten years starting from the respective dates of the buy-outs.
- RUCO does not agree with recovery of the buy-out costs because the Company did not ask for and get an accounting order to defer the costs at the time the buy-outs occurred.
- Staff Witness Emily S. Medine recommends – at pages 33 through 35 of her Direct Testimony – denying the Sundt buy-out recovery and recommends that the San Juan buyout cost should be amortized over the life of the agreement remaining – starting from the time of the buyout.
- As clarified through data requests, Staff Witness Smith's Direct Testimony and adjustments agree with the recommendations of Ms. Medine.

Q. What do you make of these varying positions?

A. Both AECC and Staff recognize the benefit to the customers of the buy-outs -- the disagreement is over how to amortize the buy-out costs. RUCO does not address the benefits created but rather dismisses the recovery out of hand because the Company did not ask for an accounting order to defer costs – even though the Company's generation had

been deregulated. Ms. Kissinger's Rebuttal Testimony discusses RUCO's flawed position in more detail.

Q. Given the disparate positions of the other parties, does TEP believe its treatment of the coal contracts is still appropriate?

A. Yes, for the reasons stated in my Direct Testimony.

V. SHORT-TERM SALES.

Q. Please summarize the positions of the Parties regarding the treatment of short term sales margins.

A. Staff proposes to include the entire net margin from short-term sales in the determination of TEP's base rate revenue deficiency or excess. Staff also proposes to include a provision in the PPFAC to adjust for annual deviations from the amount of the margin credit established in this case.

RUCO also recommends a 100% credit of short term sales margins to base rates. Since RUCO recommends rejection of the PPFAC, there would be no annual adjustment.

AECC recommends a full credit of test year short term sales margin in the determination of base rates. AECC is neutral as to the adoption of a PPFAC. However, AECC states that if a PPFAC were approved, 90% of the fluctuations in the short term sales margin should accrue to customers.

Q. Does TEP agree with crediting 100% of margins?

A. No. TEP recommends keeping a portion of the margins as an incentive to maximize short-term sales margins.

Q. What is Staff's position on keeping part of margin?

A. Staff testimony seems to agree that an incentive based on margins is appropriate. Mr. Smith states in his Direct Testimony at page 131, lines 13 through 14: "the credit for such off-system sales should be based on a percentage of the margin (revenue less cost of such sales), not on the revenue."

Q. Does Staff propose such an incentive?

A. No. Mr. Smith states further at page 131 lines 18 through 21 of his Direct Testimony: "[in] part because of the difficulties TEP has cited in determining the margins related to such sales, Staff proposes that the credit against fuel costs be based upon 100 percent of the revenues (hence margins) realized on off-system sales". It should be noted that both the terms "off-system" and "short-term" sales are used interchangeably by both the Company and Staff.

Q. Has TEP stated that it is difficult to measure the short-term sales margins?

A. Yes. In responses to data requests TEP has explained that it is a very rigorous process to determine the short-term sales margins, especially on a monthly basis.

Q. Does TEP have a better way to get to the same result?

A. Yes. TEP believes that the same result can be achieved in a more simple, straight-forward and understandable manner by crediting a percentage of revenue.

Q. Please explain.

A. Using the information the table on page 65 of Staff Witness Smith's Direct Testimony, the short-term sales margin from the test year is $25,259,000. The Sales for Resale (short-term or off-system) revenue is $77,685,000. Therefore, the margin as a percentage of revenue is 33% ($25,259,000/$77,685,000). If the margin is known as a percentage of revenue (here

33%) and a certain percentage of margin is desired, that percentage of margin can be expressed as a percentage of revenue. In this case, 33% of short-term margin equates to about 10% of short-term revenue. Consequently, 10% of short-term margin equates to about 3.33% of short-term revenue (*i.e.* three times as much of the percentage of short-term revenue equals the percentage of short-term margin).

Q. Please provide an example

A. Using the test year information from above, if as TEP proposed, the Company kept 10% of the short-term revenue it would be keeping 30% of the margins as shown below:

Margin = (0.33)Revenue TEP's Proposal = (0.1)Revenue

So;

TEP's Proposal as % of Margin = (0.1)Revenue/Margin

⇨ {(0.1)Revenue}/{(0.3)Revenue} = 30% of Margin

Or, if Revenues = $100, then Margin = $33 and TEP proposal = $10.

Q. Is TEP willing to increase the percentage of short-term sales revenue credited to the PPFAC?

A. Yes. As a compromise, TEP is willing to credit 95% of short-term sales revenue to the PPFAC. Using the formula above, TEP's 5% of revenue would equate to 15% of the margin.

Q. Does TEP have an alternate method it can propose?

A. Yes. Although the Company still believes the percentage of revenue method is the simplest, easiest to manage, track and audit, and is equivalent to a percentage of margin as explained above, TEP is willing to consider an alternative method as well. Recognizing

the difficulty in the process of determining the margin associated with short-term sales, TEP would propose that this calculation be done annually as part of its PPFAC rate filing and include the calculations for Staff's review. TEP's share of the margin would be used in calculating the True-Up Component and thus recovered over the next PPFAC year. During the year, the short-term sales revenues would be credited 100% to the PPFAC.

Q. What does TEP propose as its share of the short-term sales margin?

A. TEP proposes to use 15% of the margin. This is equivalent to its proposal of 5% of revenue.

Q. How does Staff recommend crediting short-term sales margin?

A. In Mr. Smith's Direct Testimony at page 65, line 17, he states: "Staff proposes to include the net margin from short-term sales in the determination of TEP's base rate revenue deficiency or excess." Staff also proposes to include a provision in the PPFAC wherein the fluctuations in the net margin from short-term sales over or under the $25.259 million amount being considered in base rates are reflected in the PPFAC."

Q. Does the Company agree with this methodology?

A. No. The Company believes that there should not be any adjustment to base rates but rather the short-term sales revenue should be credited to the PPFAC (and not reflected in base rates) on a going forward basis (in one of the two methods proposed by the Company above). My discussion of the details of Staff's PPFAC proposal below provides additional information on the Company's position on the appropriate treatment.

Q. Is this how Arizona Public Service's short-term sales margins are treated?

A. Yes. In the APS Plan of Administration ("POA"), short-term sales revenues are a credit (at 100%) to its PPFAC.

VI. WHOLESALE TRADING PROFITS.

Q. Please summarize the proposed treatment of Wholesale Trading Profits by the Parties.

A. Staff proposes to credit 10 percent of the net positive margin on TEP's wholesale trading activity against retail expenses. Similar to its proposed treatment of short term sales, Staff proposes that any deviations in trading profits established in the test year be included in the PPFAC. RUCO proposes that the entire test year wholesale trading profit be credited to base rates. AECC does not discuss wholesale trading profits.

Q. What is the Company's response to these recommendations?

A. The Company agrees with Staff that 10% is an appropriate amount of trading profit to share with customers. This provides an incentive to the Company to leverage its resources and expertise in energy markets for the benefit of both customers and shareholders. However, the Company maintains that the 10% credit should be included in the PPFAC on a going forward basis – not reflected in base rates. My discussion of the details of Staff's PPFAC proposal below provides additional information on the Company's position on the appropriate treatment.

Q. RUCO witness Ms. Diaz Cortez states on line 17, page 24 of her testimony that "TEP claims that the margins that are realized through the Company's wholesale trading activities should be credited to TEP's proposed PPFAC". Does the Company agree with this statement?

A. No, this is contrary the Company's position described in my Direct Testimony at page 14, where I simply describe the adjustment "that removes the revenue and purchased power expense associated with wholesale sales from trading." I do not agree with crediting 100% of wholesale trading activities from non-Company resources to TEP's proposed PPFAC.

To the contrary, TEP agrees with Staff regarding crediting 10% of wholesale trading activity – except that the entire credit should be reflected through the PPFAC and not through base rates.

VII. PURCHASED POWER AND FUEL ADJUSMENT CLAUSE ("PPFAC")

Q. Describe what is meant by the PPFAC rate.

A. The PPFAC rate has two components which adjust the base cost of fuel and purchased power rate embedded in base rates as approved by the Commission. The Forward Component adjusts annually for the difference between the forecasted fuel and purchased power costs (expressed as a rate of ¢/kWh) less the base cost of fuel and purchased power embedded in base rates (also expressed as a ¢/kWh rate). The other component of the PPFAC, the True-Up Component (expressed as a ¢/kWh rate), also annually adjusts the fuel and purchased power rate embedded in base rates. The purpose of the True-Up rate is to reconcile any over or under-recovered amounts of fuel and purchased power from the preceding year.

Q. Provide summary of Staff's proposed PPFAC

A. Staff supports the Company position that a PPFAC should be approved by the Commission in this rate case. Staff acknowledges that the Company proposed PPFAC is similar to the forward-looking Power Supply Adjustor that was approved by the Commission in a recent APS rate case. Staff recommends expenses in the following FERC accounts be included in the PPFAC: 501- Fuel Steam Production, 547 Fuel Other Production, 555 Purchased Power, and 565 Wheeling. Staff also supports allowing the Company to recover prudent direct costs of contracts it uses in hedging system fuel and purchased power.

Q. Does the Company agree with the PPFAC proposed by Staff?

A. For the most part. The majority of the mechanics are the same as those proposed by the Company. The Company is in agreement with Staff's proposal in terms of general structure, timeline, and start date. A discussion of the areas of disagreement follows.

A. TREATMENT OF SHORT-TERM SALES, SULFUR DIOXIDE (SO2) EMISSIONS, AND WHOLESALE TRADING.

Q. Describe the treatment for Short-Term sales, SO2 emission allowances and Wholesale Trading.

A. As I discussed previously in my Rebuttal Testimony:

- Staff, RUCO and AECC propose to credit short-term sales margins to base rates and then true-up through the PPFAC.
- Staff proposes a 10% credit of wholesale trading profits to base rates and an annual true up. RUCO proposes a 100% credit of wholesale trading profits to base rates.
- Staff recommends that all of the gains from the sale of SO2 emission allowances are credited to customers in base rates with a true-up through the PPFAC. RUCO recommends a full credit of the gains from the sale of SO2 emission allowances to base rates.

Q. Does TEP agree with the methodology of applying these credits to base rates and performing a true-up through the PPFAC?

A. No. This methodology distorts the relationship between the base rate and PPFAC rate and adds another level of complexity to the PPFAC that is not needed. Further, all these credits in the test year are not necessarily reflective of the credits going forward. It is difficult to accurately depict what the credits will be in the future as they are all subject to the volatility of the energy and emissions markets, in other words they are not "normal"

amounts and have the potential to vary significantly. Therefore it is appropriate to flow the entire amount of these varying credits through the PPFAC annually and not make any adjustments to base rates.

Q. What does TEP recommend?

A. Regardless of the actual percentage of margins or revenues credited, there should be no adjustments to base rates. Rather, short-term sales, wholesale trading credit and gains on SO2 emissions allowances should be credited against fuel and purchased power in the PPFAC on a going forward basis.

Q. Does the Intervenors' recommended treatment affect the total costs paid by customers?

A. No. The proposal to reduce base rates by this adjustment and provide a true-up is equivalent from a total cost recovery perspective. However, it shifts recovery from base rates to the PPFAC.

Q. Why does TEP desire its recommended treatment?

A. TEP's treatment keeps base rates closer to the actual total rates (base rates plus PPFAC) paid by customers and reduces complexity in administering the PPFAC.

Q. What other benefit does TEP's treatment afford?

A. It makes the PPFAC simpler and easier to administer. Mr. Bentley Erdwurm, in his Rebuttal Testimony, testifies that the PPFAC is designed with simplicity and appropriate rate design in mind.

Q. What complexity does the intervenors' treatment add to the PPFAC?

A. By applying the test year amounts to the base rates, it will require additional true-up calculations in the PPFAC. This will require a separate tracking account and true-up rate for each such component. For example (numbers are examples only), if the short-term sales margin applied to the test year base rates is $20 million, and the sales are 10,000 GWh, it would provide a $0.002/kWh reduction in base rates. If in 2009 the sales are 11,000 GWh, the test year rate short-term sales margin credit ($0.002/kWh) would supply $22 million in credit. If short-term sales margins were only $18 million in 2009, the $4 million difference would need to be recovered through the PPFAC. Similar calculations and tracking would be required for other components applied to base rates and PPFAC true-ups.

Q. What is the APS treatment of short-term sales and wholesale trading?

A. APS short-term sales are credited to the PPFAC like the Company proposes here, strictly through the PPFAC mechanism. The Company is not aware of any wholesale trading sharing in the APS Power Supply Adjustor.

B. PROCESS FOR APPROVING THE PPFAC RATE.

Q. What does Staff propose as to the approval process for the PPFAC rate?

A. The last sentence of the first paragraph on page 6 of Exhibit RCS-4 to the Direct Testimony of Mr. Smith states "The new PPFAC rate will go into effect on April 1 only after approval by the Commission".

Q. Do you agree with Staff's recommendation that the PPFAC rates have to be approved by the Commission?

A. No. Commission approval is a time consuming process. Given that the PPFAC rate adjustments are proposed to be implemented on April 1st of each year, there is insufficient time allotted for Commission review and approval.

Q. If Commission approval was not required, what protections could be afforded the Customers by the Commission?

A. The Commission is able to audit the Company at any time. Staff review should be used to determine if an audit is required when it receives the annual filing. Therefore, the permanency of the annual Forward and True-Up Components could be conditioned upon the outcome of such an audit.

Q. Should this hold up the process of approving the rates?

A. No. Any finding can be applied retroactively to the start date of that PPFAC rate.

Q. Does APS have such a requirement for Commission approval of its PSA Rate?

A. No. The first full sentence on page 6 of APS' final PSA POA states: "Unless the Commission has otherwise acted on the APS calculation by February 1, the PSA rate proposed by APS shall go into effect with the first February billing cycle."

Q. Are there other protections in the POA relating to the prudence reviews?

A. Yes. Although, as previously discussed, the Commission has the right to audit the Company's fuel and purchased power at any time, the POA specifically addresses this issue in Section 6 as set forth below:

"6. **VERIFICATION AND AUDIT**

The amounts charged through the PPFAC will be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded in the True-Up Component for the following year (i.e. starting the next April 1.)"

Q. Do other Arizona utilities have "automatic" adjustment mechanisms?

A. Yes. Southwest Gas Company and UNS Gas, Inc. have automatic adjustment mechanisms.

Q. Does the Company have any other comments regarding Staff's proposal on the PPFAC or its Plan of Administration?

A. Yes. Staff witness Emily S. Medine, on page 39, line 17 of her Direct Testimony states "The cost of credit support is a real cost that the utility incurs to purchase power and natural gas and TEP should be allowed to recover it in some way". Although she further states that the PPFAC may not be the best way to recover such a cost, she does not eliminate the PPFAC as a potential mechanism for recovery. It appears that Ms. Medine endorses recovery of credit support costs provided a utility is able to isolate and quantify credit support related to fuel and power procurement for the purpose of serving native load.

C. RUCO'S POSITION ON TEP'S PROPOSED PPFAC.

Q. Does RUCO agree with the Company and Staff's position that the PPFAC is necessary and appropriate?

A. No. Surprisingly, RUCO does not believe the Company experiences sufficient volatility in fuel prices to warrant a PPFAC.

Q. On what does RUCO base this conclusion?

A. Ms. Diaz Cortez for RUCO appears to simply rely on a coal cost comparison from 2004 to 2006. Ms. Diaz Cortez, at page 28 starting at line 2 of her Direct Testimony, states only that coal costs have only risen 8% over the past three years.

Q. Does the Company agree with this coal cost comparison?

A. No. RUCO states that coal costs have risen 8% in three years and points to exhibit MDC-B to support this statement. While it is true that coal costs increased 8.3% from 2004 to 2006 (a two year period, not three), this occurred during the last years of a fixed price short-term (3 year) coal arrangement at the Sundt facility and ignores the information on: (i) actual cost increases in 2007, especially at Sundt, San Juan and Navajo and (ii) projected increases in 2008 and 2009. If RUCO continued its analysis through 2007 in its own Attachment MDC-B, it would have shown a 8.8% increase just from 2006 to 2007 or a total of 17.8% from 2004 to 2007.

Q. Does RUCO claim gas prices are stable?

A. No. RUCO characterizes the recent roller coaster trend in natural gas prices as simply "somewhat less stable than coal prices". RUCO dismisses this volatility by stating it does not affect a large percentage of the MWh produced by TEP.

Q. Is RUCO's dismissal of gas volatility based strictly on MWh percentage a valid conclusion?

A. No. One cannot just look at the relative percentages between fuels but must consider ALL fuel costs and purchased power in determining the need for a PPFAC. Using RUCO's own exhibit MDC-B, we see a total fuel and purchased power rate increase of 23% between 2004 and 2005 and a 19% increase from 2006 to 2007.

Q. What is the Company's view of the volatility in its fuel and purchased power prices?

A. They are, indeed, volatile. Further, the Company generally agrees with Staff on the subject of price volatility. Mr. Smith accurately discusses this topic at pages 123 through 124 of his Direct Testimony.

Q. Did RUCO look at any indication of fuel and purchased power market volatility?

A. Yes. In response to TEP's Data Request No. 2-16, RUCO stated that "this data review confirmed that energy prices are volatile" and "current data sources confirm that prices are volatile". RUCO then goes on to state that "the price predictions in TEP's prefiled direct testimony are already obsolete".

Q. Do you have historical prices for natural gas, coal and power?

A. Yes. Attached as DGH-13 are data showing natural gas and power prices. Exhibit EVA-20 from Ms. Medine's Direct Testimony provides relevant coal price information.

Q. RUCO asserted that TEP's coal costs are stable. What was Staff Witness Medine's conclusion on coal cost stability?

A. Ms. Medine explains the effect of global competition on coal prices and correctly concludes that the mines serving TEP's plants are not insulated from higher prices.

Exhibit EVA-20 specifically addresses the volatility of Colorado coal prices. Coal that was priced at $15/ton in January of 2003 was priced over $40/ton in January of 2006.

Q. Why is this important?

A. It is important because TEP's coal supplies are not all under long-term supply arrangements. In fact, Sundt supply is directly affected by the volatility in the coal markets. Although the other plants are under long-term agreements that ensure the supply of coal, the price of such coal is still subject to increases in the miner's costs and changes in mining regulations. Beginning in 2010, the price of coal from Lee Ranch Mine to supply Springerville Station will be based on the then current Powder River Basin coal market. The long term agreement with the railroad to deliver coal to Springerville expires in 2011 and TEP will be required to negotiate a new agreement with the BNSF Railroad.

Q. Please Describe RUCO's recommended adjustment mechanism.

A. According to the Direct Testimony of Ms. Diaz Cortez on page 30, starting on line 19, RUCO appears to propose a one-dimensional mechanism that only addresses Purchased Power. Also in TEP Data Request 2-17 RUCO states:

> "RUCO expects TEP's overall weighted cost of fuel and purchased power to be relatively stable considering that RUCO has accepted TEP's post-test year proforma adjustments to restate fuel and purchased power to 2009 expected prices. Further, RUCO has recommended that the **cost of purchased power** for any incremental post-test growth be subject to automatic adjustment." (emphasis added)

However, in response to TEP Data Request 2-21 RUCO states:

> "RUCO's recommended power supply adjustor is not intended to be limited to purchased power, but rather is applicable to any source of power that TEP may secure to service incremental load."

Further, in response to TEP Data Request TEP 3-2 RUCO states:

> "While RUCO's testimony does not explicitly state that its proposed adjustor is not intended to be limited purchased power, neither does it state the adjustor is limited to purchased power. RUCO's testimony does explicitly limit its proposed adjustor to incremental load, however, there is no explicit limitation expressed on the source of incremental power." (original emphasis)

and in response to TEP Data Request 3-3 when asked if it is RUCO's intent to include all types of fuel in an adjustor mechanism, states:

> "Under RUCO's proposed adjustor the answer is yes, to the extent that fuels other than purchased power are used to serve incremental load growth. From a practical standpoint, however, it is unlikely that TEP will service incremental load with anything other than purchased power unless it intends to purchase or build additional generation".

Q. Do RUCO's data request responses clarify how its proposed mechanism would work?

A. Only on the point that RUCO's mechanism is not meant to be limited to purchased power as was implied in its Direct Testimony.

Q. Do you agree with RUCO that it is unlikely that TEP will service incremental load with anything other than purchased power?

A. No. Ms Diaz Cortez does not understand the nature of load growth and the way in which we serve it with existing assets and purchased power. Load growth occurs throughout the 8,760 hours of the year. There are many hours that TEP has excess coal and gas resources available to serve the load growth more economically than with purchased power. Only in the hours where load requirements are greater than the capability of TEP's existing assets is it necessary that purchased power be employed.

Q. Can you comment further on RUCO's proposed mechanism?

A. The Company has asked for clarification of RUCO's mechanism through data requests in an attempt to understand exactly how the mechanism will work. It is apparent through RUCO's testimony and data request responses that it has not fully developed how the mechanism will function.

Q. Please be more specific on why you do not know how RUCO's mechanism works?

A. The only calculations described in RUCO's Direct Testimony are mathematically incorrect and RUCO did not attempt to provide any clarification in its response to Data Request No. TEP 3-4. The Company is hopeful that RUCO will supply sufficient information on its proposed mechanism in its Surrebuttal such that the Company can make informed comments on its proposal.

Q. RUCO states that their proposed mechanism is "very similar" to the ECAC proposed by TEP in Docket No. E-1933A-05-0650. Do you agree?

A. No. While I have stated that the Company does not fully understand RUCO's mechanism, it is clear that they are not proposing something similar to ECAC proposed by the Company. In the ECAC mechanism, TEP proposed that the incremental load, no matter what fuel or purchased power source was used, would be priced at market. This is fundamentally and substantially different than RUCO's proposal to allow TEP to recover the difference in cost, however ultimately defined by RUCO. Another substantial difference is that TEP's proposed ECAC did not credit wholesale sales margin as proposed by RUCO.

D. AECC's POSITION ON TEP'S PROPOSED PPFAC.

Q. Does AECC support TEP's proposed PPFAC?

A. AECC does not take a position for or against adoption of a PPFAC for TEP. It bases this on the opinion that TEP has not produced "compelling quantitative evidence" demonstrating its financial exposure to fuel volatility.

Q. Is there "compelling quantitative evidence" in the record that supports TEP's request for a PPFAC?

A. Yes. I have provided ample evidence to show TEP's more than substantial exposure to fuel volatility. For instance, I discussed at length earlier in my Rebuttal Testimony regarding the increased coal costs from various locations. Further, there is no doubt that natural gas prices have increased significantly in recent years as shown in Exhibit DGH-13

Further, there is ample public information available on TEP's historical costs and historical gas, coal, and purchased power prices. TEP also provided information on this topic through numerous data requests from other parties in the proceeding. Responses to fuel and purchased power related data requests are included in STF 2.24, 2.25, 2.29, 2.33 and 2.34; LCG 8.5, 13.8, and 13.10; LA 11.29,11.34,11.52 and 19.5; RUCO 1.15, 5.6, 5.7 and 8.5; EVA 10.12 and AECC 2.6. The information provided in these numerous responses is sufficient to demonstrate a degree of Company exposure (both volumetric and price) necessary to warrant adoption of a PPFAC. Given the voluminous amount of data available to this point, TEP did not believe this would be questioned, let alone the need for the PPFAC challenged. Additionally, Staff has provided analysis on this topic in Mr. Smith's Direct Testimony. This substantial evidence clearly shows a compelling need for an adjustor mechanism like the PPFAC TEP proposes.

Q. What conditions/changes does AECC recommend to TEP's filed PPFAC?

A. AECC proposes to (i) eliminate the forward component; (ii) adopt a 90/10 sharing mechanism for fuel and purchased power costs; (iii) adopt a 90/10 sharing mechanism for changes in off system (short-term) sales margins; and (iv) design a PPFAC rate differentiated by voltage level.

Q. Does TEP agree with the 90/10 sharing on fuel and purchased power?

A. No. The Company agrees with Staff that a 90/10 sharing mechanism for fuel and purchased power is inappropriate. This is especially of concern based on Staff and Intervenor proposals to move PPFAC credits into base rates, thus creating the potential for a large difference between actual fuel and purchased power rates and those in base rates. AECC's 90/10 sharing proposal together with these other proposals could cause the Company to absorb a large portion of costs just based on rate structure. This problem is also compounded by the expectation that fuel and purchased power costs will increase over time. The Company has no control over the energy markets and it would be patently unfair for it to automatically absorb a portion of those costs.

Q. Does TEP agree with the 90/10 sharing on off-system sales margin?

A. No. It is inappropriate to base a sharing mechanism on test-year margins when TEP's wholesale sales are expected to decline over time as more generation is used for retail service leaving less available for wholesale transactions. TEP believes its proposals on short-term sales margins provide the correct structure and incentive to optimize the benefit to the Company and its customers.

Q. What is the Company's position on AECC's proposal to impose a voltage differentiation on the PPFAC rate?

This is not appropriate. It appears that AECC is trying to correct for its recommendation of crediting short-term sales to base rates. As I discuss elsewhere in my Rebuttal, this treatment artificially deflates base rates and inflates the PPFAC rate. AECC should instead recommend that wholesale sales (and any credit) be credited to the PPFAC on a going forward basis so that rate design issues (such as voltage level) can be properly addressed in base rates without creating an unnecessary level of complexity in the PPFAC.

VIII. SO2 EMISSION ALLOWANCE CREDITS.

Q. Please summarize the Parties positions on SO2 emission revenue credits.

A. RUCO recommends crediting test year sales gains to base rates. Staff recommends crediting a normalized gain on SO2 allowance sales based on the years 2004 through 2007. Staff further proposes that any annual difference between actual SO2 allowance sales and the normalized amounts reflected in base rates be reconciled through the PPFAC.

Q. How are lime costs and SO2 emission credits related?

A. Lime costs are incurred in the SO2 removal process. In general, the more lime used in the scrubbing process, the more SO2 is removed thus creating excess credits available for sale. However, incrementally more lime is needed per ton of SO2 to remove the same amount of SO2 as higher removal rates are achieved. The total amount or percentage of SO2 removed is also limited by coal type and scrubber design.

Q. How should the lime costs/SO2 relationship be recognized?

A. The incremental lime costs not included in base rates should be netted against the SO2 emission allowance sale proceeds in the PPFAC.

Q. Does Staff recognize there are costs associated with generating excess SO2 credits?

A. Yes. In Staff Witness Medine's Direct Testimony on page 45, lines 3-6, it states: "annual differences in the amounts of SO2 emission allowances (costs and benefits) from the normalized amounts reflected in TEP's base rates should be addressed in the PPFAC." In its response to Data Request No. TEP 2-12, Staff states "Staff acknowledges that lime is used in the scrubbing process and is therefore related to coal burn and SO2 allowances". However, Staff goes on to state that "TEP records lime expense in Account 502, which is not one of PPFAC-includible accounts proposed by either TEP or Staff".

Q. What does the Company propose for lime cost recovery given Staff's comments?

A. Staff acknowledges the correlation between SO2 credits and lime costs but does not address it simply because of the technicality that Account 502 has not been proposed as a PPFAC-includible account. TEP therefore proposes that the amount of lime expense, above or below that in the test year, be netted against the SO2 revenues credited to the PPFAC on a going forward basis.

Q. Do you agree with Staff's position that SO2 emission allowances should be recovered (or credited) through the PPFAC?

A. Yes. Ms. Medine is correct that SO2 emission allowances are like fuel in that they are required to operate coal-fired plants.

Q. Do you agree with Staff and RUCO's recommended base rates treatment?

A. No. As previously discussed, the Company believes that it is more appropriate to apply the SO2 credits (net of incremental lime costs) to the PPFAC on a going forward basis.

Q. Do you agree with Staff's crediting percentage?

A. No. TEP has a specific circumstance that needs to be considered.

Q. Please describe this circumstance.

A. As part of the Springerville Expansion Project ("SEP") - accomplished through UniSource Energy Development Corporation ("UED"), an unregulated subsidiary of UniSource Energy Corporation – there were upgrades made to the pollution control equipment (including SO2 scrubbers) of Springerville Units 1 and 2 to reduce the SO2 emissions.

Q. Are any of these Springerville Units 1 and 2 scrubber upgrades in current rates?

A. No. These were part of the Springerville Expansion Project. Because reimbursement for the upgrade costs is accounted for as a Contribution in Aid of Construction, there is no net cost to put in rates.

Q. Who does Staff believes owns emission allowances?

A. Ms. Medine for Staff states, on page 42 starting at line 3 of her Direct Testimony, that: "It is my experience that the SO2 emission allowances are commonly believed to be the assets of the party bearing responsibility for the costs incurred to own the generating asset."

Q. Who was responsible for scrubber upgrades at Springerville?

A. UED was responsible for these upgrades as part of the SEP. In other words, the ratepayers did not pay for the Springerville 1 and 2 scrubber upgrades because they are not reflected in rates.

Q. Who owns the excess emission allowances generated from the Springerville scrubber upgrades?

A. UED bore the risk and the cost of the scrubber upgrades as part of the SEP. Neither TEP, nor its customers, have any risk or cost associated with the scrubber upgrades. Therefore, UED, or more directly UniSource Energy Shareholders, own – and should receive the full

benefits of -- the associated excess emission allowances generated from the scrubber upgrades.

Q. Ms. Medine states on page 43, lines 15 through 18 of her Direct Testimony, that the development fee "presumably compensated UED for the risk it assumed in developing Unit 3". What is your reaction to this statement?

A. The development fee was only part of a total package of benefits that UED required to offset the risk of developing Unit 3. Another critical and substantial part of the benefits received from the SEP are the excess SO2 allowances generated from the project.

Q. Staff witness Medine states that Springerville accounts for less than 25 percent of the excess emission allowances (page 43. lines 7-8). Is this correct?

A. No. While Exhibit EVA-25 is an accurate depiction of the 2009 and forward allowance allocations and expected emissions, it does not take into account the allowances and emissions prior to the upgrades. Therefore, it ignores the benefit of the scrubber upgrades.

Q. Please provide the additional information needed to determine the excess emission allowances generated from the scrubber upgrades.

A. In 2004, prior to the upgrades or any increased SO2 scrubbing, Springerville Units 1 and 2 emitted 17,975 tons of SO2. In 2006, the first full year after the scrubber upgrades, Springerville Units 1 and 2 emitted 4,329 tons of SO2. Therefore, the excess emission allowances generated from the scrubber upgrades was 13,646 tons.

Q. Is the 13,646 tons of excess SO2 allowances then the net benefit of the scrubber upgrades?

A. No. As part of the SEP, TEP agreed to supply Tri-State with 3,695 tons of SO2 allowances for Springerville 3 and 4. This amount needs to be subtracted from the 13,646

tons which leaves a net benefit of 9,951 tons of excess SO2 emission allowances due to the scrubber upgrades.

Q. What percentage of the excess SO2 allowances is due to the scrubber upgrades?

A. Using the information from EVA-25 and adjusting for the amount of allowances allocated to Tri-State (3,695 tons per year), the amount of excess allowances due to the scrubber upgrades amounts to 93% in 2009 and 100% in 2011 and beyond.

Q. How should the excess allowances be allocated based on this information?

A. The first 9,951 tons of excess allowances are due to the Springerville 1 and 2 scrubber upgrades and belong to the Company. The amount of excess allowances above 9,951 belongs to the customers.

Q. If additional allowances are required, how should those expenses be recovered?

A. As previously discussed, SO2 allowances are like fuel and should be recovered through the PPFAC net of incremental lime costs.

Q. How should the customers' portion of the SO2 allowances be credited?

A. As previously discussed, it should be credited to the PPFAC on a going forward basis net of incremental lime costs.

IX. FUEL AND PURCHASED POWER AUDIT.

Q. Do you have any comments on the Fuel and Purchased Power Audit results as presented in Ms. Medine's Direct Testimony?

A. Yes. Ms. Medine makes several recommendations with which I agree, and two recommendations with which I do not agree.

Q. Please list the recommendations with which you agree?

A. The Company agrees with the following recommendations made by Ms. Medine as summarized on pages 46 and 47 of her Direct Testimony:

- TEP must improve the level of documentation in all areas.
- TEP should prepare a policies and procedures manual for coal procurement.
- TEP should improve its measurements of risk in order to comply with Company policy regarding keeping risk at an "acceptable level".
- TEP should consider revisions to its gas and power hedging policies such that hedging is performed not only to reduce volatility but to minimize costs.
- TEP should diversify the counterparties used for financial natural gas fixed price swaps.

Q. Please provide your comments on the first two bullets ?

A. TEP has been operating in a deregulated generation environment since the 1999 Settlement Agreement went into effect. As such, its fuel and wholesale power decisions have been made internally without the need to create an auditable "paper trail" for outside review. The Company understands the need to improve its documentation for these purposes and is already in the process of addressing this through structural and procedural changes.

Q. Do you have any comments on the recommendations of improving risk measurement?

A. This has been a topic of conversation within the group and the Company's Risk Management Committee for some time. The Company is currently evaluating implementing additional risk metrics and tools.

Q. What are your comments to the recommendation that hedging policies address minimizing costs?

A. Minimizing costs is always an implicit goal of hedging and one that we have been following diligently. However, it has to be understood that "minimizing costs" does not mean "beating the market". A hedging program's primary goal is to reduce volatility and provide a known value for future expenses, not to ultimately have prices below the market. Within that goal, the Company strives to minimize the cost of hedges through competitive bids, bilateral negotiations, market intelligence, and alternative product mixes. Since this is already our practice, it can be articulated in our policies in the annual updates.

Q. Has TEP already addressed diversifying its financial natural gas counterparties?

A. Yes. In the past few months we have added several additional counterparties.

Q. Please list the recommendations with which you disagree?

A. The Company disagrees with the following recommendations made by Ms. Medine as summarized on pages 46 and 47 of her Direct Testimony.

- TEP should create a separate legal entity for wholesale trading transactions.
- TEP should eliminate any commercial duties from designated Risk Manager.

Q. Why do you disagree with a separate legal entity?

A. Creating such a separate legal entity is not cost effective. Wholesale trading is currently performed by employees having functions within the scope of fuel and power procurement for native load and is a very small portion of the wholesale group's functions. The trading component is an ancillary activity which leverages their market intelligence, skills and existing information systems/applications. Duplicating this activity and these resources in a separate entity with an opportunity to earn a relatively small operating margin is not reasonable.

Q. Why do you disagree with eliminating all commercial duties from the designated Risk Manager?

A. Eliminating all commercial duties from the Risk Manager is a much too severe solution to address Ms. Medine's concern. The source of Ms. Medine's concern is a statement in TEP's control policy which states that the Risk Manager will "Prepare and distribute periodic valuation reports". Perhaps there is a misunderstanding regarding the provider of market information. Although the Risk Manager prepares such reports, the market prices used in the mark to market calculations are provided by the Risk Controller. Thus, the underlying inputs which determine the value of positions are controlled solely by the Risk Controller. This can be clarified in the next policy revision. It is also important to understand that the duties of the Risk Manager as described in these policies are solely related to managing fuel and purchased power risk. Therefore, it is critical that this position reside in the wholesale area to fully understand and oversee these functions.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

EXHIBIT

DGH-13

Exhibit DGH-13

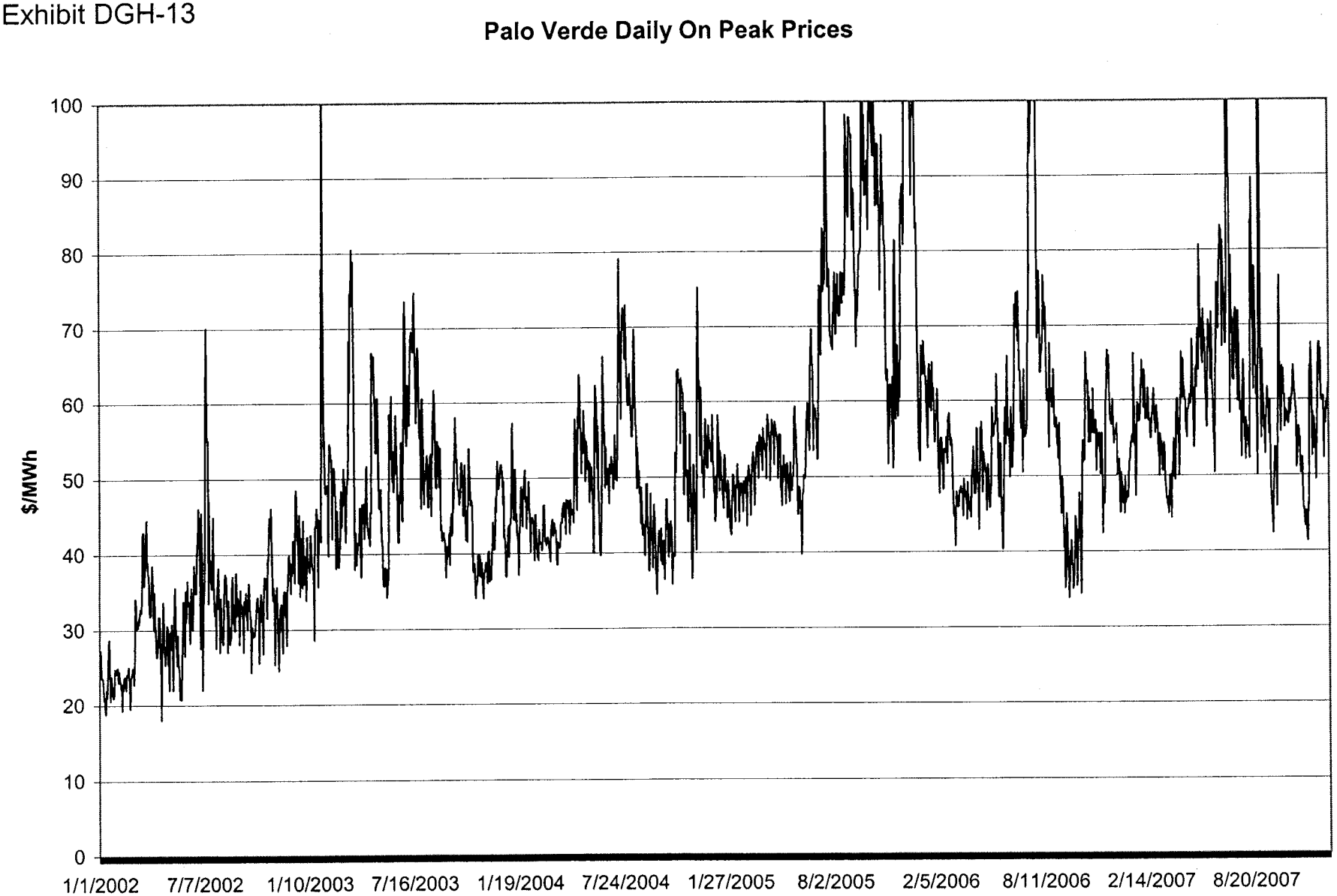
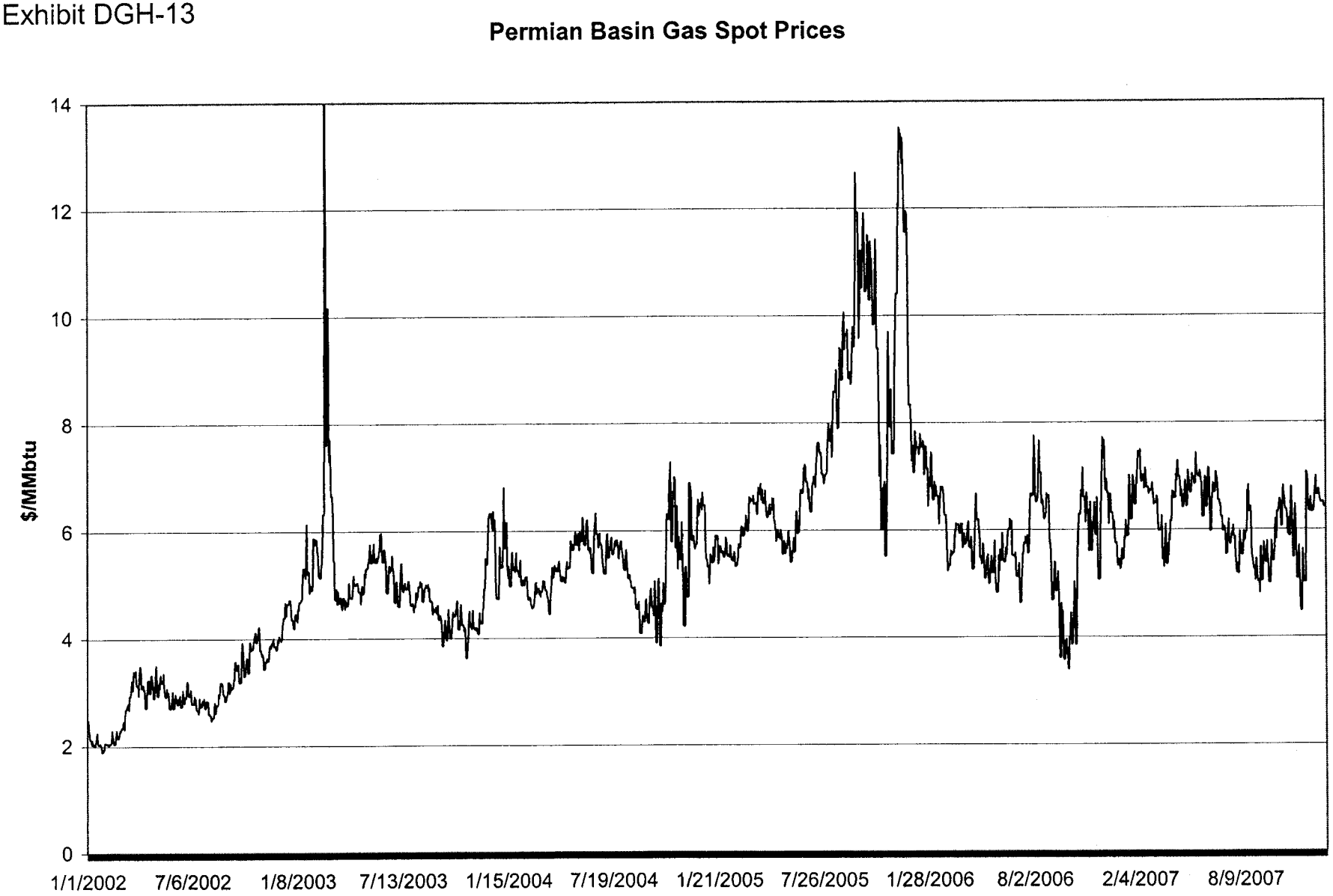


Exhibit DGH-13



BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-0402

Rebuttal Testimony of

Kentton C. Grant

on Behalf of

Tucson Electric Power Company

April 1, 2008

Executive Summary of the Direct Testimony of Kentton C. Grant

Mr. Grant is the Vice President of Finance and Rates for UniSource Energy Corporation ("UniSource Energy") and Tucson Electric Power Company ("TEP" or the "Company"). Mr. Grant's Rebuttal Testimony addresses the following matters:

1. **Proposed Treatment of True-up Revenues.**

Mr. Grant's rebuttal testimony points out that if TEP's generation services are returned cost-of-service ratemaking without a fully compensatory TCRA (termination costs regulatory asset), as is being advocated by Staff, RUCO and AECC, it would be grossly unfair to TEP to also require a refunding or crediting of the Company's Fixed CTC true-up revenues. Under the positions taken by these parties, customers would already receive substantial economic benefits to the clear detriment of TEP, benefits which are not provided for under the 1999 Settlement Agreement. Mr. Grant further testifies that if the Commission ultimately determines that TEP should refund or otherwise credit the true-up revenues, at most only a partial refund or credit would be warranted based on the revenue requirement being recommended AECC, RUCO and Staff. All three parties recognize that TEP was under-earning in the 2006 test year and the level of under-recovery should, at a minimum, be offset against any true-up refund.

2. **Termination Costs Regulatory Asset.**

Mr. Grant's rebuttal testimony describes numerous flaws and faulty assumptions underlying the positions taken by Staff, RUCO and AECC on the Company's request for a TCRA. In justifying their rejection of the TCRA, all three parties present a flawed analysis of the Company's financial performance and retail revenue deficiency during the rate freeze period. All three parties also rely on faulty interpretations of the 1999 Settlement Agreement in their quest to deny TEP any compensation for the cost of terminating this agreement. Mr. Grant points out that Staff and RUCO are merely applying a "lower of cost or market" standard to the pricing of TEP's generation services, a pricing option that does not exist under the terms of the 1999 Settlement Agreement approved by the Commission. If these parties now desire a return to cost-of-service ratemaking, on the heels of an unprecedented nine-year rate freeze, TEP must now be compensated for the taking of substantial economic value from the Company. As discussed by Mr. Grant, this compensation, in the form of a TCRA, can be calculated based on either (i) TEP's foregone revenues during the rate freeze period as proposed by the Company or (ii) the difference between the market value of TEP's generation and the book value of that generation, a methodology that would result in a much higher TCRA. Finally, for illustrative purposes only, Mr. Grant points out that even the flawed revenue requirement findings of Staff, RUCO and AECC provide evidence of a substantial economic burden being borne by TEP during the rate freeze period.

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Exhibits

Exhibit KCG-6 Calculation of Foregone Revenues Based on Staff Revenue Deficiency

Exhibit KCG-7 Calculation of Foregone Revenues Based on RUCO Revenue Deficiency

Exhibit KCG-8 Calculation of Foregone Revenues Based on AECC Revenue Deficiency

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Kentton C. Grant.

Q. Are you the same Kentton C. Grant that previously submitted Direct Testimony on behalf of Tucson Electric Power Company ("TEP" or "Company") in this Docket?

A. Yes.

Q. Have you reviewed the Direct Testimonies filed on behalf of the Arizona Corporation Commission Staff ("Staff"), the Residential Utility Consumer Office ("RUCO") and the Phelps Dodge Mining Company and Arizonans for Electric Choice and Competition ("AECC")?

A. Yes I have.

Q. Please provide your general assessment of that Direct Testimony.

A. With respect to the issue of true-up revenues, the treatment proposed by AECC and RUCO would be grossly unfair to TEP and is unwarranted in light of the substantial benefits that retail customers would enjoy under the return to cost-of-service ratemaking that each of these parties recommends. Furthermore, as discussed in the Rebuttal Testimony of TEP witness Kevin P. Larson, the refunding of true-up revenues proposed by AECC and RUCO would be devastating to the Company's financial well-being when coupled with other rate recommendations made by these parties and by Staff. Finally, if it is ultimately determined that TEP should refund the true-up revenues, at most only a partial refund would be warranted based on the revenue requirement being recommended by AECC, RUCO and Staff. All three parties recognize that TEP was under-earning in

the 2006 test year and the level of under-recovery should, at a minimum, be offset against any true-up refund.

Regarding the Company's request for a Termination Costs Regulatory Asset ("TCRA"), all three parties (Staff, RUCO and AECC) recommend that the TCRA be denied based on faulty assumptions regarding the requirements of the 1999 Settlement Agreement and a flawed analysis of TEP's financial performance and revenue deficiency during the rate freeze period. When coupled with each party's recommendation to put TEP back on cost-of-service ratemaking, rejection of the TCRA would be grossly unfair to TEP and would severely limit the Company's ability to attract capital needed for future plant investment. (See Rebuttal Testimony of Kevin P. Larson for a discussion of financial impact.) Essentially, each of these parties is recommending the Commission now apply a "lower of cost or market" standard in the setting of rates for TEP's generation services, nine years after the 1999 Settlement Agreement was approved and the current rate freeze was initiated, without any recognition of the substantial termination costs born by the Company and its shareholders. Such a result would be clearly contrary to the intent of the 1999 Settlement Agreement and would serve to transfer substantial economic value to customers at the expense of the Company and its shareholders.

II. PROPOSED TREATMENT OF TRUE-UP REVENUES.

Q. Please summarize the positions taken by Staff, RUCO and AECC on the issue of true-up revenues.

A. Surprisingly, Staff did not take a position on this issue. Although Staff asserts (at page 20 (lines 28-30) of the Direct Testimony of Ralph C. Smith) that no proposal was provided because "the amount of possible true-up revenues has not been determined," the Company

did, in fact, provide a relatively accurate estimate of the amount of true-up revenues in its Direct Testimony filed in July of 2007 – eight months before Staff's testimony was due.

AECC witness Kevin C. Higgins recommends that all true-up revenues be refunded to customers over a 12 month period if either the Market or Hybrid ratemaking methodology is approved by the Commission. Under the cost-of-service methodology favored by AECC, Mr. Higgins recommends either (i) a refund of all true-up revenues over a three-year period or (ii) a crediting of all true-up revenues against fuel and purchased power costs if a purchased power and fuel adjustment clause ("PPFAC") is adopted.

RUCO witness Marylee Diaz Cortez recommends that all true-up revenues be refunded to customers. However, as described on page 37 (lines 11-13) of her Direct Testimony, she believes that an appropriate refunding period cannot be determined "until the magnitude of the over collections is actually known."

A. <u>Response to Staff Witness Ralph C. Smith</u>

Q. What is your response to Mr. Smith's Direct Testimony on the issue of true-up revenues?

A. First, I am troubled by the fact that Mr. Smith chose not to make a recommendation in his Direct Testimony. An estimate of the total true-up revenues to be collected by TEP was provided on page 11, line 27, of my Direct Testimony. Detailed calculations supporting this estimate, totaling $66 million, were provided to Staff as part of the work papers supporting my Direct Testimony. Moreover, Staff only recently submitted data requests further inquiring about true up revenues. Should Mr. Smith choose to adopt a position in his Surrebuttal Testimony that is adverse to TEP, such a delay would put the Company at a disadvantage in terms of responding to any such testimony.

Q. Do you wish to address any other aspects of Mr. Smith's Direct Testimony on the issue of true-up revenues?

A. Yes. On page 20, lines 23-25, Mr. Smith makes the following statement:

> "If TEP has a base rate revenue deficiency, but all or part of that deficiency would be offset from the impact of True-Up Revenues, this may impact the base rates that should be established for TEP."

Without additional explanation by Mr. Smith, it is difficult to understand what he means by this cryptic statement. One possible interpretation, however, is that any base rate increase to which TEP would be entitled should somehow be reduced or eliminated due to the Company's collection of true-up revenues in 2008. In other words, it is possible that Mr. Smith views a reduced level of rate relief as an alternate method of returning true-up revenues to TEP's customers. If this is indeed his position, it is seriously flawed in several important respects.

Q. Assuming Mr. Smith is considering a reduction to TEP's base rates as a means of returning true-up revenues to customers, what are the flaws underlying such a proposal?

A. First, this position would be contrary to long-standing ratemaking principles and would be clearly unfair to the Company. Second, if common sense and basic logic are applied to the facts assumed in Mr. Smith's statement, an exactly opposite conclusion would be reached that supports the retention of true-up revenues by TEP.

With regard to the first point above, even if TEP were found to be "over-earning" in 2008 as a result of collecting true-up revenues in 2008, the goal of this proceeding is to establish rates for the period following the rate freeze (i.e., 2009 and beyond). Absent a settlement agreement specifying such treatment, I am not aware of any regulatory body having the authority to "reach back" and return prior period base rate revenues to customers through a forward-looking base rate adjustment. Such an action would appear to constitute

retroactive ratemaking, a practice that is not allowed in most, if not all, of the ratemaking jurisdictions in the United States. While I clearly understand that the Fixed CTC is set to expire pursuant to the terms of the 1999 Settlement Agreement, and that this expiration date is tied to the full amortization of $450 million of generation-related assets, this requirement represents only one of the many obligations placed on the parties to the 1999 Settlement Agreement. Unless all of the terms of the 1999 Settlement Agreement are upheld, including the continuation of the market generation credit ("MGC") and the expiration of the Floating CTC as of December 31, 2008, it would be unfair to the Company to require it to return any portion of the Fixed CTC revenues collected in 2008 either as a refund or as a credit against future rates. Such an approach could only be supported through a "piece-meal" and selective interpretation of the 1999 Settlement Agreement, an interpretation that would clearly benefit customers to the detriment of TEP and its shareholders. However, that approach permeates Staff's position throughout their testimony in this docket.

Regarding the second point above, I believe that the statement cited above from Mr. Smith's testimony is framed in a backward manner, and if it is re-arranged properly, an exactly opposite conclusion regarding the treatment of true-up revenues is reached. From my perspective, a more logical framing of the facts assumed in Mr. Smith's statement would be as follows (marked for changes from Mr. Smith's statement):

> "If TEP has true-up revenues ~~a base rate revenue deficiency~~, but all or part of those true-up revenues ~~that deficiency~~ would be offset from the impact of a base rate revenue deficiency ~~True-Up Revenues~~, this may impact the amount of true-up revenues ~~base rates~~ that should be returned by ~~established for~~ TEP."

In other words, it is TEP's revenue deficiency that should have some bearing on the amount of true-up revenues to be returned to customers, and not the other way around. Although it is TEP's position that no refund or credit of true-up revenues is warranted,

absent the implementation of market-based rates or the recognition of a sufficiently compensatory TCRA, the Commission should take into account the Company's annual revenue deficiency if it chooses to consider a refund or credit of true-up revenues under the Hybrid or Cost-of-Service rate methodologies.

Q. How should the Company's true-up revenues be viewed in light of the revenue deficiency identified by the Company and by Staff in this proceeding?

A. Under the Company's Cost-of-Service Methodology, an annual revenue deficiency of $158 million was identified before consideration of the requested TCRA. Although a portion of this revenue deficiency included fuel and purchased power cost adjustments necessary to reflect implementation of a PPFAC in 2009, it is fair to say that a similar revenue deficiency would be calculated if TEP were allowed to implement a PPFAC in 2008 instead of 2009. By contrast, the Company's Fixed CTC generates approximately $90 million per year in revenues. (For example, the amount collected during the 2006 test year was $89.6 million.) Therefore, it is apparent that under the Company's Cost-of-Service Methodology, TEP has demonstrated a cost of service revenue deficiency that greatly exceeds the level of Fixed CTC revenues being collected by the Company. As such, it is difficult to justify the return of Fixed CTC revenues on the basis of "over-earning" or the collection of "unjust revenues" by TEP during the 2008 true-up period.

Moreover, Staff is recommending stepping entirely away from the 1999 Settlement Agreement -- full re-regulation of TEP's generation, the re-instatement of TEP's exclusive CC&N and the elimination of unbundled rates. Given that position, continuing any rate freeze through the end of 2008 seems unnecessary and undue. Had new traditional cost of service based rates been adopted in time to meet the expiration of the Fixed CTC, the dilemma of over-collection and true-up revenues would be avoided. TEP's alternative

proposal concerning treatment of true-up revenues attempts to recognize the sea change of returning to full cost of service regulation without unduly penalizing TEP.

At first glance, when compared to Staff's annual revenue deficiency of only $17 million, it would appear that a substantial portion of TEP's true-up revenues cannot be justified on a cost-of-service basis. However, when the revenue impact of Staff's PPFAC recommendation is taken into account, the difference between Staff's revenue deficiency and the Fixed CTC revenue stream is substantially reduced. As discussed in the Rebuttal Testimony of TEP witness David Hutchens, Staff's PPFAC recommendation is expected to result in an average all-in rate of approximately 3.2¢ per kWh for fuel and purchased power costs in 2009. Relative to the fuel and purchased power revenue requirement reflected in Staff's $17 million revenue deficiency, an historical cost level that supports an all-in fuel and purchased power rate of only 2.5¢ per kWh, Staff's PPFAC recommendation adds approximately $65 million to TEP's annual revenue requirement. [$65 million = (3.2¢– 2.5¢) x 9,319 GWh test year sales.] The resulting annual revenue deficiency of $82 million covers approximately 90 percent of the annual Fixed CTC revenue stream being collected by TEP. Consequently, should the Commission determine that a refund or credit of true-up revenues be warranted, based on Staff's revenue requirement a refund of only 10% of TEP's true-up revenues could be justified on a cost-of-service basis.

Q. Do you have any other comments regarding Staff's position on true-up revenues?

A. Yes. Based on the Rebuttal Testimony prepared by Mr. Kevin Larson, TEP's Chief Financial Officer, I am hopeful that Staff will at least consider impact on the Company's financial condition and ability to attract capital when formulating its recommendation on true-up revenues. A refund or other rate credit of approximately $65 million to $70

million, when combined with Staff's other rate recommendations, would have a devastating impact on the Company's financial condition.

B. <u>Response to AECC Witness Kevin C. Higgins</u>

Q. What is your overall impression of Mr. Higgins' testimony regarding TEP's true-up revenues?

A. Mr. Higgins' recommendation to refund or otherwise credit customer bills for the full amount of true-up revenues under the Hybrid and Cost-of-Service Methodologies should be rejected. There are several reasons supporting this conclusion. First, as described on page 13 of my Direct Testimony, the Hybrid Methodology already provides customers with substantial benefits relative to either the Market or Cost-of-Service Methodologies. Second, because Mr. Higgins chooses to reject the Company's request for a TCRA under the Cost-of-Service Methodology, his recommendation to return TEP to cost-of-service ratemaking would result in rates that are substantially below the rates that are required under the 1999 Settlement Agreement. To require a full refund or credit of true-up revenues under such circumstances does nothing more than add salt to TEP's financial wounds. Finally, if the annual revenue requirement identified in Mr. Higgins' Direct Testimony were adopted, only a small fraction of TEP's true-up revenues should be considered for refund or credit to customers based on cost-of-service ratemaking principles.

Q. Why do you say that only a small fraction of TEP's true-up revenues should be considered for refund or credit under AECC's proposed revenue requirement?

A. As summarized on page 6 of his Direct Testimony, lines 23 through 26, Mr. Higgins claims to identify five adjustments that would serve to reduce TEP's current rates (including the Fixed CTC) by $3.5 million. This amount represents only a small fraction

(approximately 4%) of TEP's annual Fixed CTC revenue stream. As such, Mr. Higgins' own testimony regarding the Company's revenue requirement supports the retention by TEP of at least 96% of true-up revenues under cost-of-service ratemaking principles.

Q. Do you have any other comments to offer in response to Mr. Higgins' proposed treatment of true-up revenues?

A. Yes. I would like to address his recommendations concerning (i) the use of a three-year refund period under the Cost-of-Service Methodology, (ii) the alternative method of crediting of future PPFAC balances accrued by TEP, (iii) the alternative method of offsetting the TCRA balance and (iv) use of the Company's cost of capital to calculate carrying costs on the balance of true-up revenues yet to be returned to customers.

Although TEP does not concur with Mr. Higgins' recommendation to refund true-up revenues under the Cost-of-Service Methodology, his use of a three-year period to refund true-up revenues is at least positive from the standpoint of protecting the Company's near-term cash flow. If the Company were required to refund true-up revenues and take a related charge to earnings, it is important to recognize the impact such a decision would have on the Company's balance sheet and ability to attract capital.

Mr. Higgins' alternative recommendation to offset future PPFAC balances with true-up revenues would have a similar impact on TEP's earnings and balance sheet (i.e., immediate charge to earnings and equity), but is less supportive of the Company's near-term cash flow. By starting with a large negative PPFAC balance, TEP would be put in the position of under-recovering its fuel and purchased power costs by a substantial margin in either the first or second year under the new PPFAC. Unless the credit related to true-up revenues were amortized against TEP's fuel and purchased power costs over a specified period of

three or more years, the cash flow impact to TEP would be more severe compared with Mr. Higgins' three-year refund recommendation.

At first glance it appears that Mr. Higgins' recommendation to offset the Company's TCRA balance with true-up revenues is consistent with the treatment proposed by TEP under the Cost-of-Service Methodology. However, as described on page 43 of his Direct Testimony, lines 2 through 4, he recommends that the TCRA be offset with 100% of TEP's true-up revenues regardless of whether TEP's proposed TCRA is "adopted in whole or in part." Obviously, if the Commission were to adopt a TCRA balance that does not fully compensate the Company for a return to cost-of-service ratemaking, Mr. Higgins' recommendation would add insult to injury in the context of unwinding the 1999 Settlement Agreement.

Finally, the carrying cost that Mr. Higgins recommends be applied to the balance of true-up revenues is unreasonably high. Although he is content to apply a lower carrying cost as part of his recommendation to credit the Company's PPFAC balance, he recommends a much higher carrying cost under each of the scenarios involving an outright refund of true-up revenues. This higher carrying cost, reflecting the Company's cost of long-term capital, is more appropriate for determining the allowed rate of return on long-lived assets and liabilities included in rate base. It is clearly much higher than either the cost of short-term debt to the Company or the opportunity cost to customers as measured by yields on high quality short-term debt securities. As such, the Company's proposal to use its short-term cost of debt as a carrying cost should instead be adopted if any portion of TEP's true-up revenues is to be returned to customers.

C. Response to RUCO Witness Marylee Diaz Cortez

Q. Please summarize your understanding of Ms. Diaz Cortez' testimony on the subject of true-up revenues.

A. At the top of page 37 in her Direct Testimony Ms. Diaz Cortez refers to TEP's true-up revenues as an "overpayment of the Fixed CTC" by customers. After reiterating RUCO's rejection of the Company's requested TCRA, she goes on to state RUCO's preference for a refunding of all true-up revenues to customers through bill credits "based on their individual usage during the over collection period." She then closes her discussion of true-up revenues by stating that the refunding period cannot be determined "until the magnitude of the over collections is actually known."

Q. Do you believe that TEP's true-up revenues reflect an "over collection" from customers?

A. No. As was discussed above in my response to Staff witness Ralph Smith, the annual revenue deficiency identified by the Company under the Cost-of-Service Methodology is much larger than the annual amount of Fixed CTC revenues collected by TEP. And despite their reliance on flawed adjustments to the Company's revenue requirement, both Staff and AECC have proposed a revenue requirement that supports over 90% of TEP's Fixed CTC revenue stream on a cost-of-service basis. RUCO's reference to true-up revenues as being an "over collection" from customers can only be supported through a series of flawed revenue requirement adjustments and their denial of a PPFAC that would provide TEP with timely fuel and purchased power cost recovery. However, even if their revenue requirement and PPFAC recommendations were adopted, at best only a partial refund of true-up revenues would be warranted under cost-of-service ratemaking principles. And from a practical standpoint, it is doubtful that TEP would even have the financial wherewithal to make any refunds under RUCO's proposed revenue requirement.

Q. Is it practical to refund true-up revenues through bill credits that reflect actual usage by each customer during the true-up period?

A. Probably not. Although I am not an expert on TEP's customer billing system, this recommendation appears to place a huge administrative burden on the Company and may not even be feasible from a systems technology standpoint.

III. TERMINATION COSTS REGULATORY ASSET.

Q. Please summarize the positions taken by Staff, RUCO and AECC with regard to the TCRA.

A. All three parties recommend denial of TEP's requested TCRA in its entirety. In general, all three parties contend that TEP was not financially harmed during the nine-year rate freeze period. Additionally, they argue that even if TEP was somehow harmed, the Company has no right to compensation since the 1999 Settlement Agreement was either voided or can be interpreted in such a way as to allow for cost-of-service ratemaking. Armed with flawed financial analyses and bizarre contract interpretations, the consultants hired by each of these parties paint a revisionist view of history surrounding the 1999 Settlement Agreement and the industry restructuring efforts that led to that agreement. Unfortunately, the original intent of the 1999 Settlement Agreement, and the real cost to TEP of complying with that agreement, are overlooked in their proposals to reject the TCRA.

A. Response to Staff Witness John Antonuk.

Q. Mr. Antonuk devotes 41 pages of testimony to his discussion of alternative rate methodologies, the workings of the 1999 Settlement Agreement and the Company's request for a TCRA. How have you organized your response to his testimony?

A. My response is organized in three sections. The first section deals with Mr. Antonuk's analysis of TEP's financial performance during the rate freeze period. The second section addresses his analysis of the 1999 Settlement Agreement and his conclusion that TEP is not entitled to any compensation as a result of a return to cost-of-service ratemaking. The third and final section provides an alternative calculation of the requested TCRA, for illustrative purposes only, that reflects Staff's conclusions regarding TEP's retail revenue deficiency in both the 2003 and 2006 test years.

1. TEP's Financial Performance

Q. What are the key points Mr. Antonuk attempts to make regarding TEP's financial performance during the nine-year rate freeze period?

A. The key conclusions reached on this subject by Mr. Antonuk are listed on pages 7 and 8 of his Direct Testimony. First, he believes that TEP somehow earned more money that it should have over the period 1999-2002, and that this over-earning should somehow be used to offset any under-earning by TEP during the period 2003-2008. Second, he believes that the 2003 test year reviewed by Staff, RUCO and AECC in the 2004 Rate Review was not a good year to choose for purposes of determining whether TEP was over-earning. Third, he casts doubt on the robustness of the analysis performed by Staff and RUCO in the 2004 Rate Review. Fourth, Mr. Antonuk attempts to cast doubt on the Company's calculation of foregone revenues by criticizing my use and extrapolation of the 2003 test year revenue deficiency through 2008. Fifth, he cites the stock performance of

TEP's parent company (UniSource Energy Corporation or "UniSource Energy"), selected financial statistics for UniSource Energy and certain quotes from UniSource Energy financial documents in support of his belief that TEP somehow enjoyed tremendous financial results during the rate freeze period. Sixth, he concludes that the analysis of Staff witness Smith in this proceeding somehow supports his view that TEP has not suffered "material financial harm" during the rate freeze. Although not mentioned in his summary list of conclusions, in his Direct Testimony Mr. Antonuk also points to the earnings TEP derived from the Fixed CTC, and argues that these earnings should somehow be used to offset the revenue deficiency findings of Staff and the other parties in both the 2003 and 2006 test years.[1]

Q. What is your view of the points raised by Mr. Antonuk?

A. Each of his key conclusions is based either on a flawed analysis or a faulty underlying premise. As such, his conclusions are without merit and should be given little or no weight when evaluating the costs of terminating or amending the 1999 Settlement Agreement.

Q. Will you briefly address each of the key points raised by Mr. Antonuk in his review of TEP's financial performance?

A. Certainly. With regard to TEP's earnings over the period 1999-2002, several key points are worthy of mention:

(1) In Decision No. 62103 approving the 1999 Settlement Agreement, the Commission made specific reference to prior rate orders where TEP's rates were found to be just and reasonable, and recognized that TEP's new rates simply reflected an "an unbundling of TEP's approved bundled rates." (See Findings of Fact Nos. 38 – 40.) Consequently, it is apparent that the Commission still viewed TEP's overall

[1] See Antonuk Direct Testimony at page 32, lines 17-19 and page 34, lines 12-15.

bundled rates as being just and reasonable when the Settlement Agreement was approved in late 1999.

(2) Mr. Antonuk's revenue requirement analysis focuses almost exclusively on the savings achieved by TEP on operations and maintenance expense and on fuel expense. Considered in isolation, these factors would naturally point to a lower retail revenue requirement for TEP. However, there are several serious shortcomings with this type of analysis. Most obvious is the piece-meal nature of the analysis, as no attempt was made to calculate the impact of other changes to TEP's retail revenue requirement over this period. Also, based on the Shared Savings Plan approved by the Commission in 1998, and the rate decreases that accompanied this plan, it is apparent that the Commission was well aware of the cost savings that TEP was attempting to squeeze out of its operations. Finally, if the Commission were truly concerned about TEP over-earning as a result of these cost reductions, it is unlikely it would have allowed the Company to wait until 2004 before making a formal cost-of-service filing.

(3) Mr. Antonuk uses financial information published by UniSource Energy Corporation, TEP's parent company, to draw conclusions regarding TEP's retail revenue deficiency over this time period. No attempt was made to segregate TEP's financial performance from that of its parent company, which included significant unregulated operations. Furthermore, no attempt was made to translate these published financial statements, which were prepared using Generally Accepted Accounting Principles ("GAAP"), into a regulatory basis of accounting. Since there are significant differences between TEP's GAAP accounting and regulatory accounting, including treatment of the Company's substantial capital lease obligations, it is difficult to draw any conclusions regarding TEP's retail revenue deficiency from these published financial statements. Likewise, no attempt was

made by Mr. Antonuk to quantify the impact of TEP's wholesale jurisdictional earnings on the total company results.

(4) Mr. Antonuk cites high prices on TEP's short-term wholesale sales as a significant factor to consider in evaluating TEP's earnings over this period. However, it should be recognized that TEP did not have a PPFAC in place during this period, and that the Company relied on short-term wholesale margins to offset the high costs of supplying retail power in peak summer months. Additionally, Mr. Antonuk completely overlooks the substantial contribution to earnings that TEP received over this period as a result of the mortgage-style amortization of stranded costs approved by the Commission as part of the 1999 Settlement Agreement. The Commission was well aware of this accounting treatment when it approved the Settlement Agreement, and as such, the income derived from the Fixed CTC and related stranded cost amortization should not now be held against the Company in the context of an historical earnings review.

(5) Finally, Mr. Antonuk makes repeated references to 1999 as a year that should be considered in evaluating TEP's earnings during the rate freeze. However, the final order approving the 1999 Settlement Agreement was not signed until November 30 of that year, making only the last month of 1999 relevant to any review of TEP's financial performance under the rate freeze.

Q. With regard to Mr. Antonuk's second point, do you believe that the 2003 test year used in the 2004 Rate Review was somehow unrepresentative of the Company's normal recurring earnings?

A. No, I do not. And even if 2003 were somehow unrepresentative, all of the parties to the 2004 Rate Review had ample opportunity to review the impact of specific business events (e.g., Citizens acquisition and proposed sale of parent company to private equity investors) and operational events (e.g., power plant outages) on the retail revenue deficiency for TEP.

Q. Do you agree with Mr. Antonuk's characterization of Staff's analysis in the 2004 Rate Review, or his assertion that earnings derived from the Fixed CTC should somehow be used to offset TEP's revenue deficiency during the rate freeze period?.

A. No, I do not. Staff's review was certainly not cursory in nature, as evidenced by the large difference between TEP's filed revenue requirement and Staff's revenue requirement. Also, Mr. Antonuk seems to imply that more negative adjustments would have been made to TEP's revenue requirement if Staff had just made the extra effort. This is nothing more than pure speculation on Mr. Antonuk's part, and certainly casts Staffs' efforts in a negative light. Further, if Mr. Antonuk's speculation is correct, and Staff indeed truncated its analysis to focus on more pressing issues, it must have occurred because TEP had a very large revenue deficiency, one that could not be overcome with a series of smaller and less significant adjustments.

As for Mr. Antonuk's contention that earnings from the Fixed CTC should somehow be used to reduce the revenue deficiency identified by TEP during the rate freeze period, this recommendation flies in the face of the stranded cost recovery provisions contained in the 1999 Settlement Agreement, as well as the revenue requirement positions taken by Staff in both the 2004 Rate Review and in this proceeding. The Fixed CTC was designed to provide for a mortgage-style amortization of $450 million of generation-related assets over the nine-year rate freeze period, with a return to be earned on the unamortized balance and a provision for income taxes on that return. As noted in Section 2.1(c) of the 1999 Settlement Agreement, the forecasted amortization schedule and related revenue stream were specified in Exhibit A to the agreement. As may be seen in that exhibit, scheduled amortization expense started out very small and increased gradually over time in order to maintain a constant rate for the Fixed CTC. Consequently, the income earned by TEP from the Fixed CTC was significantly higher in the early years of the rate freeze period when compared with the later years. In both the 2004 Rate Review and in this proceeding,

Staff revenue requirement witnesses recognized that the Fixed CTC was designed to recover a specific amount of stranded costs with an associated return component. As such, all Fixed CTC revenues and related amortization expense were removed from TEP's test year operating results in order to determine a retail revenue deficiency. A discussion of this point may be found in the Direct Testimony of Staff witness Ralph Smith in this proceeding (page 18, line 6 through page 19, line 9) and in the Direct Testimony of Staff witness James Dorf in the 2004 Rate Review (page 5, line 18 through page 6, line 13).

If the Company's TCRA were somehow reduced by the earnings TEP derived from the Fixed CTC during the rate freeze period, as Mr. Antonuk apparently advocates, two things become readily apparent. First, such an action would be clearly contrary to the Commission's stated intent that the stranded cost portion of the 1999 Settlement Agreement not be revisited. (See Decision No. 62103, page 12, lines 5-7.) Second, TEP would need to be made whole for the return it was entitled to earn on the unamortized balance of stranded costs, and the whole question of how the $450 million in generation-related assets was amortized would have to be revisited. The end result of unwinding TEP's stranded cost recovery, which called for the accelerated amortization of certain long-lived generation assets, would be a much higher rate base than is currently reflected in TEP's Cost-of-Service Methodology.

Q. Mr. Antonuk's fourth point listed on page 7 of his Direct Testimony criticizes the Company's use of the 2003 revenue deficiency identified by TEP as the primary basis for calculating the TCRA. Does he offer a better method for calculating TEP's revenue deficiency during the rate freeze period?

A. No, he does not. Other than offering a value of zero for the TCRA, and criticizing TEP for not having a "year-over-year" analysis of the entire rate freeze period, Mr. Antonuk offers no suitable alternative for making such a calculation. Even though Staff itself has

identified a material retail revenue deficiency in both 2003 and 2006, Mr. Antonuk has chosen to ignore this fact and instead criticizes TEP for the lack of comprehensive retail revenue requirement data for every year from 1999 through 2008.

Q. Is it reasonable to expect TEP to have prepared comprehensive revenue requirement information for every year during the rate freeze period?

A. No. By definition, rates cannot change during a rate freeze. Therefore, TEP had no need to calculate its retail revenue deficiency on a year-by-year basis. Furthermore, as evidenced by the numerous adjustments to operating income and rate base under TEP's Cost-of-Service Methodology in this proceeding, as well as the numerous jurisdictional allocations required, such a year-by-year analysis would have required a substantial resource commitment that simply could not be justified under the circumstances. To go back and calculate a detailed year-by-year revenue deficiency at this point, given the passage of time and resources required, is simply not feasible without the procurement of substantial outside consulting services at considerable cost to the Company and its customers.

Q. If TEP had prepared such information on a year-by-year basis, do you believe that the cumulative retail revenue deficiency would be significantly different from the amount the Company calculated for the TCRA?

A. Yes, and it would probably be much higher. That is because TEP likely had a substantial retail revenue deficiency in 2002, and possibly in earlier years as well. Also, due to substantial increases in fuel and purchased power costs, TEP's retail revenue deficiency was higher in 2006 than in 2003, and would be likely be even higher over the last two years of the rate freeze (2007 and 2008). As a consequence, had TEP prepared such information on a year-by-year basis, the requested TCRA would likely be much higher than the $788 million figure that uses a 2003 test year revenue deficiency.

Q. Mr. Antonuk cites historical shareholder returns and selected financial information for UniSource Energy Corporation, TEP's parent company, as evidence of amazing financial performance at TEP. Do you agree with his characterization of TEP's financial performance or his use of selected parent company information to draw conclusions surrounding TEP's financial performance?

A. No, I do not. As I mentioned earlier, it is difficult to draw any conclusions regarding the Company's retail revenue deficiency from TEP's published financial statements, let alone those of its parent company. Also, the stock price performance of UniSource Energy Corporation is based on many factors, including investor expectations for the future financial performance of TEP after the rate freeze has expired. It is likely, based on the superior shareholder returns for the period cited by Mr. Antonuk, that investors began to realize TEP would experience a substantial increase in retail rates in 2009 based on the terms of the 1999 Settlement Agreement and the increased cost of natural gas and wholesale power relative to the lower cost of TEP's coal-fired generating facilities. As such, UniSource Energy Corporation's stock price performance is a relatively a poor indicator of historical earnings, and a better gauge of what investors expect will happen in the future.

Q. In his sixth and final point listed on page 8 of his Direct Testimony Mr. Antonuk states that Staff's analysis of the 2006 test year results supports his conclusion that TEP has not suffered "material harm" as a result of the retail rate freeze. Do you agree that Staff's 2006 test year analysis supports his conclusion of no material harm?

A. No, I do not. Staff' annual retail revenue deficiency of $17 million, which does not even take into account the higher fuel and purchased power costs incurred by TEP after the 2006 test year, is certainly material to TEP. Also, when this figure is combined with the $67 million revenue deficiency identified by Staff in the 2004 Rate Review, the cumulative

revenue deficiency for TEP is quite substantial. This topic is discussed further below in part 3 of my response to Mr. Antonuk's testimony.

2. The 1999 Settlement Agreement and Requested TCRA

Q. Regarding the issue of whether or not TEP has a "right" to compensation for the costs of terminating or modifying the 1999 Settlement Agreement, what are the key points Mr. Antonuk attempts to make on this subject?

A. In contrast to his discussion of TEP's financial performance, Mr. Antonuk did not provide a concise summary of his conclusions on this matter. However, based on my reading of his testimony, here are some of the key conclusions he reached:

(1) Since retail competition has not materialized, and since cost-of-service regulation for TEP's generation is now less expensive to customers than market-based pricing, the Company's generation services should now be priced using cost-of-service ratemaking principles.[2]

(2) Allowing TEP to charge market-based generation rates at this time would "unjustly transfer from customers to shareowners the benefits of its low-cost generation assets." [3]

(3) The Company's Market Generation Credit ("MGC") and Floating CTC were temporary pricing measures that would have been replaced with a cost-based rate for Standard Offer generation service reflecting the actual cost of TEP's power procurement following divestiture.[4]

(4) A better test of the cost to TEP of abandoning retail competition is to look at what the Company might have earned in the fully competitive market envisioned at the time of the 1999 Settlement Agreement.[5]

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[2] See Antonuk Direct Testimony at page 4 lines 22-26, page 17 lines 8-12, and page 24 lines 14-27.
[3] See Antonuk Direct Testimony at page 5 lines 1-5.
[4] See Antonuk Direct Testimony at page 6 lines 4-11 and page 20 lines 16-20.
[5] See Antonuk Direct Testimony at page 8, lines 16-21.

Q. Do you agree with Mr. Antonuk on these points?

A. With the exception of point (4) listed above, I do not.

Q. Are other TEP witnesses addressing these points as well?

A. Yes. TEP's President and Chief Executive Officer Mr. James Pignatelli addresses many of these same points as well.

Q. From what perspective are you addressing these points?

A. My comments are being offered to provide a more accurate description of the economic bargain that was struck in the 1999 Settlement Agreement and to shed additional light on the events and circumstances leading to TEP's request for a TCRA.

Q. Mr. Grant, when you make reference to certain provisions of the 1999 Settlement Agreement, are you attempting to offer any sort of legal opinion?

A. No, I am not an attorney. My comments are being offered from the perspective of a business manager and financial executive. They are not intended to be legal opinions.

Q. What role did you play in the development of the 1999 Settlement Agreement and related industry restructuring efforts?

A. At the time the 1999 Settlement Agreement was being negotiated I was employed by TEP as Manager of Financial Planning and Analysis. In this role I was responsible for analyzing the potential impact of retail competition and stranded cost recovery from a financial perspective. This work involved the preparation of financial forecasts, estimates of stranded costs, the design of stranded cost recovery mechanisms and related topics. While I was not a direct participant in the negotiation of the 1999 Settlement Agreement, I had a very keen understanding of the economics being bargained for and the general intent of the parties who negotiated this agreement. Prior to the 1999 Settlement Agreement, I

also assisted the Company in preparing comments on the electric competition rules, attended related workshops at the Commission, and helped prepare TEP's stranded cost recovery application filed in August 1998. Prior to joining TEP in 1995, I was also involved in the initial review of issues surrounding retail competition and stranded cost recovery in Texas as a senior staff member at the Public Utility Commission of Texas. This experience provided me with excellent insight into the goals, objectives and impediments related to the introduction of retail competition in the electric utility industry.

Q. Based on this experience, do you believe you have a good grasp of the issues associated with an unwinding of the 1999 Settlement Agreement?

A. Yes, I do. And based on this experience, I believe I have a more informed and longer-term perspective on this agreement than Mr. Antonuk possesses. While Mr. Antonuk certainly has broad-based consulting experience in other rate jurisdictions, he simply does not have the perspective of a participant in the Arizona restructuring process.

Q. Regarding the first key point listed above from Mr. Antonuk's testimony, please explain your area of disagreement.

A. Certainly. It is apparent that Mr. Antonuk is simply applying a "lower of cost or market" standard in selecting a preferred ratemaking methodology for TEP's generation services. This is problematic from several different standpoints.

First, this perceived option to apply a different ratemaking methodology does not exist under the terms of the 1999 Settlement Agreement approved by the Commission. Even though retail competition did not develop as anticipated at the time the 1999 Settlement Agreement was adopted, there was no expectation that TEP would be returned to cost-of-service ratemaking at the end of the rate freeze period, or that some menu of ratemaking options would someday be presented to the Commission. The bargain struck by the

parties, at the encouragement of the Commission, represented a radical departure from cost-of-service ratemaking with no return ticket. From the standpoint of the Company, it would have been ludicrous for TEP to agree to any contract that specified a nine-year rate freeze coupled with an option to adopt *the lower of* cost or market-based pricing at the end of the rate freeze period. The best the Company could do under such a one-sided contract would be to pass along 100% of the cost savings it achieved during the rate freeze period to customers. The worst the Company could do would be to go out of business from charging market prices that did not cover its costs. No rational person would ever consider signing such a contract.

Second, one of the reasons that cost-of-service ratemaking now looks so attractive to Mr. Antonuk is the accelerated amortization of $450 million of generation-related assets that occurred during the rate freeze period. Per the 1999 Settlement Agreement this was the amount of stranded cost recovery to be recovered through the Fixed CTC. Now that these assets have been written down, TEP's cost-of-service rate base looks much more attractive to customers than it did in 1999. Unfortunately, Mr. Antonuk fails to recognize that the original intent of the 1999 Settlement Agreement was to allow TEP's shareholders to benefit from this cost reduction by bringing the all-in cost of the Company's generation more in line with competitive market prices. Now that this has been accomplished, in tandem with other cost-cutting efforts of the Company, Mr. Antonuk would like to simply pass along these benefits to customers without providing any compensation or offsetting benefits to TEP.

Third, if Mr. Antonuk truly believes that cost-of-service ratemaking now represents the best alternative for setting TEP's rates, at a minimum he should at least consider some type of transition pricing mechanism or phase-in period for accomplishing this objective. Just as deregulation represented a huge departure from cost-of-service regulation, a return to

cost-of-service regulation would represent a huge departure from the market-based pricing the Company and other parties agreed to in 1999. The Company's proposed TCRA, as well as the proposed Hybrid Methodology, were both intended accommodate a transition back to cost-of-service ratemaking in response to preferences voiced previously by Staff and other parties.

Q. What response do you have to Mr. Antonuk's other assertion that the charging of market-based rates by TEP would "unjustly transfer from customers to shareowners the benefits of its low-cost generation assets"?

A. First, the decision to transfer to shareholders any benefits (as well as related risks) of TEP's generation was already made when the 1999 Settlement Agreement was approved by the Commission. Second, since this transfer was approved by the Commission at a time when there was significant uncertainty surrounding the development of retail competition and related market forces, it is only through hindsight that Mr. Antonuk is now able to attach the label of "unjust" to this decision. The bottom line is that TEP's generation assets were not viewed as being "low-cost" at the time the 1999 Settlement was entered into. Now that these assets look attractive relative to market pricing, Mr. Antonuk is essentially advocating a regulatory "do-over" because of some perceived injustice. While TEP is certainly sympathetic toward its customers, and their desire for the lowest possible pricing, the Company is simply not in a position to walk away from the settlement it agreed to in 1999.

Q. As noted above, Mr. Antonuk apparently believes that the Company's Market Generation Credit ("MGC") and Floating CTC represented temporary pricing measures that would have been replaced with a cost-based rate following the divestiture of TEP's generation assets. Why do you disagree with Mr. Antonuk on this point?

A. The terms of the 1999 Settlement Agreement are very clear with respect to (i) the expected date of divestiture (or transfer of generation assets to a TEP subsidiary), (ii) the required date of expiration for the Floating CTC, and (iii) the lack of any expiration date for the MGC or any contingent events causing such an expiration. Furthermore, in light of the intense focus placed on the MGC and related Adder as a customer "shopping credit," Mr. Antonuk's interpretation is clearly inconsistent with intent of the parties who negotiated the 1999 Settlement Agreement.

Q. What specific terms are you referring to in the 1999 Settlement Agreement?

A. Section 3.1 of the Settlement Agreement states that "on or before December 31, 2002 TEP shall transfer its generation and other assets deemed to be competitive (as defined in the Electric Competition Rules) to a subsidiary of TEP, at market value." Furthermore, Section 2.1(c) of the Settlement Agreement specifies that "the Floating CTC shall be calculated using a Market Generation Credit ("MGC") methodology...and will terminate on December 31, 2008." Consequently, it is clear that the MGC and Floating CTC were both expected to survive as retail pricing mechanisms well after divestiture was to occur in 2002.

Q. Does the role of the MGC as a customer shopping credit have some bearing on the expected life of the MGC under the 1999 Settlement Agreement?

A. Yes, I believe it does. Most, if not all, of the parties to the Settlement Agreement were keenly focused on the role of the MGC and the Adder as a "shopping credit". From the

Company's perspective, if the MGC and related Adder were set too low, few if any customers would choose competing suppliers and TEP would be stuck with charging below-market prices to its Standard Offer retail customers. If the MGC and related Adder were set too high, most customers would likely choose competing suppliers and TEP would be forced to give these customers shopping credits (i.e., price reductions from the Standard Offer rate) that exceeded the price TEP could receive in the wholesale market. In other words, if the shopping credit were set too high or too low, there would be serious economic consequences for both the Company and its customers. In light of these potential consequences, which could have seriously affected the economic bargain negotiated by each of the parties to the 1999 Settlement Agreement, I believe it was clearly intended by the parties to leave the MGC or similar market-based pricing mechanism in place well beyond the period covered by TEP's rate freeze. Indeed, Decision No. 62103 expressly noted (at page 17, lines 23-25) that: "While some of the potential competitors have argued that higher "shopping credits" will result in greater choice, we find that a higher shopping credit would mean rate increases *for TEP customers*." (emphasis added)

Q. Is there any record describing the importance of the MGC in the Commission's final order approving the 1999 Settlement Agreement?

A. Yes. The following statement was included in Decision No. 62103 beginning on page 6, line 28:

> "Similar to the APS Settlement, one of the contentions issues in the hearing was the level of the "shopping credit." The "shopping credit" is the difference between the customer's Standard Offer Rate and the Direct Access Rate available to customers who take service from ESPs. TEP's proposed shopping credit included both a market generation credit as well as an Adder (to reflect additional retail costs). As a result, most of the contentiousness at the hearing revolved around the sufficiency of the Adder in determining the level of the shopping credit."

Q. Does the fact that the Company did not divest its generating assets somehow undermine the role of the MGC as a retail pricing mechanism?

A. No, it did not. No one seriously questioned continuation of the Company's MGC and Adder after divestiture was stayed or in the 2004 Rate Review. Instead, attempts were made to modify the Adder in light of the potential implementation of retail competition at a later date. Having no expiration date, the presence of the MGC still leaves open the possibility of implementing retail competition as originally intended.

Q. Does the absence of divestiture materially change the economics expected by TEP in the 1999 Settlement Agreement?

A. No, it does not. Since TEP was allowed under the Settlement Agreement to transfer its generating assets to a wholly-owned subsidiary, the economic impact of retail competition and market-based pricing on the Company's shareholders would have been largely the same with our without the transfer of generating assets. Granted, under divestiture, the parent company of the affiliate holding the generation assets, TEP, would have had to procure all of its standard offer power requirements from third parties in the wholesale market, possibly including its unregulated generation subsidiary. However, that unregulated generation subsidiary would also be selling in the same wholesale market, possibly including sales to its regulated parent company. So long as the MGC was retained as the retail pricing mechanism at TEP, and so long as both companies (parent and subsidiary) maintained similar yet oppositely positioned contract portfolios in the same wholesale market, the economic impact of competition on the consolidated entity would have looked very similar to the economic impact on TEP as it presently exists without divestiture.

Q. Getting now to the fourth and final point listed above from Mr. Antonuk's testimony, why do you agree it is relevant to examine what TEP might have earned in a fully competitive market as envisioned under the 1999 Settlement Agreement?

A. It is relevant because this is exactly what TEP bargained for under the 1999 Settlement Agreement. And as described above, this economic bargain remains largely the same whether or not TEP divested of its generating assets as originally contemplated or does so at some future point in time. Also, because the MGC was pegged to short-term wholesale power prices, TEP would have been largely indifferent to the entry of competitive suppliers into its retail market. That is because power supplied to Standard Offer customers could instead be sold by TEP or its unregulated generation subsidiary into the wholesale market at a comparable price. Consequently, the extent to which retail competition may or may not have materialized, either historically or in the future, was not a factor that was particularly meaningful to the economics TEP would realize from the 1999 Settlement Agreement. Instead, it was recognized by TEP management that other forces would have a much larger impact on the Company's financial success after deregulation. These forces included the level of wholesale power market prices, the costs of operating and fueling TEP's coal-fired generating facilities, the success or failure of TEP's cost-cutting and debt reduction efforts, and other macroeconomic factors including cost inflation, interest rate levels and economic growth in the Tucson metropolitan area.

Because of the option to divest generating assets into a wholly-owned subsidiary, and the adoption of a competitively neutral MGC pricing mechanism, it is unlikely that TEP's consolidated financial performance would have been significantly different over the past nine years even if divestiture and retail competition had taken place as originally contemplated. Likewise, assuming the MGC is retained for retail pricing purposes as originally contemplated, the Company faces many of the same risks and rewards from this point forward that it would have had with divestiture and retail competition. Under these

circumstances, it is difficult for me to understand how Mr. Antonuk can refer to TEP's past and future potential earnings as being "windfall profits" or an "inequity."[6] Although the retail and wholesale energy markets have certainly taken some unforeseen turns over the past nine years, as have the costs of fuel and other essential commodities, the basic economic package that TEP bargained for, expected, and agreed to in 1999 remains largely unchanged nine years later regardless of whether retail competition takes hold or not. The question before the Commission now is whether to change the economic package that TEP expected under the 1999 Settlement Agreement, and if so, how to compensate TEP for any such modification of that contract.

Ultimately, breaking the 1999 Settlement Agreement and forcing TEP to return to cost-of-service regulation reduces the value of TEP's generation assets from their fair market value to their book value. TEP ought to be compensated for this taking of the value of its property. This difference in value would be a fair measure of the TCRA. But using this method to calculate the TCRA would have resulted in a much higher TCRA and a much higher cost of transitioning back to cost-of-service ratemaking. Indeed, under that approach, the estimated TCRA would be $1.9 billion, which is more than twice the size of the $788 million TCRA proposed by TEP. TEP chose the lower, more customer-friendly method of calculating the TCRA. It simply sought to be made whole for the huge pricing concessions and under-earnings it endured during an unprecedented nine-year rate freeze. Unfortunately, Mr. Antonuk has seized on this method of calculation in order to mischaracterize the Company's financial performance during the rate freeze period and to use an alleged financial overachievement to help justify the taking of economic value from TEP (i.e., the value of below-market generation assets). If Mr. Antonuk objects to this method of calculation as either conceptually flawed or practically difficult to compute, then TEP is certainly willing to use the difference between the market value and book

[6] See Antonuk Direct Testimony at page 24, lines 5-12.

value of its generating assets as a method of calculating the TCRA. Notably, Mr. Antonuk did not propose such a calculation. Instead, he seems to believe that TEP is due no compensation for this taking of the value of its assets. I must strongly disagree.

3. TCRA Calculation Using Staff's Estimate of Revenue Deficiency

Q. What is the purpose of this section of your Rebuttal Testimony?

A. The purpose is to demonstrate that even under Staff's flawed analysis of TEP's revenue requirement, the cumulative retail revenue deficiency endured by TEP during the rate freeze period was still very substantial. This analysis is provided for illustrative purposes only, and is not intended to replace or diminish in any respect the Company's request for a fully-compensatory $788 million TCRA.

Q. Using the retail revenue deficiency determined by Staff in both the 2003 and 2006 test years, what is the cumulative level of foregone revenues for TEP during the rate freeze period?

A. As may be seen in the top half of Exhibit KCG-6, the cumulative level of foregone revenues with carrying costs totals $345 million. This calculation is based on the $67 million revenue deficiency identified by Staff for the 2003 test year, the $17 million revenue deficiency identified by Staff for the 2006 test year, as well as the cost of capital recommended by Staff in the 2004 Rate Review and in this proceeding as well.

Q. Should this calculation be adjusted to account for inconsistencies between positions taken by Staff in the current proceeding versus prior proceedings?

A. Yes. At least three adjustments come to mind. First, since Staff is now challenging the reduction in depreciation rates implemented in 2002 for the Sundt generating station, a higher level of depreciation expense should be reflected in the 2003 test year revenue

deficiency identified by Staff. (See note 2 on Exhibit KCG-6.) Second, since Staff offered no rationale for its reduction of Springerville Unit 1 cost recovery, from $20/kW/month in the 2003 test year to $15/kW/month in the 2006 test year, an upward adjustment to the 2006 test year revenue deficiency is warranted. (See note 3 on Exhibit KCG-6.) Also, since Staff is recommending the creation of a $112 million regulatory liability to offset the impact of TEP's adoption of SFAS 143, and since this would be inconsistent with the Commission's prior determination of stranded costs in the 1999 Settlement Agreement, an upward adjustment (net of deferred income taxes) should be made to the cumulative balance of foregone revenues. (See note 4 on Exhibit KCG-6.) As may be seen in the bottom half of Exhibit KCG-6, these three adjustments serve to increase the level of foregone revenues, with carrying costs, from $345 million to $501 million.

Q. Why is it appropriate to adjust the level of foregone revenues and the TCRA if a regulatory liability is recognized by the Commission in connection with TEP's adoption of SFAS 143?

A. As described in the Rebuttal Testimony of TEP witnesses Karen Kissinger and Alan Felsenthal, the regulatory liability being recommended by Staff would result in a double benefit to customers at the expense of TEP. Customers have already benefited from the higher balance of accumulated depreciation that existed prior to the adoption of SFAS 143. To create an additional regulatory liability at this point in time, to offset the reduction in accumulated depreciation that occurred upon adoption of SFAS 143, would simply add to the already substantial costs of terminating the 1999 Settlement Agreement.

Q. Why do you say that customers have already benefited from the higher balance of accumulated depreciation that existed prior to the adoption of SFAS 143?

A. Because the higher balance of accumulated depreciation resulted in a lower net book value of TEP's generating assets, which in turn led to a lower calculation of stranded costs by

TEP during the period leading up to the 1999 Settlement Agreement. As a result of this lower stranded cost calculation, the Company was able to limit its stranded cost recovery to $450 million under the Fixed CTC. Had the Company's net book value of generating assets been higher, with a corresponding increase to stranded costs, TEP would have required a higher fixed component of stranded cost recovery in order to avoid large asset write-downs on a balance sheet that had only a small percentage of shareholder equity on it. Facing the need for a higher Fixed CTC, the Company's ability to make two additional rate reductions, as called for under the 1999 Settlement Agreement, would have been seriously compromised or eliminated entirely. And since the Commission made it very clear in Decision No. 62103 that the issue of stranded costs was not to be revisited, it is clearly inappropriate to give customers a benefit that they already received as a result of a prior Commission order.

Q. The adjustments you have made relate to inconsistencies between the positions taken by Staff in this case and in previous proceedings. Are other adjustments to Staff's revenue deficiency and the calculation of foregone revenues also warranted?

A. Yes. The Rebuttal Testimonies of other TEP witnesses identify numerous problems with Staff's revenue requirement recommendations. However, the intent of this section of my testimony is to demonstrate how material TEP's cumulative revenue deficiency would be even if Staff's flawed revenue requirement recommendations were adopted. Consequently, the calculation of foregone revenues in Exhibit KCG-6 considered only a few adjustments that would be needed to make Staff's filings consistent over time and with the Commission's prior order on stranded costs.

B. Response to RUCO Witness Ben Johnson

Q. What is your overall impression of the testimony filed by Mr. Johnson on TEP's request for a TCRA?

A. Based on my reading of Mr. Johnson's testimony, here are the main points he presented with respect to the TCRA:

(1) It is a matter of speculation as to whether TEP would have been entitled to charge higher retail rates, absent the stipulated rate freeze, under cost-of-service ratemaking principles.[7]

(2) Even if TEP did have a retail revenue deficiency during the rate freeze period, any termination costs are irrelevant because market-based rates are (i) not required under the 1999 Settlement Agreement,[8] (ii) potentially impermissible under Arizona law,[9] and (iii) are not reasonable or fair to consumers at this time.[10]

1. TEP's Financial Performance

Q. What did Mr. Johnson have to say regarding TEP's financial performance during the rate freeze period?

A. Mr. Johnson's comments on this subject were limited primarily to a discussion of (i) how different parties have expressed different views on the magnitude of TEP's revenue deficiency and (ii) why it is speculative to determine what the Commission may have done with TEP's rates in the absence of the stipulated rate freeze.

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[7] See Johnson Direct Testimony at page 19, lines 18-19 and at page 21, lines 12-15.
[8] See Johnson Direct Testimony at page 16, lines 19-26.
[9] See Johnson Direct Testimony at page 18, lines 3-5 and lines 9-18.
[10] See Johnson Direct Testimony at page 31, lines 14-21.

Q. Do you agree that different parties have expressed different views with respect to TEP's revenue deficiency?

A. Yes, of course I do. The testimonies filed by Staff, RUCO and AECC in the 2004 rate review, as well as in this proceeding, indicate a divergence of opinion on many revenue requirement issues. However, it is important to point out that all of these parties have determined that TEP had a retail revenue deficiency in both 2003 and 2006. It is only the magnitude of revenue deficiency that separates the parties, and not the question of whether or not TEP actually had a revenue deficiency.

Q. Do you agree that it would be speculative to determine what the Commission may have done with TEP's retail rates in the absence of a rate freeze?

A. I agree that it would be speculative to determine the exact size and timing of the rate increases that TEP would have been entitled to over this period. However, it is clearly not speculative, based on the testimony filed in the 2004 Rate Review as well as in this proceeding, to conclude that TEP would have been entitled to substantial rate relief during the rate freeze period using cost-of-service ratemaking principles, certainly as early as 2003 if not earlier. Using the revenue requirement information filed in both proceedings, it is a fairly straightforward task to estimate the cumulative revenue deficiency experienced by TEP during the rate freeze period.

Q. Should the requested TCRA be rejected just because we will never know for sure what level of rate relief the Commission would have granted?

A. No. As stated in my response to Mr. Antonuk's testimony, use of the foregone revenues approach represents only one possible means of quantifying the cost to TEP of terminating or amending the 1999 Settlement Agreement. Another approach would be to use the difference between the fair market value of TEP's generation and the net book value of TEP's generation as a measure of the TCRA. However, that approach would result in a

much larger TCRA and a much higher cost to customers to effectuate a transition back to cost-of-service ratemaking.

Regardless of how the TCRA is quantified, two key points should be highlighted. First, as described at length in my response to Mr. Antonuk, TEP is entitled to some form of compensation or offsetting benefit if the Commission now decides that TEP's generation should be returned to cost-of-service ratemaking. Second, any method used to determine the appropriate level of compensation or benefit will inherently be dependent on certain assumptions, the use of informed estimates and the application of careful judgment. The fact that we will never know for certain what might have happened in the absence of the 1999 Settlement Agreement does not give the parties to that agreement an "out" with respect to the costs of terminating or modifying that agreement.

2. The 1999 Settlement Agreement and Requested TCRA

Q. What is your response to Mr. Johnson's assertions that market-based rates are (i) not required under the 1999 Settlement Agreement, (ii) potentially impermissible under Arizona law, and (iii) are not reasonable or fair to consumers at this time?

A. With regard to points (i) and (iii), Mr. Johnson's testimony suffers from many of the same flaws plaguing the testimony of Staff witness Antonuk. With regard to his point on the legal status of the MGC, I am not in any position to offer a legal opinion in response to Mr. Johnson. However, I would point out that TEP has filed legal briefs on this subject that support the legality and enforceability of the 1999 Settlement Agreement and its use of the MGC as a pricing mechanism. Furthermore, even if the MGC were found to be questionable on legal grounds, it still does not diminish the economic cost to TEP associated with a nine-year rate freeze and a regulatory "do over" on the retail pricing of generation services.

Q. What is the main flaw in Mr. Johnson's interpretation of the 1999 Settlement Agreement as it pertains to the MGC?

A. Based on his statements appearing on page 16 of his Direct Testimony, lines 21-26, it is apparent that Mr. Johnson believes the sole purpose of the MGC is to calculate the Floating CTC. As pointed out in my response to Staff witness Antonuk, this interpretation ignores the vital role of the MGC as a customer "shopping credit," and stands in direct contrast to the discussion contained in Decision No. 62103 (starting on page 6, line 28) that highlighted the importance of the MGC and related Adder to the parties who negotiated the 1999 Settlement Agreement.

Q. Mr. Johnson also believes that market-based rates would not be reasonable or fair to consumers at this time. What is your response to this assertion?

A. Similar to Staff witness Antonuk, Mr. Johnson is simply applying a "lower of cost or market" standard in making this determination. As I pointed out in my response to Mr. Antonuk, the Commission already determined, through its approval of the 1999 Settlement Agreement, that market-based rates were reasonable and in the public interest. To suggest otherwise is to make a mockery of the industry restructuring process that took place in the late-1990s. It is only now that market-based rates appear more expensive than cost-based rates that Mr. Johnson advocates a lower of cost or market approach to ratemaking. Such an option to choose between cost or market, at a later date, simply does not exist in the 1999 Settlement Agreement approved by the Commission.

3. <u>TCRA Calculation Using RUCO's Estimate of Revenue Deficiency</u>

Q. What is the purpose of this section of your Rebuttal Testimony?

A. Similar to section 3 of my response to Mr. Antonuk, the purpose of this section is to demonstrate that even under RUCO's flawed analysis of TEP's revenue requirement, the

cumulative retail revenue deficiency endured by TEP during the rate freeze period was still very substantial. This analysis is provided for illustrative purposes only, and is not intended to replace or diminish in any respect the Company's request for a fully-compensatory $788 million TCRA.

Q. Using the retail revenue deficiency determined by RUCO in both the 2003 and 2006 test years, what is the cumulative level of foregone revenues for TEP during the rate freeze period?

A. As may be seen in the top half of Exhibit KCG-7, the cumulative level of foregone revenues with carrying costs totals $255 million. This calculation is based on the $32 million revenue deficiency identified by RUCO for the 2003 test year, the $36 million revenue deficiency identified by RUCO for the 2006 test year, as well as the cost of capital recommended by RUCO in the 2004 Rate Review and in this proceeding as well.

Q. Similar to your analysis of foregone revenues under Staff's case, did you make adjustments to the calculation of foregone revenues?

A. Yes. Since RUCO agrees with Staff that TEP should not have changed depreciation rates when it did, and that a large regulatory liability should be created in response to TEP's adoption of SFAS 143, I made two adjustments reflecting these recommendations as described in notes 2 and 3 on Exhibit KCG-7. The result of these two adjustments is to increase the level of foregone revenues from $255 million to $346 million over the rate freeze period. (See bottom half of Exhibit KCG-7.)

Q. What conclusion can be reached from this analysis?

A. Even if RUCO's flawed revenue requirement recommendations were to be adopted, along with the devastating impact such an action would have on the Company's finances, it is

apparent there are very real and substantial termination costs to consider if TEP's generation services are to be returned to cost-of-service ratemaking.

C. Response to AECC Witness Kevin C. Higgins

Q. What is your overall impression of the testimony filed by Mr. Higgins on TEP's request for a TCRA?

A. With regard to the Company's financial performance during the rate freeze period, Mr. Higgins asserts that the requested TCRA is overstated and does not properly take into account TEP's profitability during this period. Also, since he does not believe that TEP has any right to charge the MGC beyond 2008, he finds that there is no basis for recognizing termination costs and the related TCRA in this proceeding. For many of the same reasons offered in response to Staff witness Antonuk and RUCO witness Johnson, I find Mr. Higgins' testimony to be flawed in many important respects.

1. TEP's Financial Performance

Q. What does Mr. Higgins have to say regarding TEP's financial performance during the rate freeze period and related quantification of the TCRA?

A. Mr. Higgins claims that the requested TCRA is overstated because (i) the retail revenue deficiency identified by TEP in the 2004 Rate Review is too high,[11] (ii) the calculation of foregone revenues fails to properly account for regulatory lag[12] and (iii) the requested amount fails to take into account "the realities of the very profitable years the Company experienced throughout much of the rate cap period."[13]

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[11] See Higgins Direct Testimony at page 19, lines 1-8.
[12] See Higgins Direct Testimony at page 19, lines 9-19.
[13] See Higgins Direct Testimony at page 19, lines 20-21.

Q. What is your response to Mr. Higgins on these points?

A. His first point regarding the 2004 Rate Review is similar to the testimony of Staff witness Antonuk and RUCO witness Johnson. Like those witnesses, Mr. Higgins points out the significant difference between the $38 million revenue deficiency identified by AECC and the $111 million revenue deficiency identified by TEP for the 2003 test year. However, even though the AECC revenue deficiency was smaller, it is important to recognize that it nonetheless was a deficiency that would have been remedied were it not for the 1999 Settlement Agreement and related rate freeze. Additionally, Mr. Higgins' own revenue requirement recommendations in this proceeding, based on a 2006 test year, serve to further substantiate the existence of a large retail revenue deficiency during the nine-year rate freeze period.

Mr. Higgins' second point regarding the effects of regulatory lag on the calculation of foregone revenues is observant, but unfortunately, off the mark. While it is certainly true that regulatory lag exists, and that it affects the timing of rate relief granted to utilities, its presence in no way diminishes the economic burden borne by TEP as measured by revenue deficiency. Additionally, Mr. Higgins fails to take into account TEP's ability to file for rate relief on an as-needed basis, absent the provisions of the rate freeze. Taking this fact into account, it is highly unlikely that TEP would have waited until 2004 to file another rate case. Instead, under continued cost-of-service ratemaking, it is much more likely that TEP would have filed a series of rate cases starting with a 2002 test year in order to keep pace with the increasing costs of providing retail electric service. Under such a scenario, TEP's cumulative foregone revenues *with* regulatory lag would have likely been very similar to the Company's current calculation of foregone revenues *without* regulatory lag.

Regarding the third point made by Mr. Higgins, namely that TEP was highly profitable during the rate freeze period, it should be noted that he relies on total company financial

information prepared in accordance with GAAP in reaching this conclusion. As was discussed in my response to Staff witness Antonuk, there are many differences between the GAAP basis of accounting and regulatory basis of accounting for TEP. Additionally, when it comes to establishing a revenue requirement, there are often non-recurring items that need to be examined, as well as a determination of above-the-line vs. below-the-line treatment for specific transactions. As a final step, jurisdictional cost allocations must also be made in order to arrive at a retail revenue requirement. In light of these complexities, the existence of which should be apparent when examining the schedules filed by TEP in this proceeding, it is simply impossible to make any reasonable determination of revenue deficiency based solely on TEP's published financial statements. If such a tight linkage between TEP's earnings on a GAAP basis and a retail jurisdictional basis exists, as Mr. Higgins implies, then it begs the question as to how Mr. Higgins could identify such a large retail revenue deficiency in both 2003 and 2006, years in which TEP did fairly well according to the table presented on page 20 of Mr. Higgins' Direct Testimony.

2. The 1999 Settlement Agreement and Requested TCRA

Q. What does Mr. Higgins have to say regarding the requirement under the 1999 Settlement Agreement to charge market-based rates and TEP's related request for a TCRA?

A. Mr. Higgins asserts that (i) the MGC was intended for the sole purpose of calculating the Floating CTC and stranded costs,[14] (ii) the issue of market-based rates became moot when the requirement to divest of generating assets was cancelled[15] and (iii) because TEP has no right to charge market-based rates, the Company's request for a TCRA is unwarranted and without merit.[16]

[14] See Higgins Direct Testimony at page 8, line 14.
[15] See Higgins Direct Testimony at page 9, lines 10-12.
[16] See Higgins Direct Testimony at page 14, lines 17-19.

Q. What is your response to Mr. Higgins on these points?

A. I disagree with Mr. Higgins on all three points. With respect to the first point listed above concerning the MGC, please see my response to Staff witness Antonuk and RUCO witness Johnson on this very same point. Regarding Mr. Higgins' second point, a conclusion that appears to be shared with Staff witness Antonuk, please see my response to Mr. Antonuk which explains why divestiture (or the lack thereof) had absolutely no impact on the role of the MGC as a long-term retail pricing mechanism. As for the third point listed above, it simply has no relevance if the Commission determines that TEP had a reasonable expectation of charging market-based rates. Furthermore, even if it were determined that events subsequent to the approval of the 1999 Settlement Agreement somehow nullified TEP's right to charge the MGC, such a finding would not diminish the economic cost to TEP associated with enduring a nine-year rate freeze and a regulatory "do over" on the retail pricing of generation.

3. TCRA Calculation Using AECC's Estimate of Revenue Deficiency

Q. What is the purpose of this section of your Rebuttal Testimony?

A. Similar to section 3 of my response to Mr. Antonuk and Mr. Johnson, the purpose of this section is to demonstrate that even under AECC's flawed analysis of TEP's revenue requirement, the cumulative retail revenue deficiency endured by TEP during the rate freeze period was still very substantial. This analysis is provided for illustrative purposes only, and is not intended to replace or diminish in any respect the Company's request for a fully-compensatory $788 million TCRA.

Q. Using the retail revenue deficiency determined by AECC in both the 2003 and 2006 test years, what is the cumulative level of foregone revenues for TEP during the rate freeze period?

A. As may be seen in the top half of Exhibit KCG-8, the cumulative level of foregone revenues with carrying costs totals $476 million. This calculation is based on the $38 million revenue deficiency identified by AECC for the 2003 test year, the $92 million revenue deficiency identified by AECC for the 2006 test year, as well as the cost of capital recommended by AECC in the 2004 Rate Review and in this proceeding as well.

Q. Are any adjustments to the calculation of foregone revenues warranted with respect to forward-looking fuel and purchased power costs?

A. Yes. Since AECC's $92 million revenue deficiency incorporated most of the forward-looking fuel and purchased power adjustments proposed by the Company, the revenue deficiency identified by AECC is not technically a 2006 test year revenue deficiency. Even though TEP has incurred higher fuel and purchased power costs in 2007 and 2008, I have decided to strip out $32 million of forward-looking fuel and purchased power pricing adjustments for purposes of establishing a range of foregone revenues associated with AECC's revenue requirement filings. Doing so results in a smaller, yet still very substantial estimate, of $366 million in foregone revenues over the rate freeze period. (See bottom half of Exhibit KCG-7, as well as note 2 on that Exhibit.)

Q. What conclusion can be reached from this analysis?

A. Even if AECC's flawed revenue requirement adjustments were to be adopted, it is apparent that there are very real and substantial termination costs to consider if TEP's generation services are to be returned to cost-of-service ratemaking.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT

KCG-6

Exhibit KCG-6

Tucson Electric Power Company
Calculation of Foregone Revenues Under Rate Freeze
Based on ACC Staff Revenue Deficiency - ACC Jurisdictional

A. Calculation Based on Staff Revenue Deficiency as Filed

- $ in Thousands -	2003	2004	2005	2006	2007	Jan-Dec 2008
Full-Year Revenue Deficiency	$ 66,903	$ 66,903	$ 66,903	$ 17,838	$ 17,838	$ 17,838
Cumulative Balance with Carrying Costs						
Beginning Balance	$ -	$ 69,639	$ 144,975	$ 226,473	$ 262,978	$ 302,378
Current Year Revenue Deficiency	$ 66,903	$ 66,903	$ 66,903	$ 17,838	$ 17,838	$ 17,838
Carrying Costs (1)	$ 2,736	$ 8,433	$ 14,595	$ 18,667	$ 21,561	$ 24,686
Ending Balance	$ 69,639	$ 144,975	$ 226,473	$ 262,978	$ 302,378	**$ 344,901**

B. Calculation Based on Staff Revenue Deficiency as Adjusted

- $ in Thousands -	2003	2004	2005	2006	2007	Jan-Dec 2008
Full-Year Revenue Deficiency	$ 66,903	$ 66,903	$ 66,903	$ 17,838	$ 17,838	$ 17,838
Reversal of Depreciation Rate Changes in 2003 (2)	$ 3,003	$ 3,003	$ 3,003	$ -	$ -	$ -
Recognition of Springerville Unit 1 at $20/kW/mo (3)	$ -	$ -	$ -	$ 20,794	$ 20,794	$ 20,794
Adjusted Full-Year Revenue Deficiency	$ 69,906	$ 69,906	$ 69,906	$ 38,632	$ 38,632	$ 38,632
Cumulative Balance with Carrying Costs						
Beginning Balance	$ -	$ 72,765	$ 151,482	$ 236,638	$ 295,566	$ 359,168
Current Year Revenue Deficiency	$ 69,906	$ 69,906	$ 69,906	$ 38,632	$ 38,632	$ 38,632
Carrying Costs (1)	$ 2,859	$ 8,811	$ 15,250	$ 20,297	$ 24,970	$ 30,014
Ending Balance	$ 72,765	$ 151,482	$ 236,638	$ 295,566	$ 359,168	**$ 427,814**
Adjustment for SFAS 143 Regulatory Liability (4)						**$ 73,672**
Adjusted Ending Balance						**$ 501,486**

Notes

(1) Carrying costs based on Staff's cost of capital: 8.18% in 2003 7.93% in 2006

(2) Depreciation Adjustment = $3,279 x 2003 Retail Jurisdictional Allocation of 91.6%.

(3) Springerville Unit 1 Adjustment = ($20 - $15) x 380MW x 12mo./year x Retail Jurisditional Allocation of 91.2%.

(4) SFAS 143 Adjustment = ($112,756 Reg. Liab.x 94.53% Retail Juris. Alloc.) - ($44,679 ADIT x 73.68% Retail Juris. Alloc.)

EXHIBIT

KCG-7

Exhibit KCG-7

Tucson Electric Power Company
Calculation of Foregone Revenues Under Rate Freeze
Based on RUCO Revenue Deficiency - ACC Jurisdictional

A. Calculation Based on RUCO Revenue Deficiency as Filed

- $ in Thousands -	2003	2004	2005	2006	2007	Jan-Dec 2008
Full-Year Revenue Deficiency	$ 31,658	$ 31,658	$ 31,658	$ 36,254	$ 36,254	$ 36,254
Cumulative Balance with Carrying Costs						
Beginning Balance	$ -	$ 32,896	$ 68,364	$ 106,606	$ 152,539	$ 202,037
Current Year Revenue Deficiency	$ 31,658	$ 31,658	$ 31,658	$ 36,254	$ 36,254	$ 36,254
Carrying Costs (1)	$ 1,238	$ 3,810	$ 6,584	$ 9,679	$ 13,244	$ 17,085
Ending Balance	$ 32,896	$ 68,364	$ 106,606	$ 152,539	$ 202,037	**$ 255,376**

B. Calculation Based on RUCO Revenue Deficiency as Adjusted

- $ in Thousands -	2003	2004	2005	2006	2007	Jan-Dec 2008
Full-Year Revenue Deficiency	$ 31,658	$ 31,658	$ 31,658	$ 36,254	$ 36,254	$ 36,254
Reversal of Depreciation Rate Changes in 2003 (2)	$ 3,003	$ 3,003	$ 3,003	$ -	$ -	$ -
Adjusted Full-Year Revenue Deficiency	$ 34,661	$ 34,661	$ 34,661	$ 36,254	$ 36,254	$ 36,254
Cumulative Balance with Carrying Costs						
Beginning Balance	$ -	$ 36,016	$ 74,848	$ 116,717	$ 163,435	$ 213,778
Current Year Revenue Deficiency	$ 34,661	$ 34,661	$ 34,661	$ 36,254	$ 36,254	$ 36,254
Carrying Costs (1)	$ 1,355	$ 4,172	$ 7,208	$ 10,464	$ 14,089	$ 17,996
Ending Balance	$ 36,016	$ 74,848	$ 116,717	$ 163,435	$ 213,778	**$ 268,028**
Adjustment for SFAS 143 Regulatory Liability (3)						**$ 77,528**
Adjusted Ending Balance						**$ 345,556**

Notes

(1) Carrying costs based on RUCO's cost of capital: 7.82% in 2003 7.76% in 2006

(2) Depreciation Adjustment = $3,279 x 2003 Retail Jurisdictional Allocation of 91.6%.

(3) SFAS 143 Adjustment = $112,807 Reg. Liab. x 68.73% Retail Jursidictional Allocation Factor.

EXHIBIT

KCG-8

Exhibit KCG-8

Tucson Electric Power Company
Calculation of Foregone Revenues Under Rate Freeze
Based on AECC Revenue Deficiency - ACC Jurisdictional

A. Calculation Based on AECC Revenue Deficiency as Filed

- $ in Thousands -	2003	2004	2005	2006	2007	Jan-Dec 2008
Full-Year Revenue Deficiency	$ 38,175	$ 38,175	$ 38,175	$ 91,619	$ 91,619	$ 91,619
Cumulative Balance with Carrying Costs						
Beginning Balance	$ -	$ 39,771	$ 82,866	$ 129,565	$ 235,827	$ 350,963
Current Year Revenue Deficiency	$ 38,175	$ 38,175	$ 38,175	$ 91,619	$ 91,619	$ 91,619
Carrying Costs (1)	$ 1,596	$ 4,921	$ 8,523	$ 14,644	$ 23,517	$ 33,131
Ending Balance	$ 39,771	$ 82,866	$ 129,565	$ 235,827	$ 350,963	**$ 475,713**

B. Calculation Based on AECC Revenue Deficiency as Adjusted

- $ in Thousands -	2003	2004	2005	2006	2007	Jan-Dec 2008
Full-Year Revenue Deficiency	$ 38,175	$ 38,175	$ 38,175	$ 91,619	$ 91,619	$ 91,619
Reversal of Certain Fuel & Purch. Pwr. Adjustments (2)	$ -	$ -	$ -	$ (32,265)	$ (32,265)	$ (32,265)
Adjusted Full-Year Revenue Deficiency	$ 38,175	$ 38,175	$ 38,175	$ 59,354	$ 59,354	$ 59,354
Cumulative Balance with Carrying Costs						
Beginning Balance	$ -	$ 39,771	$ 82,866	$ 129,565	$ 202,215	$ 280,932
Current Year Revenue Deficiency	$ 38,175	$ 38,175	$ 38,175	$ 59,354	$ 59,354	$ 59,354
Carrying Costs (1)	$ 1,596	$ 4,921	$ 8,523	$ 13,297	$ 19,363	$ 25,936
Ending Balance	$ 39,771	$ 82,866	$ 129,565	$ 202,215	$ 280,932	**$ 366,222**

Notes

(1) Carrying costs based on AECC's cost of capital: 8.36% in 2003 8.35% in 2006

(2) Forward-looking fuel & purchased power costs:	Total Company	Retail Juris.
PPFAC Pricing Adjustment	$ 15,925	$ 14,309
Sundt Coal Pricing Adjustment	$ 7,384	$ 6,613
San Juan Coal Pricing Adjustment	$ 9,884	$ 8,852
Navajo Coal Pricing Adjustment	$ 2,780	$ 2,490
Total	$ 35,973	$ 32,265

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-0402

Rebuttal Testimony of

Dallas J. Dukes

on Behalf of

Tucson Electric Power Company

April 1, 2008

Executive Summary of the Rebuttal Testimony of Dallas J. Dukes

Mr. Dukes is the Manager of Rates and Revenue Requirements for Tucson Electric Power Company ("TEP" or the "Company"). Mr. Dukes' Rebuttal Testimony addresses the following matters:

1. **Rate Base Adjustments.** Staff has recommended that a portion of the Customer Care and Billing ("CC&B") system be removed from rate base to reflect that affiliates of TEP are using the system in subsequent years. The CC&B system went into service for TEP in April 2006 and in April 2007 for TEP's affiliates. Within the test year, $16.7 million was capitalized for the CC&B system, which represented the portion of the asset placed in service as used and useful in serving TEP's customers at that time. In 2007, an additional $7.8 million was capitalized, reflecting the complete installation of CC&B and its reporting system. To serve TEP and its affiliates, CC&B and its reporting system has a total cost of $24.5 million, not just the $16.7 million capitalized in the test year to serve TEP customers. Therefore, the portion in rate base at the end of the test year for the CC&B system fairly and properly reflected the investment in used and useful plant to serve TEP customers at that point in time and Staff's recommendation should be rejected.

2. **Operating Income Adjustments.**

   a. **Springerville Unit 1 – Revenue & Expense** – Staff and Interveners have recommended alternative non-fuel pro-forma operating expense levels for Springerville Unit 1. These are discussed in detail in the Rebuttal Testimony of Company's Witnesses Kissinger and Hutchens. The Company defends its proposal to use a market rate as ordered and upheld in previous Commission Decisions. The Company also points out the numerous short comings of the Staff and Intervener's proposals. The most egregious being Staff's proposal to go back to the 1989 market rate ignoring prior decisions and Staff's own recommendation in the 2004 rate review as well as not reflecting and return on or return of the substantial investments made in the form of leasehold improvements since that time.

   b. **Generating Facilities – Operating Lease** – RUCO's witness Marylee Diaz Cortez is recommending that the Company's recovery of Springerville Unit 1 non-fuel cost be based solely on test year "book cost". This proposal, though a significant improvement over Staff's proposal is not proper as well - as the books represent Capital Lease accounting on a GAAP basis and are not reflective of cost based rate making treatment. The proper corrections needed to convert to cost base accounting for Springerville Unit 1 are discussed in the Rebuttal Testimony of Company's Witness Kissinger.

   c. **Lime Usage Costs – Revenue & Expense** – If Ms. Diaz Cortez's recommendation for "Book Cost" treatment is approved her Lime Usage adjustment must be modified to reflect the proper numbers.

   d. **Rate Case Expense** – RUCO has recommended that rate case expense incurred in this filing by TEP be ignored and the amount to be recovered be based on recent unrelated and incomparable decisions. This is clearly a violation of fairness and ignores the clear facts in this case. The costs in this preceding are being incurred prudently and legitimately as a direct

result of this case. They are not duplicative of any other services being recovered in rates or being requested by the Company in this case.

e. **Membership Dues – EEI** – Staff is recommending the normal and recurring core dues associated with Edison Electric Institute ("EEI") be reduced well beyond the portion identified as lobbying based on a 2005 NARUC study. This recommendation produces an unwarranted reduction that is contradictory to recent Commission Decisions including the most resend UNS Gas Decision for similar fees to the American Gas Association. The Company has properly excluded all fees associated with Lobbying activity consistent with the recent and past Commission Decisions.

f. **CC&B Normalization** – Similar to the rate base discussion above – Staff is recommending that test year expense levels be reduced to reflect services to be provided to affiliates in subsequent periods. However, also like the discussion above Staff failed to recognize that the test year did not include all cost to serve TEP and its affiliates and only reflected the cost to serve TEP and its customers. So to reduce that level below that to serve TEP's customers would be inappropriate.

g. **Bad Debt Expense** – The Company, Staff and Interveners are essentially all in agreement on the calculation of this adjustment subject to all parties updating for corrections by the Company.

h. **Legal Expense – Motion to Amend** – Staff is recommending to exclude test year outside legal cost related to the Motion to Amend as being non-recurring and RUCO is recommending they be recovered over four years. However, both parties ignore the fact that outside legal cost vary case-by-case each year and each individual cost causer could probably be deemed as non-recurring or not normal and recurring looked at in isolation. However, the test year level of expense is commensurate with the most recent three year average and equivalent to what was spent in 2007 – so in total the test year level should not be reduced as that will set pro-forma outside legal cost well below the normal and expected recurring levels, which would be inappropriate.

i. **Legal Expense – California Proceeding** – Staff is recommending that these cost be excluded because they are related to wholesale activity and should not be recovered from retail ratepayers. Though technically that is a valid assertion it ignores the fact that all test year legal cost are reduced associated with jurisdictional allocations to reflect the fact that FERC regulated activity should not be recovered through ACC established rates. By taking the cost related to this individual preceding out prior to the allocations you are effectively giving retail customers the benefit of excluding it twice and that is inappropriate.

j. **Markup Above Cost – Affiliate Charges SES** – Staff is recommending a reduction to test year cost to eliminate the "Mark-up" on direct labor cost related to SES invoices for supplemental services. This adjustment ignores that fact that all businesses have to charge a mark-up sufficient to recover cost to operate the business and is not relevant in determining if the expenses to be recovered through rates are reasonable.

k. **Normalize Affiliate Charges to TEP** – Staff attempts to reduce test year expenses by analyzing vendor's charges to the Company. This produces illogical adjustments that recommend a credit balance in a test year expense account and to further reduce maintenance accounts below three and four year averages for the individual accounts.

l. **Postage Expense** – Rebuttal adjustment to reflect the increase postage rates applied to test year mailing levels.

m. **WestConnect Charges in ICRA** – Company agrees that the bill is currently reflected twice in expenses and in our ICRA recovery request and includes a Rebuttal adjustment to remove one.

n. **Inappropriate/Unnecessary Expenses** – RUCO continues to attempt to remove normal and recurring expenses based on vendor name and by simply overwhelming the Commission and Company with the impractical task of judging or justifying thousands of minor, yet normal business expenditures. The Company removed close to a million dollars of test year expenses that were deemed to be inappropriate to request in rates, including amounts identified by RUCO during the discovery process. However, the Company believes that the remaining expenses are recurring, appropriate and incurred to provide service – and therefore should not be reduced.

o. **Normalization of Overhead Line Maintenance** – RUCO is attempting to pick one maintenance account and in isolation deem its variance that is above the five year average and should be normalized. However, they ignore other maintenance accounts that are below the three or five year average. In aggregate and after adjustments the Company believes its pro-forma test year maintenance expenses are recurring, reflective of normal levels and incurred to provide service – and therefore should not be reduced.

p. **Penalties and Fines** – Rebuttal adjustment to reflect the elimination of charges that RUCO found during the discovery phase that should have been excluded from pro-forma expenses.

q. **Employee Recognition and Employee Benefits** – RUCO is essentially requesting the elimination of employee recognition awards for things like years of service, jobs well done and going above and beyond the requirement of their positions. These programs are a very inexpensive and very valuable motivation and retention tool that ultimately provide real benefits to customers and are common in the industry and should not be excluded from pro-forma expenses.

r. **Miscellaneous Expense** – Rebuttal adjustment to reflect the elimination of charges found during the discovery phase that should have been excluded from pro-forma expenses.

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Exhibits

Exhibit DJD-1 Comparison of Adjustments to Revenue Requirements – Market Methodology
Exhibit DJD-2 Comparison of Adjustments to Revenue Requirements – Hybrid Methodology
Exhibit DJD-3 Comparison of Adjustments to Revenue Requirements – COS Methodology

I. INTRODUCTION.

Q. Mr. Dukes, did you file Direct Testimony is this case?

A. Yes, I did.

Q. Have you reviewed the Direct Testimony filed by the Commission Staff and Interveners in this case?

A. Yes, I have.

Q. Which Commission Staff and/or Intervener testimony will you be addressing in your Rebuttal Testimony?

A. In my Rebuttal Testimony, I address certain adjustments that Staff Witness Ralph C. Smith recommends in his Direct Testimony. I also address several adjustments that Residential Utility Consumer Office ("RUCO") witnesses Marylee Diaz Cortez and Rodney L. Moore propose in their Direct Testimonies. While I agree with some of the adjustments made, the majority of adjustments made by Staff and RUCO are inappropriate and should be rejected. I have provided comparisons of adjustments to revenue requirements for Tucson Electric Power Co. ("TEP"), Staff, RUCO and Arizonans for Electric Choice and Competition ("AECC") for all three methodologies originally filed by TEP attached as Exhibits DJD-1 to DJD-3. My Rebuttal Testimony provides ample justification for rejecting Staff and RUCO adjustments in favor of TEP's proposals on these adjustments. Except where I state otherwise, TEP's proposals and adjustments apply equally under all three methodologies. In short, TEP's revenue requirements, expenses, and adjustments are reasonable based on the substantial documentation it has provided in its case and during discovery. Further, many of Staff's and RUCO's adjustments are not supported by the evidence and documents in this case and should be rejected.

II. REBUTTAL TO RATE BASE ADJUSTMENTS.

A. Customer Care and Billing (Staff Adjustment B-9).

Q. Mr. Dukes, do you agree with Mr. Smith's adjustment to remove a portion of the Customer Care and Billing ("CC&B") asset from rate base?

A. No, Mr. Smith has removed a portion of the CC&B asset cost as of the end of the test year to reflect the fact that the system is used by other affiliates in the year following the test year. Conceptually it is fair to allocate a portion of the system based on those deriving benefits from it. In this case, however, the adjustment is not proper because the balance of the CC&B asset in rate base at the end of the test year only reflected the portion placed in service to serve TEP's customers – and was only being used at that time to serve TEP's customers. To reduce that portion by a percentage to serve affiliates' customers would be improper and unfair to the Company.

As Mr. Smith correctly points out in his Direct Testimony on page 47, CC&B went into service for TEP in April 2006. He also correctly points out on page 48, of his testimony CC&B went into service for TEP's affiliates in April 2007. However, Mr. Smith incorrectly assumes that 100% of the CC&B system was capitalized within the test year. But within the test year, only $16.7 million or about 68.2%, was capitalized for the CC&B system representing the portion of the asset placed in service as used and useful in serving TEP's customers at that time. In 2007 an additional $7.8 million was capitalized, reflecting the complete installation of CC&B and its reporting system. The total cost for the CC&B and its reporting system for TEP *and* its affiliates was $24.5 million – $16.7 million plus $7.8 million. Mr. Smith's analysis misses this critical component.

Therefore, the $16.7 million for the CC&B system in rate base at the end of the test year fairly and properly reflects the investment in used and useful plant serving TEP customers. Consequently, Mr. Smith's proposed adjustment should be rejected.

B. Cash Working Capital (Staff Adjustment B-4).

Q. Did the Staff and Interveners comment on and adjust the Company's cash working capital adjustment?

A. Staff, RUCO and the AECC agreed with the Company's calculations of revenue and expense leads and lags within the cash working capital adjustment as proposed by the Company. The differences between the Company's calculation and that of Staff's and AECC's are because of different input amounts as a result of different pro forma adjustment amounts. The same is true for RUCO as well as some computational errors within RUCO's application of the cash working capital calculation.

III. REBUTTAL TO OPERATING INCOME ADJUSTMENTS.

A. Springerville Unit 1 – Revenue & Expense (Staff C-1 & RUCO 24).

Q. Do you agree with the adjustments to operating revenue and expense for Springerville Unit 1 as proposed by ACC Staff Witness Smith, RUCO Witness Diaz Cortez and AECC Witness Higgins?

A. No. Mr. David Hutchens and Ms. Karen Kissinger will discuss TEP's position with respect to market-based rates and accounting issues regarding going to cost, respectively. But assuming that Springerville Unit 1 is either restored to embedded cost or to a rate per kW month, the adjustments proposed by Staff and AECC are incomplete.

Q. Please explain why Staff and AECC adjustments to embedded cost are wrong.

A. Staff recommends including Springerville Unit 1 operating expense in the revenue requirement at the rate of $15 per kW-month, or approximately $68.4 million. However, Staff does not reverse the approximately $62 million of net Springerville Unit 1 leasehold improvements that TEP removed from rate base. These leasehold improvements were removed as part of the pro forma adjustments to include Springerville Unit 1 in the revenue requirement at a current market-based rate. If Springerville Unit 1 is recovered at any rate other than a current market-based rate, then TEP should be allowed to recover the cost of, and earn a return on, the related leasehold improvements. By failing to make this adjustment, Staff ignores the fact that these capital improvements are used and useful in directly providing service to the customer. As used and useful, they must be included in rate base.

AECC recommends including Springerville Unit 1 operating expense in the revenue requirement at the embedded cost of approximately $85 million. But AECC makes the same error Staff makes, because AECC does not reverse the $62.2 million of net Springerville Unit 1 leasehold improvements. As I explained above, TEP removed these improvements from rate base as part of the pro forma adjustments to include Springerville Unit 1 in the revenue requirement at a market-based rate. TEP is entitled to recover the cost of, and earn a return on, these leasehold improvements as they were made for the benefit of serving customers.

Q. Are there also problems with RUCO's adjustment on this issue?

A. Yes. Like AECC, RUCO recommends the use of the actual test year embedded cost of Springerville Unit 1 of approximately $85 million. RUCO also recommended restoring the Springerville Unit 1 net leasehold improvements at embedded cost. But as I explain

below in Subsection III.B., RUCO's adjustment is incomplete and inaccurate for additional reasons.

Q. Are there other adjustments that are needed if current market-based rates are not approved for Springerville Unit 1?

A. Yes. If Springerville Unit 1 is included in the revenue requirement at anything other than the current market-based rate, then the Company should be allowed to have the leasehold improvements included in rate base. In addition, depreciation and property tax expense would require additional pro forma adjustments to property include the correct expense in the revenue requirement for the leasehold improvements included in rate base.

Q. In short, Mr. Dukes, was the purpose of your discussion on Springerville Unit 1 change TEP's position on using current market-based rates?

A. No. Having illustrated mistakes the other parties make in arguing against TEP's proposal, TEP still believes market-based rates are appropriate to reflect the cost of Springerville Unit No. 1. My testimony on this issue is to simply show the *additional* adjustments needed if Springerville Unit 1 is in the revenue requirement at anything other than current market based rates. In his Rebuttal Testimony, Mr. Hutchens explains why $29.72 per kW-month is the current market-based rate that should be included for Springerville Unit 1. If anything but TEP's approach and proposed rate is approved, then the other adjustments are necessary and appropriate.

Finally, it is completely unfair and imbalanced to force the Company to write down the value of assets to be reflective of a market proxy almost twenty years ago and then to come back almost twenty years later and say that the current reduced book value is the embedded "cost". That is not "cost"; it is the book value after a $185 million forced reduction at the expense of the Company and its Shareholders. Essentially, the Company was not allowed

to recover cost because at the time they were deemed too high versus market comparables, but now that the original cost as written down is less than market comparables that the Company should be allowed to recover cost based on the "written down" amount. That is unreasonable and unfair to TEP.

B. <u>Generating Facilities – Operating Lease (RUCO 23).</u>

Q. Do you agree with Operating Adjustment No. 23 for Generating Facilities - Operating Lease as proposed by RUCO Witness Diaz Cortez?

A. No. Ms. Diaz Cortez proposes a correction to the Company's operating lease expense that she asserts is necessary because RUCO is rejecting the Company's proposed treatment of Springerville Unit 1 at market rates. As I stated above, TEP does not agree with the proposed adjustment to operating lease expense because I do not accept RUCO's proposal to restore Springerville Unit 1 to test-year embedded cost for ratemaking purposes. Ms. Kissinger for TEP discusses the accounting background for Springerville Unit 1 in much more detail in her Rebuttal Testimony. But even assuming that Springerville Unit 1 is restored to embedded cost, Ms. Diaz Cortez's proposed adjustments are still incomplete and therefore incorrect.

Q. What is the change proposed by Ms. Diaz Cortez?

A. Ms. Diaz Cortez states that because RUCO is rejecting the market rate-based expense for Springerville Unit 1, it is necessary to remove 100% of the Springerville Coal Handling Facilities expense in the operating lease expense adjustment. This is incorrect. The Springerville Unit 1 adjustment "removed" all non-fuel operations and maintenance expense ("O&M") and "replaced" it with market-based expense. The expense "removed" included 50% of the Springerville Coal Handling Facilities capital lease expense. Because

50% of the Coal Handling Facilities capital lease expense was "removed" in the Unit 1 adjustment, the remaining 50% was removed in the operating lease expense adjustment.

Instead of just removing the 50% not included in the Springerville Unit 1 adjustment, Ms. Diaz Cortez removes 100% - for Springerville Coal Handling Facilities expense – from the operating lease expense.

Q. Are there other issues that must be addressed with RUCO's proposed adjustments?

A. Yes. If Springerville Unit 1 is restored to "cost" for ratemaking purposes as Ms. Diaz Cortez suggests, then other issues must be addressed:

- First, the lease would need to be converted to an operating lease for ratemaking purposes. This issue is discussed in more detail by Ms. Kissinger in her Rebuttal Testimony.
- Second, as Ms. Kissinger notes in her Rebuttal Testimony – the levelized amount based on the initial liability is not a fair and proper reflection of "cost" recovery and would not allow TEP to return to FAS 71 accounting for that particular generating facility. Simply put, a return to levelized recovery based on that original amount would "not" be equivalent to "cost" based rates. For example, if you commit to pay $100 out over ten years and are allowed to collect $5 over the first five years and $10 (levelized amount) over the last five years from your customers you have not recovered cost. Therefore, the only way to insure that rates set **prospectively** are cost based for Springerville Unit 1 is to look at cash yet to be paid out and insure that rates properly reflect the recovery of those amounts.

C. **Lime Usage Costs - Revenue & Expense (RUCO 21).**

Q. Do you agree with Operating Adjustment No. 21 for Lime Usage Costs as proposed by RUCO Witness Diaz Cortez?

A. No. Ms. Diaz Cortez proposes this adjustment to lime usage revenue and expense for Springerville Unit 1 that she asserts is necessary because RUCO is rejecting the Company's proposed treatment of Springerville Unit 1 at market rates. Even aside from the fact that TEP opposes restoring Springerville Unit 1 to test year embedded cost for ratemaking purposes, Ms. Diaz Cortez's adjustment is incorrect. That is because Ms. Diaz Cortez used the incorrect amount of revenue associated with Springerville Unit 1. She identified revenue of $598,676 (before ACC jurisdictional allocations) as shown in RUCO Exhibit RLM-8. Per the TEP workpaper for the pro forma identified by Bates No. TEP(0402)002394, the correct revenue amount is $566,941 (before ACC jurisdictional allocations). Ms. Diaz Cortez incorrectly used the revenue for Springerville Unit 2.

If Springerville Unit 1 is restored to embedded cost, then it would be correct to remove the lime usage revenue and expense associated with Springerville Unit 1. However, as I stated previously, I do not agree with the proposed adjustment to lime usage revenue and expense because I do not accept RUCO's proposal to restore Springerville Unit 1 to test year embedded cost for ratemaking purposes

D. **Rate Case Expense (RUCO 6).**

Q. Do you agree with Operating Adjustment No. 6 for Rate Case Expense as proposed by RUCO Witness Moore?

A. No. Mr. Moore is making an improper and illogical comparison of the rate case expense in this case to the amount recently rewarded in the UNS Gas case, Decision No. 70011. He

does so without providing any evidence as to any imprudence and uses a completely arbitrary discount factor to arrive at his proposed expense level. He appears to be completely ignoring the obvious increased scope of issues and additional complexities of this particular filing to that of UNS Gas. He also ignores the fact that the Company has already incurred $522,000 in rate case expense as of January of this year – prior to the filing of Mr. Moore's direct testimony.

Further, each individual case and the expenses to litigate should be evaluated based on the facts of that particular case and the circumstances of the Company in that case. TEP has not filed and fully litigated rate case in well over a decade. But perhaps more importantly, this case involves more complex rate issues – including several methodologies and with a full discussion about Decision No. 62103 – as well as having with significantly more intervenors. Staff, RUCO, AECC, and other parties have issued – in total – thousands of data request. The case itself covers a multitude of complex issues that date back to the mid-1990's; it can hardly be classified as a typical rate case. The case further implicates issues directly stemming from the electric competition rules and retail electric competition in Arizona. While all parties have the right to explore and question the Company about its application, the Company has the equal right to defend its position. Doing so, as TEP has done and is doing here, is entirely appropriate and Mr. Moore cannot say otherwise.

Q. Does Mr. Moore's recommendation on rate case expense penalize the Company for having the structure it has?

A. Yes. Some utility's have large internal legal and rates departments and have those cost included in base rates and some have much smaller internal departments and rely on outside consultants as they are needed. TEP has a small internal rates department and an even smaller internal legal department and as such relied upon professional outside services as opposed to having the cost already built into base rates. Further, there is no presumption in

fact about what constitutes a "normal" level of rate case expense, because each case has issues that are unique and specific to it. So, it is improper to just say that a normal rate case expense amount is "$X" for every Company and we are going to recommend reducing your incurred cost to reflect that, without doing the proper analysis and without providing adequate support for the adjustment. Simply comparing one case to another – as RUCO has done here – is insufficient to justify its adjustment.

In short, TEP's rate case expense was and is being incurred prudently and legitimately as a direct result of this case. It is not duplicative of any other services being recovered in rates or being requested by the Company in this case. As such, the Company should be allowed to recover the requested level and the Commission should consider adjusting that level before the close of this record to the best known "actual' level incurred in this case.

E. <u>Membership Dues - EEI (Staff C-6)</u>

Q. Do you agree with the proposed adjustment for Edison Electric Institute ("EEI") dues as proposed by ACC Staff Witness Ralph Smith?

A. Partially. I agree that based on the historical standard of excluding lobbying cost we should have excluded 100 percent of the EEI Utility Air Regulatory Group ("UARG") dues and 10 percent of the EEI Utility Solid Waste Activities Group ("USWAG").

I disagree, however, with Staff's exclusion of 49.93 percent of EEI core dues, as advocated by Mr. Smith. The Company provided a pro forma adjustment reducing the test-year expense associated with EEI core dues for lobbying activity (20 percent) based on the most recent information provided by EEI themselves. This information is from a July 2006 letter from EEI outlining the percentage of activities related to influencing legislation and is identified Bates No. TEP(0402)002404. This workpaper was also relied on by Mr. Smith

in arriving at the amounts of the UARG and USWAG dues to remove from test year expense, as noted in his direct testimony at Page 57, Lines 7 through 8 and at Page 57, Lines 24 through 26.

Mr. Smith bases his 49.93 percent on information obtained from National Association of Regulatory Utility Commissioners ("NARUC"). As stated by Mr. Smith in his Direct Testimony at Page 55, this information was as of December 31, 2005. In other words, Mr. Smith is relying on older (December 2005) information to make his 49.93 percent adjustment – when he used EEI's June 2006 letter to justify removing UARG and USWAG dues from test-year expense. Therefore, Mr. Smith is inconsistent in his use of authoritative information as the basis for his disallowance of EEI expense versus EEI sub-group dues expense. Since the information provided as of December 31, 2005 is outdated, Mr. Smith's 49.93 adjustment should be rejected.

F. <u>CC&B Normalization (Staff C-16 & RUCO 17).</u>

Q. Do you agree with Staff's Operating Adjustment C-16 for CC&B Normalization?

A. No. Mr. Smith's adjustment is directly related to his rate base adjustment to the CC&B asset that I discussed earlier. As I explained earlier in Subsection II.A. of my Rebuttal Testimony, Mr. Smith mistakenly believed $16.7 million reflected CC&B for TEP and its affiliates; in fact, that number equals $24.5 million. The Company's proposed normalized CC&B expense adjustment is based on the system as capitalized in the test year to serve the TEP customers only and the support cost needed to serve those customers. To make this adjustment, Mr. Smith's starting total cost numbers need revising to reflect the entire CC&B system within rate base, as well as all of the additional supporting cost necessary to provide service to its affiliates. Because Mr. Smith's adjustments start with the CC&B

costs only to support TEP, his adjustment understates the cost to support TEP's customers. Therefore, this adjustment should be rejected.

Q. Do you agree with RUCO's Operating Adjustment No. 17 for CC&B Normalization as proposed by RUCO Witness Moore?

A. No. Mr. Moore attempts to restate test year expenses to be reflective of the prior cost for the predecessor system to CC&B. Mr. Moore argues that the quality of customer service has not improved and therefore the cost increases associated with the new system should not be recovered from TEP's customers.

Q. Why do you believe Mr. Moore's argument against allowing TEP to recover the cost associated with the new system are inappropriate and should be rejected?

A. Essentially, Mr. Moore's argument is that the Company should not invest in new technology that provides increased services and should not replace fully depreciated and out dated systems if it cost more initially and there is the potential for some minor customer service issues during the implementation and initial service periods. That is analogous to saying that RUCO should write testimony and data requests with a typewriter, prepare schedules with a 10-key calculator and green bar paper – and then type those schedules with a typewriter – and copy all of that with a mimeograph machine. RUCO may save a little money on equipment and the same basic services could be provided. But the level of that service could hardly be argued as being the same. In fact, it is probably safe to assume that RUCO would be less efficient and productive without computers. But to have computers, you need to have support for the computers, and for the network those computers are a part of.

Mr. Moore completely ignores the reality that improved technology and the cost to replace older technology are needed in today's world. Decisions to replace such significant systems

are not undertaken lightly. TEP spent many years working through from analysis to go live and spent over $25 million dollars to install the CC&B system and its reporting system. The main frame system CIS+, was installed in 1998 and served TEP well for eight years, but at some point these dated and non-vendor supported systems simply have to be replaced

G. <u>Bad Debt Expense (Staff C-5 & RUCO 15).</u>

Q. Do you agree with the proposed adjustment for Bad Debt Expense as proposed by ACC Staff Witness Ralph Smith?

A. Yes. In addition, we have identified another revision to this pro forma adjustment related to the revenues included in the Customer Annualization pro forma adjustment that was omitted from the original calculation. TEP originally filed an increase of $622,366 to recorded test year bad debt expense for the test year. Mr. Smith proposed a decrease of $115,164 to recorded test year bad debt expense for the test year. The bad debt expense as corrected for the Customer Annualization pro forma revenue by TEP is now a decrease of $108,977 to test year recorded bad expense.

Q. Do you agree with the adjustment for Bad Debt Expense as proposed by RUCO Witness Diaz Cortez?

A. Yes. However, RUCO did not include all the corrections included in TEP's first Supplemental Response to Staff's Data Request No. STF 1.85. And, as noted above, TEP included another revision related to the revenues included in the Customer Annualization pro forma adjustment.

H. Legal Expense – Motion to Amend (Staff C-21 & RUCO 26).

Q. Do you agree with the adjustment for Legal Expense – Motion to Amend (Staff C-21) as proposed by Staff Witness Mr. Smith?

A. No. Staff Witness Mr. Smith is excluding outside legal cost from the test year incurred in reference to the Motion to Amend proceedings essentially saying it is not a "normal expense" for TEP. That is an incorrect adjustment because it ignores that the total amount of legal expense in the test year for TEP is normal and recurring.

Q. Please explain.

A. TEP is involved in proceedings before the Commission on a regular basis and it is very normal for TEP to incur outside legal cost due to various proceedings before the Commission. In response to Staff Data Request No. LA 23-4, I provided an analysis of outside legal cost incurred by TEP for the last four years. From 2004 through 2007, TEP incurred annual costs for legal expense equaling $2.77, $1.95, $2.37 and $2.15 million respectively. The four-year average equals $2.31 million. For the test year, the legal expenses equaled approximately $2.37 million. This is practically identical to the average incurred over the last four years. Therefore, the test-year expense for cannot be deemed abnormal. By excluding the $481,000 incurred for outside legal cost related to the Motion to Amend proceeding, Mr. Smith has proposed a pro forma total outside legal cost amount that is well below the level TEP normally incurs. Thus, it should be rejected.

Mr. Smith's real issue appears to be with the amount of the expense for the Motion to Amend proceedings that took place last year. But that proceeding was not a frivolous action. Nor can Mr. Smith argue that TEP's filing was inappropriate in any way. It is entirely reasonable for TEP to seek clarification regarding previous Commission decisions

when legitimate issues exist. That proceeding involved many complex issues that were not decided; in fact, that proceeding was ultimately rolled into TEP's rate case.

Finally, while a historical test year is the starting point to examine costs and revenues, the Commission is setting rates prospectively. Mr. Smith's adjustment to disallow legal expenses associated with a perfectly legitimate proceeding ignores the fact that TEP's total request accurately reflects this amount of expense going forward. Further, Mr. Smith cannot find anything outrageous or unreasonable about the amount spent on the Motion to Amend proceeding. For all of these reasons, Mr. Smith's adjustment to legal expense is inappropriate and should be rejected.

Q. Do you agree with the adjustment for Legal Expense – Motion to Amend (RUCO 26) as proposed by Ms. Diaz Cortez?

A. No. For the same reasons as described above, the test year level reflects the normal, recurring and expected outside legal services cost.

Q. Are there any differences between Ms. Diaz Cortez's recommendation on behalf of RUCO and Mr. Smith's for Staff?

A. Yes. Ms. Diaz Cortez is recommending that the cost be treated as a unique rate litigation cost and be amortized over the life of the rates. I do appreciate the recognition that it is a cost that should be recovered, but I still believe the most proper treatment is to leave the test year level unadjusted.

I. Legal Expense – California Proceeding (Staff C-22).

Q. Do you agree with the adjustment for Legal Expense – California Proceeding (Staff C-22) as proposed by Staff Witness Mr. Smith?

A. No. Mr. Smith is arguing that the legal costs incurred during the test year related to wholesale activity should not be recovered from retail customers. I agree with Mr. Smith on that point, but I have already excluded an appropriate portion of this expense through the jurisdictional allocation process, recognizing that some portion of legal cost should not be recovered from retail customers. In response to Staff Data Request LA 20-13(b), I provided the explanation as follows:

> "In the Cost-of-Service and Hybrid Methodologies, the amount would have been reduced 4.32% to allocate cost to the FERC jurisdiction for firm wholesale sales activity. The remaining Arizona Corporation Commission ("Commission") jurisdictional portion is then reduced by 6.64%, to allocate to FERC jurisdiction the cost associated with providing transmission services. That equates to an end result Commission jurisdictional amount of 93.36% of the original amount expensed.
>
> In the Market Methodology, the amount would have been reduced 4.32% to allocate the cost to the FERC jurisdiction for firm wholesale sales activity. The remaining Commission jurisdictional portion is then reduced by 6.64% to allocate to the FERC jurisdiction the cost associated with providing transmission services and 64.19% for cost associated with generation services. That equates to an end result Commission jurisdictional amount of 27.91% of the original amount expensed."

This response clearly indicates that the test year total outside legal cost is being reduced to recognize a portion of those expenditures as non-ACC jurisdictional activity – thus

reducing the amount to be included in retail rates. It is not appropriate to simply exclude invoices that are not related to retail customers on a piecemeal basis without considering that a jurisdictional allocation will be applied to remove expenditures for just that purpose. Mr. Smith's adjustment effectively double counts these expenses and removes them when they have already been removed. That is inequitable and should be rejected.

J. <u>Markup Above Cost – Affiliate Charges SES (Staff C-17).</u>

Q. Do you agree with the adjustment for Markup Above Cost – Affiliate Charges SES (Staff C-17) as proposed by Staff Witness Mr. Smith?

A. No. Mr. Smith points out on page 74 of his Direct Testimony – for work classified as "supplemental" SES charges the employees' actual cost plus the cost of employer's taxes, workers' compensation, benefits and an additional mark-up of 10% on the base wages of the employees. What Mr. Smith ignores is the fact that no business could survive if they could only charge the direct cost of the job and the direct benefit cost of the employees on that job. Every business, including SES, has overhead cost such as the building cost, management & administrative personnel cost, inventory carrying cost and all of the normal cost of a running a business including income tax expense. SES recovers those overhead cost through markups on their direct expenses just like any other contractor. I cannot imagine that Mr. Smith is only charging the Commission for his direct wages and direct benefits – he has an office, support personnel and other overhead costs that he somehow has to recover to stay in business.

SES provides service to TEP on an as needed basis for "supplemental work", which allows TEP to ultimately reduce expense and benefit TEP customers. For Mr. Smith to say that TEP should not recover those costs because a portion of SES's billing is called markup is unfair and unreasonable. For those reasons, Mr. Smith's adjustment should be rejected.

1 **K. <u>Normalize Affiliate Charges to TEP (Staff C-18).</u>**

2

3 **Q. Do you agree with the adjustment to Normalize Affiliate Charges to TEP (Staff C-18)**
4 **as proposed by Staff Witness Mr. Smith?**

5 A. No. Mr. Smith is solely looking at the cost as charged from SES, service provider to TEP,
6 rather than looking at the actual expense levels of TEP. This makes no sense. SES crews
7 are used when TEP crews are not available due to commitments to other projects. For
8 example, if a TEP crew is performing a capital project and is unavailable to do a needed
9 maintenance project a SES crew might be brought in to supplement the work force during
10 that period of need. When SES crews are not needed, TEP does not pay for them. It would
11 then be the responsibility of SES, like any outside contractor, to keep those crews active
12 somewhere and to recover their cost and to produce a profit. But it is not the responsibility
13 of TEP or its customers in those circumstances.

14

15 The benefit to TEP is flexibility and cost savings – by having the ability to add additional
16 crews or workforce as needed and to shed the related payroll, benefits, equipment expenses
17 and overhead expenses when the crews or workforce are not needed. In other words, TEP
18 and its customers only pay for SES crews when those crews are working on operations and
19 maintenance for the benefit of customers. This is a valuable way for TEP to control cost
20 and is an ultimate benefit to the customers of TEP.

21

22 **Q. So you believe that Mr. Smith's adjustment is unnecessary and incorrect?**

23 A. Yes. The accounts that Mr. Smith is adjusting are FERC 908, 923 and 592. FERC 908,
24 Customer Assistance Expenses, is essentially zero after the Company's adjustment to
25 remove "Renewable Resources Expenses", but Mr. Smith's proposed adjustment would
26 make it a negative expense or a credit to the customer. That obviously makes no sense
27 because SES is not paying TEP. The reason for such an illogical outcome is because Mr.

Smith is only looking at vendor billing to evaluate the Company's expenses which does not give an accurate picture of the normal expense levels of the Company.

Further, even though TEP believes the amounts in FERC account Nos. 592 and 923 are in the test year are reasonable, TEP could easily argue that those expenses are below normal in the test year. This is because the expense for FERC account Nos. 592 & 923 – from 2004 through 2006 - averages $8.9 million. By contrast, the test year level was $8.6 million. This further shows that Mr. Smith's adjustment is inconsistent as well as illogical. Therefore, Staff adjustment C-18 should be rejected.

L. <u>Postage Expense (Staff C-23).</u>

Q. Do you agree with the adjustment for Postage Expense (Staff C-23) as proposed by Staff Witness Mr. Smith?

A. Yes. And I have proposed an additional increase of $27,494 in my Rebuttal exhibits to reflect the postage increase that will be effective May 12, 2008. The total adjustment to postage expense, which includes the 2007 and 2008 postage rate increases, is $92,957 (prior to ACC jurisdictional allocations).

M. <u>WestConnect Charges in ICRA (Staff C-24).</u>

Q. Do you agree with the pro forma adjustment to reduce test year expense by $221,813 for WestConnect charges already included in the proposed Implementation Cost Regulatory Asset as proposed by ACC Staff Witness Ralph Smith?

A. Yes. This amount should be removed from test year expense to avoid double counting, since it is being amortized as part of the Implementation Cost Regulatory Asset. TEP is also removing an additional $51,632 of test year expense (before ACC jurisdictional

allocations) for WestConnect that is also included in the Implementation Cost Regulatory Asset. Both of these amounts (totaling $273,445 before ACC jurisdictional allocations) were identified in the first Supplemental Response to STF 1.85.

N. <u>Inappropriate/Unnecessary Expenses (RUCO 3).</u>

Q. Do you agree with the pro forma adjustment to reduce test year expense by $513,731 for items identified as "unnecessary or inappropriate" as proposed by RUCO Witness Rodney Moore?

A. No. TEP reduced test year expense for approximately $741,000 in pro forma adjustments for Advertising and Sponsorship, Outside Services, Out of Period Expenses and Membership Dues when this rate case was originally filed. In addition, TEP has reduced expense by $46,621 (FERC Account 921 in TEP's first Supplemental Response to Staff Data Request No. STF 1.85, included in Company's Miscellaneous Rebuttal adjustment as noted). Of this amount, $21,123 is still incorrectly included in RUCO's proposed pro forma to reduce expense.

The Company did carefully review the work papers provided by Mr. Moore as part of our response to RUCO Data Request Nos. 5.17 and 8.1 – and agreed to remove a number of expenses for various reasons (per TEP's first Supplemental Response to Staff Data Request No. STF 1.85). We provided explanations for other expenses which Mr. Moore had assumed were either unnecessary or inappropriate because he did not have backup details available in his initial review. Mr. Moore continues to argue for removing expenses that are legitimate and reasonable operating expenditures. For example, payments to Tucson Regional Economic Opportunities, Inc. for strategic plan sponsorship benefit customers as well as the Company's shareholders by promoting effective regional economic development plans for population and job growth. The Company believes that, after the expenses

identified in the first Supplemental Response to Staff Data Request STF No. 1.85, the remaining expenses included in the test year revenue requirement are legitimate and reasonable operating expenses.

O. <u>Normalization of Overhead Line Maintenance (RUCO 8).</u>

Q. Do you agree with the pro forma adjustment to reduce test year expense by $126,584 the normalization of overhead line maintenance as proposed by RUCO Witness Rodney Moore?

A. No. RUCO's approach is inconsistent and RUCO offers no justification for its varying approach to FERC O&M accounts. I do not believe that the test year level in FERC Account 593 deviates materially enough from "normal" to warrant being isolated from all of the other deviation in operation in maintenance accounts. In other words, RUCO cannot simply pick and choose to normalize accounts simply because that produces the lowest level of expense. As I point out above, the test year expense levels in FERC Account Nos. 592 and 923 are $300,000 below their three-year average. These accounts could just as easily be normalized, as RUCO proposes for FERC Account 593. In aggregate, I believe the Company has normalized accounts in an appropriate manner and/or accepted adjustments as proposed by Interveners. In this particular case, I believe the test year levels are within acceptable limits, especially when considered in the context of TEP's year over year increases in operating cost.

P. Penalties and Fines (RUCO 9).

Q. Do you agree with the pro forma adjustment to reduce test year expense by $9,433 for penalties and fines as proposed by RUCO Witness Rodney Moore?

A. Yes. These expenses were included in the test year revenue requirement in error. TEP has removed the $9,433 from test year operating expense (before ACC jurisdictional allocations).

Q. Employee Recognition and Employee Benefits (RUCO 19 & 20).

Q. Do you agree with the pro forma adjustment to reduce test year expense to eliminate expenses associated with employee recognition as proposed by RUCO Witness Rodney Moore?

A. No. Mr. Moore is suggesting that it is not appropriate for the retail customers to be "burdened" by $76,125 in employee recognition awards administered by the OC Tanner Recognition Company. I could not disagree with Mr. Moore any more strongly – these costs are directly related to years of service awards and are an integral and normal part of employment service recognition and employee compensation. These awards are provided to recognize the value and benefit of long-term service and the value of employees' service and experience to TEP and to its customers. I don't believe Mr. Moore actually disagrees with emphasizing low employee turn-over and the retention of experienced and valuable employees – precisely because customers benefit from that. Nonetheless, Mr. Moore's proposed adjustments here are therefore short-sighted and will only put such programs in jeopardy of elimination. The costs should be included in the revenue requirement like any other normal and recurring cost incurred to provide services to retail customers.

Q. Do you agree with the Mr. Moore's proposed pro forma adjustment to reduce test year expense to eliminate expenses associated with employee benefits (*i.e.* appreciation events)?

A. No. Mr. Moore is suggesting that expenses for employee appreciation events are an inappropriate "burden" to TEP customers and therefore should not be included in pro forma expenses. While I do not believe Mr. Moore conceptually opposes such events, he appears to believe that retail customers should not pay for these expenses. But such events also recognize employee accomplishments, promote low employee turn-over and help to retain experienced and valuable employees. I think Mr. Moore would concede that these programs ultimately benefit TEP customers. That is because having such programs best ensure that qualified and dedicated professionals and employees continue to work – and want to work – for TEP. It is therefore the Company's position that employee benefit expenses directly benefit the customer and are normal and recurring cost. Thus, it is standard ratemaking practice to include those expenses in the revenue requirements established in the case.

R. <u>Miscellaneous Expenses (New Company Adjustment).</u>

Q. Please describe the pro forma adjustment for Miscellaneous Expenses.

A. This adjustment removes $46,621 (before ACC jurisdictional allocations) of expenses for membership dues, sponsorships and meals and entertainment as identified in TEP's first Supplemental Response to Staff Data Request No. STF 1.85. These expenses should not be included in the test year revenue requirement.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

EXHIBIT

DJD-1

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2006

	ACC Jurisdictional - MARKET			
	As Filed	Rebuttal		
	TEP	TEP		TEP
	7/2/07	4/1/08		Witness
RATE BASE				
Original Cost Rate Base - Unadjusted	$594,811,820	$594,811,820	Reflect the Exclusion of Transmission and Generation as Non-ACC Jurisdictional	
Rate Base Adjustments				
Implementation Cost Regulatory Asset	14,212,658	14,212,658	No Rebuttal Adjustment	Kissinger
Springerville Unit 1	($7,865,948)	($7,865,948)	No Rebuttal Adjustment	Kissinger - accounting issues; Pignatelli & DeConcini - treatment.
Renewable Resources	($739,990)	($739,990)	No Rebuttal Adjustment	
Luna Plant	($5,256,819)	($5,256,819)	No Rebuttal Adjustment	Pignatelli & DeConcini - treatment
Delayed Unitization (STF 1.86)	-	434,121	Increase plant in service and accumulated depreciation for generation plant that was in service at 12/31/06 but not unitized or included in FERC 106 (Completed Construction Not Classified).	Kissinger
Delayed Unitization - ADIT (STF 1.86)	-	(30,631)	Adjust test year recorded deferred income taxes associated with the increase in plant in service for generation plant that was in service at 12/31/06 but not unitized or included in FERC 106 (Completed Construction Not Classified).	Kissinger
Accumulated Deferred Income Taxes	($47,207,280)	($69,667,191)	Changes result from rate base adjustments.	Kissinger
Allowance for Cash Working Capital	($7,079,838)	($7,598,192)	Changes result from rate base and operating income adjustments.	Dukes
Allowance for Working Capital	($555,613)	($555,613)	No Rebuttal Adjustment	Kissinger & Hutchens
Total Adjustments to Rate Base	(54,492,830)	(77,067,604)		
Rate Base	540,318,990	517,744,217		
Requested Rate of Return	8.35%	8.35%		Hadaway & Larson
Required Operating Income	$45,122,521	$43,237,282		

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2006

	ACC Jurisdictional - MARKET			
	As Filed	Rebuttal		
	TEP	TEP		TEP
	7/2/07	4/1/08		Witness
OPERATING INCOME				
Original Operating Income - Unadjusted	$406,644,105	$406,644,105	Reflect the Exclusion of Transmission and Generation as Non-ACC Jurisdictional	
Operating Revenue Adjustments				
Stranded Costs & Fixed CTC	(89,640,816)	(89,640,816)	No Rebuttal Adjustment	
SlimFast Contract Termination Fee	(278,215)	(278,215)	No Rebuttal Adjustment	
Customer Annualization	7,514,575	7,514,575	No Rebuttal Adjustment	
Weather Normalization	4,572,055	4,572,055	No Rebuttal Adjustment	
Short-Term Sales Exclusion	-	-	No Rebuttal Adjustment	Hutchens
Wholesale Trading Activity	-	-	No Rebuttal Adjustment	Hutchens
Heavy Equipment - Operating Lease	197,342	197,342	No Rebuttal Adjustment	
Springerville Unit 1	(566,941)	(566,941)	No Rebuttal Adjustment	Hutchens - market rate, Kissinger - accounting issue, Dukes - adjustment
Renewable Resources	(6,888,380)	(6,888,380)	No Rebuttal Adjustment	
Service Fees & Late Fees (RUCO 3.14)	1,308,077	2,469,342	TEP increases Miscellaneous Service Fees	Erdwurm
Lime Usage Costs	(598,676)	(598,676)	No Rebuttal Adjustment	Dukes
Tri-State Fuel Oil Sales	(7,262,954)	(7,262,954)	No Rebuttal Adjustment	
Building Usage Allocations	150,685	150,685	No Rebuttal Adjustment	
Springerville Unit 3	(3,084,442)	(3,084,442)	No Rebuttal Adjustment	
Total Adjustments to Operating Revenues	(94,577,690)	(93,416,425)		
Operating Expense Adjustments				
Implementation Cost Regulatory Asset	3,553,211	3,553,211	No Rebuttal Adjustment	Kissinger - accounting, Hutchens - benefits & savings, Grant - financing cost
Stranded Costs & Fixed CTC	(12,981,031)	(12,981,031)	No Rebuttal Adjustment	
Customer Annualization	-	-	No Rebuttal Adjustment	
Weather Normalization	-	-	No Rebuttal Adjustment	
Unit Availability Normalization	-	-	No Rebuttal Adjustment	
Short-Term Sales Exclusion	-	-	No Rebuttal Adjustment	Hutchens & Erdwurm
Wholesale Trading Activity	-	-	No Rebuttal Adjustment	Hutchens & Erdwurm
Test Power Exclusion	-	-	No Rebuttal Adjustment	
Sundt Coal Contract	-	-	No Rebuttal Adjustment	

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2006

	ACC Jurisdictional - MARKET			
	As Filed	Rebuttal		
	TEP	TEP		TEP
	7/2/07	4/1/08		Witness
Navajo Coal Contract	-	-	No Rebuttal Adjustment	Hutchens
San Juan Coal	-	-	No Rebuttal Adjustment	Hutchens
PPFAC Adjustment	-	-	No Rebuttal Adjustment	Hutchens
Gain on Sale of S02 Allowances	698,382	698,382	No Rebuttal Adjustment	Hutchens
Generating Facilities - Operating Lease	(1,780,011)	(1,780,011)	No Rebuttal Adjustment	Kissinger - background accounting, Dukes - RUCO's adjustment
Heavy Equipment - Operating Lease	(2,564)	(2,564)	No Rebuttal Adjustment	
Railcar - Operating Lease	-	-	No Rebuttal Adjustment	
Springerville Unit 1	3,930,203	6,191,717	Adjustment to increase market rate from $25.67 to $29.72	Hutchens - market rate, Kissinger - accounting issues, Dukes - RUCO's adjustment
Luna O&M	(366,970)	(366,970)	No Rebuttal Adjustment	Hutchens & Kissinger
Plant Overhaul & Outage Normalization	127,819	127,819	No Rebuttal Adjustment	DeConcini & Kissinger
Renewable Resources (STF 1.85)	(5,918,191)	(5,959,217)	To reduce test year expense for additional renewables expense totaling $41,313 that were not removed in the original pro forma adjustment.	Dukes
Payroll Expense (STF 1.86)	230,631	468,182	An additional 3% increase in wages for 2008. Supplied in Supplemental response 1.85	Sabers
Payroll Tax Expense (STF 1.86)	82,585	149,126	Adjustment reflects increase in wages	Sabers
Pension & Benefits	(933,894)	(933,894)	No Rebuttal Adjustment	Sabers
Post Retirement Medical	(62,592)	(62,592)	No Rebuttal Adjustment	Sabers
Incentive Compensation	114,112	853,620	TEP is restating adjustment from a 4-year average to actual test year expense and then reduced Officers portion of expense by 50% (sharing on a 50/50 basis).	Sabers
Rate Case Expense	215,291	215,291	No Rebuttal Adjustment	Dukes
Membership Dues (Staff C-6)	(64,792)	(168,649)	To reduce membership dues expense for EEI for amounts identified by ACC Staff in pro forma C-6 for UARG and USWAG dues primarily related to lobbying and other activities that should not be in rates.	Dukes
Advertising & Sponsorship	(436,175)	(436,175)	No Rebuttal Adjustment	
Outside Services	(138,038)	(138,038)	No Rebuttal Adjustment	
CC&B Normalization	433,987	433,987	No Rebuttal Adjustment	Dukes
Out of Period Expenses	57,272	57,272	No Rebuttal Adjustment	
Lime Usage Costs	(95,592)	(95,592)	No Rebuttal Adjustment	Dukes
Tri-State Fuel Oil Sales	-	-	No Rebuttal Adjustment	
Bad Debt Expense (STF 1.85)	622,366	(108,977)	Adjustment filed in Supplemental response 1.85 plus, TEP accepts the Staff adjustment and makes an additional correction for the Customer Annualization revenue adjustment.	Dukes

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2006

	ACC Jurisdictional - MARKET			
	As Filed	Rebuttal		
	TEP	TEP		TEP
	7/2/07	4/1/08		Witness
Capital Cost Allocations	1,764,588	1,764,588	No Rebuttal Adjustment	
Corporate Cost Allocations	(103,400)	(103,400)	No Rebuttal Adjustment	
SERP	-	(443,943)	TEP removing 50% of SERP	Sabers
Miscellaneous Expenses (STF 1.85)		(62,831)	Remove various expenses (this adjustment originally included WestConnect charges in the ICRA; TEP accepts that adjustment included in WestConnect line below in this spreadsheet).	Dukes
Postage Expense (STF 1.86)	-	92,956	To increase test year expense for the postage rate increase in effect on May 14, 2007 that was not included in the original filing	Dukes
West Connect Charges in ICRA (Staff C-24)	-	(225,915)	Removal of WestConnect expense that was already included in the ICRA. (it was included in Miscellaneous Expenses filed in the Supplemental Response #1 to STF 1.85)	Dukes
Penalties and Fines (RUCO 9)	-	(8,227)	TEP is accepting RUCO's adjustment to reduce expense for invoices indicating penalties and fines as identified in the response to STF 1.114.	Dukes
OATT	84,094,549	84,094,549	No Rebuttal Adjustment	
MGC	696,305,032	696,305,032	No Rebuttal Adjustment	
Must Run - Fuel	9,131,845	9,131,845	No Rebuttal Adjustment	
Delayed Unitization - Depr Expense (STF 1.86)	-	152,168	Increase test year recorded depreciation expense associated with the increase in plant in service for generation plant that was in service at 12/31/06 but not unitized or included in FERC 106 (Completed Construction Not Classified).	Kissinger
Delayed Unitization - Property Tax (STF 1.86)		550	Increase test year recorded property tax expense associated with the increase in plant in service for generation plant that was in service at 12/31/06 but not unitized or included in FERC 106 (Completed Construction Not Classified).	Kissinger
Depr. & Amort. Expense Annualization	(10,384,020)	(10,384,020)	No Rebuttal Adjustment	Kissinger
Property Tax (STF 1.85)	1,285,141	1,033,641	To adjust expense as originally filed for a change in the assessment rate and most current average property tax rate	Kissinger
Income Taxes	(341,334,136)	(341,221,188)	Changes result from proposed rate base and operating revenue & expense adjustments.	Kissinger
Total Adjustments to Operating Expense	428,045,608	429,840,701		
Total Net Adjustments	(522,623,298)	(523,257,126)		
Adjusted Operating Income	(115,979,193)	(116,613,021)		
Operating Income Deficiency	161,101,714	159,850,303		
Gross Revenue Conversion Factor	1.6609	1.6598		
Increase in Gross Revenue Requirement	267,570,334	265,316,268		

EXHIBIT

DJD-2

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2006

	ACC Jurisdictional - HYBRID			
	As Filed	Rebuttal		
	TEP	TEP		TEP
	7/2/07	4/1/08		Witness
RATE BASE				
Original Cost Rate Base - Adjusted COS @ End of Test Period	$981,720,777	$952,425,652	Difference due to adjustments made in the COS-Rebuttal Model that are brought forward as the starting position for the Hybrid-Rebuttal Model	See DJD-3
Rate Base Adjustments				
Navajo Plant	(53,057,377)	(53,057,377)	No Rebuttal Adjustment	
Four Corners Plant	($15,389,890)	($15,389,890)	No Rebuttal Adjustment	
Accumulated Deferred Income Taxes	$10,453,709	$10,845,064	Changes result from rate base adjustments.	Kissinger
Allowance for Cash Working Capital	$1,578,076	$1,548,754	Changes result from rate base and operating income adjustments.	Dukes
Allowance for Working Capital	($4,351,257)	($4,351,257)	No Rebuttal Adjustment	
Total Adjustments to Rate Base	(60,766,739)	(60,404,706)		
Rate Base	920,954,038	892,020,946		
Requested Rate of Return	8.35%	8.35%		
Required Operating Income	$76,909,694	$74,493,465		
OPERATING INCOME				
Original Operating Income - Adjusted COS @ End of Test Period	$37,684,547	$28,000,757	Difference due to adjustments made in the COS-Rebuttal Model that are brought forward as the starting position for the Hybrid-Rebuttal Model - Primary being SP-1 Mkt. Rate	See DJD-3
Operating Revenue Adjustments				
	-	-	No Rebuttal Adjustment	
Total Adjustments to Operating Revenues	-	-		
Operating Expense Adjustments				
Navajo O&M Exclusion	(8,849,124)	(8,849,124)	No Rebuttal Adjustment	
Four Corners O&M Exclusion	(6,169,761)	(6,169,761)	No Rebuttal Adjustment	

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2006

	ACC Jurisdictional - HYBRID			
	As Filed	Rebuttal		
	TEP	TEP		TEP
	7/2/07	4/1/08		Witness
Navajo Plant Overhaul & Outage Normalization	(533,900)	(533,900)	No Rebuttal Adjustment	
Four Corners Overhaul & Outage Normalization	(415,260)	(415,260)	No Rebuttal Adjustment	
PPFAC Adjustment	87,451,050	87,451,050	No Rebuttal Adjustment	
OATT	84,094,549	84,094,549	No Rebuttal Adjustment	
Depr. & Amort. Expense Annualization	(8,299,929)	(8,299,929)	No Rebuttal Adjustment	
Property Tax	(1,792,572)	(1,780,153)	To adjust expense as originally filed for a change in the assessment rate and most current average property tax rate	Kissinger
Income Taxes	(56,739,145)	(56,748,269)	Changes result from proposed rate base and operating revenue & expense adjustments.	Kissinger
Total Adjustments to Operating Expense	88,745,906	88,749,202		
Total Net Adjustments	(88,745,906)	(88,749,202)		
Adjusted Operating Income	(51,061,359)	(60,748,444)		
Operating Income Deficiency	127,971,053	135,241,910		
Gross Revenue Conversion Factor	1.6609	1.6598		
Increase in Gross Revenue Requirement	212,544,334	224,471,769		

EXHIBIT

DJD-3

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2006

	ACC Jurisdictional - COS						
	As Filed	Direct	Direct	Direct	Rebuttal		
	TEP	ACC	RUCO	AECC	TEP		TEP
	7/2/07	2/29/08	2/29/08	2/29/08	4/1/08	Summary	Witness
RATE BASE							
Original Cost Rate Base - Unadjusted	$1,154,149,459	$1,154,149,459	$1,154,149,459	$1,154,149,459	$1,154,149,459		
Rate Base Adjustments							
Implementation Cost Regulatory Asset (Staff B-3, RUCO 4, AECC)	47,454,880	14,212,499	14,212,843	36,273,953	47,454,880	Staff and RUCO remove the portion of the ICRA for which TEP did not pre-request ACC approval for deferral (San Juan & Sundt Coal Contract Fees and Generation-Related Financing Costs. AECC recommends recovery over an extended amortization period beginning at the time of the buyouts.	Kissinger
Springerville Unit 1 (RUCO 2)	($54,784,951)	(54,784,951)	-	($54,784,951)	($54,784,951)	Staff, RUCO & AECC disagree with the market rate recovery proposed by TEP. RUCO restores Springerville Unit 1 leasehold improvements and accumulated depreciation at embedded cost, while Staff & AECC do not change TEP's pro forma removing leasehold improvements. RUCO & AECC restore Springerville Unit 1 operating expense to embedded cost. Staff restores operating expense to the original $15/kw/month cap. RUCO reverses TEP's reduction of revenue, while Staff and AECC do not.	Kissinger - accounting issues; Pignatelli & DeConcini - treatment.
Renewable Resources	($6,727,183)	(6,727,183)	(6,727,183)	($6,727,183)	($6,727,183)	No Rebuttal Adjustments.	
Luna Plant (Staff B-2, RUCO 3, AECC)	($45,829,034)	-	-	-	($45,829,034)	Staff, RUCO and AECC reject the TEP proposal to use a market-based fixed recovery rate and restore plant and accumulated depreciation to rate base at embedded cost.	Pignatelli & DeConcini - treatment
Accum Depr- Cost of Removal (FAS 143) (Staff B-5 & RUCO 5)	-	(99,814,938)	(78,018,592)	-	-	Staff and RUCO reverse the TEP $112.8 million write-off of accumulated depreciation for estimated cost of removal related to adoption of FAS 143. Staff states that this amount should be a regulatory liability for ratemaking and that TEP did not obtain ACC approval for implementing FAS 143. RUCO stated that if the write-off is recognized for ratemaking purposes, this will result in double recovery of the previously accrued asset retirement costs.	Kissinger
Accum Depr-Unauthorized Depreciation Rate Changes (Staff B-6 & RUCO 1)	-	(41,567,880)	($43,916,606)	-	-	Staff and RUCO revise rate base for unauthorized changes in depreciation rates.	Kissinger
Miscellaneous ADIT, Account 190 (Staff B-7)	-	-	-	-	-	Staff adjusts ADIT in FERC 190 for various items to coordinate ADIT with items included in rate base (ADIT related to various compensation items and the moratorium/reduction for lease SL vs. Cash).	Kissinger
Other Deferred Credits (Staff B-8)	-	(2,625,627)	-	-	-	Staff adjusts rate base to include deferred credits for San Juan & Four Corners Reclamation Costs, UET Tower Lease Costs & Environmental Costs to be consistent with amounts included in ADIT FERC 190.	Kissinger
Customer Care & Billing System (Staff B-9)	-	(4,364,894)	-	-	-	Staff adjusts rate base for the 37.2% of CC&B that is allocated to UNS Electric & UNS Gas.	Dukes
Delayed Unitization	-	-	-	-	4,021,531	Increase plant in service and accumulated depreciation for generation plant that was in service at 12/31/06 but not unitized or included in FERC 106 (Completed Construction Not Classified). **(TEP Rebuttal adjustment discussed in witness Kissinger's Rebuttal testimony)**	Kissinger
Delayed Unitization - ADIT	-	-	-	-	(57,008)	Adjust test year recorded deferred income taxes associated with the increase in plant in service for generation plant that was in service at 12/31/06 but not unitized or included in FERC 106 (Completed Construction Not Classified). **(TEP Rebuttal adjustment discussed in witness Kissinger's Rebuttal testimony)**	Kissinger
Accumulated Deferred Income Taxes	($87,859,168)	(56,548,738)	(75,032,004)	($87,577,698)	($120,439,569)	Staff and RUCO changes result from proposed rate base adjustments. **(TEP Rebuttal adjustment discussed in witness Kissinger's Rebuttal testimony)**	Kissinger

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2006

	ACC Jurisdictional - COS						
	As Filed	Direct	Direct	Direct	Rebuttal		
	TEP	ACC	RUCO	AECC	TEP		TEP
	7/2/07	2/29/08	2/29/08	2/29/08	4/1/08	Summary	Witness
Allowance for Cash Working Capital (Staff B-4/B-4.1 & RUCO 6)	($22,017,047)	(24,642,425)	(19,178,471)	($22,017,047)	($23,434,204)	Staff and RUCO changes result from rate base and operating income adjustments. **(TEP Rebuttal adjustment discussed in witness Dukes' Rebuttal testimony)**	Dukes
Allowance for Working Capital (Staff B-4.2)	($1,652,795)	(3,757,710)	(1,652,795)	($1,652,795)	($1,652,795)	Staff proposes use of target coal inventory level instead of a 13-month average balance and a fuel oil inventory level based on average daily burn rates instead of a 13-month average balance.	Kissinger & Hutchens
ACC Jurisdictional Allocation Computation Errors	-	(9,325,662)	(7,713,248)	$344,579	-		
Total Adjustments to Rate Base	(171,415,299)	(291,947,508)	(218,026,056)	(136,485,721)	(201,448,334)		
Rate Base	982,734,160	862,201,951	936,123,403	1,018,008,317	952,701,125		
Requested Rate of Return	8.35%	7.93%	7.76%	8.35%	8.35%	Staff proposes a WACC of 7.93% (cost of equity of 10.25%). RUCO proposes a WACC of 7.76% (cost of equity of 9.44%). TEP requested a WACC of 8.35% (cost of equity of 10.75%).	Hadaway & Larson
Required Operating Income	$82,069,007	$68,335,490	$72,656,054	$85,014,783	$79,560,921		
OPERATING INCOME							
Original Operating Income - Unadjusted	$22,494,183	$22,494,183	$22,494,183	$22,494,183	$22,494,183		
Operating Revenue Adjustments							
Stranded Costs & Fixed CTC	(89,640,816)	(89,640,816)	(89,640,816)	(89,640,816)	(89,640,816)	No Rebuttal Adjustments.	
SlimFast Contract Termination Fee	(278,215)	(278,215)	(278,215)	(278,215)	(278,215)	No Rebuttal Adjustments.	
Customer Annualization	7,514,575	7,514,575	7,514,575	7,514,575	7,514,575	No Rebuttal Adjustments.	
Weather Normalization	4,572,055	4,572,055	4,572,055	4,572,055	4,572,055	No Rebuttal Adjustments.	
Short-Term Sales Exclusion (Staff C-10, RUCO 22, AECC)	-	25,259,000	77,665,000	73,439,000	-	Staff and RUCO reject TEP proposed PPFAC. Staff includes 100% of the margin in base rates. RUCO and AECC include 100% of the short-term sales revenue in base rates.	Hutchens
Wholesale Trading Activity (Staff C-11 & RUCO 25)	-	171,900	106,100,000	-	-	Staff and RUCO reject TEP proposed PPFAC. Staff includes 10% of the margin in base rates. RUCO includes 100% of the wholesale trading revenue in base rates.	Hutchens
Heavy Equipment - Operating Lease	197,342	197,342	197,342	197,342	197,342	No Rebuttal Adjustments.	
Springerville Unit 1 (RUCO 1)	(566,941)	(566,941)	-	(566,941)	(566,941)	Staff, RUCO & AECC disagree with the market rate recovery proposed by TEP. RUCO restores Springerville Unit 1 leasehold improvements and accumulated depreciation at embedded cost, while Staff & AECC do not change TEP's pro forma removing leasehold improvements. RUCO & AECC restore Springerville Unit 1 operating expense to embedded cost. Staff restores operating expense to the original $15/kw/month cap. RUCO reverses TEP's reduction of revenue, while Staff and AECC do not. **(TEP Rebuttal adjustment discussed in witness Hutchen's Rebuttal testimony)**	Hutchens - market rate, Kissinger - accounting issue, Dukes - adjustment
Renewable Resources	(6,888,380)	(6,888,380)	(6,888,380)	(6,888,380)	(6,888,380)	No Rebuttal Adjustments.	
Service Fees & Late Fees (RUCO 24)	1,306,077	1,306,077	2,469,342	1,306,077	2,469,342	TEP increases Miscellaneous Service Fees; RUCO accepts the adjustment. **(TEP Rebuttal adjustment discussed in witness Erdwurm's Rebuttal testimony)**	Erdwurm
Lime Usage Costs (RUCO 21)	(598,676)	(598,676)	(1,197,352)	(598,676)	(598,676)	RUCO removes the SP1 non-recurring lime usage revenue as a result of restoring SP1 operating revenue and expenses to test year embedded cost.	Dukes

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2006

	ACC Jurisdictional - COS						
	As Filed	Direct	Direct	Direct	Rebuttal		
	TEP	ACC	RUCO	AECC	TEP		TEP
	7/2/07	2/29/08	2/29/08	2/29/08	4/1/08	Summary	Witness
Tri-State Fuel Oil Sales	(7,262,954)	(7,262,954)	(7,262,954)	(7,262,954)	(7,262,954)	No Rebuttal Adjustments.	
Building Usage Allocations	150,685	150,685	150,685	150,685	150,685	No Rebuttal Adjustments.	
Springerville Unit 3	(3,084,442)	(3,084,442)	(3,084,442)	(3,084,442)	(3,084,442)	No Rebuttal Adjustments.	
Total Adjustments to Operating Revenues	(94,577,690)	(69,146,790)	90,336,840	(21,138,690)	(93,416,425)		
Operating Expense Adjustments							
Implementation Cost Regulatory Asset (Staff C-20 & RUCO 11)	11,863,806	4,580,212	3,553,211	7,963,806	11,863,806	Staff and RUCO changes to amortization expense result from the proposed rate base change. AECC proposing different amortization level.	Kissinger - accounting, Hutchens - benefits & savings, Grant - financing cost
Stranded Costs & Fixed CTC	(49,408,684)	(49,408,684)	(49,408,684)	(49,408,684)	(49,408,684)	No Rebuttal Adjustments.	
Customer Annualization	3,614,781	3,614,781	3,614,781	3,614,781	3,614,781	No Rebuttal Adjustments.	
Weather Normalization	2,085,037	2,085,037	2,085,037	2,085,037	2,085,037	No Rebuttal Adjustments.	
Unit Availability Normalization	6,973,411	6,973,411	6,973,411	6,973,411	6,973,411	No Rebuttal Adjustments.	
Short-Term Sales Exclusion (RUCO 22)	(46,954,540)	(46,954,540)	-	-	(46,954,540)	Staff and RUCO reject TEP proposed PPFAC. Staff includes 100% of the margin in base rates in a separate adjustment. RUCO includes 100% of the short-term sales expense in base rates and also jurisdictionally allocates the cost side only - causing artificially inflated margin on the sales.	Hutchens & Erdwurm
Wholesale Trading Activity (RUCO 25)	(93,487,237)	(93,487,237)	-	(93,487,237)	(93,487,237)	Staff and RUCO reject TEP proposed PPFAC. Staff includes 10% of the margin in base rates through a separate adjustment. RUCO includes 100% of the wholesale trading expense in base rates and only jurisdictionally allocates the expense side artificially creating additional margin.	Hutchens & Erdwurm
Test Power Exclusion	(1,370,321)	(1,370,321)	(1,370,321)	(1,370,321)	(1,370,321)	No Rebuttal Adjustments.	
Sundt Coal Contract	6,613,366	6,613,366	6,613,366	6,613,366	6,613,366	No Rebuttal Adjustments.	
Navajo Coal Contract (RUCO 16)	2,489,864	2,489,864	524,631	2,489,864	2,489,864	RUCO reduces the Navajo Coal adjustment based on the incremental change in the cost of coal from using a 12-month average for 2006 to a 6-month average for 2007.	Hutchens
San Juan Coal (Staff C-4)	8,852,453	-	8,852,453	8,852,453	8,852,453	Staff rejects the TEP increase in expense for San Juan Coal on the basis that the 2007 forecast numbers will be representative of future costs.	Hutchens
PPFAC Adjustment (Staff C-19)	14,309,410	-	14,309,410	14,309,410	14,309,410	Staff rejects the TEP PPFAC adjustment to increase fuel & purchased power expense, proposing that these costs be included in a PPFAC to be effective as of 1/1/09 instead of 4/1/10, with these costs in base rates.	Hutchens
Gain on Sale of S02 Allowances (Staff C-12 & RUCO 18)	6,348,930	(1,904,632)	-	6,348,930	6,348,930	Staff rejects the TEP adjustment to remove the gain from base rates and instead normalizes the test year gain based on data from 2004 through September 2007. RUCO rejects the TEP adjustment on the basis that since ratepayers bear the cost of Springerville Units 1 & 2, and also realize any benefits received.	Hutchens
Generating Facilities - Operating Lease (RUCO 23)	(18,720,148)	(18,720,148)	(27,175,373)	(18,720,148)	(18,720,148)	RUCO reduces operating expense for the Springerville Coal Handling as a result of the adjustment to Springerville Unit 1 expense from market-based recovery to embedded cost).	Kissinger - background accounting, Dukes - RUCO's adjustment
Heavy Equipment - Operating Lease	383,794	383,794	383,794	383,794	383,794	No Rebuttal Adjustments.	
Railcar - Operating Lease	(832,554)	(832,554)	(832,554)	(832,554)	(832,554)	No Rebuttal Adjustments.	

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2006

	ACC Jurisdictional - COS						
	As Filed	Direct	Direct	Direct	Rebuttal		
	TEP	ACC	RUCO	AECC	TEP		TEP
	7/2/07	2/29/08	2/29/08	2/29/08	4/1/08	Summary	Witness
Springerville Unit 1 (Staff C-1 & RUCO 1, AECC)	29,264,811	(15,100,033)	-	-	46,104,325	Staff, RUCO & AECC disagree with the market rate recovery proposed by TEP. RUCO restores Springerville Unit 1 leasehold improvements and accumulated depreciation at embedded cost, while Staff & AECC do not change TEP's pro forma removing leasehold improvements. RUCO & AECC restore Springerville Unit 1 operating expense to embedded cost. **(TEP Rebuttal adjustment discussed in witness Hutchen's Rebuttal testimony)**	Hutchens - market rate, Kissinger - accounting issues, Dukes - RUCO's adjustment
Luna O&M (Staff C-2/C-3, RUCO 10, AECC)	13,230,208	2,121,530	-	-	13,230,208	Staff and RUCO reject the TEP proposal to use a market-based fixed recovery rate and expense to embedded cost. The Staff adjustment also includes related depreciation and property tax expense.	Hutchens & Kissinger
Plant Overhaul & Outage Normalization	1,161,990	1,161,990	1,161,990	1,161,990	1,161,990	No adjustments. But need to add Luna if it is put into rate base per Intervener's recommendations.	DeConcini & Kissinger
Renewable Resources (RUCO 14)	(4,320,436)	(4,320,436)	(4,339,446)	(4,320,436)	(4,361,485)	RUCO accepts the TEP revision per the response to STF 1.85 on 11/1/07.	Dukes
Payroll Expense (RUCO 12)	1,348,225	1,348,225	1,365,187	1,348,225	2,736,898	RUCO rejects the 2-year average and restates payroll expense to reflect the actual last year level. **(TEP Rebuttal adjustment discussed in witness Saber's Rebuttal testimony)**	Sabers
Payroll Tax Expense (RUCO 13)	125,796	125,796	128,218	125,796	227,154	RUCO adjustment reflects the change in payroll expense. **(TEP Rebuttal adjustment discussed in witness Saber's Rebuttal testimony)**	Sabers
Pension & Benefits	(871,913)	(871,913)	(871,913)	(871,913)	(871,913)	No Rebuttal Adjustments.	Sabers
Post Retirement Medical	(58,438)	(58,438)	(58,438)	(58,438)	(58,438)	No Rebuttal Adjustments.	Sabers
Incentive Compensation (Staff C-7 & RUCO 5)	(941,683)	(4,515,289)	(2,275,421)	(941,683)	(1,067,217)	Staff reduced expense by 50% for PEP and Deferred Compensation (sharing on a 50/50 basis) and 100% of LT Incentive Compensation and Stock-Based Compensation. RUCO restated the TEP adjustment from a 4-year average to actual test year expense and reduced expense by 50% (sharing on a 50/50 basis). **(TEP Rebuttal adjustment discussed in witness Saber's Rebuttal testimony)**	Sabers
Rate Case Expense (RUCO 6)	201,003	201,003	100,501	201,003	201,003	RUCO reduces the TEP proposed expense by 50% based the authorized level in the recent UNS Gas rate case (Decision No. 70011). **(TEP Rebuttal adjustment discussed in witness Dukes' Rebuttal testimony)**	Dukes
Membership Dues (Staff C-6)	(61,078)	(229,451)	(61,078)	(61,078)	(158,042)	Staff reduces expense for 49.93% of EEI dues, for 100% of USARG dues and 10% of UWAG dues based on the portion of these dues related to marketing, lobbying and governmental activities. **(TEP Rebuttal adjustment discussed in witness Dukes' Rebuttal testimony)**	Dukes
Advertising & Sponsorship	(407,227)	(407,227)	(407,227)	(407,227)	(407,227)	No Rebuttal Adjustments.	
Outside Services	(342,795)	(342,795)	(342,795)	(342,795)	(342,795)	No Rebuttal Adjustments.	
CC&B Normalization (Staff C-16 & RUCO 17)	433,987	(372,694)	137,757	433,987	433,987	Staff reduces expense related to the rate base adjustment B-9 for CC&B intangible plant allocated to TEP affiliates. RUCO normalizes 3 months of CIS expenses for 2006 instead of the normalized CC&B adjustment proposed by TEP.	Dukes
Out of Period Expenses	99,339	99,339	99,339	99,339	99,339	No Rebuttal Adjustments.	
Lime Usage Costs (RUCO 21)	(869,018)	(869,018)	(1,714,305)	(869,018)	(869,018)	RUCO removes the SP1 non-recurring lime usage expense as a result of restoring SP1 operating revenue and expenses to test year embedded cost.	Dukes
Tri-State Fuel Oil Sales	(6,796,486)	(6,796,486)	(6,796,486)	(6,796,486)	(6,796,486)	No Rebuttal Adjustments.	

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2006

	ACC Jurisdictional - COS						
	As Filed	Direct	Direct	Direct	Rebuttal		
	TEP	ACC	RUCO	AECC	TEP		TEP
	7/2/07	2/29/08	2/29/08	2/29/08	4/1/08	Summary	Witness
Bad Debt Expense (Staff C-5 & RUCO 15)	622,366	(115,164)	102,288	622,366	(108,977)	Staff includes the bad debt expense correction per LA 11.48 and STF 1.85 Supplemental #1, and also reduces bad debt expense for Fixed CTC revenue that will not exist when new rates are in effect. RUCO includes the bad debt expense correction filed in STF 1.85 on 11/1/07. TEP accepts the Staff adjustment and makes an additional correction for the Customer Annualization revenue adjustment. **(TEP Rebuttal adjustment discussed in witness Dukes' Rebuttal testimony).**	Dukes
Capital Cost Allocations	1,454,963	1,454,963	1,454,963	1,454,963	1,454,963	No Rebuttal Adjustments.	
Corporate Cost Allocations	(96,538)	(96,538)	(96,538)	(96,538)	(96,538)	No Rebuttal Adjustments.	
SERP (Staff C-8 & RUCO 4)	-	(828,957)	(828,957)	-	(414,479)	Staff removes 100% of SERP expense, citing the Southwest Gas rate case order issued February 2006. RUCO removes 100% of SERP based on decisions in the Southwest Gas, APS and UNS Gas rate cases. **(TEP Rebuttal adjustment discussed in witness Saber's Rebuttal testimony)**	Sabers
Worker's Compensation (Staff C-9)	-	(323,907)	-	-	-	Staff reduces expense for worker's compensation by normalizing test year expense based on a 3-year average, stating that test year expense was abnormally high.	Sabers
Legal Expense - Motion to Amend (Staff C-21 & RUCO 26)	-	(430,116)	(322,587)	-	-	Staff removed legal expense related to the Motion to Amend Decision No. 62103 as non recurring. RUCO adjusts expense to reflect amortization of the expenses for the Motion to Amend Decision No. 62103 over 4 years.	Dukes
Legal Expense - California Proceedings (Staff C-22)	-	(60,717)	-	-	-	Staff removed legal expense related to California wholesale market proceedings, stating that Arizona retail customers should not pay for expenses that are not related to provision of retail service.	Dukes
Depreciation Rates Adjustment (Staff C-15)	-	1,626,296	-	-	-	Staff increases depreciation expense using a placeholder calculation related to the rate base adjustments (B-6 & B-8), pending further investigation into TEP depreciation rates, FAS 143 adoption and recalculation of depreciation expense in prior years.	Kissinger
Markup Above Cost - Affiliate Charges SES (Staff C-17)	-	($211,514)	-	-	-	Staff reduces expense for the SES markup on charges to TEP based on the response to LA 20-17(c).	Dukes
Normalize Affiliate Charges to TEP (Staff C-18)	-	($197,667)	-	-	-	Staff normalizes expense for SES charges to TEP for three FERC accounts (592, 908 and 923).	Dukes
Miscellaneous Expenses		-	-	-	(41,649)	Remove various expenses (this adjustment originally included WestConnect charges in the ICRA; TEP accepts that adjustment included in WestConnect line below in this spreadsheet). **(TEP Rebuttal adjustment discussed in witness Dukes' Rebuttal testimony)**	Dukes
Postage Expense (Staff C-23)	-	$64,946	-	-	92,956	Staff increased postage expense in agreement with the additional expense proposed in response to STF 1.86 (and in the STF 1.86 Supplemental #1) as a result of the 2007 postage rate increase. An additional increase effective 5/12/08 is not yet included in TEP or Staff expense. **(TEP Rebuttal adjustment discussed in witness Dukes' Rebuttal testimony)**	Dukes
West Connect Charges in ICRA (Staff C-24)	-	($198,156)	-	-	(244,281)	Staff removes WestConnect expense that was already included in the ICRA. TEP accepts this adjustment (it was included in Miscellaneous Expenses filed in the Supplemental Response #1 to STF 1.85) and also includes another amount in the correction provided in the Supplemental Response #1 to ST	Dukes
Unnecessary Expenses/Inappropriate (RUCO 3)	-	-	(458,939)	-	-	RUCO removes expense in FERC 921, 923, 930.1 & 930.2 viewed as inappropriate or unnecessary.	Dukes
Normalization of Overhead Line Maintenance (RUCO 6)	-	-	(126,584)	-	-	RUCO normalizes a 5-year average of "inflation adjusted" annual overhead line maintenance.	Dukes

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2006

	ACC Jurisdictional - COS						
	As Filed	Direct	Direct	Direct	Rebuttal		
	TEP	ACC	RUCO	AECC	TEP		TEP
	7/2/07	2/29/08	2/29/08	2/29/08	4/1/08	Summary	Witness
Penalties and Fines (RUCO 9)	-	-	(8,427)	-	(8,427)	RUCO reduces expense for invoices indicating penalties and fines as identified in the response to STF 1.114. **(TEP Rebuttal adjustment discussed in witness Dukes' Rebuttal testimony)**	Dukes
Employee Recognition (RUCO 19)	-	-	(68,006)	-	-	RUCO disallows employee recognition expense identified in response to RUCO 6.1.	Dukes
Employee Benefits (RUCO 20)	-	-	(22,174)	-	-	RUCO disallows employee benefits expense identified in response to STF 1.79.	Dukes
Gain on Sale of Land (RUCO 27)	-	-	(193,912)	-	-	RUCO reduces expense for the gain on land sales by taking 50% of the gain and amortizing over 4 year (response to STF1.129).	Kissinger
QATT	84,094,549	$84,094,549	84,094,549	84,094,549	84,094,549	No adjustments, Staff to address in Surrebuttal	
Delayed Unitization - Depr Expense	-	-	-	-	152,168	Increase test year recorded depreciation expense associated with the increase in plant in service for generation plant that was in service at 12/31/06 but not unitized or included in FERC 106 (Completed Construction Not Classified). **(TEP Rebuttal adjustment discussed in witness Kissinger's Rebuttal testimony)**	Kissinger
Delayed Unitization - Property Tax	-	-	-	-	96,688	Increase test year recorded property tax expense associated with the increase in plant in service for generation plant that was in service at 12/31/06 but not unitized or included in FERC 106 (Completed Construction Not Classified). **(TEP Rebuttal adjustment discussed in witness Kissinger's Rebuttal testimony)**	Kissinger
Depr. & Amort. Expense Annualization (RUCO 2)	(7,575,744)	($7,575,744)	(3,869,335)	(7,575,744)	(7,575,744)	RUCO change results from proposed rate base adjustments.	Kissinger
Property Tax (Staff C-13 & RUCO 7)	(2,107,937)	($2,609,940)	(3,543,939)	(2,107,937)	(2,503,005)	Staff reduces expense to reflect the 23% assessment ratio expected to be in effect in 2009 when rates go into effect, and also incorrectly removed $19,438 of expense for Plant Held for Future Use since it is not included in final ACC jurisdictional rate base (this expense was not included in property tax expense as filed by TEP). RUCO reduces expense to reflect the 23% assessment ratio and to reflect adjustments to net plant in service. **(TEP Rebuttal adjustment discussed in witness Kissinger's Rebuttal testimony)**	Kissinger
Income Taxes (Staff calculated for each adj; RUCO 28)	(19,259,510)	$31,264,971	45,069,971	8,948,490	(24,946,498)	Staff & RUCO changes result from proposed rate base and operating revenue & expense adjustments. **(TEP Rebuttal adjustment discussed in witness Kissinger's Rebuttal testimony)**	Kissinger
ACC Jurisdictional Allocation Computation Errors	-	(205,847)	(13,444,112)	1,645,637	-		
Total Adjustments to Operating Expense	(58,910,195)	(109,112,088)	62,007,309	(28,497,038)	(48,024,620)		
Total Net Adjustments	(35,667,495)	39,965,298	28,329,531	7,358,348	(45,391,805)		
Adjusted Operating Income	(13,173,312)	62,459,481	50,823,714	29,852,531	(22,897,622)		
Operating Income Deficiency	95,242,319	5,876,009	21,834,340	55,162,253	102,458,543		
Gross Revenue Conversion Factor	1.6609	1.6598	1.6598	1.6609	1.6598		
Increase in Gross Revenue Requirement Before TCRAC	158,185,903	9,753,000	36,240,631	91,617,781	170,058,597		
TCRAC	117,622,513	-	-	-	117,622,513	Staff, RUCO and AECC oppose the Company's TCRAC Recommendation	Grant - Amount, Erdwurm Rate
Recommended Increase in Retail Revenues Excluding the Fixed CTC	$ 275,808,416	$ 9,753,000	$ 36,240,631	$ 91,617,781	$ 287,681,110		

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-0402

Rebuttal Testimony of

D. Bentley Erdwurm

on Behalf of

Tucson Electric Power Company

April 1, 2008

Executive Summary of the Rebuttal Testimony of D. Bentley Erdwurm

Mr. Erdwurm is a Lead Analyst in the Rates and Revenue Requirements department at Tucson Electric Power Company ("TEP" or the "Company"). Mr. Erdwurm's Rebuttal Testimony addresses the following matters:

1. **Recovery – Purchased Power and Fuel Adjustment Clause ("PPFAC") vs. Base Rate Cost of Fuel and Purchased Power Component.** Staff has recommended that expected cost increases in fuel and purchased power through early 2009 not be included in the Base Rate Fuel and Purchased Power Component, which will result in recovery through a PPFAC rate. TEP objects to Staff's proposal because it insures that a larger than necessary level of costs will be recovered from a mechanism intended to manage residual changes. Cost causation can be more precisely identified through the allocation factors used to establish base rates.

2. **Time-of-Use Rates ("TOU").** TEP has proposed mandatory TOU for new and moving residential and small commercial customers, and for all large commercial/industrial and large light and power customers. This will help manage peak demand. The mandatory feature is opposed only by Staff. Staff is concerned about metering and implementation costs. TEP believes that the long-term public interest is served by moving toward mandatory TOU now, because smart metering innovations are eliminating the cost-differential between TOU and non-TOU meters. Both Staff and RUCO agree with TEP's choice of TOU peak and shoulder hours, and the "super-peak" style design. TEP is opposed to RUCO's proposal that time-of-use customers be subsidized. The whole idea of TOU is to link bill reductions with load shifting. TOU customers have ample opportunities to save money by shifting load.

3. **Inclining Block Rates.** This conservation-oriented proposal is supported by Staff and RUCO.

4. **Residential Customer Charges.** TEP opposes Staff and RUCO proposals for residential customer charges lower than $9.00 per month, TEP's proposal. TEP's customer charge covers only the service drop, the meter, meter reading and billing, and is at a "bare-bones" level.

5. **Large Light and Power Rate Design.** TEP is amenable to increasing demand charges relative to customer charges, and re-examining the size of seasonal differentials, as supported by DOD, AECC, and Kroger. So long as the total paid by these customer groups remains unchanged, TEP is open to rate design changes affecting only the recovery of costs within the groups.

6. **Service Fees.** There is general agreement on TEP's proposed cost-based service fees.

7. **Production Plant Allocation.** TEP's proposed average and peaks approach is a compromise between the extremes of pure energy or pure demand allocation. Staff and RUCO support it. DOD, AECC, and Kroger propose self-serving methods that ignore the importance of energy in system planning, and would move us toward the extreme of a pure demand allocation, which would shift substantial cost to residential and small general service customers.

8. **Forfeited Discounts, Miscellaneous Service Revenue, and Rent from Electric Property Allocation.** TEP accepts RUCO's recommendation here.

9. **Transmission and Ancillary Services Based on FERC Open Access Transmission Tariff.** The 1999 Settlement Agreement at section 4.4 states "TEP shall charge rates for transmission and ancillary services based on its FERC Open Access Transmission Tariff" (OATT). Unfortunately, Staff is hinting at a different approach instead of following the FERC-approved OATT. That would ignore the Agreement as well as the authority of FERC, if Staff follows through on its suggestion and disregards the OATT tariffs in favor of an alternate bundled approach in the Surrebuttal filing. It would also completely contradict the treatment afforded to Arizona Public Service Company ("APS") In contrast, TEP appropriately removed transmission cost from the retail cost-of-service study to recognize that the FERC has primary jurisdiction over open-access transmission. As such, TEP has assigned its ACC jurisdictional retail customers transmission costs based on TEP's FERC-approved OATT rate. TEP's approach should be approved by the Commission.

10. **Transmission Allocation.** The average and peaks method applied to transmission has been previous approved by the Commission, and is a fair compromise approach.

11. **Transmission Cost Adjustment Charge- Rider 5 ("TCAC").** Charges in this Rider have been revised to match the transmission and ancillary services components in the proposed rates. A minor language change clarifies that the components vary by class.

12. **Recovery Under the Termination Cost Regulatory Asset Charge – Rider 4 ("TCRAC").** TEP has proposed a uniform volumetric charge to apply over all customer classes. This is fair to all customers and should be approved

13. **Unbundled Rates.** Rates should remain unbundled to support direct access.

14. **Distribution of Rate Increases.** TEP's proposal helps avoid undue "rate shock" and should be approved.

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Exhibits

Exhibit DBE-6

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is D. Bentley Erdwurm

Q. Are you the same D. Bentley Erdwurm that previously submitted Direct Testimony on behalf of Tucson Electric Power Company ("TEP" or "Company") in this Docket?

A. Yes.

Q. Have you reviewed the Direct Testimonies filed by the Arizona Corporation Commission Utilities Division Staff ("Staff") (Frank Radigan), the Residential Utility Consumer Office ("RUCO") (Glen E. Gregory), the Department of Defense ("DOD") (Dan L. Neidlinger), Phelps Dodge Mining Company and Arizonans for Electric Choice and Competition ("AECC") (Kevin C. Higgins), and Kroger (Stephen J. Baron)?

A. Yes I have.

II. SUMMARY.

Q. Focusing on TEP's key rate design objectives, please provide a general overview of the positions taken by the parties in their Direct Testimonies.

A. What follows is a brief description of TEP's positions on issues I address in my Rebuttal Testimony. I go into more detail on each of these topics:

Cost of Service – Production Plant Allocation.

Both Staff and RUCO support the use of TEP's average and peaks methodology as its proposed production plant allocator. This is a fair and equitable approach has been

approved by the Commission for use at TEP since the early 1990's. In simple terms, average and peaks is a compromise between two extreme views – which are to allocate solely based on energy versus just using coincident peak (CP) demand (or 4CP demand). There is no single correct way to split up a joint cost; therefore, TEP has chosen the middle ground, which is average and peaks. DOD, AECC, and Kroger support alternate approaches that move significantly toward the extreme peak allocation. DOD and AECC propose average and excess, which would – not surprisingly – shift cost burden away from their constituents and onto the numerous residential and small commercial customers on the system. Kroger supports 4CP, which has similar consequences.

Rate Design

TEP's rate design proposals promote conservation, load management, and concern for lower-income customers, while remaining as true to cost-based rate principles as possible.

TEP proposed a cost-based, "bare-bones" residential customer charge of $9.00 per month. These charges are limited to recovery of the service drop, metering, meter reading, and billing. Staff and RUCO's customer charges are insufficient to recover customer-related costs. Inadequate metering, meter reading, and billing components inhibit the formation of viable service providers for these customer-related functions – that could inhibit the manifestation of direct access. For these reasons, TEP opposes the Staff and RUCO customer charge recommendations. Both Staff and RUCO, however, support the idea of inclining or inverted block rate design. The inclining block rate for residential and general service (Pricing Plan 10) customers results in higher unit costs at higher usage levels, thus promoting conservation.

TEP is willing to support some large light and power rate design changes proposed by DOD and AECC (e.g., increased demand charges relative to energy charges, increased

summer/winter differentials). This type of change would affect how costs are allocated among the larger customers, but not the total amount allocated to the class of these customers. Finally, TEP has taken customer impacts into account in its proposed distribution of the rate increase. But TEP recommends against self-serving proposals of large light and power customers to shift a larger share of the increase to the residential class.

Time-of-Use ("TOU")

The Company's proposal to make TOU mandatory for larger customers, and for new and moving residential and general service customers, is key to sending the type of price signals that will help TEP defer capacity additions. This results in cost reductions benefiting all customers. RUCO, DOD and AECC support the Company's mandatory TOU proposals. TEP believes Staff is taking too short-term a view and ignoring the potential for mandatory TOU to defer capacity additions and save costs in the long-run for both the Company and its customers.

TEP's proposed TOU periods – including on-peak, shoulder peak, and off-peak periods – are generally supported by most parties.

TEP disagrees with RUCO's proposal that TOU should be subsidized. The whole idea of TOU is that customers save through load shifting. Subsidization could reduce the incentive to shift load, which compromises the larger goal of managing peak demand and deferring capacity.

Rate Design Issues with the Base Cost of Fuel and Purchased Power and the Purchased Power and Fuel Adjustment Clause ("PPFAC")

TEP still recommends that the base fuel and purchased power costs reflect the most current forecasts for 2009. This is because cost causation can be more precisely identified through the allocation methods TEP uses to establish the base costs. Staff's proposal will likely result in higher load factor customers bearing more of the burden and upsetting the balance TEP is striving to achieve with designing rates. TEP objects to Staff's proposal because it insures that a larger than necessary level of costs will be recovered from a mechanism intended to manage residual changes. This increased cost recovery though PPFAC will unfairly burden higher load factor customers who by definition are large energy purchasers (relative to their demands).

Service Fees

Staff and RUCO generally support the Company's proposed service fees.

Transmission Costs

The 1999 Settlement Agreement at section 4.4 states "TEP shall charge rates for transmission and ancillary services based on its FERC Open Access Transmission Tariff ("OATT"). Unfortunately, Staff is hinting at a different approach instead of following the FERC-approved OATT. That would ignore the Agreement as well as the authority of FERC, if Staff follows through on their suggestion and disregards the OATT tariffs – in favor of an alternate bundled approach in their Surrebuttal filing. I note that it would also completely contradict the treatment afforded to Arizona Public Service Company ("APS"). TEP further believes that its 4CP Average and Peaks method to allocate transmission costs is appropriate and has a couple of minor corrections to its Transmission Cost Adjustment Charge ("TCAC").

Rate Design Issues with Termination Cost Regulatory Asset Recovery

TEP has requested recovery of its Termination Cost Regulatory Asset ("TCRAC") through a uniform per-kWh charge – across all customer classes and voltages - under its TCRAC Rider 4. TEP disagrees strongly with AECC's proposal to recover these costs over classes on the basis of class revenue. This would result in the absurd result that large light and power customers would pay less per kWh for TCRA recovery, when these same customers were once expected to reap the largest rewards from direct access.

Rate Bundling

TEP opposes Staff's proposal to rebundle rates as premature. It is TEP's understanding that the Commission's Electric Competition Advisory Group is still in existence and Staff is still investigating these issues statewide.

III. COST OF SERVICE (PRODUCTION PLANT ALLOCATION).

Q. Do you still believe, even with the comments from AECC, DOD and Kroger, that the average and peaks method is the best method to use to allocate costs from a public policy standpoint?

A. Yes. TEP, as well as Staff and RUCO, all agree that average and peaks is the appropriate method to use for TEP.

Q. Why is that?

A. Because average and peaks is a compromise between two extreme views – which are allocating solely based on energy (benefitting low load factor customers like residential and small general service) versus using coincident peak (CP) demand (or 4CP demand) (favoring high load factor customers like large light and power). While there is no single correct way to allocate costs, TEP's average and peaks approach balances the two

extremes and appropriately weighs both energy and peak. By contrast, AECC, DOD, and Kroger all propose methods that simply attempt to move the allocation approach toward demand, which will put significantly more of the cost burden on residential customers. As I explain later, the so-called "average and excess" method is really another methodology that strongly favors high load factor customers.

Q. Could you elaborate on the average and peaks approach?

A. Certainly. The average and peaks method provides a simple and fair compromise between a peak demand allocation and an energy allocation. Moreover, average and peaks recognizes the importance of energy use in system planning. As I explained in Direct Testimony, TEP's method includes both the peak component to recognize that the system must have adequate capacity to satisfy demand at the time of the peak, and an average demand component to recognize that different types of capacity (*e.g.* baseload, intermediate and peak) are installed depending on energy use and the duration of load. Average and peaks recognizes that high capital cost base load plant requires sufficient energy use to be cost effective. The Company's average and peaks approach recognizes that plant is not just built to serve demand, but also to supply energy. As I also noted in my Direct Testimony, the average and peaks method TEP uses was accepted by the Commission in its rate cases since the early 1990's.

Q. How would you characterize the Average and Excess method that Mr. Higgins for AECC and Mr. Neidlinger for DOD advocate?

A. Messrs. Higgins and Neidlinger argue Average and Excess considers energy while not "double counting" demand. Both criticize the Average and Peaks methodology for essentially counting demand twice. That argument is nonsense.

Q. How do you respond to the "double counting" argument as it relates to the Average and Peaks methodology?

A. Let me say first that, in reality, the so-called "Average and Excess" approach is very close to 4-CP, which is the extreme approach favoring high load customers at the expense of residential and small commercial customers. That is why DOD and AECC support average and excess. Kroger's support 4CP is more explicit.

The "double count" argument is simply an attempt to trick the Commission into thinking that average and excess is theoretically preferable to average and peaks. Nothing in economic theory says that average and excess (or 4CP) will be preferable to average and peaks. In simple terms, average and peaks is our best chance at a balanced compromise between parties favoring either a pure energy or a pure demand allocation.

Q. Why is the "double count" argument invalid?

A. The reason is very simple. The two components of average and peaks – energy and demand – serve two different functions in the system planning process. With average and peaks, one does not get a "free ride" for peak demand based on energy use. Average and peaks appropriately identifies demand responsibility and energy responsibility among the classes. Mr. Higgins supports average and excess for the very reason that it lets high-load factor customers (his "flat" rate customers) avoid full responsibility for their contributions to peak demand. Mr. Higgins' so-called "flat" rate customers – as he refers to them on page 9 of his Direct Testimony – contribute 500 MW to the system peak (or 40% of the peak component). Yet he argues that they should not bear full responsibility for their contribution to peak, because of their energy use in other periods. But peak demand responsibility in a single peak hour is unaffected by the energy use over the other 8,759 hours that fell short of peak. (There are 8,760 hours in a 365 day year). Average and excess ignores a significant portion of "flat" rate customers' contributions to peak demand.

This is true because every MW of the "flat" rate customers' peak demand strains system capacity just as much as a MW of the lower-load factor customers' peak demand.

This is not completely unlike walking into a room with four chain smokers and six "social" smokers – all of whom happen to be smoking at the same time. If an observer were to walk in and start coughing (because of the all of the smoke) *all* of the chain smokers are contributing to the smoke in the room. While there is no doubt the six "social" smokers are contributing to the overall quantity of smoke in the room at that time – there is equally no doubt that the four chain smokers are *also* contributing to the smoke in the room. But per Mr. Higgin's argument, those chain smokers would bear a significantly reduced share of the responsibility toward all of the smoke that exists in that room at that time. That is a nonsensical argument to make, but Mr. Higgins, and Mr. Neidlinger for that matter, make that argument when discussing the so-called "double counting" of average and peaks. In fact, the average and peaks argument counts those "flat" customers exactly how they should be counted.

The theory behind average and peaks is that there must be sufficient energy use to justify the higher capital cost of baseload plants – which typically have lower variable costs (*e.g.* fuel and incremental operations and maintenance) and higher fixed costs. Therefore, energy use is one key determinant of what type of plant is built. Each customer class must pay for its percent of energy use. But there must also be sufficient capacity to serve peak demand for all customer classes – this is the second key determinant of what type of plant gets built. Each customer must also pay for its percent of peak demand use. Of the methods proposed here, only TEP's Averages and Peaks method recognizes both class contributions to energy and class contribution to demand.

Further, TEP has already addressed – through its weighted energy allocation factor – the "fuel symmetry argument." That is, higher load factor customers have already received credit for the fact that their more even loads result in relatively higher levels of lower cost, off-peak energy use. In short, any "double counting" or other accusation that TEP's average and peaks method is somehow unfair is without merit.

Q. What is the impact of moving to average and excess from average and peaks?

A. If we move away from average and peaks, the preferred method of TEP, Staff, and RUCO, to average and excess, the preferred method of the large light and power interveners, more costs will be allocated to lower load factor customers, including residential and smaller general service customers. The shift from average and peaks to average and excess would decrease costs allocated to the Large Light and Power class.

Q. Does TEP have some "vested interest" in promoting average and peaks over average and excess?

A. No. The Company does not reap a monetary benefit from promoting average and peaks over average and excess or 4CP for production plant. Actually, because residential growth is outpacing large light and power growth, the Average and Excess method would be *more* advantageous to TEP. That is because the Average and Excess method (and the 4CP method for that matter) typically allocate more cost to residential customer classes. In spite of this advantage of average and excess to TEP, the Company still supports average and peaks because TEP believes strongly it is the most equitable balancing of cost allocation among all of its customer classes.

IV. GENERAL RATE DESIGN ISSUES

A. Monthly Customer Charges.

Q. Why should TEP's full customer charge proposal be approved?

A. TEP's cost study indicates that a "bare-bones" customer charge of $8.80 per month could be supported. By "bare-bones", I mean a customer charge covering only the costs for metering, meter-reading, billing, and the service drop. TEP believes $9.00 per month is a simple charge predominantly supported by TEP's cost of service study. TEP believes $9.00 would be simpler, but can support a monthly residential customer charge equaling $8.80. Also, cost-based customer components are necessary to promote viable direct access, should it come to fruition.

Q. What monthly residential customer charges do Staff and RUCO recommend?

A. Mr. Radigan's proposes to limit residential customer charges to $7.00 per month. Mr. Gregory for RUCO recommends only a $6.50 customer charge.

Q. Why are these proposals unacceptable to TEP?

A. Both Staff and RUCO propose a charge that fails to cover minimal customer-related costs including metering, meter-reading, billing and the service drop. These are the minimum charges that should be included in a monthly customer charge. While the Company understands Staff and RUCO emphasize gradualism, an increase of $3.90 to $4.10 to this charge – which has not been increased since 1994 – can hardly be considered drastic or extreme.

1 B. **Inclining Block Rates.**

2

3 **Q. Do Staff and RUCO support the inclining block rate?**

4 A. Yes.

5

6 **Q. Does Staff offer any recommendations regarding the inclining block rate?**

7 A. Yes. Mr. Radigan has proposed a larger differential between the first block and third
8 block charges. TEP is not opposed to increasing the differential to the three-cent level
9 that Mr. Radigan proposes.

10

11 **Q. Does Mr. Higgins for AECC address the inclining block rate?**

12 A. Yes. Mr. Higgins objects to the application of an inclining block rate to general service.
13 He notes there is no need for a lifeline (as in low-income focused lifeline) for commercial
14 customers. TEP proposed this rate to increase the tail block price of energy and
15 encourage conservation, a key goal of the Commission. The General Service inclining
16 block rate was not proposed to address any welfare or "lifeline" needs for that customer
17 group.

18

19 C. **Large Light and Power Customer Class Rate Design Issues.**

20

21 **Q. Generally, what is your response to AECC and DOD proposals concerning the rate**
22 **design for Large Light & Power Customers?**

23 A, In general, TEP is willing to consider Mr. Neidlinger's and Mr. Higgins' respective
24 proposals that deal with the method of cost recovery (*i.e.* demand and energy charges or
25 seasonal differentials)– specifically from large light and power class customers. But TEP
26 does not support reallocating the costs that were allocated to these customers via TEP's
27 COSS. In other words, TEP is not willing to entertain alternate allocation approaches that

would reduce total allocated cost to the large light and power class (*e.g.,* average and excess instead of average and peaks for production plant allocation.) Further, TEP opposes collecting TCRAC costs on the basis of class revenue instead of at a uniform rate per kWh. I specifically address different approaches to collecting TCRAC costs later in my Rebuttal Testimony.

Q. Please discuss the DOD's Large Light and Power rate design proposals.

A. First, Mr. Neidlinger for DOD favors higher demand charges for Rate Schedule 90N. TEP is amenable to higher Rate 90 demand charges. But I note that – as it is defined in the current structure – the off-peak demand charge for this rate is not an excess demand charge. The newly proposed off-peak demand charge applies to all off peak demand, not just off-peak demand in excess of 150% of on-peak demand.

Second, Mr. Neidlinger proposes that transmission costs be recovered from larger customers on a demand basis as opposed to an energy basis. This is similar to a proposal made by Mr. Higgins for AECC. TEP is willing to accommodate Mr. Neidlinger's recommendation here.

Q. What about Mr. Niedlinger's desire to see voltage level discounts incorporated into TEP's rates?

A. While TEP agrees that this is common among other utilities, TEP believes the issue requires more study. TEP suggests that this recommendation be considered in a future case. If costing and pricing is to be "refined", TEP favors a more comprehensive "top to bottom" review of factors that affect cost. This could include more complex issues such as return differentials by class.

Q. Please discuss AECC's Large Light and Power rate design proposals.

A. Mr. Higgins for AECC believes that non-residential rates recover too much through energy charges. AECC wants to see more recovery through demand charges. TEP does not oppose adjusting rates with demand components, so that a larger percentage of revenue is recovered through demand charges. This will shift some costs to lower load factor large light and power customers; however, it may be useful in promoting peak demand reductions.

Mr. Higgins proposes that TEP be required to file a new interruptible rate, and participate in collaborative workshops dealing with the matter. TEP is willing to consider this and participate in workshops following the conclusion of this case, but believes that *any* interruptible rates must be carefully constructed, before agreeing to any such rate. Certainly, this rate case is not the right forum to implement any interruptible rate.

E. <u>Distribution of the Rate Increases</u>.

Q. Please discuss Mr. Neidlinger's preferred distribution of rate increases.

A. Mr. Neidlinger for DOD favors setting the residential increase at 150% of the system average increase, and setting the industrial increase at 50% of the system average increase, so as to move classes in the direction of equalized rates of return. TEP opposes Mr. Neidlinger's suggestion and favors a more gradual movement toward cost-based rates, as proposed in the Company's direct testimony.

Q. Please discuss Mr. Higgins' concerns over the distribution of rate increases.

A. Mr. Higgins notes that General Service is shown as over-recovering costs under a variety of cost studies, and LL&P is shown as over-recovering under average and excess and 4CP. TEP agrees that General Service is over-recovering, but for reasons of customer

impact continues to support the percentage of increases for each customer class as proposed in my Direct Testimony. To the extent that a lesser revenue requirement is granted, the percentage changes can be scaled back proportionately.

Q. Mr. Higgins takes issue with the recovery of $26.6 million from large light and power customers through unbundled distribution charges, even though a cost study allocates only $4 million of the costs to these customers.

A. The unbundled "distribution" charge is more accurately called a "delivery charge". The delivery charge is basically the residual remaining when unbundled charges are reconciled to the bundled charges. Even though the parties all calculate costs differently – due to different allocation approaches – all parties recognize rates probably do not exactly match anybody's defined costs. Therefore, it should come as no surprise that there are differences between allocated costs and amounts collected through rates with subsidies and surcharges built in. The discrepancy between $26.6 million and $4 million is not that surprising, nor is it a huge discrepancy between costs and amounts collected. By contrast, the elimination of subsidies immediately could result is unacceptable bill impacts. So TEP has not moved, nor are we recommending movement entirely to cost-based rates at this time.

Q. What are Kroger's concerns regarding the distribution of the increase?

A. Mr. Baron for Kroger is correct in asserting that General Service and Large General Service customers (Rates 10, 76, 13 and 85) are heavily subsidizing other customer classes. As mentioned above, the elimination of subsidies immediately could result in unacceptable bill impacts, so TEP has not moved in that direction. However, if the Commission sees fit to move rates toward cost-of-service, General Service and Large General Service Customers (Pricing Plans 10 and 13) would be most deserving of some additional rate relief, and with the remaining customer classes incurring additional costs.

V. TIME-OF-USE ("TOU") RATES.

A. Time Periods.

Q. Do you have a clarification regarding TEP's proposed TOU rates?

A. Yes. TEP, in its proposed tariffs attached to my Direct Testimony, show six holidays as off-peak. This reference to holidays was made in error. TEP's proposed on-peak, shoulder and off-peak hours apply every day of the year – including holidays.

Q. Did either Staff or RUCO take issue with the time periods chosen for time-of-use rates?

A. No. Both Mr. Radigan for Staff and Mr. Gregory for RUCO support time periods chosen. Mr. Radigan notes that the "super-peak" style will have a peak period limited to a small number of the most critical hours. Mr. Gregory notes that the limited four hour summer peak period provides load shifting opportunities.

Q. What is DOD's position on the time periods chosen for time-of-use rates?

A. Mr. Neidlinger for DOD agrees with the Company that time-of-day differentiation should also apply to Saturdays and Sundays; however, he prefers the elimination of the summer shoulder period for an eight-hour summer peak extending from noon until 8:00 p.m., as he states on page 17, line 3 to page 18, line 12 in his Direct Testimony.

TEP opposes eliminating the shoulder hours and moving to an 8-hour on-peak period. Shorter peak periods provide more incentives to move load away from the critical "super-peak" period – which is from 2:00 p.m. to 4:00 p.m. in the summer. Moreover, TEP's

proposed shorter on-peak period affords customers more saving opportunities. Therefore, TEP continues to support its proposed shoulder hours.

B. <u>Mandatory TOU rates</u>.

Q. What is Staff's position on mandatory time-of-use?

A. Staff opposes mandatory TOU rates for new and moving residential and small general service customers, although I am not sure he opposes mandatory TOU for: (i) all new and existing Large General Service customers; and (ii) all existing Large Power Service customers. It appears to me that Mr. Radigan views the issue of mandatory time-of-use from a short-run perspective.

Q. Why do you believe Mr. Radigan's argument is flawed?

A. Mr. Radigan reaches a short-sighted, overly conservative conclusion that for smaller customers, TOU metering costs outweigh the potential long-term benefits of load shifting and peak load shedding. The problem is Mr. Radigan is only looking at the costs and benefits in the near term. At present, there is a positive cost differential between a non-TOU meter and a TOU meter. It may be difficult for some smaller customers to shift enough energy from peak to fully justify the cost of a TOU meter over the short-term. Mr. Radigan's conclusion, however, is flawed because all meters will eventually have full time-of-use functionality and communications capabilities. These intermediate-term technology improvements will also lower the cost of TOU meters significantly. As the cost of storing information falls exponentially, the cost differential between time-of-use and non-time-of-use will disappear. Soon, there will be no such thing as a "non-time-of-use" meter. Mr. Radigan's argument against mandatory time-of-use quickly collapses when the cost differential between TOU and non-TOU meters disappears.

Q. So, TEP still supports mandatory TOU for new and moving residential and small commercial customers?

A. Yes. In addition, TOU rates will be voluntary for any existing residential and small general service customer. TEP believes it is sound policy to offer *all* customers the opportunity to save and shave load off of peak.

Q. Could you reiterate why TEP believes its TOU proposal, and mandatory TOU in particular is in the public interest?

A. Certainly. TEP views the issue from a long-term perspective. With technology improvements and the expansion of smart metering, the cost-differential between a meter with TOU capabilities and non-TOU meters will disappear – for the simple reason that all meters will be TOU-capable. Non-TOU meters will eventually go the way of the black and white television and become extinct. In the meantime, TOU offers customers the opportunity to shave peak load, which can defer capacity additions and save costs over the long-run for both the Company and its customers. Capacity deferrals result in long-run savings for all the system's customers. In short, the longer-term benefits far outweigh the short-term costs.

Both TEP, as well as UNS Electric, Inc. (UniSource Energy's other electric utility) strive to expand acceptance of TOU. Even though, for the interim period, and until the cost differential disappears, we must be content that there may be some cross subsidies among customers. But some subsidization already exists between customer classes, so this factor should not be an impenetrable barrier to implementing TOU rates.

Q. Has the Commission previously taken a longer run view with respect to other issues?

A. Yes. Clearly, Decision No. 69127 (November 14, 2006), which approved the Renewable Energy Standard and Tariff ("REST") Rules, is a classic example of the Commission

taking a long-term view at promoting renewable energy, even when not economical in the short-term. We propose that the same type of long-term view apply to implementation of the Company's TOU proposals.

Q. Does RUCO support mandatory TOU as proposed by TEP?

A. Mr. Gregory supports mandatory time-of-use rates, except for medical low-income and low-income customers. TEP agrees with Mr. Gregory that TOU should not be mandatory for medical low-income customers. But TEP still believes that new and moving low-income customers without medical conditions should be subject to mandatory TOU.

Q. Please discuss the Company's position regarding Mr. Gregory's exclusion of new and moving Medical Low-Income and Low-Income customers from mandatory time-of-use.

A. Because medical equipment needs – generally – to be on for very specific periods of time, opportunities for medical low-income customers to shift load away from peak are likely to be sparse at best. These particular customers warrant some protection from higher on-peak costs due to the limited discretion they have to turn off such equipment. Mr. Gregory has made a convincing case for excluding medical low income customers from mandatory time-of-use.

However, the Company believes that all other new customers, regardless of income, should play a part in shifting load away from peak periods. Non-medical low-income customers, already subsidized by the majority of customers not receiving low income discounts, still have some discretion to shift some load from peak and still have opportunities to save. Another way to view it is that these customers should "return the favor" by participating in the time-of-use program, which helps reduce peak demand and

helps defer capacity additions for all customers, including those that subsidize the low-income programs. Additionally, low-income customers, like most other customers, can often find load shifting and peak load shedding opportunities, which will result in savings that may not have been so easily achievable under the non-time-of-use alternatives. TEP's 16-hour-per-day off-peak period provides plenty of convenient opportunities for load shifting.

Q. Do DOD and AECC support mandatory TOU?

A. Yes. Mr. Higgins for AECC notes, in his Direct Testimony at page 25 lines 3 through 4, that TOU rates improve price signals to customers.

C. <u>RUCO's Proposal to Subsidize TOU Rates.</u>

Q. What is you understanding of RUCO's proposal to have TOU rate subsidized?

A. Mr. Gregory for RUCO advocates for a subsidy to time-of-use customers to make the rate more attractive.

Q. Does TEP support subsidization of TOU rates as Mr. Gregory proposes?

A. No. TEP is opposed to subsidies in that they are unnecessary and must be subsidized by remaining non-time-of-use customers. Moreover, such subsidies create built-in revenue erosion, and will hasten the need for TEP to seek additional rate relief. Finally, a subsidy could help eliminate the need for customers to shift load to save money. This sabotages the key goal of TOU, which is to manage peak demand so that capacity can be deferred.

Q. Please detail further the reasons TEP opposes RUCO's proposal.

A. First, a subsidy is unnecessary for the customer to save money. Under TOU, a customer is "rewarded" by shifting load to the lower-priced periods (e.g., off-peak), or shedding

load altogether. With a 16-hour-per-day off-peak period, there are numerous saving opportunities. Second, subsidizing TOU creates the false view that a TOU customer with the same load profile as a non-TOU customer is less costly to serve. Third, the per-customer burden of the subsidy (borne by non-time-of-use customers) grows as time-of – use subscription grows and non-time-of-use subscription falls.

Fourth, the subsidy introduces built-in revenue erosion to TEP's revenue stream. As the ratio of time-of-use to non-time of use grows, TEP's revenue per customer will erode as more TOU customers join the system. But the costs to serve those customers will not decrease (by the amount of the non-cost-based subsidy), thus creating a need for a future rate filing. The extent of the erosion will depend on the level of the subsidy. However, TEP views even a small subsidy as excessive given the reasons stated above – as well as the fact that TEP did not perform any price elasticity adjustments to recover lost revenue attributable to load shifting and shedding. In the event that the Commission opts to "sweeten the pot" for time-of-use through a subsidy, TEP requests that some adjustment be performed to compensate it for revenue erosion and/or price elasticity.

D. <u>AECC and Kroger Comments Regarding Demand Charges and TOU</u>.

Q. Do AECC and Kroger offer recommendations for the time-of-use rates?

A. Yes. AECC makes the same argument as DOD for larger demand charges relative to energy charges, and larger summer/winter differentials. Mr. Baron argues for higher demand charges in the Large General Service – Rate 85N. TEP does not oppose these rate design recommendations.

VI. RATE DESIGN ISSUES INVOLVING THE BASE COST OF FUEL AND PURCHASED POWER AND THE PFFAC.

Q. Please describe the consequences of the Staff's recommendations.

A. TEP proposes to adjust the base cost of fuel and purchased power to reflect higher costs expected to exist in early 2009. Mr. Hutchens provides an update to TEP's fuel and purchases power forecasts for 2009 in his Rebuttal Testimony. Assuming that expectations are on target, TEP proposes no initial adjustment through the PPFAC when rates go into effect. TEP proposes that updated forecasts for 2009 be reflected in the base cost. Staff opposes having 2009 forecasts for fuel and purchased power as the basis for the base cost for fuel and purchased power.

Assuming that expectations are on target or higher, Staff's approach results in an unnecessarily large initial recovery through the PPFAC. This is because the PPFAC must recover those fuel and purchased power costs not captured in base rates. TEP's 2009 forecast points toward fuel and purchased power costs being higher in 2009, so the PPFAC will have to "compensate" for the base cost's failure to recover higher cost levels expected in early 2009.

Q. What is the implication of recovering more through the PPFAC and less through base rates?

A. As proposed, TEP's PPFAC will recover fuel and purchased power costs on a per-kWh basis that does not vary across classes or voltage levels. While simpler to administer and understand, this approach does not reflect as accurately the costs as the proposed base rates. By contrast, the base cost for fuel and purchased power is set for each customer class based on cost studies using allocation approaches intended to create equitable

allocations of cost across classes. This is a typical trade-off between simplicity and accuracy.

Q. What is the impact of collecting more fuel and purchased power costs through the PPFAC versus through base rates?

A. The simple PPFAC recovery results in little distortion in cost assignment as long as the portion of costs collected through the PPFAC remains relatively small. However, when PPFAC recoveries increase substantially as compared to base rate recoveries, cost assignment among customers and classes of customers may start to deviate substantially from cost causation. Because of the volumetric PPFAC recovery mechanism, increased recoveries through the PPFAC will fall disproportionately on classes with higher load factor customers. Therefore, large light and power customers may end up paying more than their fair share of costs, unless cost recoveries can be shifted back toward base rates, or the PPFAC is redesigned.

Q. Does this necessarily affect the total of all bills paid by TEP's customers?

A. No. Total cost recovery may be unaffected; however, cost recovery among individual customers and classes will be affected significantly as the cost burden is shifted toward higher load factor customers. TEP believes this is an inequitable situation, especially given that some higher load factor customers already subsidize lower load factor customers due to historical distributions of rate increases and current rate design. In other words, if the base cost for fuel and purchased power is not set at a level as accurate as possible going forward, the overall balance TEP is striving for in rate design can be significantly upset, with higher load factor customers bearing too much of a burden for costs that lower load factor customers cause.

VII. SERVICE FEES.

Q. Do Staff and RUCO support TEP's service fee proposal?

A. Yes. Both Staff and RUCO support the service fees TEP proposes. Mr. Radigan for Staff notes that the fees are cost-based. Mr. Gregory conditions his support – regarding the late charge – on other revenue be adjusted for a correction detailed in the Company's response to RUCO's Data Request 3.14, and that customers be advised in advance of after-hours connect and reconnect fees. TEP accepts RUCO's conditions.

VIII. FORFEITED DISCOUNTS, MISCELLANEOUS SERVICE REVENUE, AND RENT FROM ELECTRIC PROPERTY ALLOCATION.

Q. Please discuss RUCO's position on this issue?

A. Mr. Gregory prefers an alternate allocation for forfeited discounts, miscellaneous service revenue, and rent from electric property. TEP has reviewed RUCO's positions on these items and accepts these changes as appropriate.

IX. TRANSMISSION COSTS.

A. TEP's Proposed Use of FERC-approved OATT to Determine Transmission and Ancillary Service Costs.

Q. Please discuss the Staff recommendations regarding TEP's proposed use of the OATT to determine transmission and ancillary service costs.

A. Staff has not yet presented its recommendation. TEP has followed ACC precedent in this docket. TEP removed transmission cost from the retail cost-of-service study to recognize that the Federal Energy Regulatory Commission ("FERC") has primary jurisdiction over

open-access transmission. As such, TEP has assigned its ACC jurisdictional retail customers transmission costs based on TEP's FERC-approved OATT rate. This is consistent with the 1999 Settlement Agreement at section 4.4, which states "TEP shall charge rates for transmission and ancillary services based on its FERC Open Access Transmission Tariff" (OATT). TEP does not believe it is appropriate to calculate transmission and ancillary service costs by any other means other than what FERC has approved through the OATT.

Q. Does Mr. Higgins recognize FERC jurisdiction and acknowledge transmission and ancillary service costs based on the OATT?

A. He mentions the use of the OATT rate at page 2, line 30 of his Direct Testimony. His concern is the volumetric recovery mechanism used to recover costs from large light and power customers. But he does not criticize the use of the OATT to calculate transmission and ancillary service costs.

B. <u>Transmission Allocation Method</u>.

Q. How do Mr. Higgins for AECC and Mr. Baron for Kroger propose to allocate transmission?

A. Both support using a 4CP (*i.e.* demand) methodology rather than the Company's 4CP average and peaks method to allocate transmission costs. TEP opposes this change away from average and peaks.

Q. Why does TEP oppose AECC's and Kroger's proposal to allocate transmission costs on 4CP rather than TEP's proposed 4CP average and peaks.

A. This Commission has approved 4CP average and peaks for transmission allocation, and rejected 4CP. Baseload plants tend to be built further from end-users on the utility

system due to environmental and cost issues. As I also explained during my discussion of cost of service allocations earlier in my Rebuttal Testimony, baseload plants require minimum load durations (energy use) to cost justify their higher capacity costs. Consequently, the transmission allocation factor should include both a demand and an energy component, which 4CP average and peaks does.

C. Transmission Cost Adjustment Charge ("TCAC") – Rider 5.

Q. Do you have a correction to make from what you attached to your Direct Testimony regarding the proposed TCAC?

A. Yes. In the TCAC – attached as Exhibit DBE-5 to my Direct Testimony – the proposed TCAC clearly shows volumetric transmission and ancillary service charges differentiated by rate class, which was the Company's intention. The inconsistency is in the last line of paragraph 3: "The TCAC applies to all system sales *and will not vary by class of service.*" (Italics added for emphasis.) Based on the charges shown, the TCAC clearly varies by class.

Q. Do you wish to make a correction to the proposed TCAC?

A. Yes. The words "*and will not vary by class of service*" should be removed, so that the last line of paragraph 3 reads: "The TCAC applies to all system sales." Exhibit DBE-6 to my Rebuttal Testimony shows the correction above and as well as corrected volumetric charges. Volumetric charges shown in Exhibit DBE-5 were preliminary numbers that were not updated. The correct unbundled components, however, were used in TEP's proposed tariffs. While the Company is willing to consider an alternate rate structure (*e.g.,* a demand charge instead of or in conjunction with a volumetric charge) for larger customers under the proposed Rider 5, Exhibit DBE-6 reflects the originally-filed volumetric structure.

Q. Is the current transmission rider, Rider 3 – Transmission and Ancillary Services, part of your rate proposal?

A. No. TEP proposes that Rider 5 – TCAC – would supersede the current Rider 3 in the TEP proposal. The current Rider 3 was inadvertently included with the proposal. Both Rider 5 and Rider 3 are based on the Open Access Transmission Tariff ("OATT"); however, proposed Rider 5 is simpler.

Q. Is AECC proposing an alternate rate structure to the TCAC?

A. Yes. Mr. Higgins proposes that any transmission component be recovered on a demand rather than an energy basis for classes with demand billing determinants. Mr. Higgins proposal is acceptable to TEP.

X. RECOVERY UNDER THE TERMINATION COST REGULATORY ASSET CHARGE ("TCRAC") – RIDER 4.

Q. What is the purpose of your Rebuttal Testimony on this issue?

A. I am simply discussing the proposals by Mr. Higgins for AECC and Mr. Baron for Kroger regarding TEP's proposal to recover the Termination Cost Regulatory Asset through a per-kWh charge. Other TEP witnesses provide substantial testimony as to why the TCRA – and the level of the TCRA – is an appropriate and legitimate cost incurred by TEP.

Q. Does TEP support AECC's recommendation to change the TCRAC to a percentage of the bill – rather than volumetric approach as proposed by the Company?

A. No. Under a percentage of the bill approach, as proposed by Mr. Higgins, the unit price paid by large light and power customers under TCRAC will be less than that paid by residential and smaller general service (e.g., Pricing Plan C-10) customers. This is unfair

to the residential and smaller general service customers, because the prevailing expectation in the mid to late 1990's was that the largest commercial and industrial customers had the most to gain from direct access. These larger customers in concert with potential energy service providers encouraged the Commission to move to implement direct access. Since these customers encouraged direct access, it is only fair that these customers pay the same per-kWh charge as residential and small general service customers.

It is not surprising that when direct access failed to live up to high expectations, the large light and power customers that originally wanted direct access were no longer as excited about it. But to have residential and small general service customers pay more than the customers who lobbied for direct access is unfair. Each customer should pay the same charge per kWh under TCRAC, as proposed by the Company. It is a fair compromise that treats all sales equally.

Q. What is Mr. Baron's position on TCRAC recoveries?

A. He proposes that these costs be assigned to classes on the basis on rate base. Like Mr. Higgins revenue-based allocation, larger customers will pay less per kWh for TCRAC under Mr. Baron's scheme. For the same reasons TEP opposes AECC's proposal on the TCRAC recovery, TEP disagrees strongly with Mr. Baron.

XI. UNBUNDLED RATES.

Q. What is TEP's position on Mr. Radigan's proposal to abandon rates and offer alternate rates with limited unbundling?

A. TEP disagrees with Mr. Radigan's proposal to abandon unbundled rates and offer alternate rates with limited unbundling.

Q. Why is TEP opposing Mr. Radigan's proposal that unbundled rates be abandoned?

A. Unbundled rates are necessary to support direct access. Direct access affects not only TEP, but customers and providers within and without the State. From a customer standpoint, elimination of unbundled tariffs closes the door on viable direct access. From a service provider standpoint, Mr. Radigan's proposal potentially eliminates the possibility of meter service providers, meter-reading service providers and billing service providers. TEP does not believe the Commission has completely locked the door on direct access and retail electric competition. It is TEP's understanding that the Commission's Electric Competition Advisory Group is still in existence and that Staff is still investigating these issues statewide. Further, TEP does not believe its rate case is the proper place to make decisions that have such far-reaching policy ramifications – which abandoning unbundled rates has the potential to do. For these reasons, TEP believes Staff's proposal to rebundle rates is premature at this time.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

EXHIBIT

DBE-6

Rider 5
Transmission Cost Adjustment Charge ("TCAC")

The Transmission Cost Adjustment Charge ("TCAC") shall apply to all of the Company's retail pricing plans. All provisions of the applicable pricing plan will apply in addition to the TCAC authorized by this Rider.

Pricing plans to which the TCAC applies include transmission and ancillary service components listed in the table below. The listed transmission and ancillary service components are based on the Company's Federal Energy Regulatory Commission ("FERC") - approved Open Access Transmission Tariff ("OATT"). The listed transmission and ancillary service components are calculated on a volumetric basis by class of service.

Pursuant to this Rider, the TCAC, which is an annual adjustment to the transmission and ancillary service components, will be submitted to the Commission for review. In the event that the Company's FERC-approved OATT changes, TEP will file an additional recalculated TCAC, unless the regular annual adjustment addresses the OATT change. The TCAC is based upon the prior year's annual Transmission and Ancillary Service costs and retail energy sales. Transmission and Ancillary Service costs are calculated by applying the Company's approved OATT rates to TEP's retail jurisdictional sales. This TCAC will be applied volumetrically to kilowatt-hour sales under applicable electric pricing plans. The TCAC applies to all system sales.

The initial transmission and ancillary service components of retail rates and are as follows:

	Residential	General Service	Lg Light & Power	Lighting	Public Authority
Transmission	$0.007525	$0.007298	$0.006184	$0.026736	$0.006129
Ancillary Services					
System Control - Load Dispatch	$0.000102	$0.000099	$0.000084	$0.000363	$0.000083
Reactive Supply and Voltage Control	$0.000402	$0.000390	$0.000330	$0.001427	$0.000327
Regulation and Frequency Response	$0.000389	$0.000377	$0.000320	$0.001383	$0.000317
Spinning Reserve Service	$0.001055	$0.001024	$0.000867	$0.003750	$0.000860
Supplemental Reserve Service	$0.000172	$0.000167	$0.000141	$0.000612	$0.000140

Note: All values presented as $/kWh

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO E-01933A-07-0402

Rebuttal Testimony of

Dawn Sabers

on Behalf of

Tucson Electric Power Company

April 1, 2008

Executive Summary of the Rebuttal Testimony of Dawn Sabers

Ms. Sabers is the Assistant Controller and General Manager of Corporate Accounting for Tucson Electric Power Company ("TEP" or "Company"). Ms. Sabers' Rebuttal Testimony addresses the following matters:

1. **Incentive Compensation Related to All Non-Officer Employees.** Incentive Compensation could be called lump sum salary payment as it is simply a core piece of compensation based on the benchmarked cost needed to attract and retain qualified personnel. As such, the Company could either raise annual salaries or continue to have an "at risk" compensation plan targeted at achieving goals to benefit ratepayers and only pay upon performance. As this is simply a core piece of compensation, the Company recommends that it be included at 100% of the 2006 expense (with no averaging). The Staff and RUCO appear to erroneously believe the compensation is in addition to that needed to attract and retain qualified personnel and believe it should only be allowed at 50%.

2. **Officer Incentive Compensation, SERP and Officers' Long-Term Incentive Program.** For Officer Incentive Compensation, SERP, and Officers' Long-Term Incentive Program, TEP recommends a 50/50 sharing between ratepayers and shareholders based on the 2006 expense with no averaging. This recognizes the benefit to ratepayers. RUCO and Staff agree with a 50/50 sharing for the Officer Incentive Compensation but, arbitrarily, believe the SERP should be excluded entirely. The Staff additionally recommends that the Long-Term Incentive Program also be excluded, while RUCO includes at 100%. The Staff and RUCO do not provide compelling support for their proposed exclusions. All of these plans are necessary to attract and retain qualified leadership for the Company.

3. **Supplemental Payroll Adjustment.** The Company has updated its adjustment for payroll to reflect the known and measurable salary increase of 3% effective January 2008. The salary increase is simply the benchmarked cost needed to attract and retain qualified personnel.

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Dawn Sabers and my business address is 4350 East Irvington Road, Tucson, Arizona, 85714.

Q. Are you the same Dawn Sabers that previously submitted Direct Testimony on behalf of Tucson Electric Power Company ("TEP" or "Company") in this Docket?

A. Yes.

Q. Have you reviewed the Direct Testimonies filed by the Arizona Corporation Commission Staff ("Staff") and Intervenors in this case?

A. Yes, I have.

Q. Which Staff and/or Intervenor Direct Testimonies will you be addressing in your Rebuttal Testimony?

A. In my Rebuttal Testimony, I would like to address several adjustments that Staff witness Ralph C. Smith recommends in his Direct Testimony and several adjustments that Residential Utility Consumer Office ("RUCO") witness Rodney L. Moore proposes in his Direct Testimony. I believe that I can provide additional insight and analysis which will support the reasonableness of Tucson Electric Power Company's (TEP's) proposals on these items and demonstrate that some of the adjustments that the Staff and RUCO witnesses recommend are inappropriate and should not be accepted.

II. REBUTTAL TO STAFF WITNESS RALPH C. SMITH AND RUCO WITNESS RODNEY L. MOORE.

Q. Which adjustments will you be addressing?

A. I would like to provide additional consideration for the following adjustments proposed by Mr. Smith in his testimony:

- Incentive Compensation
- Supplemental Executive Retirement Plan ("SERP")
- Officers' Long-Term Incentive Program
- Rodney L. Moore also proposed adjustments to Incentive Compensation and SERP. I will also address these adjustments.

Q. How do you plan to group adjustments for discussion?

A. I would like to group the items into two categories for discussion purposes:

(a) Incentive Compensation related to all non-officer employees and

(b) Officer Incentive Compensation, SERP and Officers' Long-Term Incentive Program.

Q. Why did you group these items into two categories?

A. I separated these items into two categories primarily so that I could collectively address the treatment of the items in the second category, Officer Incentive Compensation, SERP and Officers' Long-Term Incentive Program. These items are integral pieces of the officer compensation packages that are needed to attract and retain leaders. As these similar items of compensation benefit both the ratepayer and the shareholder, TEP proposes a 50/50 split of expenses between the two groups.

Q. Can you summarize the Staff, RUCO and TEP's proposals?

A. Yes, the following chart summarizes the positions:

Category	Staff	RUCO	TEP's proposal
(a) Incentive Compensation related to all non-officer employees.	50/50 sharing* based on a 3-year average	50/50 sharing* based on 2006 (no averaging)	Include 100% of 2006 expense (no averaging)
(b) Officer Incentive Compensation	50/50 sharing* based on a 3-year average	50/50 sharing* based on 2006 (no averaging)	50/50 sharing* based on 2006 (no averaging)
(c) SERP	Excluded 100%	Excluded 100%	50/50 sharing* based on 2006 (no averaging)
(d) Officers' Long-Term Incentive Program	Excluded 100%	Included at 100% based on 2006	50/50 sharing* based on 2006 (no averaging)

* 50/50 sharing between ratepayers and shareholders.

III. INCENTIVE COMPENSATION RELATED TO ALL NON-OFFICER EMPLOYEES.

Q. Ms. Sabers, can you briefly summarize Mr. Smith's adjustment to test year incentive compensation for non-officer employees?

A. Yes. Mr. Smith has suggested an equal sharing between ratepayers and shareholders of the costs associated with TEP's non-officer employee incentive program. Mr. Smith's primary reasoning for this sharing is that he believes it strikes the balance between the benefits attained by both shareholders and customers. He references a recent Commission Decision No. 68487 (February 23, 2006) – the Southwest Gas Corporation ("SWG") rate case – in which the Commission adopted such a recommendation for its management incentive plan. Mr. Smith recommends using an average of the 3 years in the period 2004 through 2006 upon which Mr. Smith applies the 50/50 sharing.

Q. Ms. Sabers, can you briefly summarize Mr. Moore's adjustment to test year non-officer employee incentive compensation?

A. Yes. Mr. Moore also recommends an equal sharing of the costs associated with the non-officer incentive compensation program of 50/50 between ratepayers and shareholders. Mr. Moore's primary reasoning for this sharing is that it follows Decision No. 70011 (dated November 27, 2007) (the "UNS Gas Rate Case") which provides "a reasonable balancing of the interests between ratepayers and shareholders." Mr. Moore recommends using 2006 expense as the base upon which the 50/50 sharing should be applied because the 2006 expense was not abnormal. In the UNS Gas Rate Case, Mr. Moore used the SWG rate case and Decision No. 68487 as justification for the 50/50 split. Both Staff and RUCO justify their 50/50 split proposals based on the Commission's approval of a 50/50 split between shareholders and ratepayers for SWG's Management Incentive Program ("MIP").

Q. Is TEP's non-officer employee incentive compensation program the same as SWG's MIP?

A. No. TEP's program is for all non-union employees, whereas my understanding of SWG's MIP is that it is limited to only management personnel. Further, a significant portion of SWG's MIP appears specifically related to return on equity targets. TEP's program, by contrast, is based on broader and more wide-ranging factors that I will discuss below.

Q. Both Mr. Smith and Mr. Moore cite other rate decisions as "binding" precedent. Can you cite any prior Commission rate decisions that would support recovery of 100% of the non-officer incentive compensation program rather than a 50/50 sharing?

A. Yes. Decision No. 69663 (dated June 28, 2007), the Decision approving the recent rate case filing for Arizona Public Service Company ("APS"), provided for recovery of 100% of the non-officer incentive compensation program. The Commission stated that APS' "at risk" pay program ties employee performance to the customer's benefit and that expenses for the program are recoverable. Decision No. 69663 did not dispute any portion of "at risk" expenses as unreasonable; in fact, it notes that Staff did not dispute inclusion of these costs:

> "APS' variable incentive program is an "at risk" pay program where a part of an employee's annual cash compensation is put at risk and expectations are established for the employee at the start of the year. If certain performance results are achieved, a predictable award will be earned based upon objective criteria. The actual amount of the award depends upon the achieved results. The intent of the plan is to: link pay with business performance and personal contributions to results; motivate participants to achieve higher levels of performance; communicate and focus on critical success measures; reinforce desired business behaviors, as well as results; and to reinforce an employee ownership culture. (APS Exhibit No. 51, Gordon Rebuttal, p. 8) Staff did not oppose inclusion of the TY variable incentive expense in cost of service, noting that although corporate earnings serve as a threshold or precondition to the payout, the TY level of expense is tied primarily to performance measures that directly benefit APS customers. (Staff Exhibit No. 43, Dittmer Direct, p. 110)".

See Decision No. 69663, page 37.

Q. Have other jurisdictions fully allowed incentive compensation expenses for similar programs?

A. Yes, two cases stand out. One involved Nevada Power Company ("NPC") – and its managerial, professional, administrative and technical Short-Term Incentive Program and Total Rewards program in 2002.[1] These programs provided incentive pay for individual performance and for contributing to NPC's overall service and financial performance. Factors considered included quality of service, system performance, reliability and cost reduction goals. NPC witnesses testified that its program attracted and retained employees needed to continue to provide excellent service to NPC's customers – while also keeping downward pressure on base salary increases and that its incentive program costs were an essential component of NPC's basic labor costs. The Nevada Public Utilities Commission found that NPC's incentive program helped NPC *to provide reliable service at reasonable rates* and allowed NPC's adjustments for its incentive program In 2007, the Nevada Commission confirmed that NPC's STIP Program did benefit ratepayers either directly or indirectly and allowed $6,023,000 of those expenses into rates – even though 35% of the STIP "performance matrix" related to financial performance.[2] The Nevada Commission approved the expenses related to NPC's STIP because "the consumers are beneficiaries of the STIP performance measures." The Nevada Commission did not appear to deny any amount of NPC's STIP on the basis that some goals may be more closely aligned with shareholders than customers. So Nevada believed if reliable service can be provided at reasonable rates, this incentive compensation should be awarded.

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[1] Before the Nevada Public Utilities Commission, Docket No. 01-10001, 2002 WL 32862407.
[2] 2007 WL 2141450.

Additionally, there is the Massachusetts Department of Telecommunications and Energy ("Mass. D.T.E.") decision regarding Boston Gas Company dba KeySpan Energy Delivery New England ("Boston Gas") in 2003.[3] Boston Gas' incentive compensation program involved specific performance goals and financial incentives linked to various performance levels. The Mass. D.T.E. found that Boston Gas' incentive program allowed incentive compensation expenses so long as they were reasonable and *were reasonably designed to encourage good employee performance*. The Mass. D.T.E. further stated that if the incentive plan was not solely based on company financial performance, then the incentive plan is reasonable to encourage good employee performance. It was also noted that Boston Gas' program is similar to those of other utilities competing for the same employees, and that several incentive categories directly dealing with cost-containment enhancing value to customers – like customer satisfaction, safety and workforce diversity. The Mass. D.T.E. allowed the Company to recover incentive compensation expenses.

Further, the Florida Public Service Commission ("FPSC") allowed Gulf Power Company ("Gulf") to recover incentive compensation in 2002.[4] The FPSC noted that Gulf offers a plan consisting of base salary and incentive compensation and that only receiving a base salary would mean Gulf employees would be compensated below employees at other companies. The Maryland Public Service Commission ("MPSC") allowed incentive compensation for Washington Gas Light Company ("Washington") in 2003 because the MPSC found that Washington's incentive compensation proposal includes criteria directly benefiting ratepayers.[5] Clearly, other Commissions have recognized how

[3] Docket No. D.T.E. 03-40 (2003 WL 22964722).
[4] Docket No. 010949-EI, Order No. PSC-02-0787-FOF-EI.
[5] Case No. 8959, Order No. 78757 (94 Md.P.S.C. 329)

programs similar to TEP's incentive compensation program provide direct benefit to ratepayers and are related to providing reliable service to customers at reasonable rates.

I provide these examples to illustrate that other public utility commissions have recognized the value of these types of incentive programs. TEP's program is not unusual and helps to keep overall compensation to these employees at a reasonable level. Further, TEP is also competing with these other utilities for quality and skilled employees. While this Commission is not bound by the findings of other commissions, these cases show that with similar facts and circumstances, these expenses are recognized as reasonable.

Q. Ms. Sabers, do you believe that the precedent set by prior rate decisions should be followed?

A. Not necessarily. I understand that, while it is important to recognize past decisions, the Commission is not obliged to follow those decisions. As demonstrated above, different rate cases have resulted in differing treatment. Each rate case should be viewed based on its unique facts and circumstances. I would argue that the facts and circumstances here justify this Commission deciding similar to the manner it did in Decision No. 69663 for APS with regard to non-officer employee incentive compensation expense.

Q. Do you agree with Mr. Smith and Mr. Moore that there should be a 50/50 sharing between ratepayers and shareholders of the non-officer employee incentive compensation program?

A. No, I do not agree. The entire amount of this program should be allowed. It appears that the only reason that Mr. Smith and Mr. Moore are questioning this cost is because of how it is titled. It appears they believe these costs to be in excess of the costs needed to attract and retain qualified employees.

Q. Why should the incentive compensation for non-officer employees be allowed at the 100% level and not a 50/50 sharing as proposed by Mr. Smith and Mr. Moore?

A. The non-officer employee incentive compensation is a necessary and reasonable cost of providing safe and reliable service to our customers.

Q. Why is the incentive compensation program necessary to serve ratepayers?

A. TEP ensures that its compensation packages are competitive with the market so that TEP can attract and retain skilled workers to provide safe, reliable service to its customers/ratepayers. TEP uses an incentive compensation program to remain competitive because approximately 79% of companies use performance-based, lump sum cash awards. The incentive compensation program helps make TEP competitive in attracting and retaining highly skilled employees.

Q. How does TEP ensure that, in addition to being competitive in attracting and retaining employees, TEP's compensation costs are reasonable?

A. TEP's compensation philosophy is to construct a total compensation package (cash compensation plus at-risk incentive compensation) that approximates the median market rate for its non-union employees. In benchmarking studies conducted by an outside consulting firm, TEP's non-union positions total average cash compensation, including incentive compensation, was competitive with the market at approximately the target level. In other words, to be competitive in attracting quality employees to TEP, the total compensation package must be commensurate with that offered by other electric utilities. TEP's base plus incentives equal the target and median level while still being competitive. Thus, the costs are reasonable.

Q. Would TEP have to consider restructuring its total compensation package if these expenses are partially excluded?

A. Yes, TEP would have to consider raising base salaries while decreasing or excluding entirely the "at risk pay" incentive compensation component. It is unfair to single out the incentive component of an employee's total compensation for scrutiny just because it is called "incentive" compensation. TEP's total compensation package is set at the median level of benchmarked compensation and is the relevant cost to be considered. If it is reasonable, it should then be allowed in rates. To follow Staff and RUCO's recommendations impacts TEP's ability to compete in attracting and retaining skilled and quality employees. TEP would have to increase base compensation to allow TEP to compete with other utilities in attracting and retaining its high quality and skilled workforce. Otherwise, TEP's total compensation would be well below the median. It is not reasonable to assume that TEP could retain employees if compensation rates are well below the median.

Q. Could you explain this further?

A. Yes, let me do so with an example. Assume we determine that the median total compensation for a non-officer employee at TEP is $50,000. We can choose to pay that employee $50,000 all in base pay. That cost would be included in the test year cost and evaluated for reasonableness. Because it is at the median level, and is at a level to attract qualified employees, it is reasonable and would be allowed. Now, assume that TEP chooses to pay that employee $48,000 in base pay, with an additional $2,000 offered as incentive compensation based on achieving certain performance based measures related to safety, customer service, the reduction of other costs and TEP's financial soundness. To the extent the employee achieves the performance goals and is awarded the $2,000 incentive, he/she is paid the same $50,000 ($48,000 base plus $2,000 incentive)

necessary to competitively attract a sound workforce. Total compensation is the relevant cost to be evaluated.

Relating this example to Mr. Smith and Mr. Moore's recommendations, they both base their recommendations on the premise that the $2,000 incentive compensation component is *over and above* the median amount TEP needs to pay to attract qualified individuals versus a *component* of that cost. This is a very important distinction that must be considered here. Further, Mr. Smith and Mr. Moore jump to the conclusion that allowing the full $2,000 is somehow not reasonable, when a base compensation at the median $50,000 level would be. If the full $2,000 is not allowed in rates, then there would be considerable pressure to increase base compensation to $50,000.

Q. What are the advantages of TEP using an incentive compensation program rather than just increasing base salaries?

A. TEP's incentive program is a pay for performance program. The incentive compensation is "at risk compensation" because employees are not guaranteed payments. The "at risk compensation" portion is awarded based on an individual basis to reward specific performance and provides management with an additional tool to encourage further cost savings, motivate individuals and to encourage employees to impact goals.

Using an incentive compensation program is less costly than increasing base salaries because incentive compensation is not included in the "base compensation" that is the basis for employee costs such as: vacation pay, sick pay, long-term disability, 401K matching, and pension expense. As a result, the incentive compensation program costs less than increasing base salaries.

Q. Besides having a skilled workforce to serve customers, are there any other direct benefits to customers of TEP having an incentive compensation program?

A. Yes, the goals or targets of the current incentive compensation program are also heavily weighted toward providing benefits to customers. The incentive compensation program uses financial performance measures weighted at 30%, operational cost containment weighted at 30% and customer service goals weighted at 40%. All of these objectives benefit the ratepayer. TEP's program promotes increased safety, increased customer service, the reduction of other costs and increases the financial soundness of TEP. But each individual employee's "at risk" component to total compensation is based on his or her contribution to the overall success of the Company. Really, the "at risk" portion of an employee's compensation is the portion of the employee's fair and reasonable compensation that varies based on what contribution he or she has made to the Company. Employees are rewarded for meeting their specific individual goals that directly relate to their respective occupations. And those occupations directly relate to providing service to the customer.

Q. Why are union employees not eligible for this incentive compensation program?

A. The union employees wage rates are collectively bargained and they have not been receptive to putting any portion of any union member's pay at risk and/or allowing equivalent grade employees to earn differing pay levels based on performance.

Q. Do you agree with the averaging of 3 years as proposed by Mr. Smith?

A. No. The test-year expense should be based on the costs expected when new rates are in effect. The 2006 level of costs is representative of that level of costs and no party disputes this level of costs in and of itself as being unreasonable. Mr. Smith provides no justification for deviating from actual and reasonable test-year expenses.

Q. Does Mr. Moore use the 2006 non-officer incentive compensation expense as the base?

A. Yes, Mr. Moore uses the 2006 non-officer incentive compensation expense as the base, without averaging. The justification is contained in Mr. Moore's direct testimony at page 20, which states:

> *"RUCO does not generally vary from the strict implementation of the Historical Test-Year principle to avoid mismatches in the ratemaking elements. RUCO determined in the instant case the test year was not abnormal; and therefore, RUCO dismisses the Company's proposal to a four-year average of the incentive compensation expenses"*

The 2006 non-officer incentive compensation expense should be used as the basis upon which the 100% inclusion should be applied. The 2006 non-officer incentive compensation expense did not contain unusual costs and is indicative of the costs that will be incurred in the future when the revised rates will be effective.

Q. Please summarize TEP's current position on the non-officer incentive compensation for this rate proceeding.

A. Because the non-officer incentive compensation expenses are reasonable and provide a direct benefit to ratepayers, TEP believes 100% of the 2006 level (no averaging) of non-officer incentive compensation expense should be included in the test year.

IV. OFFICER INCENTIVE COMPENSATION, SERP AND OFFICERS' LONG-TERM INCENTIVE PROGRAM.

A. Officer Incentive Compensation.

Q. Would you agree with the 50/50 sharing proposed by Mr. Smith and Mr. Moore for the Officer Incentive Compensation program?

A. Not entirely. TEP agrees that a 50/50 sharing is appropriate for officer incentive compensation because it recognizes that a cost benefits both ratepayers and shareholders equally. It may be, however, somewhat subjective to determine exactly the split between shareholder and ratepayers. This is because of the numerous benefits, both direct and indirect, that the Officers provide to both groups. However, a 50/50 sharing of these expenses recognizes that the Officers provide both ratepayer and shareholder benefit.

Q. Why would TEP accept a 50/50 sharing for the Officers' incentive compensation program while recommending that the non-officer employee incentive compensation program be recovered at 100%?

A. Typically, Officers will focus more on both ratepayer and shareholder needs than the non-officer employees who focus on directly serving the customer. As such, a 50/50 sharing recognizes that this cost benefits both the ratepayers and the shareholders.

Q. Do you agree with the averaging of 3 years as proposed by Mr. Smith or using the 2006 expense as the base as proposed by Mr. Moore?

A. Similar to the non-officer compensation levels, there is no reason to employ a 3-year average, as proposed by Staff, as the 2006 levels are representative of the expense levels that will be incurred when new rates become effective.

B. **Supplemental Executive Retirement Program.**

Q. In simplistic terms what is the purpose of the SERP plan?

A. The purpose of the SERP is to ensure that Officers receive the same proportion of retirement compensation relative to all employees; the SERP ensures there is no discrimination.

Q. Why is the SERP a necessary part of the overall compensation given to the Officers?

A. The SERP is necessary because of Internal Revenue Service ("IRS") limitation rules that differentiate treatment based on levels of compensation. Put another way, the SERP is necessary because of funding deductibility limits defined in the Internal Revenue Code. SERP eliminates discriminating based on salaries.

Q. Should the IRS rules dictate the ratemaking treatment of SERP?

A. No. Rate-making is based on determining the reasonable costs of providing safe, reliable service to customers; the IRS rules are not. Rather, the IRS rules are set based on revenue collection needs. Therefore, IRS rules should not dictate rate-making.

C. **SERP and Officers' Long-Term Incentive Program.**

Q. Do you agree with the exclusion of all expenses related to SERP and Officers' Long-Term Incentive Program proposed by Mr. Smith and the exclusion of SERP proposed by Mr. Moore?

A. No, I do not agree. The SERP and the Officers' Long-Term Incentive Programs are integral pieces of total compensation packages. Neither Staff nor RUCO challenges the actual amount of expenses for either program as unreasonable. The participants in these

programs help to ensure we meet our goals of providing customers with safe and reliable service. The participants also ensure an adequate return to the shareholders. Both of these objectives benefit the ratepayers. The first directly benefits the ratepayers who rely on power to meet their needs. The second objective indirectly benefits ratepayers by having a company that is able to attract needed capital at a reasonable cost so that the company can continue to provide safe, reliable power to ratepayers.

Q. What support does Staff and RUCO provide for excluding SERP?

A. Staff references a recent Southwest Gas Decision as support for removal of SERP. Without reference to support, RUCO simply states that SERP is a supplemental benefit and is not a necessary cost of service.

Q. Do you agree with RUCO and Staff?

A. No. The rationale in the SWG case is that SERP is additional, unnecessary compensation. However, SERP is just a component of compensation to be able to attract and retain qualified leaders. Based on Clark Consulting's 2007 "*Executive Benefits – A Survey of Current Trends*", approximately 67% of companies have SERPs. Also, based on the SERP discussion in IV.B. above, SERP is a mechanism to promote equality among all employees regarding benefits that are calculated on base pay.

Q. What support does Staff provide for the proposed exclusion of the Long-Term Incentive Plan?

A. Staff does not provide a reason for the exclusion. Instead, Staff simply states that the cost should be "borne by shareholders and not ratepayers."

Q. Do you agree with Staff?

A. No. Based on the October 2007 Executive Compensation Competitive Review draft report, the Officers' total compensation levels are "in line with the median to 75th percentile of 'competitive practice'." Thus, this cost is needed to attract and retain leaders.

Q. What percentage of the objectives of the incentive plans and SERP benefits shareholders rather than ratepayers?

A. Because of the numerous benefits to both groups, both direct and indirect, determining the split between ratepayers and shareholders is difficult. An objective such as a targeted earnings per share ("EPS") seemingly benefits the shareholder. But this also benefits the ratepayer in that the company is able to raise capital at a lower cost to build the infrastructure needed to serve the ratepayers. A 50/50 sharing of these expenses does recognize that there is both ratepayer and shareholder benefit. A 50/50 sharing would also be generally consistent with Staff's and RUCO's recommended 50/50 sharing for the officer incentive compensation.

Q. Do you believe that SERP and Officers' LTIP costs are reasonable and necessary?

A. Yes, similar to the Officer Incentive Compensation program, I believe these costs are reasonable and necessary. These costs are necessary to attract and retain highly-skilled executives. These costs represent a portion of the Officers' total compensation, and are an integral part of a competitive compensation program.

To ensure Officers' compensation levels are reasonable, TEP's Board of Directors ("Board") has set compensation levels for Officers to target approximately median to 75% of a peer group of publicly-traded companies. The peer group is reviewed

periodically. The October 2007 study includes 16 electric and gas utility companies that are comparable to UniSource Energy Corporation in terms of size as measured by annual revenues and market capitalization. The Board uses an outside consulting firm, which reports directly to the Board, to evaluate the compensation programs and levels, and to compare them to the peer group. The last study performed in October 2007 showed that the Officers' total compensation levels are in the median to 75th percentile for peer companies. Thus, this cost is needed to attract and retain leaders.

Q. Should the exclusion of these costs in other rate proceedings determine the treatment in this proceeding?

A. No, I do not believe that previous Commission orders excluding these types of expenses for other utilities should dictate treatment in this proceeding. I believe that the particular facts and circumstances here justify inclusion of these expenses for TEP.

Q. Please summarize TEP's current position on Officers' Incentive Compensation program, SERP and Officers' LTIP for this rate proceeding.

A. Because of the benefits to ratepayers and shareholders, TEP believes the 2006 expense (no averaging) should be included at 50% to reflect a 50/50 sharing.

V. SUPPLEMENTAL PAYROLL ADJUSTMENT.

Q. Please explain the supplemental Payroll adjustment.

A. The Payroll adjustment increase payroll expense by the pay increase of 3% effective January 2008. This wage increase should be included in the test year wages as this known and measurable increase will be in effect when the approved rates are in effect.

Q. Does that conclude your Rebuttal Testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-0402

Rebuttal Testimony of

Thomas N. Hansen

on Behalf of

Tucson Electric Power Company

April 1, 2008

Executive Summary of the Rebuttal Testimony of Thomas N. Hansen

Mr. Hansen is Vice President, Environmental Services, Conservation and Renewable Energy for Tucson Electric Power Company ("TEP" or the "Company"). Mr. Hansen's Rebuttal Testimony addresses the following matters:

1. **Demand-Side Management ("DSM") Program accelerated funding.** TEP supports Staff's recommendation that the DSM Adjustor Mechanism and initial DSM funding levels should be considered as part of this subject rate case to provide long term surety of DSM funds which are essential to success of a DSM program. The funding approval process should not be accelerated to a particular date in advance of rate case adjudication. The primary purpose of a DSM program is to assist customers with financial incentives to procure and use energy efficient appliances in their homes and businesses. Surety of utility funding builds customer confidence in investing their own dollars in DSM equipment and practices.

2. **Efficiency Enhanced Financial Incentive**. TEP believes that the Efficiency Enhanced Financial Incentive Program should be approved, as it provides a valuable tool for large customers, and the utility itself, to implement energy efficiency measures that would otherwise not quite be cost effective under traditional utility investment criteria. The Efficiency Enhanced Financial Incentive Program was proposed to provide the opportunity for TEP to support Utilities Energy Service Contracts ("UESC") for larger customers. UESCs generally have a higher level of risk than traditional utility investments and should be supported by a higher rate of return on the investment.

3. **REST Performance Incentive.** To properly align utility interests with customer interests and provide some benefit for the potential risks a utility incurs in not meeting the distributed generation portion of the REST, the REST Performance Incentive should be approved for recovery as a component of the REST Adjustor Mechanism. TEP's proposed REST Performance Incentive is based on only the success of meeting the Distributed Generation portion of the annual REST goals. Without the Performance Incentive a utility has no opportunity to seek a benefit for the risks the utility takes in performing to the REST annual distributed generation renewable energy requirements.

4. **Over-collected DSM Funds.** If DSM funds are over-collected to the point that the DSM balance has more funds collected than would be spent on DSM programs in the entire following year and that results in a refund to customers as a credit on the bills for the DSM line item, TEP believes that it would be appropriate for interest to be credited to the DSM account balance until the refunds are complete. However, if the over-collected funds simply are used to reduce the amount of DSM funds collected the following year and do not result in customer refunds, there should be no interest credited to the DSM account.

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I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Thomas N. Hansen. My place of business is 255 South Washington, St. Johns, Arizona.

Q. Are you the same Thomas Hansen that previously submitted Direct Testimony on behalf of Tucson Electric Power Company ("TEP" or "Company") in this Docket?

A. Yes.

Q. Have you reviewed the Direct Testimonies filed by the Arizona Corporation Commission Staff ("Staff") and Department of Defense ("DOD") and Southwest Energy Efficiency Project ("SWEEP")?

A. Yes, I have.

II. REBUTTAL OF STAFF DIRECT TESTIMONY.

Q. Please provide your general assessment of the Direct Testimony of Staff.

A. Staff supports the following TEP proposals: DSM Adjustor Mechanism, DSM Performance Incentive, initial DSM tariff rates, REST Adjustor Mechanism and the definition for initial REST rates as being what is approved in the pending TEP REST Implementation Plan docket (Docket No. E-01933A-07-0594). Staff does not support the following TEP proposals: Efficiency Enhanced Financial Incentive and the REST Performance Incentive.

Q. Are there any areas where TEP disagrees with the Direct Testimony of Staff?

A. Yes.

Q. Would you please elaborate, please?

A. Staff did not support TEP's proposed TEP DSM Efficiency Enhanced Financial Incentive Program or its proposed REST Performance Incentive Program. In addition, Staff's position that interest should be credited on over-collected DSM balances when a refund of those funds is to be made to customers, needs clarification.

Q. Would you explain why the DSM Efficiency Enhanced Financial Incentive program is of benefit to customers and to the Company?

A. The primary purpose of a DSM program is to assist customers with financial incentives to procure and use energy-efficient appliances in their homes and businesses. The DSM program offers standardized packages of incentives to reduce transaction costs that would be incurred if custom DSM programs were tailor-made for customers. However, many industrial customers have inefficient energy consuming devices that are not able to benefit from the standard energy efficiency packages and need help financing large energy efficiency projects. Additionally, TEP's own facility upgrade projects may at times be able to take advantage of new energy efficiency measures and equipment that are not quite cost effective at the time the upgrade is needed, but can take advantage of the higher efficiency measures if an extra incentive is available to allow cost effectiveness to be achieved from the utility's perspective – just as traditional DSM programs are designed to provide that opportunity for customers.

The criteria for qualification as an Efficiency Enhanced Financial Incentive Program project of being 15% more efficient and costing no more than 20% over a conventional piece of equipment are to ensure the program-qualified equipment has at least an increment better in efficiency than the standard product available and is not unduly expensive. As DOD noted in its testimony, larger customers need an avenue for tailor-made energy efficiency support from the utilities for Utilities Energy Services Contracts

("UESC"). The Efficiency Enhanced Financial Incentive Program was proposed to provide the opportunity for TEP to support such UESCs for larger customers. Such UESCs generally have a higher level of risk than traditional utility investments and should be supported by a higher rate of return on the investment. I believe the Efficiency Enhanced Financial Incentive Program should be approved as it provides a valuable tool for large customers, and the utility itself, to implement energy efficiency measures that would otherwise not quite be cost effective under traditional utility financing return rates. SWEEP also generally supports approval of the Efficiency Enhanced Financial Incentive Program. TEP requests that Staff reconsider its recommendation and support the Efficiency Enhanced Financial Incentive Program.

Q. Why should a Performance Incentive be approved for the REST programs, since customers are already paying for the REST program?

A. The REST programs should provide the utilities a balance of risk with reward. The REST rules provide for the possible imposition upon utilities of financial penalties if a utility is unable to meet its REST annual renewable energy requirements, including the distributed renewable energy requirements, which are fully dependent upon customers for purchase of sufficient annual installations of distributed renewable energy systems to meet the REST requirements. Thus there is a risk a utility takes -- with no corresponding related reward -- of a penalty based on customers not supporting the utility target. Also, distributed generation does erode utility recovery of fixed expenses by reducing energy sales. The REST Adjustor Mechanism without the Performance Incentive allows for recovery of only direct REST expenses -- with no allowance for an opportunity to recover a benefit for the risks the utility takes for possibly not meeting the REST annual distributed generation renewable energy requirements or revenue erosion. The proposed REST Performance Incentive is solely based on the success of meeting the Distributed Generation portion of the annual REST goals. To properly align utility interests with

customer interests and provide some benefit for the potential risks that a utility incurs in not meeting the distributed generation portion of the REST, the REST Performance Incentive should be approved for recovery as a component of the REST Adjustor Mechanism.

Q. Should interest be collected on DSM funds that are over-collected and that will be refunded to customers?

A. I would agree that if DSM funds are over-collected to the point that the DSM fund balance has more funds collected than would be spent on DSM programs in the entire following year, and that results in a refund to customers as a credit on the bills for the DSM line item, then it would be appropriate for interest to be credited to the DSM account balance until the refunds are complete. However, if the over-collected funds simply are used to reduce the amount of DSM funds collected the following year and do not result in customer refunds, there should be no interest credited to the DSM account.

Q. Is there any other clarification you would like to make regarding the Direct Testimony of Staff?

A. Yes. Staff recommends that changes to the REST Adjustor Mechanism rate should be approved by the Commission and not be automatic. I completely agree. It was not the intent of TEP to have the REST Adjustor Mechanism be reset automatically without Commission approval of the annual REST Implementation Plan and tariff filing.

III. REBUTTAL OF DOD DIRECT TESTIMONY.

Q. Please provide your general assessment of the Direct Testimony of DOD.

A. DOD generally supports the DSM programs proposed by TEP and takes no position on the DSM or REST Adjustor Mechanisms, but asserts that the DSM programs proposed do

not offer sufficient range to support the energy efficiency needs of larger customers. Specifically, DOD proposes that TEP offer a program to support UESCs.

Q. Does TEP agree with DOD's assertion that it is unlikely Fort Huachuca (Fort) or Davis-Monthan Air Force Base ((DMAFB) would receive any benefits from the proposed portfolio?

A. No. It will be entirely up to the Fort and DMAFB as to which DSM programs they choose to utilize. Upon Commission approval of the proposed DSM programs and the funding of those programs, they will all be available to the Fort and DMFAB through the proposed DSM portfolio filed in Docket No. E-01933A-07-0401. TEP has submitted three commercial and industrial programs for Commission approval: (i) Non-residential Existing Facilities Program (attachment 8 to TEP's DSM Program Portfolio), (ii) Efficient Commercial Building Design Program (attachment 9 to TEP's DSM Program Portfolio), and (iii) Small Business Program (attachment 10 to TEP's DSM Program Portfolio). The Fort and DMAFB can take advantage of the Non-residential Existing Facilities Program as well as the Efficient Commercial Building Design Program. The Small Business Program is reserved for customers who qualify for TEP's Pricing Plan 10 – typically less than 200 kW of aggregate monthly demand. In addition, the numerous residential DSM programs proposed by TEP would be available to the housing areas located on the Fort and DMAFB to reduce their associated residential energy consumption.

Q. What kinds of commercial scale technologies are funded through the proposed DSM programs?

A. The same technologies listed in DOD's Direct Testimony. TEP's Non-residential Existing Facilities Program provides prescriptive incentives to customers for such energy efficient measures as lighting, HVAC equipment, motors, and refrigeration. In addition to the prescriptive incentives, this program also will offer custom incentives as DSM program

components which can include any cost effective measure. The custom incentive could cover such items as building insulation, shading structures over chillers and cooling towers, and thermal energy storage projects, as long as they meet the Commission's societal cost test. TEP's Efficient Commercial Building Design Program is targeted at new commercial construction or major renovation projects. TEP will provide incentives to offset design costs as well as energy improvements to the building system.

Q. Does TEP's proposed DSM portfolio provide project financing as proposed by DOD in its direct testimony?

A. No, the proposed DSM portfolio would not provide project financing. However, TEP's proposed Efficiency Enhanced Financial Incentive would provide an opportunity for such project financing for energy efficiency or demand reduction measures that are cost effective or very nearly cost effective. This incentive would apply to capital projects installed at customer premises in TEP's service territory and are recovered through customer payments. However, these projects would not also qualify for incentives under TEP's DSM program – the Efficient Commercial Building Design Program and the Non-residential Existing Facilities Program.

Q. DOD states the Company does not need any additional financial incentives to construct energy efficient plant or customer projects funded through the Company. What is your response?

A. An electric utility, like any other business, makes investment decisions on level of investment, investment benefits and investment risks. The Efficiency Enhanced Financial Incentive is an incentive mechanism that gives the utility an extra financial benefit to balance against the higher risk of investing in customer-sited energy efficiency measures when compared against traditional utility infrastructure investments. This is a utility analogy to a customer using a DSM program incentive to financially justify a positive

decision to install energy efficient equipment. The Efficiency Enhanced Financial Incentive is a tool that electric utilities and large electricity customers can use for the financing of projects with good energy efficiency benefits that might not quite be cost effective given traditional utility investment return rates at the time the capital expenditure must be made, to help the project become cost effective through a slightly higher rate of return.

IV. REBUTTAL OF SWEEP DIRECT TESTIMONY.

Q. Please provide your general assessment of the Direct Testimony of SWEEP.

A. SWEEP is supportive of TEP's proposed DSM Adjustor Mechanism, DSM Performance Incentive and Efficiency Enhanced Financial Incentive programs. SWEEP is concerned that delay of approval of DSM funding until the TEP rate case is complete would unacceptably delay implementation of the DSM programs.

Q. Does TEP agree with SWEEP that delayed implementation of the expanded and new cost effective energy efficiency programs until after the conclusion of this rate case is not in the public interest?

A. TEP agrees with SWEEP that a delay of approval of the DSM programs until conclusion of this rate case will delay the implementation of those programs if the programs themselves are approved prior to the conclusion of this rate case. However, TEP does not agree with SWEEP that the short delay of time expected for the completion of this rate case after DSM program approval is not in the public interest. In fact, the short delay is likely to provide long-term surety of initial program funding and future funding support. Long term program surety is very important to DSM program success. TEP is already in the process of planning the implementation of the DSM programs for customers.

Therefore the implementation timeframe should be relatively short after funding mechanism and level approval in this rate case.

Q. Does TEP agree with SWEEP that increasing energy efficiency in the TEP service territory as soon as possible will achieve significant and cost-effective benefits for TEP customers, the electric system, the economy and the environment?

A. TEP requested approval of cost effective and customer beneficial DSM programs. TEP's analysis of these proposed DSM programs shows a reduction in customer peak annual demand, annual energy consumed or both for each of the proposed DSM programs. A reduction in annual energy consumed generally benefits the environment. A reduction in peak annual demand benefits the electrical system. Customers participating in the proposed DSM programs will benefit from a reduction in their electric bills. TEP does not take a position regarding the impact, positive or negative, on the impact of those DSM programs on the economy as it did not perform such an analysis.

Q. Considering that Commission Staff has recommended in their testimony that the DSM Adjustor Mechanism be considered as part of the subject Rate Case, does TEP agree with the SWEEP recommendation to accelerate approval of DSM funding to no later than June 4, 2008?

A. TEP supports the Staff's recommendation that the DSM Adjustor Mechanism be considered as part of this subject docket. If acceleration of the approval of DSM funding is considered as SWEEP proposes, that process must ensure any considered funding mechanism is well defined, allows long-term surety of recovery and does not delay the review, or affect the approval, of other items in the TEP rate case.

Q. **Does TEP agree with SWEEP that an adjustor mechanism is an appropriate means for cost recovery of the DSM programs?**

A. Yes.

Q. Does TEP agree with SWEEP that an additional incentive for increasing efficiency of electrical distribution components is possibly not needed?

A. TEP does not agree with SWEEP at this time. Just as incentives are currently needed by electrical consumers to reduce the initial cost of their high efficiency appliances, recent increases in the cost of copper and steel, primary elements of high efficiency electrical distribution equipment, are making an extra up-front financial incentive necessary to demonstrate life cycle cost effectiveness of high efficiency distribution components. The Efficiency Enhanced Financial Incentive is a tool that electric utilities and large electricity customers can use for financing of projects with good energy efficiency benefits that given traditional utility investment return rates might not quite be cost effective at the time the capital expenditure must be made, to help the project become cost effective through a slightly higher rate of return.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

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Rebuttal Testimony of

Samuel C. Hadaway, Ph. D.

on Behalf of

Tucson Electric Power Company

April 1, 2008

Executive Summary of the Rebuttal Testimony of Samuel C. Hadaway, Ph. D.

Dr. Hadaway is a Principal in FINANCO, Inc., Financial Analysis Consultants. Dr. Hadaway's Rebuttal Testimony addresses the rate of return on equity.

1. TEP continues to support an ROE of 10.75 percent based on the Company's requested capital structure containing 45 percent equity, and an ROE of 11.75 percent if the test year capital structure containing only 39.1 percent equity is applied. TEP's requested base ROE of 10.75 percent is reasonable. Dr. Hadaway's conclusions are also supported by the interest rate risk associated with projections for higher rates over the coming year and the ongoing risks and uncertainties that exist in the electric utility industry as well as the specific risks that TEP continues to face.

2. Dr. Hadaway rebuts the rate of return recommendations offered by Staff witness David C. Parcell and Residential Utility Consumer Office witness William A. Rigsby. In his analysis, he responds to their rate of return recommendations and demonstrates that their recommendations are not consistent with the much wider interest rate spreads that the current market turmoil has created or the much higher relative capital costs that corporate borrowers like TEP are currently required to pay.

3. Contrary to the assertions of Messrs. Parcell and Rigsby, Dr. Hadaway demonstrates that current utility capital costs are higher, not lower, as a result of recent market turmoil. While the Federal Reserve System's efforts to stabilize market conditions have reduced short-term borrowing rates for banks and the "flight to safety" by some market participants has pushed down interest rates on U.S. Government securities, rates for corporate borrowers have increased.

4. Dr. Hadaway demonstrates these facts in Table 1 on page 5 of his rebuttal testimony. The data in Table 1 show that triple-B utilities are currently required to pay much wider spreads over Government interest rates than has been the case in many years. The data also show that triple-B interest rates are currently above the levels that existed when the Company's direct case was prepared and above the rates that the over parties used when they prepared their testimony. Dr. Hadaway concludes that, in this light, the other parties' rate of return recommendations are below TEP's cost of capital.

5. Dr. Hadaway also provides specific technical rebuttal of the ROE analyses provided by Messrs. Parcell and Rigsby. He responds to the other witnesses' criticisms of the Company's ROE analysis and he updates that analysis for current market costs and conditions. Dr. Hadaway concludes that a base ROE of 10.75 percent is appropriate with the Company's requested capital structure and that an ROE of 11.75 percent is appropriate if the test year capital structure is used.

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I. INTRODUCTION AND SUMMARY OF REBUTTAL TESTIMONY.

Q. Please state your name and affiliation.

A. My name is Samuel C. Hadaway. I previously filed Direct Testimony on behalf of Tucson Electric Power Company (hereinafter "TEP" or the Company) in this proceeding.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut the return on equity ("ROE") recommendations of Arizona Corporation Commission Staff ("Staff") witness David C. Parcell and Residential Utility Consumer Office ("RUCO") witness William A. Rigsby. In my analysis, I will respond to their rate of return recommendations and demonstrate that their recommendations are not consistent with much wider interest rate spreads that the current market turmoil has created or the much higher relative capital costs that corporate borrowers like TEP are currently required to pay. I will also respond to these witnesses' comments on the methodology I used in my direct testimony to estimate TEP's cost of equity and I will update my ROE analysis for current market costs and conditions. My rebuttal analysis continues to support an ROE of 10.75 percent based on the Company's requested capital structure containing 45 percent equity, and an ROE of 11.75 percent if the test year capital structure containing only 39.1 percent equity is applied.

Q. What are the parties' ROE recommendations?

A. Mr. Parcell recommends an ROE of 10.25 percent. Mr. Rigsby recommends an ROE of only 9.44 percent. As I demonstrated in my Direct Testimony and reconfirm here, based on its requested capital structure containing 45 percent equity, TEP's cost of equity is 10.75 percent; if the test year capital structure containing only 39.1 percent equity is used, TEP's cost of equity is 11.75 percent.

Q. What are your general assessments of the other parties' rate of return positions?

A. The other parties rate of return recommendations are below TEP's cost of equity capital. While Mr. Parcell's ROE is near the bottom of the range I recommended in my Direct Testimony, his overall recommendation is deficient on at least two accounts. First, his 10.25 percent ROE is not consistent with the more highly leverage capital structure he recommends. The comparable companies he uses to estimate ROE have significantly higher equity ratios and, therefore, far less financial risk than he proposes for TEP. His 25 basis point adjustment above the midpoint of his ROE range is not nearly adequate to account for the higher financial risk his capital structure position would impose on TEP. Also, utility capital costs have increased and Mr. Parcell's recommendation does not adequately reflect those increases.

Mr. Rigsby's ROE recommendation is entirely unreasonable. His application of the constant growth discounted cash flow ("DCF") model produces an ROE of only 8.62 percent, while his capital asset pricing model ("CAPM") indicates an ROE of 10.25 percent. Rather than mechanically averaging these numbers, as Mr. Rigsby does, the DCF result should have been discarded entirely. Had he relied on his CAPM estimate of ROE, at 10.25 percent, his overall rate of return based on his acceptance of TEP's requested capital structure would have been at the low end of the reasonable range.

Q. Do Messrs. Parcell and Rigsby adequately consider recent capital market turbulence?

A. No. Their analyses and recommendations entirely ignore the effects that recent market turbulence has had on capital costs for corporate borrowers, and especially for those corporate entities, such as TEP, on the border between an investment grade and speculative bond rating. While both provide substantial discussions of economic conditions (Parcell at 9-13 and Rigsby at 31-45), neither directly acknowledges the extreme market turbulence or the resulting wider interest rate spreads that corporate borrowers, like TEP, are having to

pay. In fact, both focus their discussions on declining short-term and Government interest rates and conclude their remarks by saying that recent conditions have led to lower capital costs (Parcell at 13, line 11 and Rigsby at 43, lines 34-36). This conclusion is simply wrong. Corporate borrowing costs have increased and any reasonable analysis of the cost of equity capital must consider these market conditions.

Q. Can you demonstrate that their conclusions about lower capital costs are inconsistent with actual capital market costs for utilities?

A. Yes. While it is convenient for them to recount recent Government efforts to stabilize the economy, these activities have only affected short-term borrowing costs for banks and, due to "flight to safety" issues, pushed down interest rates on U.S. Treasury securities. The picture they paint is, in fact, incomplete and potentially misleading. Providers of long-term capital for corporations now require higher, not lower, capital costs. Corporate interest rate "spreads" (the difference between corporate borrowing costs and rates on U.S. Treasury bonds) are currently at the highest levels seen in many years. Wider spreads are signaling a clear increase in the price of risk, a cost that affects equity holders even more than debt holders. Messrs. Parcell and Rigsby both ignore this important capital markets message in their cost of equity analysis.

Q. If Messrs. Parcell and Rigsby had more reasonably considered long-term corporate borrowing costs, what would their results have shown?

A. They would have shown increasing corporate capital costs. While short-term interest rates have been driven down by the Federal Reserve System's recent monetary policies, long-term corporate borrowing rates have increased. The following table is an update through February 2008 of the interest rate summary data that I provided in my Direct Testimony. The most recent data available in my Direct Testimony were March 2007. Since then, although the Federal Reserve System has continued to reduce the short-term Federal Funds

rate, long-term corporate interest rates have, in fact, increased. While market turmoil and "flight to safety" issues have also pushed down shorter-term Treasury rates, corporate spreads, which reflect investors' risk perceptions, have widened significantly. The data in Table 1 show that such spreads are currently much wider than they have been at any time in the past two years. These factors provide important perspective for evaluating the alternative rate of return positions.

Table 1
Long-Term Interest Rate Trends

Month	Triple-B Utility Rates	20-Year Treasury Rates	10-Year Treasury Rates	20-Year Treasury Spreads	10-Year Treasury Spreads
Jan-05	5.95%	4.77%	4.22%	1.18%	1.73%
Feb-05	5.78%	4.61%	4.17%	1.17%	1.61%
Mar-05	6.01%	4.89%	4.50%	1.12%	1.51%
Apr-05	5.95%	4.75%	4.34%	1.20%	1.61%
May-05	5.88%	4.56%	4.14%	1.32%	1.74%
Jun-05	5.70%	4.35%	4.00%	1.35%	1.70%
Jul-05	5.81%	4.48%	4.18%	1.33%	1.63%
Aug-05	5.80%	4.53%	4.26%	1.27%	1.54%
Sep-05	5.83%	4.51%	4.20%	1.32%	1.63%
Oct-05	6.08%	4.74%	4.46%	1.34%	1.62%
Nov-05	6.19%	4.83%	4.54%	1.36%	1.65%
Dec-05	6.14%	4.73%	4.47%	1.41%	1.67%
Jan-06	6.06%	4.65%	4.42%	1.41%	1.64%
Feb-06	6.11%	4.73%	4.57%	1.38%	1.54%
Mar-06	6.25%	4.91%	4.72%	1.34%	1.53%
Apr-06	6.54%	5.22%	4.99%	1.32%	1.55%
May-06	6.59%	5.35%	5.11%	1.24%	1.48%
Jun-06	6.61%	5.29%	5.11%	1.32%	1.50%
Jul-06	6.61%	5.25%	5.09%	1.36%	1.52%
Aug-06	6.43%	5.08%	4.88%	1.35%	1.55%
Sep-06	6.26%	4.93%	4.72%	1.33%	1.54%
Oct-06	6.24%	4.94%	4.73%	1.30%	1.51%
Nov-06	6.04%	4.78%	4.60%	1.26%	1.44%
Dec-06	6.05%	4.78%	4.56%	1.27%	1.49%
Jan-07	6.16%	4.95%	4.76%	1.21%	1.40%
Feb-07	6.10%	4.93%	4.72%	1.17%	1.38%
Mar-07	6.10%	4.81%	4.56%	1.29%	1.54%
Apr-07	6.24%	4.95%	4.69%	1.29%	1.55%
May-07	6.23%	4.98%	4.75%	1.25%	1.48%
Jun-07	6.54%	5.29%	5.10%	1.25%	1.44%
Jul-07	6.49%	5.19%	5.00%	1.30%	1.49%
Aug-07	6.51%	5.00%	4.67%	1.51%	1.84%
Sep-07	6.45%	4.84%	4.52%	1.61%	1.93%
Oct-07	6.36%	4.83%	4.53%	1.53%	1.83%
Nov-07	6.27%	4.56%	4.15%	1.71%	2.12%
Dec-07	6.51%	4.57%	4.10%	1.94%	2.41%
Jan-08	6.35%	4.35%	3.74%	2.00%	2.61%
Feb-08	6.60%	4.37%	3.53%	2.23%	3.07%

Sources: Mergent Bond Record (Utility Rates); www.federalreserve.gov (Treasury Rates).

Q. What levels of interest rates are forecast for the coming year?

A. Both corporate and government interest rates are expected to rise from present levels. I have reproduced as Exhibit SCH-10 Standard & Poor's most recent economic forecast from its *Trends & Projections* publication for February 2008. The summary interest rate data from that publication are presented in the following table:

Table 2:
Standard & Poor's Interest Rate Forecast

	Feb. 2008 Average	Average 2008 Est.	Average 2009 Est.
Treasury Bills	2.1%	2.0%	2.6%
10-Yr. T-Bonds	3.7%	4.0%	4.9%
30-Yr. T-Bonds	4.5%	4.5%	5.1%
Aaa Corporate Bonds	5.5%	5.7%	6.4%

Sources: www.yahoo.com Yahoo Finance (Current Rates); Standard & Poor's *Trends & Projections*, February 2008, page 8 (Projected Rates).

The data in Table 2 show that interest rates are projected to increase further during the coming year. Relative to current levels, rates on 10-year and 30-year Treasury bonds for 2009 are expected to increase by over 100 basis points. Corporate borrowing costs are also expected to increase by an additional 90 basis points.

These factors indicate that the other parties' ROE recommendations are below the cost of equity for TEP. Their recommendations are inconsistent with the wider corporate spreads that borrowers like TEP are currently required to pay. Their positions are also inconsistent with projections for further interest rate increases in 2009.

II. RESPONSE TO STAFF WITNESS DAVID C. PARCELL.

Q. How did Mr. Parcell obtain his 10.25 percent ROE recommendation?

A. Mr. Parcell's results are summarized on page 3 of his testimony. Based on DCF, CAPM, and comparable earnings ("CE") analyses, he concludes that the reasonable range is 9.5 percent to 10.5 percent. From this range he selects an ROE that is 25 basis points above the midpoint of his range, at 10.25 percent.

Q. Is Mr. Parcell's 25 basis point adjustment adequate to compensation for the financial risk his capital structure implies?

A. No, not at all. Mr. Parcell's recommended capital structure contains 5 percentage points more debt and 5 percentage points less equity than the Company has requested. This additional financial risk, if expected to prevail, would likely lead to a non-investment grade bond rating for TEP, which in turn would result in much higher capital costs than Mr. Parcell is recommending. The following table demonstrates the non-compensatory nature of Mr. Parcell's recommendation:

Table 3
Equivalent ROEs with Alternative Capital Structures

	Parcell Recommendation			Pre-Tax	Equivalent ROE			Pre-Tax
	Percent	Cost	Return	Return	Percent	Cost	Return	Return
Short-Term Debt	2.16%	5.92%	0.13%	0.13%	0.00%	5.92%	0.00%	0.00%
Long-Term Debt	57.94%	6.40%	3.71%	3.71%	55.00%	6.40%	3.52%	3.52%
Common Equity	**39.90%**	**10.25%**	4.09%	6.82%	**45.00%**	**9.50%**	4.28%	7.13%
Total	100.00%		7.93%	**10.65%**	100.00%		7.80%	**10.65%**

*Assumes 40% income tax rate.

The combination of Mr. Parcell's ROE and capital structure recommendations is shown in the left-hand side of Table 3. With his 10.25 percent ROE, his more financially risky capital structure produces a pre-tax return of 10.65 percent. However, with TEP's

requested capital structure (which is approximately equivalent to the average capital structures for his comparable companies), the equivalent ROE is only 9.5 percent. This calculation shows that Mr. Parcell's 25 basis point addition to ROE is a sham. He would apparently have the Commission believe that he is being generous in his upward adjustment when, in fact, his overall recommendation is equivalent to the very bottom of his own ROE range. Such an approach is inappropriate and would significantly increase TEP's cost of capital. As I demonstrated in my Direct Testimony, TEP's cost of capital would be at least 100 basis points higher with a non-investment grade bond rating. This factor is entirely ignored in Mr. Parcell's analysis.

Q. Please summarize your technical disagreements with Mr. Parcell's analysis?

A. Relative to typical standards for estimating ROE, portions of Mr. Parcell's analysis are extreme and do not appear to be consistent with the Commission's recent findings on ROE. Portions of his DCF analysis produce average returns that are so low that they should have been rejected out of hand. In that analysis, several of the average results are at or only slightly above the cost of debt and eight of his ten calculations produce a DCF range of only 6.7 percent to 9.2 percent (see his Exhibit DCP-1 - Schedule 8, page 4 of 4). He then uses these unrealistically low results to average down higher results based on analysts' growth rates (10.4 percent to 11.5 percent) to arrive at a final quantitative DCF range of only 8.2 percent to 8.5 percent. Such results are not ROE estimates at all and should be simply dismissed. Although Mr. Parcell considers the data further (at 27) and subjectively determines a "DCF cost" of 9.5 percent to 10.5 percent to be appropriate, this recommendation has virtually no connection to his DCF analysis and should be evaluated accordingly.

Similarly, the validity of Mr. Parcell's comparable earnings analysis, which relies entirely on earned rates of return on book value, is extremely questionable. For his comparable

group, that analysis indicates an ROE range of only 8.1 percent to 9.3 percent (Parcell Direct Testimony at 32). As with his DCF analysis, he blends these unrealistically low results with higher results from my larger comparable group and then subjectively states that his CE analysis supports a range of 10.0 percent to 10.5 percent (at 34, line 3). In fact, his group's 8.1 percent to 9.3 percent CE results should have been discarded and, if the CE approach were to be considered at all, the 10.2 percent to 11.3 percent range he finds for my comparable group should be used.

Q. What are your specific criticisms of Mr. Parcell's DCF analysis?

A. I disagree with his singular reliance on the constant growth version of the DCF model. I disagree with his selection of only an eight-company primary comparable group. And, I especially disagree with his use of historical growth rates and "retention" growth rates in that analysis. I will show why these factors detract significantly from of Mr. Parcell's DCF estimates.

As I explained in my Direct Testimony, under present market conditions the constant growth DCF model, using traditional growth rate methodologies, does not produce reasonable estimates of ROE. On their face, Mr. Parcell's DCF calculations that produce results in the 6.7 percent to 9.2 percent range, such as those found in his Schedule 8, are not legitimate estimates of ROE. Furthermore, for him to add one additional observation based on higher First Call analysts' growth rates is not supported. He should simply have dismissed his constant DCF growth results as being unrepresentative of the current market cost of equity capital.

His small group approach is also wrong. Although Mr. Parcell also applied his methods to my comparable group, his selected primary reference group contains only eight companies (my original group contained 28 companies, however due to acquisitions, the group is now

26 companies, as shown in Exhibit SCH-11). A small comparable group may be statistically less reliable and unrepresentative of the subject company whose cost of capital is being estimated. For these reasons, when possible, most economists rely on larger comparable company groups.

Mr. Parcell's problems with the constant growth DCF model and his small sample are compounded by his growth rate estimates. Two of his five growth rates are based strictly on historical data and produce growth rate averages of only 2.7 percent to 3.2 percent.[1] His prospective growth rates are from Value Line (5.1 percent) and First Call (7.5 percent). As I demonstrated in my Direct Testimony, growth rate estimates from Value Line have dropped significantly over the past five years. Had Mr. Parcell more realistically evaluated his results, he should have seen that a longer-term, broader-based growth rate estimate, like the gross domestic product ("GDP") growth forecast I provided in my Direct Testimony, should have been used.

Q. What would the results of Mr. Parcell's DCF analysis have been is he had used the longer-term GDP growth rate?

A. In Exhibit SCH-12, I have updated my GDP growth rate estimate with data through the end of 2007. That analysis indicates a long-term nominal GDP growth rate of 6.5 percent. In Exhibit SCH-13, I have updated Mr. Parcell's eight-company DCF analysis and applied my 6.5 percent GDP growth rate in that analysis. The indicated ROE range is 11.0 percent to 11.1 percent. I will also discuss a similar update for my larger group DCF analysis in the final section of this rebuttal testimony.

[1] But for his elimination of three out of eight companies with negative historical growth rates, his 3.2 percent growth rate would have been a negative number.

Q. What are your criticisms of Mr. Parcell's comparable earnings analysis?

A. The general criticism of the CE method is that *returns on book equity* may bear no relationship to the market's required rate of return. For regulated utilities the argument can be made that book value and rate base are the same and, therefore, that CE methods have some validity. However, in today's markets with the industry's restructuring and consolidation and current market-to-book ratios significantly above one, the connection between market and book returns is tenuous at best. For this reason, the CE method provides little useful guidance for setting the allowed rate of return.

In addition, Mr. Parcell's application of the CE method and his interpretation of the results are highly questionable. In his primary CE analysis, he uses only eight comparable companies and attempts to show that their recent and prospective earned rates of return would support an ROE of 8.1 percent to 9.9 percent (See his Exhibit DCP-1 - Schedule 11, page 1 of 2.) The results of his small group analysis are seriously skewed by average returns for the past five years of 8.2 percent to 9.0 percent and by prospective returns in the 4.5 percent to 9.0 percent for four of his eight companies. In contrast, when Mr. Parcell applied the same analysis to my 28-company comparable group, he found an ROE range of 10.2 percent to 11.8 percent. If any weight is to be given to earned rates of return on book value, Mr. Parcell's CE results should be interpreted to support an ROE range of 10.2 percent to 11.8 percent.

Q. On pages 38-48, Mr. Parcell criticizes various aspects of your ROE analysis. What is your general response to his criticisms?

A. His criticisms are not accurate. They are principally focused on my use of the GDP growth rate in my DCF model and his mistaken view that capital costs for utilities are declining. His characterization of my GDP growth forecast is not accurate and his contention that corporate borrowing costs are declining is simply wrong.

Q. On pages 39-40, Mr. Parcell criticizes your GDP growth forecast because it is based on historical GDP data. Is it accurate to say that your GDP growth rate is a historical input?

A. No. My GDP growth rate is my best forecast of what investors may reasonably expect nominal GDP growth to be in the very long run as required by the DCF model. While the St. Louis Federal Reserve Bank data base contains data dating back to 1947, my forecast is not a simple average or extrapolation of the historical data. Like most econometric forecasts, my approach uses the long-run historical relationships to project what investors may reasonably expect for the long-run future. To account for recent data having a greater influence on current expectations, I applied a weighted averaging process that gives about five times as much weight to the most recent 10 years as compared to the earliest 10 years. Giving more weight to the more recent, low inflation years also lowers the overall forecast. For example, my updated forecast is for a future growth rate of 6.5 percent, while the overall long-run average of the data is a growth rate of 7 percent. In this context, Mr. Parcell's criticism of my use of historical GDP data is unwarranted and his comparison to my use of forecasted earnings growth rates is a red herring.

Q. On page 40, Mr. Parcell offers a table of GDP growth rate forecasts that are lower than your forecast. How do you respond to this comparison?

A. GDP forecasts and economic forecasts in general are difficult and are often dominated by current data and very recent experience. I used the very long-term St. Louis Federal Reserve Bank data to mitigate this well-known forecasting deficiency.

Mr. Parcell's forecasts from the Social Security Administration ("SSA") and the Energy Information Agency ("EIA") of the U.S. Department of Energy indicate that nominal GDP is expected to grow at rates of 4.4 percent and 4.8 percent, respectively (See his Exhibit DCP-1 - Schedule 15.) The reason these forecasts are much lower than mine, which is

based on actual long-run historical data published by the St. Louis Federal Reserve Bank, is because both SSA and EIA project lower real growth and much lower inflation than has occurred heretofore in the U.S. economy. The SSA forecast indicates that the real growth rate in the U.S. economy will decline by 50 percent relative to the historical average (less than 2.0 percent projected growth versus over 3.0 percent historical growth). EIA projects that real growth will be near the long-run average at 2.9 percent, but that inflation will fall to below 2 percent and remain at that low level throughout the forecast period to 2030.

SSA develops annual very long-term forecasts to be used in its actuarial evaluation of the Social Security System. Under status quo tax rates and payments, and with SSA's Intermediate economic assumptions, Social Security disbursements are expected to exceed receipts in 2017 and the System is expected to be entirely depleted in 2040.[2] SSA's forecast for GDP growth is even lower because the SSA forecast assumes that real GDP will grow at only 2 percent per year, or less, beginning in 2013. In combination the 2.0 percent real GDP growth rate and the 2.4 percent assumed inflation rate produce a nominal GDP growth rate of only 4.4 percent, which is shown in Mr. Parcell's table.

These forecasts are in stark contrast to historical experience. The actual St. Louis Federal Reserve GDP data in Exhibit SCH-6 of my Direct Testimony show that only one subperiod had an inflation rate as low as low as 2.0 percent per year. While Government forecasters may hope, for policy, deficit reduction, and the survival of Social Security, to see permanently low growth and inflation, their recent forecasts are not at all consistent with longer-term historical results.

Q. On pages 45-48, Mr. Parcell criticizes your bond yield plus risk premium analysis saying that a triple-B interest rate of 6.3 percent should currently be used in that

[2] Social Security Administration: 2006 OASDI Trustees Report (www.ssa.gov/OACT/TR/TR06/II_highlights.html)

analysis. How do you respond to Mr. Parcell's criticism and suggestion that a lower triple-B rate should be used?

A. Mr. Parcell's criticisms are again inaccurate for three reasons. First, as shown previously in Table 1, the triple-B utility interest rate for February 2008 was 6.6 percent not the 6.3 percent that Mr. Parcell inserted into my analysis. Furthermore, in risk premium analyses, ROE does not change by the same amount as interest rates. As I demonstrated in my risk premium study in Exhibit SCH-9 of my Direct Testimony, ROE tends to change by about half as much as interest rates. It is well documented that for this reason when interest rates increase, risk premiums become smaller and when interest rates decrease, risk premiums become larger. I will demonstrate in my ROE update in the final section of this testimony that higher current and projected interest rates do indicate a slightly higher ROE from my risk premium analysis, but not in the one-for-one fashion that Mr. Parcell applied.

Additionally, Mr. Parcell's more basic criticism of my risk premium methodology is also wrong. On page 45, he states that the authorized returns I use in my risk premium analysis are not necessarily reliable indicators of investor-required risk premiums. I entirely disagree with this assertion. The data in my risk premium study, covering essentially all major rate cases before state commissions since 1980, represent the best efforts of decision makers in literally hundreds of cases to estimate investors' return requirements. While it is true that there will always be timing differences and other case specific issues that may affect ROE, over an almost 30-year period the average annual results represent as nearly as possible an unbiased estimate of what investors expected utilities to receive. In this context, Mr. Parcell's criticism of my basic risk premium methodology is incorrect.

Finally, Mr. Parcell's recount of recent ROE allowances is stale and his conclusion that an average allowed ROE of 10.22 percent should be used is wrong. As I show in the following section in my rebuttal of Mr. Rigsby, the average allowed ROE for the 4th quarter of 2007 was 10.56 percent, which resulted in an overall average ROE for 2007 of

10.36 percent. Mr. Parcell also fails to acknowledge that the recent lower ROEs for delivery-only companies have had a significant negative effect on the overall averages. When all these factors are considered, Mr. Parcell's criticisms of my risk premium analysis are without merit.

III. RESPONSE TO RUCO WITNESS WILLIAM A. RIGSBY.

Q. What is the basis for Mr. Rigsby's 9.44 percent ROE recommendation?

A. He derives his recommendation by averaging the results of his constant growth DCF analysis (8.62%) with the results of his CAPM analysis (10.25%). His growth rate in the DCF model is based entirely on the "b times r" sustainable growth rate approach. The "b times r" or "br" method as applied by Mr. Rigsby produces a growth rate of only 4.32 percent. When this low growth rate is added to the projected dividend yield for his comparable group (4.30%), it produces the exceptionally low DCF estimate of ROE upon which Mr. Rigsby relies.

Q. What is your assessment of Mr. Rigsby' DCF analysis?

A. Without even considering the specific technical deficiencies in his DCF analysis, Mr. Rigsby's DCF result of 8.62 percent should be rejected on its face. With current triple-B utility bond yields at 6.60 percent, Mr. Rigsby's DCF outcome is only 200 basis points above the current cost of utility debt (8.62% - 6.60% = 2.02%). Spreads between utility equity returns and utility interest rates are typically in the range of 400 to 450 basis points. This relationship is illustrated in the table below. Over the past five years, utility equity spreads have ranged between 425 and 487 basis points and have averaged 446 basis points. In this light, it is clear that Mr. Rigsby's DCF result is below the range of reasonableness and should be rejected outright.

Authorized Electric Utility Equity Returns

	2003	2004	2005	2006	2007
1st Quarter	11.47%	11.00%	10.51%	10.38%	10.27%
2nd Quarter	11.16%	10.54%	10.05%	10.69%	10.27%
3rd Quarter	9.95%	10.33%	10.84%	10.06%	10.02%
4th Quarter	11.09%	10.91%	10.75%	10.39%	10.56%
Full Year	10.97%	10.75%	10.54%	10.36%	10.36%
No. of Cases	22	19	29	25	39
T&D Cases	4	3	6	10	10
Average Utility Debt Cost	6.61%	6.20%	5.67%	6.08%	6.11%
Indicated Risk Premium	4.36%	4.55%	4.87%	4.28%	4.25%

Source: *Regulatory Focus*, Regulatory Research Associates, Inc., Major Rate Case Decisions, January 8, 2008.[3]

Q. Are there other reasons why Mr. Rigsby should have rejected his DCF outcome as being reasonably low?

A. Yes, not only is his DCF average of 8.62 percent unreasonably low on its face, but the underlying data that lead to that average are even more highly questionable. As shown in Schedule WAR-2, of the 26 companies in his comparable group, almost half (12 companies) have DCF cost of equity estimates below 8 percent. In fact, for two of the companies (Central Vermont Public Service and NiSource) Mr. Rigsby computes equity costs below 7 percent. Such outcomes are patently unreasonable as they are barely above the current utility cost of debt. Faced with this analysis, rather than average his DCF result with his CAPM result, Mr. Rigsby should have ignored the unacceptable DCF outcome altogether.

[3] The RRA averages, particularly for 2006 and 2007, are lower due to an increasing percentage of Transmission and Distribution (T&D) only companies. The average ROEs for T&D companies for 2006 and 2007 were 9.91 percent and 9.94 percent, respectively. For integrated electric companies like TEP, the average ROEs for 2006 and 2007 were 10.65 percent and 10.51 percent, respectively.

Q. Why are Mr. Rigsby's DCF results so low?

A. Mr. Rigsby's DCR results are so low because his growth rates are not reasonable.

Q. What problems do you have with Mr. Rigsby's growth rate estimations?

A. The growth rates used by Mr. Rigsby are overly subjective and overly narrow.

Q. Why do you say his growth rates are overly subjective?

A. Mr. Rigsby claims that "a company's dividend growth can be measured by multiplying its retention ratio (1 – dividend payout ratio) by its book return on equity. This can be stated as g = b x r" (Rigsby Direct, page 11, lines 5-8). He spends several more pages explaining why the "br" method is the preferred approach for determining a utility's expected growth rate. However, in reality, the growth rates that he ultimately uses are based more on his subjective opinions than the "br" formula.

The simple average of Mr. Rigsby's 2002-2006 "br" results (without adjustment) from Schedule WAR-5 is a growth rate of 3.35 percent. Yet somehow Mr. Rigsby determines that the final "br" growth rate average is 3.83 percent (before the external growth adjustment, from Schedule WAR-4). Apparently, Mr. Rigsby recognizes that pure "br" results understate utility long-term growth and cannot be relied on without adjustment, however subjective.

His discussion of Hawaiian Electric's growth rate is another example of the arbitrary nature of his growth rate analysis (Rigsby Direct, beginning on page 21). Mr. Rigsby mentions the following growth rate values for Hawaiian Electric: 2.65 percent, 0.67 percent, 1.58 percent, 0.07 percent, 1.91 percent, -1.00 percent, -0.50 percent. He then states that "based on the aforementioned projections and estimates, I believe that a 1.75% rate of internal sustainable growth is reasonable for HE." This approach is more conjecture and personal

speculation that it is analysis and should be rejected. Mr. Rigsby makes similar adjustments for each company in his DCF analysis. With these kinds of adjustments, Mr. Rigsby could have produced almost any level of ROE. In fact, because Mr. Rigsby failed to provide an explanation of his subjective analysis for any of his comparable companies other than Hawaiian Electric, it is not possible to know how he arrived at the final growth rates for each company. Such subjectivity in DCF calculations raises serious questions about the entire exercise.

Q. Why do you say his growth rate analysis is overly narrow?

A. Mr. Rigsby's growth rate analysis is too narrow because it relies on only one estimation approach, that is, the "br" method. Furthermore, Mr. Rigsby relied only on the constant growth version of the DCF model with no consideration given to nonconstant growth versions of the model which are likely to be more meaningful under current market conditions. To complete his growth rate analysis, Mr. Rigsby should also have considered analysts' growth rate estimates and other estimates for long-term growth, such as growth in GDP. It is clear why Mr. Rigsby did not want to directly consider analysts' growth rate estimates in his analysis. In Schedule WAR-6, he has a column showing consensus analysts' estimates from Zacks. The average of these growth rate forecasts is 5.94 percent which is a full 164 basis points higher than his "br" growth estimate of 4.30 percent. Simply combining Zacks average growth of 5.94 percent with Mr. Rigsby's 4.32 percent dividend yield (Schedule WAR-3) would produce an ROE estimate of 10.26 percent which, while still at the bottom of the reasonable range, is much more reasonable than his recommendation.

In my Direct Testimony and in my discussion of Mr. Parcell above, I explained why long-term growth in GPD is a valuable input for estimating the growth component of the DCF formula. Mr. Rigsby completely ignored such input in his DCF approach. Had he

considered GDP growth his results would have been much more reasonable. Combining my long-term GDP forecast of 6.5 percent with his 4.32 percent dividend yield would produce a reasonable ROE estimate of 10.82 percent.

Q. At page 53, Mr. Rigsby criticizes your use of GDP growth rates in portions of your DCF analysis. How do you respond to these criticisms?

A. As I explained in my Direct Testimony, many of the traditional sources for DCF growth rates have become extremely volatile and, particularly those often relied upon from Value Line, have been very low relative to prior time periods. In this context, I recommend using the long-term nominal GDP growth rate. As shown in my updated forecast in Exhibit SCH-12, that estimate is currently 6.5 percent. I use long-term GDP data because, unlike analysts' forecasts, that data produces a consistent and stable growth rate as required by the assumptions of the DCF model. In that context, in the present case I have presented both analysts' growth rate forecasts and GDP forecasts. In my updated DCF analysis (Exhibit SCH-14), I also present DCF results based only on analysts' growth rates with no GDP growth at all. The ROE range from that analysis is 10.8 percent to 11.5 percent, with a midpoint of 11.15 percent. Based on these results, Mr. Rigsby's criticism of my growth rate estimates is without merit.

Q. Does Mr. Rigsby display a possible misunderstanding of the proper growth rate to include in the DCF analysis?

A. Yes, it is not clear that Mr. Rigsby considered the technical requirements of the DCF model. The model requires a growth rate to <u>infinity</u>, not just for the next five years. This is why an estimate of long-term GDP growth is a valuable input to the model. Mr. Rigsby states, however, that his short-term "br" rates are superior because "the 5-year period is in line with the number of years that a utility will file for rate relief as opposed to a GDP rate of growth that is calculated into perpetuity and inflates a utility's cost of equity capital"

(Rigsby Direct, at page 55). The growth rate input to the DCF model must, by definition, capture expected growth to infinity, not just for the period that "a utility will file for rate relief." These statements from Mr. Rigsby reflect a potentially serious misunderstanding of the DCF model and cast serious doubt on the validity of his analysis.

IV. UPDATE OF ROE ESTIMATES.

Q. What are the results of your updated DCF analyses?

A. My updated DCF results are shown in Exhibit SCH-14. My comparable group now consists of 26 companies (the original 28 companies from my direct testimony less two companies that are now being acquired, Energy East and Puget Energy). Those updates apply current versions of the analysts' and GDP growth rates I used in my direct testimony. The indicated DCF range is 10.8 percent to 11.5 percent.

Q. What are the results of your updated CAPM analysis?

A. The results of that analysis are shown in Exhibit SCH-15. The indicated ROE from the CAPM analysis based on a long-term Treasury bond risk-free rate is 9.95 percent. I give less weight to the current CAPM result because it is negatively affected by current "flight to safety" issues, and it is based on historical risk premium data that cannot reflect the wider corporate spreads caused by recent market turbulence.

Q. What are the results of your updated risk premium analysis?

A. My updated risk premium analysis is presented in Exhibit SCH-16. Based on currently projected Baa utility interest rates for 2009 (which are slightly lower than current Baa utility rates shown previously in Table 1), the risk premium analysis indicates an ROE of 10.81 percent. The updated results of the Ibbotson risk premium analysis and the Harris-Marston risk premium analysis indicate ROEs of 11.0 percent (6.5% + 4.5% = 11.0%) and

11.6 percent (6.5% + 5.13% = 11.63%), respectively. As noted in my Direct Testimony, the Ibbotson and Harris-Marston results are not used in my ROE estimates, but are presented for general perspective on overall capital market costs.

Q. What do you conclude from your updated ROE analyses?

A. My updated analyses show that TEP's requested base ROE of 10.75 percent is reasonable. My conclusions are also supported by the interest rate risk associated with projections for higher rates over the coming year and the ongoing risks and uncertainties that exist in the electric utility industry as well as the specific risks that TEP continues to face.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT

SCH-10

Economic Indicators

Seasonally Adjusted Annual Rates — Dollar Figures in Billions

A2007	E2008	E2009	Annual % Change A2007	E2008	E2009		2007 3Q	2007 4Q	E2008 1Q	E2008 2Q	E2008 3Q	E2008 4Q	E2009 1Q	E2009 2Q
						Gross Domestic Product								
$13,843.0	$14,309.0	$14,822.0	4.9	3.4	3.6	GDP (current dollars)	$13,971.0	$14,081.0	$14,153.0	$14,201.0	$14,376.0	$14,507.0	$14,588.0	$14,732.0
4.9	3.4	3.6	-	-	-	Annual rate of increase (%)	6.0	3.2	2.1	1.3	5.0	3.7	2.3	4.0
2.2	1.2	1.9	-	-	-	Annual rate of increase–real GDP (%)	4.9	0.6	(0.7)	(0.7)	3.2	2.4	0.3	2.3
2.7	2.2	1.7	-	-	-	Annual rate of increase–GDP deflator (%)	1.0	2.6	2.8	2.1	1.8	1.3	1.9	1.7
						***Components of Real GDP**								
$8,276.0	$8,405.0	$8,563.0	2.9	1.6	1.9	Personal consumption expenditures	$8,302.0	$8,343.0	$8,347.0	$8,342.0	$8,437.0	$8,493.0	$8,502.0	$8,533.0
2.9	1.6	1.9	-	-	-	% change	2.8	2.0	0.2	(0.3)	4.7	2.7	0.4	1.5
1,237.0	1,229.9	1,255.4	4.8	(0.6)	2.1	Durable goods	1,241.9	1,254.7	1,231.9	1,208.5	1,236.2	1,243.1	1,230.5	1,243.6
2,393.8	2,424.8	2,471.8	2.4	1.3	1.9	Nondurable goods	2,396.8	2,408.0	2,403.8	2,406.9	2,436.2	2,452.2	2,457.9	2,465.9
4,671.3	4,767.6	4,854.6	2.8	2.1	1.8	Services	4,689.5	4,708.2	4,732.0	4,739.6	4,782.9	4,815.8	4,826.6	4,840.0
1,369.6	1,380.1	1,370.9	4.8	0.8	(0.7)	Nonresidental fixed investment	1,387.3	1,412.7	1,398.1	1,377.8	1,371.1	1,373.3	1,356.3	1,364.3
4.8	0.8	(0.7)	-	-	-	% change	9.4	7.5	(4.1)	(5.7)	(1.9)	0.6	(4.9)	2.4
1,064.9	1,074.6	1,106.5	1.4	0.9	3.0	Producers durable equipment	1,073.5	1,083.4	1,074.1	1,067.2	1,068.4	1,088.6	1,082.5	1,101.7
464.2	354.0	351.7	(17.1)	(23.8)	(0.6)	Residental fixed investment	454.3	423.8	384.1	355.7	341.8	334.3	335.8	346.1
(17.1)	(23.8)	(0.6)	-	-	-	% change	(20.8)	(24.2)	(32.6)	(26.4)	(14.8)	(8.5)	1.8	13.0
8.3	(12.2)	5.4	-	-	-	Net change in business inventories	30.6	(3.4)	(10.1)	(16.0)	(19.8)	(3.0)	(3.8)	(1.9)
2,022.5	2,065.3	2,074.8	2.1	2.1	0.5	Gov't purchases of goods & services	2,033.6	2,046.7	2,059.5	2,064.5	2,067.2	2,070.0	2,071.5	2,073.9
754.9	785.8	795.8	1.7	4.1	1.3	Federal	764.0	764.5	776.0	783.3	789.2	794.4	797.1	796.5
1,267.3	1,280.1	1,280.0	2.3	1.0	(0.0)	State & local	1,269.6	1,282.0	1,283.6	1,281.7	1,278.7	1,276.6	1,275.5	1,278.4
(560.0)	(458.9)	(412.7)	-	-	-	Net exports	(533.1)	(521.0)	(495.3)	(460.4)	(441.0)	(439.1)	(424.6)	(410.3)
1,407.6	1,518.2	1,633.1	7.9	7.9	7.6	Exports	1,441.2	1,455.0	1,478.2	1,503.6	1,530.0	1,561.0	1,589.3	1,620.4
1,967.6	1,977.1	2,045.8	2.0	0.5	3.5	Imports	1,974.3	1,975.9	1,973.5	1,963.9	1,971.0	2,000.1	2,013.9	2,030.6
						****Income & Profits**								
$11,667.0	$12,139.0	$12,645.0	6.2	4.1	4.2	Personal income	$11,747.0	$11,876.0	$11,991.0	$12,067.0	$12,181.0	$12,319.0	$12,457.0	$12,573.0
10,184.0	10,723.0	11,056.0	5.8	5.3	3.1	Disposable personal income	10,258.0	10,364.0	10,471.0	10,552.0	11,099.0	10,770.0	10,895.0	10,995.0
0.5	1.7	1.2	-	-	-	Savings rate (%)	0.5	0.2	0.6	1.0	4.5	0.6	1.2	1.2
1,881.9	1,574.0	1,893.6	4.2	(16.4)	20.3	Corporate profits before taxes	1,879.7	1,900.4	1,604.3	1,529.0	1,585.1	1,577.4	1,869.3	1,890.4
1,411.5	1,189.5	1,420.0	4.4	(15.7)	19.4	Corporate profits after taxes	1,410.2	1,430.9	1,213.4	1,154.9	1,196.8	1,192.9	1,404.1	1,419.1
76.80	71.20	71.20	(5.8)	(7.3)	0.0	‡Earnings per share (S&P 500)	78.70	76.80	75.10	70.40	73.10	71.20	69.10	70.20
						† Prices & Interest Rates								
2.9	2.5	1.6	-	-	-	Consumer price index	1.9	4.3	2.8	0.9	1.5	0.8	1.9	2.0
4.4	2.0	2.6	-	-	-	Treasury bills	4.4	3.4	2.3	1.9	2.0	2.1	2.2	2.3
4.6	4.0	4.9	-	-	-	10-yr notes	4.7	4.3	3.7	3.8	4.2	4.4	4.6	4.7
4.8	4.5	5.1	-	-	-	30-yr bonds	4.9	4.6	4.3	4.3	4.6	4.7	4.8	4.9
5.6	5.7	6.4	-	-	-	New issue rate–corporate bonds	5.8	5.5	5.4	5.5	5.9	6.0	6.1	6.2
						Other Key Indicators								
1,340.0	870.0	1,110.0	(25.8)	(35.4)	28.2	Housing starts (1,000 units SAAR)	1,300.0	1,150.0	950.0	830.0	820.0	870.0	970.0	1,070.0
16.1	15.0	15.3	(2.3)	(6.8)	1.7	Auto & truck sales (1,000,000 units)	15.9	16.1	15.3	14.7	14.9	15.2	14.8	15.1
4.6	5.4	5.8	-	-	-	Unemployment rate (%)	4.7	4.8	5.0	5.4	5.6	5.6	5.8	5.8
(5.6)	(7.6)	2.5	-	-	-	§U.S. dollar	(11.4)	(17.9)	(5.1)	(5.2)	1.0	5.0	4.5	2.1

Note: Annual changes are from prior year and quarterly changes are from prior quarter. Figures may not add to totals because of rounding. A–Advance data. P–Preliminary. E–Estimated. R–Revised. *1996 Chain-weighted dollars. **Current dollars. ‡Trailing 4 quarters. †Average for period. §Quarterly % changes at quarterly rates. This forecast prepared by Standard & Poor's.

Exhibit SCH-10

EXHIBIT

SCH-11

Tucson Electric Power Company

Comparable Company Fundamental Characteristics

		YE 2007 Capital Structure			*Value Line* 3-5 Year Estimated Capital Structure		
	Company	Common Equity Ratio	Long-Term Debt Ratio	Preferred Stock Ratio	Common Equity Ratio	Long-Term Debt Ratio	Preferred Stock Ratio
1	ALLETE	64.4%	35.6%	0.0%	53.5%	46.5%	0.0%
2	Alliant Energy Co.	61.9%	32.4%	5.7%	55.5%	41.0%	3.5%
3	Ameren	53.4%	45.0%	1.6%	50.0%	49.0%	1.0%
4	American Elec. Pwr.	41.2%	58.6%	0.2%	40.5%	59.0%	0.5%
5	CH Energy Group	55.2%	42.6%	2.2%	48.5%	49.5%	2.0%
6	Cent. Vermont P.S.	57.0%	40.0%	3.0%	55.5%	42.0%	2.5%
7	Cleco Corporation	57.0%	43.0%	0.0%	54.0%	46.0%	0.0%
8	Con. Edison	51.0%	47.0%	2.0%	50.5%	48.5%	1.0%
9	DTE Energy Co.	45.6%	54.4%	0.0%	45.0%	55.0%	0.0%
10	Empire District	49.9%	50.1%	0.0%	55.5%	44.5%	0.0%
11	FirstEnergy	49.0%	51.0%	0.0%	51.5%	48.5%	0.0%
12	Hawaiian Electric	46.0%	53.0%	1.0%	47.0%	51.5%	1.5%
13	IDACORP	52.5%	47.5%	0.0%	50.0%	50.0%	0.0%
14	MGE Energy, Inc.	64.8%	35.2%	0.0%	66.0%	34.0%	0.0%
15	NiSource Inc.	47.6%	52.4%	0.0%	47.0%	53.0%	0.0%
16	NSTAR	40.1%	58.9%	1.0%	50.5%	48.5%	1.0%
17	PNM Resources	49.0%	50.5%	0.5%	51.0%	48.5%	0.5%
18	Pinnacle West	51.5%	48.5%	0.0%	50.5%	49.5%	0.0%
19	PPL Corporation	43.7%	53.9%	2.4%	55.0%	43.0%	2.0%
20	Progress Energy	49.5%	50.0%	0.5%	50.0%	49.5%	0.5%
21	SCANA Corp.	49.7%	48.4%	1.9%	44.5%	54.0%	1.5%
22	Southern Co.	46.0%	51.5%	2.5%	46.0%	52.0%	2.0%
23	Teco Energy, Inc.	39.0%	61.0%	0.0%	41.0%	59.0%	0.0%
24	UIL Holdings Co.	51.0%	49.0%	0.0%	52.0%	48.0%	0.0%
25	Vectren Corp.	49.8%	50.2%	0.0%	50.5%	49.5%	0.0%
26	Xcel Energy Inc.	47.5%	51.5%	1.0%	45.0%	54.5%	0.5%
	Average	50.5%	48.5%	1.0%	50.2%	49.0%	0.8%

Source: Value Line Investment Survey, Electric Utility (East), Feb 29, 2008; (Central), Mar 28, 2008; (West), Feb 8, 2008.

Tucson Electric Power Company

Comparable Group Fundamental Characteristics

		(1)	(2)		(3)	
		% Regulated	Credit Rating		Value Line Data	
No.	Company	Revenue	S&P	Moody's	Beta	11-13 Earned ROE
1	ALLETE	86.0%	A-	Baa1	0.95	9.0%
2	Alliant Energy Co.	90.5%	A-	A2	0.80	10.0%
3	Ameren	100.0%	BBB	Baa2	0.80	9.5%
4	American Elec. Pwr.	90.4%	BBB	Baa1	0.85	12.0%
5	CH Energy Group	65.4%	A	A2	0.90	8.5%
6	Cent. Vermont P.S.	100.0%	BBB+	NR	1.05	7.5%
7	Cleco Corporation	95.9%	BBB	Baa1	1.00	11.0%
8	Con. Edison	77.2%	A	A1	0.75	8.5%
9	DTE Energy Co.	79.6%	A-	A3	0.75	9.0%
10	Empire District	99.3%	BBB+	Baa1	0.85	11.0%
11	FirstEnergy	88.3%	BBB	Baa1	0.80	14.0%
12	Hawaiian Electric	83.0%	BBB	Baa2	0.75	11.0%
13	IDACORP	76.0%	A-	A3	0.95	7.0%
14	MGE Energy, Inc.	99.0%	AA-	Aa2	0.90	12.0%
15	NiSource Inc.	73.1%	BBB	Baa2	0.90	7.5%
16	NSTAR	95.8%	AA-	A1	0.75	14.5%
17	PNM Resources	99.9%	BBB	Baa2	0.90	7.0%
18	Pinnacle West	82.8%	BBB-	Baa2	0.80	8.0%
19	PPL Corporation	63.3%	A-	A3	0.90	21.5%
20	Progress Energy	99.8%	A-	A2	0.80	9.5%
21	SCANA Corp.	66.2%	A-	A1	0.80	10.5%
22	Southern Co.	82.3%	A	A1	0.70	14.0%
23	Teco Energy, Inc.	78.8%	BBB-	Baa2	0.85	11.0%
24	UIL Holdings Co.	99.9%	NR	Baa2	0.90	10.0%
25	Vectren Corp.	77.0%	A	A3	0.90	11.0%
26	Xcel Energy Inc.	99.3%	A-	A3	0.80	10.0%
	Average	86.5%	A-/BBB+	A3	0.85	10.6%

Sources:
(1) Most recent company 10-Ks.
(2) AUS Utility Reports, Mar 2008.
(3) Value Line Investment Survey, Electric Utility (East), Feb 29, 2008; (Central), Mar 28, 2008; (West), Feb 8, 2008.
For the Value Line (West) companies, data is for "10-12"

EXHIBIT

SCH-12

Tucson Electric Power Company
GDP Growth Rate Forecast

	Nominal GDP	% Change	GDP Price Deflator	% Change	CPI	% Change
1947	244.2		15.5		22.3	
1948	269.2	10.2%	16.4	5.6%	24.1	7.7%
1949	267.3	-0.7%	16.4	-0.2%	23.8	-1.0%
1950	293.8	9.9%	16.5	1.0%	24.1	1.1%
1951	339.3	15.5%	17.7	7.2%	26.0	7.9%
1952	358.4	5.6%	18.0	1.7%	26.6	2.3%
1953	379.4	5.9%	18.2	1.2%	26.8	0.8%
1954	380.4	0.3%	18.4	1.0%	26.9	0.3%
1955	414.8	9.0%	18.7	1.8%	26.8	-0.2%
1956	437.5	5.5%	19.4	3.5%	27.2	1.4%
1957	461.1	5.4%	20.0	3.3%	28.1	3.4%
1958	467.2	1.3%	20.5	2.3%	28.9	2.7%
1959	506.6	8.4%	20.8	1.2%	29.2	1.0%
1960	526.4	3.9%	21.0	1.4%	29.6	1.5%
1961	544.7	3.5%	21.3	1.1%	29.9	1.0%
1962	585.6	7.5%	21.6	1.4%	30.3	1.2%
1963	617.8	5.5%	21.8	1.1%	30.6	1.3%
1964	663.6	7.4%	22.1	1.5%	31.0	1.3%
1965	719.1	8.4%	22.5	1.8%	31.6	1.6%
1966	787.8	9.5%	23.2	2.8%	32.5	3.0%
1967	832.6	5.7%	23.9	3.1%	33.4	2.7%
1968	910.0	9.3%	24.9	4.3%	34.8	4.2%
1969	984.6	8.2%	26.1	5.0%	36.7	5.4%
1970	1038.5	5.5%	27.5	5.3%	38.8	5.9%
1971	1127.1	8.5%	28.9	5.0%	40.5	4.2%
1972	1238.3	9.9%	30.2	4.3%	41.8	3.3%
1973	1382.7	11.7%	31.8	5.6%	44.4	6.3%
1974	1500.0	8.5%	34.7	9.1%	49.3	11.0%
1975	1638.3	9.2%	38.0	9.4%	53.8	9.1%
1976	1825.3	11.4%	40.2	5.8%	56.9	5.8%
1977	2030.9	11.3%	42.7	6.3%	60.6	6.5%
1978	2294.7	13.0%	45.7	7.0%	65.2	7.6%
1979	2563.3	11.7%	49.5	8.3%	72.6	11.3%
1980	2789.5	8.8%	54.0	9.1%	82.4	13.5%
1981	3128.4	12.1%	59.1	9.4%	90.9	10.4%
1982	3255.0	4.0%	62.7	6.1%	96.5	6.2%
1983	3536.7	8.7%	65.2	3.9%	99.6	3.2%
1984	3933.2	11.2%	67.6	3.8%	103.9	4.4%
1985	4220.3	7.3%	69.7	3.0%	107.6	3.5%
1986	4462.8	5.7%	71.2	2.2%	109.7	1.9%
1987	4739.5	6.2%	73.2	2.7%	113.6	3.6%
1988	5103.8	7.7%	75.7	3.4%	118.3	4.1%
1989	5484.4	7.5%	78.6	3.8%	123.9	4.8%
1990	5803.1	5.8%	81.6	3.9%	130.7	5.4%
1991	5995.9	3.3%	84.4	3.5%	136.2	4.2%
1992	6337.8	5.7%	86.4	2.3%	140.3	3.0%
1993	6657.4	5.0%	88.4	2.3%	144.5	3.0%
1994	7072.2	6.2%	90.3	2.1%	148.2	2.6%
1995	7397.7	4.6%	92.1	2.0%	152.4	2.8%
1996	7816.8	5.7%	93.8	1.9%	156.9	2.9%
1997	8304.3	6.2%	95.4	1.7%	160.5	2.3%
1998	8747.0	5.3%	96.5	1.1%	163.0	1.5%
1999	9268.4	6.0%	97.9	1.4%	166.6	2.2%
2000	9817.0	5.9%	100.0	2.2%	172.2	3.4%
2001	10128.0	3.2%	102.4	2.4%	177.0	2.8%
2002	10469.6	3.4%	104.2	1.7%	179.9	1.6%
2003	10960.8	4.7%	106.4	2.1%	184.0	2.3%
2004	11685.9	6.6%	109.5	2.9%	188.9	2.7%
2005	12433.9	6.4%	113.0	3.2%	195.3	3.4%
2006	13194.7	6.1%	116.6	3.2%	201.6	3.2%
2007	13843.0	4.9%	119.7	2.7%	207.3	2.9%
10-Year Average		5.2%		2.3%		2.6%
20-Year Average		5.5%		2.5%		3.1%
30-Year Average		6.6%		3.5%		4.2%
40-Year Average		7.3%		4.1%		4.7%
50-Year Average		7.1%		3.7%		4.1%
60-Year Average		7.0%		3.5%		3.8%
Average of Periods		6.5%		3.3%		3.8%

Source: St. Louis Federal Reserve Bank, www.research.stlouisfed.org

EXHIBIT

SCH-13

Tucson Electric Power Company
Update of Parcell DCF Analysis (Considering Long-Term GDP Growth)

(1) COMPANY	(2) DPS	(3) January, 2008 - March 26, 2008 HIGH	(4) LOW	(5) AVERAGE	(6) YIELD	(7) ADJUSTED YIELD	(8) GDP GROWTH	(9) DCF RATES
Comparison Group								
Avista Corp.	$0.60	$21.73	$17.80	$19.77	3.0%	3.1%	6.5%	9.6%
Hawaiian Electric	$1.24	$23.85	$20.95	$22.40	5.5%	5.7%	6.5%	12.2%
Northeast Utilities	$0.80	$31.62	$23.96	$27.79	2.9%	3.0%	6.5%	9.5%
Pepco Holdings, Inc.	$1.08	$29.64	$23.80	$26.72	4.0%	4.2%	6.5%	10.7%
PNM Resources	$0.92	$21.69	$8.95	$15.32	6.0%	6.2%	6.5%	12.7%
Puget Energy, Inc.	$1.00	$27.74	$25.06	$26.40	3.8%	3.9%	6.5%	10.4%
TECO Energy	$0.78	$17.75	$14.48	$16.12	4.8%	5.0%	6.5%	11.5%
Westar Energy	$1.16	$25.92	$21.75	$23.84	4.9%	5.0%	6.5%	11.5%
Average						4.5%	6.5%	**11.0%**
Median						4.6%	6.5%	**11.1%**

Columns:
(1) See Exhibit___(DCP-1), Schedule 8, page 4.
(2) Most recent quarterly dividend from most recent Value Line multiplied by four.
(3)-(4) Yahoo.com
(5) Average of columns 4-5.
(6) Column 2 divided by column 5.
(7) Column 6 multiplied by one plus half of column 8.
(8) See Exhibit SCH-12.
(9) Column 7 plus column 8.

EXHIBIT

SCH-14

Tucson Electric Power Company
Discounted Cash Flow Analysis
Summary Of DCF Model Results

Company	Constant Growth DCF Model Analysts' Growth Rates	Constant Growth DCF Model Long-Term GDP Growth	Low Near-Term Growth Two-Stage Growth DCF Model
1 ALLETE	10.8%	11.3%	11.0%
2 Alliant Energy Co.	11.2%	10.7%	10.8%
3 Ameren	11.3%	12.2%	11.3%
4 American Elec. Pwr.	10.1%	10.7%	11.1%
5 CH Energy Group	NA	12.1%	11.4%
6 Cent. Vermont P.S.	12.3%	9.9%	9.3%
7 Cleco Corporation	15.4%	10.2%	11.5%
8 Con. Edison	9.0%	12.0%	11.2%
9 DTE Energy Co.	10.8%	11.6%	11.1%
10 Empire District	12.8%	12.5%	12.0%
11 FirstEnergy	12.8%	10.0%	10.0%
12 Hawaiian Electric	10.7%	12.0%	11.1%
13 IDACORP	9.5%	10.3%	9.6%
14 MGE Energy, Inc.	NA	10.9%	10.3%
15 NiSource Inc.	8.2%	11.6%	11.1%
16 NSTAR	10.9%	11.3%	11.3%
17 PNM Resources	15.7%	12.6%	12.2%
18 Pinnacle West	10.9%	12.1%	11.6%
19 PPL Corporation	15.1%	9.5%	10.6%
20 Progress Energy	10.4%	12.1%	11.4%
21 SCANA Corp.	10.2%	11.5%	11.1%
22 Southern Co.	9.7%	11.2%	11.0%
23 Teco Energy, Inc.	10.7%	11.7%	11.1%
24 UIL Holdings Co.	15.4%	11.9%	11.0%
25 Vectren Corp.	9.9%	11.5%	11.0%
26 Xcel Energy Inc.	10.9%	11.1%	10.9%
GROUP AVERAGE	11.4%	11.3%	11.0%
GROUP MEDIAN	10.8%	11.5%	11.1%

Sources: Value Line Investment Survey, Electric Utility (East), Feb 29, 2008; (Central), Mar 28, 2008; (West), Feb 8, 2008.

NOTE: SEE PAGE 5 OF THIS SCHEDULE FOR FURTHER EXPLANATION OF EACH COLUMN.

Tucson Electric Power Company
Constant Growth DCF Model
Analysts' Growth Rates

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				Analysts' Estimated Growth					
Company	Recent Price(P0)	Next Year's Div(D1)	Dividend Yield	Zacks	Reuters	Thomson	SNL	Average Growth *(Cols 4-7)*	**ROE** K=Div Yld+G *(Cols 3+8)*
1 ALLETE	37.13	1.80	4.85%	5.00%	8.75%	5.00%	5.00%	5.94%	10.8%
2 Alliant Energy Co.	36.69	1.53	4.17%	6.00%	7.00%	6.00%	9.00%	7.00%	11.2%
3 Ameren	44.95	2.54	5.65%	5.00%	7.00%	5.40%	5.00%	5.60%	11.3%
4 American Elec. Pwr.	42.91	1.80	4.19%	5.40%	5.78%	6.03%	6.50%	5.93%	10.1%
5 CH Energy Group	38.78	2.16	5.57%	NA	NA	NA	NA	NA	NA
6 Cent. Vermont P.S.	27.08	0.92	3.40%	NA	9.00%	8.90%	NA	8.95%	12.3%
7 Cleco Corporation	24.41	0.90	3.69%	9.50%	NA	14.00%	NA	11.75%	15.4%
8 Con. Edison	43.23	2.36	5.46%	3.20%	4.04%	3.76%	3.00%	3.50%	9.0%
9 DTE Energy Co.	41.49	2.12	5.11%	6.00%	6.00%	5.75%	5.00%	5.69%	10.8%
10 Empire District	21.35	1.28	5.99%	NA	6.00%	6.00%	8.40%	6.80%	12.8%
11 FirstEnergy	70.31	2.45	3.48%	7.50%	11.25%	11.00%	7.50%	9.31%	12.8%
12 Hawaiian Electric	22.56	1.24	5.50%	4.50%	3.60%	7.60%	5.00%	5.18%	10.7%
13 IDACORP	31.82	1.20	3.77%	5.00%	6.00%	6.00%	6.00%	5.75%	9.5%
14 MGE Energy, Inc.	32.89	1.45	4.41%	NA	NA	NA	NA	NA	NA
15 NiSource Inc.	17.99	0.92	5.11%	2.80%	3.10%	2.90%	3.50%	3.08%	8.2%
16 NSTAR	31.97	1.53	4.79%	6.20%	5.87%	6.04%	6.50%	6.15%	10.9%
17 PNM Resources	15.82	0.97	6.13%	5.80%	11.50%	9.42%	11.50%	9.56%	15.7%
18 Pinnacle West	37.58	2.12	5.64%	6.70%	5.58%	3.63%	NA	5.30%	10.9%
19 PPL Corporation	47.95	1.46	3.04%	10.30%	13.33%	12.40%	12.00%	12.01%	15.1%
20 Progress Energy	44.08	2.49	5.65%	4.60%	4.52%	4.88%	5.00%	4.75%	10.4%
21 SCANA Corp.	38.32	1.92	5.01%	4.70%	5.64%	5.56%	5.00%	5.23%	10.2%
22 Southern Co.	36.46	1.72	4.72%	4.60%	5.06%	5.21%	5.00%	4.97%	9.7%
23 Teco Energy, Inc.	15.89	0.82	5.16%	7.30%	5.00%	4.45%	5.30%	5.51%	10.7%
24 UIL Holdings Co.	32.06	1.73	5.40%	NA	12.00%	10.00%	8.00%	10.00%	15.4%
25 Vectren Corp.	26.98	1.35	5.00%	4.70%	5.00%	4.85%	5.20%	4.94%	9.9%
26 Xcel Energy Inc.	20.73	0.95	4.58%	5.20%	6.12%	6.94%	7.00%	6.32%	10.9%
GROUP AVERAGE	33.90	1.61	4.83%	5.71%	6.83%	6.74%	6.40%	6.63%	11.4%
GROUP MEDIAN			5.01%						10.8%

Sources: Value Line Investment Survey, Electric Utility (East), Feb 29, 2008; (Central), Mar 28, 2008; (West), Feb 8, 2008.

NOTE: SEE PAGE 5 OF THIS SCHEDULE FOR FURTHER EXPLANATION OF EACH COLUMN.

Outlier growth rates were excluded (two growth rates over 15% for CLECO and a negative 5% growth rate for Pinnacle West).

Tucson Electric Power Company
Low Near-Term Growth
Two-Stage Growth DCF Model

	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)
				CASH FLOWS							
Company	Next Year's Div	2012 Div	Annual Change to 2012	Recent Price	Year 1 Div	Year 2 Div	Year 3 Div	Year 4 Div	Year 5 Div	Year 5-150 Div Growth	ROE=Internal Rate of Return *(Yrs 0-150)*
1 ALLETE	1.80	2.00	0.07	-37.13	1.80	1.87	1.93	2.00	2.13	6.50%	11.0%
2 Alliant Energy Co.	1.53	1.92	0.13	-36.69	1.53	1.66	1.79	1.92	2.04	6.50%	10.8%
3 Ameren	2.54	2.54	0.00	-44.95	2.54	2.54	2.54	2.54	2.71	6.50%	11.3%
4 American Elec. Pwr.	1.80	2.40	0.20	-42.91	1.80	2.00	2.20	2.40	2.56	6.50%	11.1%
5 CH Energy Group	2.16	2.25	0.03	-38.78	2.16	2.19	2.22	2.25	2.40	6.50%	11.4%
6 Cent. Vermont P.S.	0.92	0.92	0.00	-27.08	0.92	0.92	0.92	0.92	0.98	6.50%	9.3%
7 Cleco Corporation	0.90	1.50	0.20	-24.41	0.90	1.10	1.30	1.50	1.60	6.50%	11.5%
8 Con. Edison	2.36	2.42	0.02	-43.23	2.36	2.38	2.40	2.42	2.58	6.50%	11.2%
9 DTE Energy Co.	2.12	2.30	0.06	-41.49	2.12	2.18	2.24	2.30	2.45	6.50%	11.1%
10 Empire District	1.28	1.40	0.04	-21.35	1.28	1.32	1.36	1.40	1.49	6.50%	12.0%
11 FirstEnergy	2.45	3.00	0.18	-70.31	2.45	2.63	2.82	3.00	3.20	6.50%	10.0%
12 Hawaiian Electric	1.24	1.24	0.00	-22.56	1.24	1.24	1.24	1.24	1.32	6.50%	11.1%
13 IDACORP	1.20	1.20	0.00	-31.82	1.20	1.20	1.20	1.20	1.28	6.50%	9.6%
14 MGE Energy, Inc.	1.45	1.50	0.02	-32.89	1.45	1.47	1.48	1.50	1.60	6.50%	10.3%
15 NiSource Inc.	0.92	1.00	0.03	-17.99	0.92	0.95	0.97	1.00	1.07	6.50%	11.1%
16 NSTAR	1.53	1.85	0.11	-31.97	1.53	1.64	1.74	1.85	1.97	6.50%	11.3%
17 PNM Resources	0.97	1.09	0.04	-15.82	0.97	1.01	1.05	1.09	1.16	6.50%	12.2%
18 Pinnacle West	2.12	2.28	0.05	-37.58	2.12	2.17	2.23	2.28	2.43	6.50%	11.6%
19 PPL Corporation	1.46	2.40	0.31	-47.95	1.46	1.77	2.09	2.40	2.56	6.50%	10.6%
20 Progress Energy	2.49	2.55	0.02	-44.08	2.49	2.51	2.53	2.55	2.72	6.50%	11.4%
21 SCANA Corp.	1.92	2.10	0.06	-38.32	1.92	1.98	2.04	2.10	2.24	6.50%	11.1%
22 Southern Co.	1.72	2.00	0.09	-36.46	1.72	1.81	1.91	2.00	2.13	6.50%	11.0%
23 Teco Energy, Inc.	0.82	0.88	0.02	-15.89	0.82	0.84	0.86	0.88	0.94	6.50%	11.1%
24 UIL Holdings Co.	1.73	1.73	0.00	-32.06	1.73	1.73	1.73	1.73	1.84	6.50%	11.0%
25 Vectren Corp.	1.35	1.47	0.04	-26.98	1.35	1.39	1.43	1.47	1.57	6.50%	11.0%
26 Xcel Energy Inc.	0.95	1.10	0.05	-20.73	0.95	1.00	1.05	1.10	1.17	6.50%	10.9%
GROUP AVERAGE											11.0%
GROUP MEDIAN											11.1%

Sources: Value Line Investment Survey, Electric Utility (East), Feb 29, 2008; (Central), Mar 28, 2008; (West), Feb 8, 2008.

NOTE: SEE PAGE 5 OF THIS SCHEDULE FOR FURTHER EXPLANATION OF EACH COLUMN.

Tucson Electric Power Company
Constant Growth DCF Model
Long-Term GDP Growth

	(10)	(11)	(12)	(13)	(14)
Company	Recent Price(P0)	Next Year's Div(D1)	Dividend Yield	GDP Growth	ROE K=Div Yld+G *(Cols 12+13)*
1 ALLETE	37.13	1.80	4.85%	6.50%	11.3%
2 Alliant Energy Co.	36.69	1.53	4.17%	6.50%	10.7%
3 Ameren	44.95	2.54	5.65%	6.50%	12.2%
4 American Elec. Pwr.	42.91	1.80	4.19%	6.50%	10.7%
5 CH Energy Group	38.78	2.16	5.57%	6.50%	12.1%
6 Cent. Vermont P.S.	27.08	0.92	3.40%	6.50%	9.9%
7 Cleco Corporation	24.41	0.90	3.69%	6.50%	10.2%
8 Con. Edison	43.23	2.36	5.46%	6.50%	12.0%
9 DTE Energy Co.	41.49	2.12	5.11%	6.50%	11.6%
10 Empire District	21.35	1.28	5.99%	6.50%	12.5%
11 FirstEnergy	70.31	2.45	3.48%	6.50%	10.0%
12 Hawaiian Electric	22.56	1.24	5.50%	6.50%	12.0%
13 IDACORP	31.82	1.20	3.77%	6.50%	10.3%
14 MGE Energy, Inc.	32.89	1.45	4.41%	6.50%	10.9%
15 NiSource Inc.	17.99	0.92	5.11%	6.50%	11.6%
16 NSTAR	31.97	1.53	4.79%	6.50%	11.3%
17 PNM Resources	15.82	0.97	6.13%	6.50%	12.6%
18 Pinnacle West	37.58	2.12	5.64%	6.50%	12.1%
19 PPL Corporation	47.95	1.46	3.04%	6.50%	9.5%
20 Progress Energy	44.08	2.49	5.65%	6.50%	12.1%
21 SCANA Corp.	38.32	1.92	5.01%	6.50%	11.5%
22 Southern Co.	36.46	1.72	4.72%	6.50%	11.2%
23 Teco Energy, Inc.	15.89	0.82	5.16%	6.50%	11.7%
24 UIL Holdings Co.	32.06	1.73	5.40%	6.50%	11.9%
25 Vectren Corp.	26.98	1.35	5.00%	6.50%	11.5%
26 Xcel Energy Inc.	20.73	0.95	4.58%	6.50%	11.1%
GROUP AVERAGE	33.90	1.61	4.83%	6.50%	11.3%
GROUP MEDIAN			5.01%		11.5%

Sources: Value Line Investment Survey, Electric Utility (East), Feb 29, 2008; (Central), Mar 28, 2008; (West), Feb 8, 2008.

NOTE: SEE PAGE 5 OF THIS SCHEDULE FOR FURTHER EXPLANATION OF EACH COLUMN.

Tucson Electric Power Company
Discounted Cash Flow Analysis
Column Descriptions

Column 1: Three-month Average Price per Share (Jan 2008-Mar 26, 2008)

Column 2: Estimated 2009 Dividends per Share from Value Line (2008 Dividends for Value Line West Companies)

Column 3: Column 2 Divided by Column 1

Column 4: "Next 5 Years" Company Growth Estimate as Reported by Zacks.com

Column 5: Mean Estimate of "LT Growth Rate (%)" Reported by Reuters.com

Column 6: "Next 5 Years (per annum) Growth Estimate Reported by Thomson Financial Network (at Yahoo Finance)

Column 7: Mean "LTGR" (Long-Term Growth Rate) Reported by SNL

Column 8: Average of Columns 4-7

Column 9: Column 3 Plus Column 8

Column 10: See Column 1

Column 11: See Column 2

Column 12: Column 11 Divided by Column 10

Column 13: Average of GDP Growth During the Last 10 year, 20 year, 30 year, 40 year, 50 year, and 60 year growth periods. See Exhibit SCH-3R

Column 14: Column 12 Plus Column 13

Column 15: See Column 2

Column 16: Estimated 2012 Dividends per Share from Value Line (2011 Dividends per Share for Value Line West Companies)

Column 17: (Column 16 Minus Column 15) Divided by Three

Column 18: See Column 1

Column 19: See Column 15

Column 20: Column 19 Plus Column 17

Column 21: Column 20 Plus Column 17

Column 22: Column 21 Plus Column 17

Column 23: Column 22 Increased by the Growth Rate Shown in Column 24

Column 24: See Column 13

Column 25: The Internal Rate of Return of the Cash Flows in Columns 18-23 along with the Dividends for the Years 6-150 Implied by the Growth Rates shown in Column 24

EXHIBIT

SCH-15

Tucson Electric Power Company
Capital Asset Pricing Model Analysis

Long-Term CAPM Analysis

Risk-free Rate[1]		Value Line Beta[2]		Long-Term Ibbotson Risk Premium[3]		Cost of Common Equity
5.10%	+	0.85	x	5.70%	=	9.95%

Notes:
[1] Projected 30-yr Treasury bond rate from Exhibit SCH-11.
[2] Average beta from Exhibit SCH-10, page 2.
[3] Ibbotson Associates 2008 Yearbook, page 31, average of Geometric and Arithmetic risk premiums; Long-Term risk premium is difference between "Large Company Stocks" and "Long-Term Government."

EXHIBIT

SCH-16

Tucson Electric Power Company

Risk Premium Analysis

	MOODY'S AVERAGE PUBLIC UTILITY BOND YIELD (1)	AUTHORIZED ELECTRIC RETURNS (2)	INDICATED RISK PREMIUM
1980	13.15%	14.23%	1.08%
1981	15.62%	15.22%	-0.40%
1982	15.33%	15.78%	0.45%
1983	13.31%	15.36%	2.05%
1984	14.03%	15.32%	1.29%
1985	12.29%	15.20%	2.91%
1986	9.46%	13.93%	4.47%
1987	9.98%	12.99%	3.01%
1988	10.45%	12.79%	2.34%
1989	9.66%	12.97%	3.31%
1990	9.76%	12.70%	2.94%
1991	9.21%	12.55%	3.34%
1992	8.57%	12.09%	3.52%
1993	7.56%	11.41%	3.85%
1994	8.30%	11.34%	3.04%
1995	7.91%	11.55%	3.64%
1996	7.74%	11.39%	3.65%
1997	7.63%	11.40%	3.77%
1998	7.00%	11.66%	4.66%
1999	7.55%	10.77%	3.22%
2000	8.14%	11.43%	3.29%
2001	7.72%	11.09%	3.37%
2002	7.53%	11.16%	3.63%
2003	6.61%	10.97%	4.36%
2004	6.20%	10.75%	4.55%
2005	5.67%	10.54%	4.87%
2006	6.08%	10.36%	4.28%
2007	6.11%	10.36%	4.25%
AVERAGE	9.23%	12.40%	3.17%

INDICATED COST OF EQUITY

PROJECTED TRIPLE-B UTILITY BOND YIELD*	6.50%
MOODY'S AVG ANNUAL YIELD DURING STUDY	9.23%
INTEREST RATE DIFFERENCE	-2.73%
INTEREST RATE CHANGE COEFFICIENT	-41.83%
ADUSTMENT TO AVG RISK PREMIUM	1.14%
BASIC RISK PREMIUM	3.17%
INTEREST RATE ADJUSTMENT	1.14%
EQUITY RISK PREMIUM	4.31%
PROJECTED TRIPLE-B UTILITY BOND YIELD*	6.50%
INDICATED EQUITY RETURN	**10.81%**

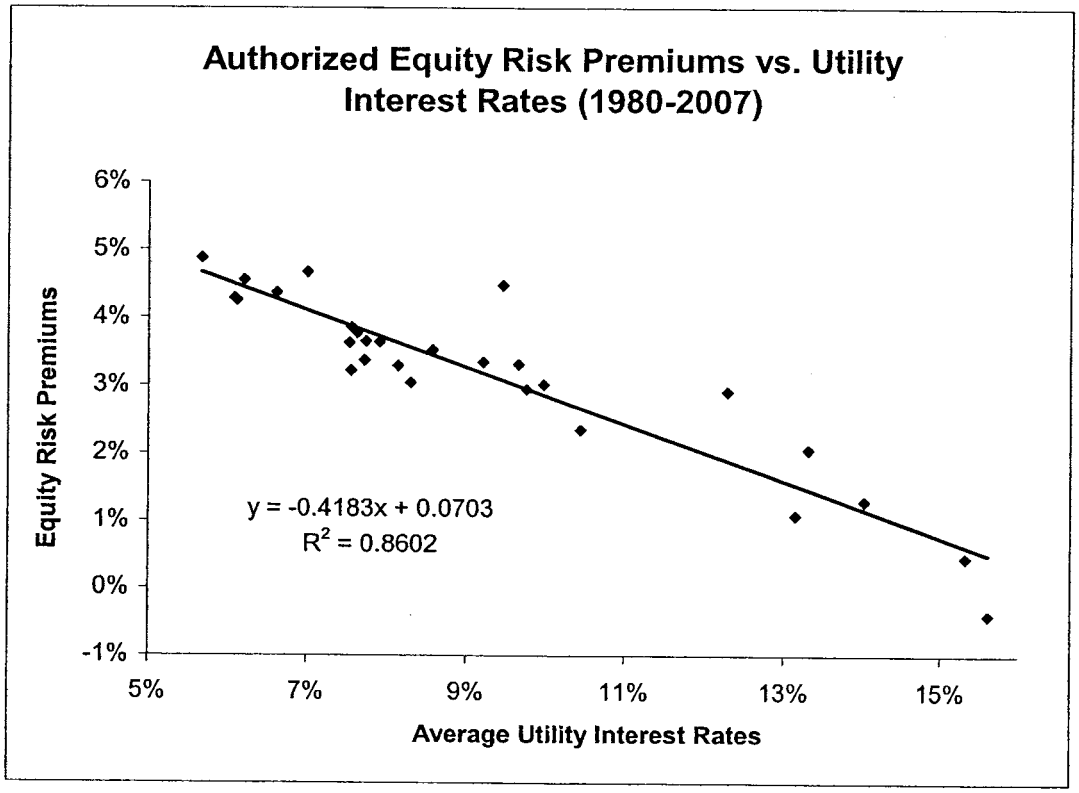
(1) Moody's Investors Service

(2) Regulatory Focus, Regulatory Research Associates, Inc.

*Projected triple-B bond yield is 140 basis points over projected 30-year Treasury bond rate of 5.1% from Exhibit SCH-11. The average triple-B spread for 2007 was 142 basis points.

Tucson Electric Power Company

Risk Premium Analysis



BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-0402

Rebuttal Testimony of

Judah L. Rose

on Behalf of

Tucson Electric Power Company

PUBLIC VERSION

April 1, 2008

Executive Summary of the Rebuttal Testimony of Judah L. Rose

Mr. Rose is a Managing Director of ICF International ("ICF"). Mr. Rose's Rebuttal Testimony addresses the following matters:

1. **Replacement Cost and Fair Market Value.** Mr. Radigan's claim that the estimate of Reconstructed Cost New Less Depreciation (RCND) of $1.274 billion represents the fair market value for the existing power plants of Tucson Electric Power Company ("TEP" or the "Company") is refuted and is shown to be 55 percent below the estimated fair market value developed using the correct approach, i.e. using the income or discounted cash flow approach, of $2.83 billion. The RCND here results in the wrong estimate primarily because of its improper use of depreciation accounting and the depreciation estimate is: (1) unrelated to the remaining useful life of TEP's existing plants, (2) erroneous because the US coal plant show no sign of retiring even though they have already eclipsed on average the useful life that the depreciation is based on, and (3) ignores the advantage of existing units relative to new units in that they do not require long development and construction lead times and are a much less risky asset compared to new coal power plants.

2. **New Unit Construction Costs.** The claim that the estimates of the construction costs for new power plants used by the company are 25-35 percent too high is refuted and this claim is shown to be based on out of date and/or erroneous information. Indeed, the company's estimates made last year now appear to be too low – i.e., need to be [redacted] - in light on ongoing escalation in the costs of new power plants.

3. **Mr. Radigan's View of the Income Approach –** Mr. Radigan concedes that the value of low cost coal power plants selling into a market where the prices are set by natural gas power plants facing record high oil and natural gas prices is "tremendous", but claims that fair value rate base must be based on the assumption that the plants cannot earn market revenues. This contradicts any possible basis for his endorsement of RCND approach to estimating fair value rate base, contradicts the Chaparral decision and is refuted by pointing out that Mr. Radigan's approach results in the fair value rate base being no different than original cost less accumulated depreciation or being based on arbitrarily decided numbers.

4. **Wholesale Power Market Volatility.** Mr. Antonuk expresses concern that if rates are based on the use of MGC (Market Generation Credit) "ratepayers will be subjected to the short term volatility of the wholesale market", and that the use of short term prices is particularly troubling because it was part of the past California market design. I respond that there are mechanisms to decrease this volatility such as using rolling averages (e.g., a 3 year rolling average), or hedging with forward contract, and for the state of Arizona to avoid a repetition of the California crisis, the state should not combine market pricing with retail price caps.

5. **Wholesale Power Market Conditions** Mr. Johnson shares Mr. Antonuk's concerns about the volatility of the MGC and further expresses the view that the wholesale power market cannot be relied upon to establish just and reasonable rates. I respond by referencing the same mechanisms for reducing volatility mentioned in reference to Mr. Antonuk, pointing out that FERC has given TEP authority to use market based rates under the standard of just and reasonable, and highlighting the fact that Mr. Johnson ignores all of the specifically identified changes in the wholesale power markets contained in my direct testimony that have occurred over the last seven years.

6. **Fuel and Purchase Power Adjustment Clauses.** Ms. Cortez opposes the proposed PPFAC in part because she believes market purchases are only "somewhat less stable than coal prices". She contradicts Mr. Antonuk and Mr. Johnson *vis a vis* market prices for power, simply cannot believe natural gas prices are not highly volatile, and may not be aware of how widespread full fuel and purchase power purchase clauses are. Finally, to the extent TEP's coal capacity buffers the volatility of fuel and purchase power, this highlights how high the market value of these plants is.

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VI. Fuel and Purchase Power Adjustment Clauses 33

VII. Wholesale Power Market Conditions 36

I. INTRODUCTION AND SUMMARY.

Q. Please state your name and address.

A. My name is Judah Rose.

Q. Are you the same Judah Rose that previously submitted Direct Testimony on behalf of Tucson Electric Power Company ("TEP" or "Company") in this Docket?

A. Yes.

Q. Have you reviewed the Direct Testimonies filed by the Arizona Corporation Commission Staff ("Staff") and by the Residential Utility Consumer Office?

A. Yes, I have.

Q. What does your rebuttal testimony address?

A. First, I respond to the testimony of Mr. Frank Radigan given on behalf of ACC Staff. Second, I respond to selected issues raised by: (1) Mr. Antonuk on behalf of the ACC Staff, (2) Ms. Diaz Cortez of the Residential Utility Consumer Office, and (3) Mr. Johnson also on behalf of the Residential Utility Consumer Office.

Q. Can you summarize Mr. Radigan's testimony?

A. Yes. In his February 29, 2008 Testimony on behalf of the Utility Division Staff of the ACC, Mr. Frank Radigan concludes that my valuation estimate for TEP's generation capacity of $2.8 billion is "not reasonable". Specifically, he makes the following points concerning my testimony:

(1) My evaluation is "unreasonable" because it is 2.2 times that of Ms. Kissinger's Reconstructed Cost New Less Depreciation (RCND). In Mr. Radigan's view, Ms. Kissinger's RCND estimate is more reliable. Also, he argues that her estimate contradicts my conclusion that the replacement cost approach qualitatively

corroborates my estimate which is based on the income or discounted cash flow approach;[1]

(2) Mr. Radigan reviews eight estimates of the construction costs of new plants, he concludes that my estimates of the construction costs for new power plants are too high by 25-35 percent;[2]

(3) Mr. Radigan argues that construction cost estimates should be reduced by one half to three quarters before being applied to TEP's units because they do not factor in depreciation. Because I did not undertake this approach, my valuation is unreasonable;[3]

(4) In any case, my use of the income approach is wrong. While Mr. Radigan admits it is true that a low cost coal unit selling in a market where the clearing price is set by natural gas can have "tremendous value" and TEP's coal plants account for 93 percent of my total estimated value, he argues that it is inappropriate for a regulated utility to use a market method because such an approach would overstate the fair value of the rate base.[4]

Q. Can you summarize your response to Mr. Radigan?

A. Yes.

(1) The RCND approach fails to provide a reasonable estimate of fair market value of TEP's coal plants, and in fact, grossly underestimates this value. Its principal flaw is to use accounting based estimates of depreciation to decrease by half the construction cost of new units without any reference to economic or technological obsolescence or the actual physical remaining useful of TEP's existing plants. TEP's existing plants have significant remaining useful life which is effectively ignored even though: (1) TEP's coal plants also already have advanced emission

[1] Page 4, lines 9-15.
[2] Page 5, line 25
[3] Page 5, line 25
[4] Page 6, lines 4-14.

controls, facilitating long-term operation, (2) ICF's analysis already incorporates the effects of additional potential future regulations such as CO_2 controls, and (3) record high oil and natural gas prices result in high wholesale power prices which in turn raises value and incentivizes continued operation. The RCND procedure also fails to account for the advantages of existing plants over new plants deriving from their immediate availability. In contrast, new coal plants take many years to permit, obtain other regulatory approvals, design, construct, and bring on-line and coal plant development is a risky and difficult endeavor compared to operation of already existing plants. In the interim period, until a new plant comes on-line, existing plants also currently benefit from the lack of federal CO_2 regulations. In contrast, if CO_2 controls are enacted and implemented in the future, they could diminish the value of new coal plants more than existing plants since new plants which might not have any significant operations during periods without CO_2 controls.

(2) Not only are ICF estimates of the construction costs of new power plants not too high, they in fact are too low compared to current costs which have continued to rise since my direct testimony was filed last year. Mr. Radigan's cost estimates are almost entirely out-of-date and/or wrong. They are contradicted by detailed up-to-date engineering analysis contained in sworn testimony and much other evidence.

(3) The application of accounting depreciation to estimate fair market value can lead to the absurd result that existing U.S. coal-fired power plants have practically no fair market value. The average age of U.S. coal plants already exceeds their average book life, and hence, their accounting value after accounting depreciation increasingly approaches zero. In fact, modern coal plants practically never retire. No modern SO_2 scrubbed coal plant has ever retired. Thus, the estimates of book life underlying accounting depreciation have been proven to be wrong; specifically they are way too short. Further, it is hard to find an asset more valuable in the

power industry given record high oil and natural gas prices. Additional evidence of the high value is the strenuous opposition to relying on market pricing by Staff and the Residential Utility Consumer Office.

(4) Mr. Radigan argues that market-based valuation is inappropriate for TEP's plants because they are regulated. Such an argument also contradicts the use of RCND, which is an attempt to measure fair market value. If market-based valuation is inappropriate, the only alternative to fair market value is original cost less accounting depreciation and, if this approach is used, the fair value rate base would be no different than the original cost based rate base. Even if his view that fair market value may exceed the fair value rate base is true, fair market value should be properly estimated as an input into developing fair value and that this estimate must be based on market assumptions, processes, and information.

Q. Can you summarize the part of Mr. Antonuk's testimony that you respond to and your response?

A. Yes. Mr. Antonuk expresses concern that if rates are based on the Market Generation Credit (MGC) "ratepayers will be subjected to the short-term volatility of the wholesale market.[5]" Further, he states that the use of short-term wholesale market prices rather than long-term bilateral agreements was a characteristic of the flawed California market, and hence, is particularly troubling.[6] I respond that there are ways to decrease the volatility of the MGC which might be useful such as long-term rolling averages of short-term or spot wholesale power prices. This approach has the virtue of retaining the readily observable spot prices which are subject to FERC price caps instituted after the problems in California and numerous other new controls as described in my direct testimony. Another way is to hedge prices with a mix of forward contracts entered at different times. I also pointed out

[5] Page 13, lines 11, 12, February 29, 2008.
[6] Pages 21 and 22.

that the failure of the California market was in large part due to the combination of price caps and market pricing, a combination that should be avoided.

Q. Can you summarize the portion of Mr. Ben Johnson's testimony that you respond to and your response.

A. Mr. Johnson expresses the view that the Commission cannot rely on the wholesale power market to establish fair and reasonable prices. He also expresses concern about the "volatility of the MGC.[7]" I respond that: (1) FERC has given market-based rate authority to TEP and it too has a just and reasonable standard, (2) his standard appears undefined, and (3) he ignores the long list of specific improvements in the wholesale market contained in my direct testimony. My response to Mr. Antonuk on "MGC volatility" also applies to Mr. Johnson.

Q. Can you summarize the part of Ms. Diaz Cortez's testimony that you respond to and your response?

A. Yes. Ms. Diaz Cortez opposes the proposed Purchase Power and Fuel Adjustor Clause ("PPFAC") in part because she believes market purchases are only "somewhat less stable than coal prices.[8]" I respond that her position contradicts that of Mr. Antonuk that rates based on the MGC will mean "ratepayers will be subjected to the short-term volatility of the wholesale market," as well as the similar testimony of Mr. Johnson on MGC volatility and fails to account for unexpected events such as plant outages, and unexpectedly high market prices. It is also inconsistent with the very widespread use of full and automatic fuel and purchase power adjustments on the federal and state level which was done precisely to avoid California-like eventualities – a discrepancy between costs and rates leading to utility illiquidity. Finally to the extent TEP's coal capacity buffers the volatility of fuel and purchase power, it emphasizes its high value.

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[7] Page 25.
[8] Page 28, February 29, 2008, line 14.

II. REPLACEMENT COST AND FAIR MARKET VALUE.

Q. What exactly did you say in your direct testimony about the replacement cost approach to valuation?

A. First, I clearly explained I was not using the replacement cost valuation approach to quantitatively estimate the fair market value of TEP's power plants:

> *We rely on the income approach for our quantitative results and believe it is most appropriate for power plants.*[9].
>
> *I did not use replacement cost as a basis for a quantitative estimate, but rather used the income approach. I note replacement costs are inputs into the income approach as discussed later in my testimony.*[10]

Second, I stated:

> *Q. What role does the replacement cost approach play in your valuation?*
>
> *A. The replacement cost plays a qualitative role and in this case corroborates my valuation.*[11].

Q. Why did you limit the role of the replacement cost approach to a qualitative consideration?

A. As I stated in my direct testimony:

> *Q. Why does it play only a qualitative role?*
>
> *A. The underlying assumption is that replacement is appropriate. In some case, in markets with excess capacity, purchases from the market are more economic*

[9] Pages 6, line 27, page 7, line 1.
[10] Page 7, line 25, page 8, lines 1 & 2.
[11] Page 7, lines 14 and 15.

> *than replacement. Conversely, when there are long lead times, construction risks and replacement is difficult due to permitting problems, existing units can have premium value. In other cases, a different asset is more appropriate for replacement. <u>These issues are ultimately resolved in the income approach</u> as are the related categories of physical deterioration, functional obsolescence and economic obsolescence* (underline added).[12]

Q. Has any relevant evidence been presented by any witness that would allow the replacement cost approach be used to provide a quantitative estimate of the fair market value of TEP's assets?

A. No. While evidence has been presented on the construction costs on new plants, I have seen no evidence on:

- Physical deterioration
- Functional obsolescence
- Economic obsolescence
- The potential premium available to existing plants due to the long lead time for new units
- The potential discount due to the availability of purchase power at lower cost.

Q. Why did you not provide such evidence?

A. As stated, the required adjustments involve the income approach, and hence, it is more appropriate to directly use the income approach. Indeed, since the income approach is required to provide the adjustments for a reasonable application of the replacement cost approach, the replacement cost approach is effectively not a stand-alone method.

[12] Page 7, lines 14 – 24.

Q. How could Mr. Radigan assert a discrepancy between replacement cost and your valuation in the absence of a properly prepared replacement valuation accounting for various types of obsolescence, lead times, etc.?

A. Mr. Radigan relies on the application of the RCND approach of Ms. Kissinger which results in an estimate of $1.274 billion and compares this to my estimate of $2.83 billion.

Q. Did Ms. Kissinger assert that her RCND calculation corresponds to fair market value?

A. No. Ms. Kissinger estimated the construction costs of new units and decreased this value using an estimate of the accounting based depreciation that could apply.

Q. Did Ms. Kissinger address the required obsolescence and economic adjustments to replacement value or the actual physical remaining useful life of the asset?

A. No.

Q. Why did Ms. Kissinger estimate RCND?

A. My understanding is a RCND report is required by ACC rules for large rate case applications.

Q. If no one has conducted a valuation using the replacement cost approach with the proper adjustments, why did you claim the replacement cost approach qualitatively corroborates your quantitative estimate from the income approach?

A. I made this qualitative conclusion because my income or discounted cash flow analysis already accounts for the needed adjustments to new unit construction cost and it showed the fair market value to be similar to the unadjusted construction costs of new plants.

Q. Why does Ms. Kissinger's RCND estimate differ so much from your estimate of fair market value?

A. Ms. Kissinger's RCND estimate of $1.274 billion is 55 percent lower than my fair market value estimate primarily due to her subtraction of an accounting based estimate of depreciation from estimated construction new unit cost (see Exhibit 25). Specifically, of the total difference of $1.56 billion (i.e., $2.83 billion - $1.274 billion) between her RCND calculation and my fair market value estimate:

- 76 percent or $1.18 billion of the difference is due to the use of accounting depreciation by Ms. Kissinger;
- 7 percent or $0.12 billion of the difference is due to the fact that my fair market valuation is higher than the costs of constructing new units; and
- 17 percent or $0.26 billion of the difference is due to the fact that my new unit construction cost is higher than Ms. Kissinger's estimated cost (her RCN).

Put another way, my income analysis shows that subtracting an accounting based estimate of depreciation to account for the fair market value difference between existing and new plants alone results in a huge error of approximately $1.2 billion. Other errors add $0.3 billion to the total error.

EXHIBIT 25
TEP Power Plants (Billion 2006$)

Source/Type	Value
ICF Fair Market Value	2.83
ICF Replacement Cost Unadjusted for Various Factors	2.71[1]
Ms. Kissinger's RCN	2.45
Ms. Kissinger's RCND	1.274

RCN – Reconstructed Cost New
RCND – Reconstructed Cost New – Less Depreciation
[1] 980 MW of coal at $2,431/kW, 217 MW of combustion turbine at $581/kW, 187 MW of combined cycle at $896/kW, and 267 MW of gas steam plants assumed to have minimal value in $/kW.

Q. How old are TEP's coal units?

A. The capacity weighted average age of TEP's coal plant is 28 years. Springerville Unit #2 is only 18 years old while the other coal-fired units valued range between 28 and 39 years old.

Q. How did you handle the age of TEP's plants in your testimony?

A. I handled the age of TEP's plants by:

- Limiting the analysis to 30 years thereby assuming that the capacity weighted average life of TEP's coal plants would be 58 years;
- Including the costs of retrofitting pollution control equipment and other costs of environmental controls including assessments of potential future new environmental regulations; and
- Using up-to-date power plant performance and cost parameters reflecting the effects of aging on the plants.

Q. How could the value of TEP's existing coal plants be similar to or above the costs of constructing brand new coal-fired power plants given their age?

A. The strong value of TEP's existing units derives from several factors. First, new coal-fired units have long and uncertain lead times of as much as 5 to 7 years due to the difficulties in permitting, obtaining necessary regulatory approval such as certificates of public need and necessity, financing, design, worker mobilization, equipment ordering lead time, construction, testing, and bringing on line a new coal plant. These difficulties include the potential risk that development attempts will ultimately be unsuccessful, a risk that does not exist for existing units. As a result, during the first 5 to 7 years, the existing unit earns revenues while the new unit does not. The value of these up-front earnings is magnified by the higher present value of these earnings compared to earnings in later years. As an

illustrative example, at a discount rate of 8 percent, a dollar of income in year 7 has 39 percent less value than a dollar in year 1.

Q. Why else is the value of existing coal-fired units so high?

A. The high value of existing coal-fired units is also based in part on the very long lives of existing coal plants. Thus, even though the lifetimes of new units extend beyond those of the existing units, this does not occur until many years in the future, and hence, the present value of the incremental earnings in these years are highly diminished.

Q. Can you give an example of these effects?

A. Yes. As an illustration of these effects, I made some calculations based on my forecast of the cash flows for a TEP coal plant and the following additional assumptions. First, I assumed a discount rate of 8.1 percent which is similar to TEP's proposed weighted average after tax cost of capital. Second, I assumed a new coal unit lead time of six years, and a lifetime of 60 years for this new unit. Third, I calculated the minimum remaining useful life of the existing plant that would cause its present value of net revenues to be equal to that of the brand new plant. Remarkably, the earnings of an existing coal plant equal that of a new coal plant even if its remaining useful life is only 17 years compared to 40 years for the new unit. The calculation accounts for the zero earnings of a new plant in the first six years as well as the zero earnings of an existing plant in year 18 to 66.

Q. Are there aspects of your cash flow projections that also contribute to the desirability of having a coal plant immediately available to sell into the local wholesale power markets?

A. Yes, there are two that affect this result. First, oil and natural gas prices are at record levels, while ICF projects lower future natural gas prices in real terms. 2008 and 2009 gas prices are assumed to be 11 percent higher in real terms than the 2010 – 2026 average.

Thus, coal-fired power plant earnings are higher in the near-term. Second, potential future CO_2 emission regulations are back end loaded, decreasing the attractiveness of coal generation in the out-years compared to the near-term. Thus, being on-line immediately is a large advantage for existing coal-fired units.

Q. You mentioned that the high value of existing coal plants is based in part on the very long lives of these plants. How long can one expect existing coal plants to last?

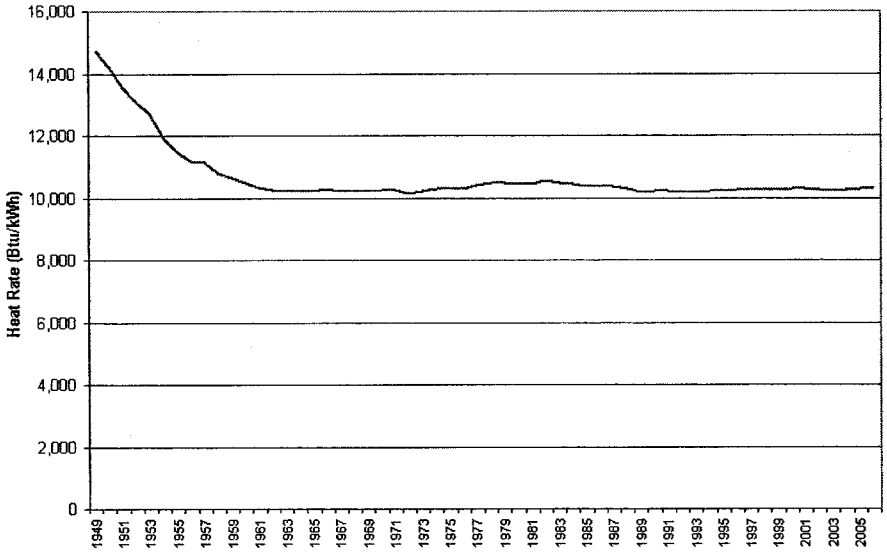
A. Precise estimates are not possible since modern U.S. coal plants rarely retire and then only under special circumstances. Note:

- The average capacity weighted age of U.S. coal power plants is already 36 years. Not only are there very few announced plans to retire major existing coal-fired units in the U.S., there are no TEP plans to retire the coal plants valued here.
- While half the capacity is already older than 36 years, essentially none are older than 60 years. However, this is not necessarily a sign the coal plant lifetimes are limited to 60 years. Modern coal plants, i.e., units > 100 MW did not exist until the 1950s, and hence, there is no experience with modern units greater than approximately 58 years old except one – Trenton Channel (110 MW and 59 years old). Not only are there no signs of major retirement of the nation's more than 300,000 MW of existing coal-fired power plants, the performance of 1950's vintage units can be very impressive. For example, one 1950s vintage unit has recently had a record long "run" without an outage.[13]
- There have been no breakthroughs in basic coal power plant technology since the 1950s.[14] This can be seen in Exhibit 26 which shows U.S. coal plant average heat rates, a measure of thermal efficiency, relatively static.

[13] TVA Shawnee Unit #6 recently won the nation's continuous operating title. The plant came on line in 1955. The plant also has low operating cost. Other units of very similar vintage at the same plant have also performed very well. Power, February 2008.

[14] Though the size of the coal plants have increased breaking the 200 MW level in the 1960s and the pollution controls have also become much tighter.

EXHIBIT 26
National Average Coal Heat Rates



[1] Source is EIA Annual Energy Review 2006 (http://www.eia.doe/gov/aer/), (accessed March 18, 2008).
[2] 2006 data is preliminary.

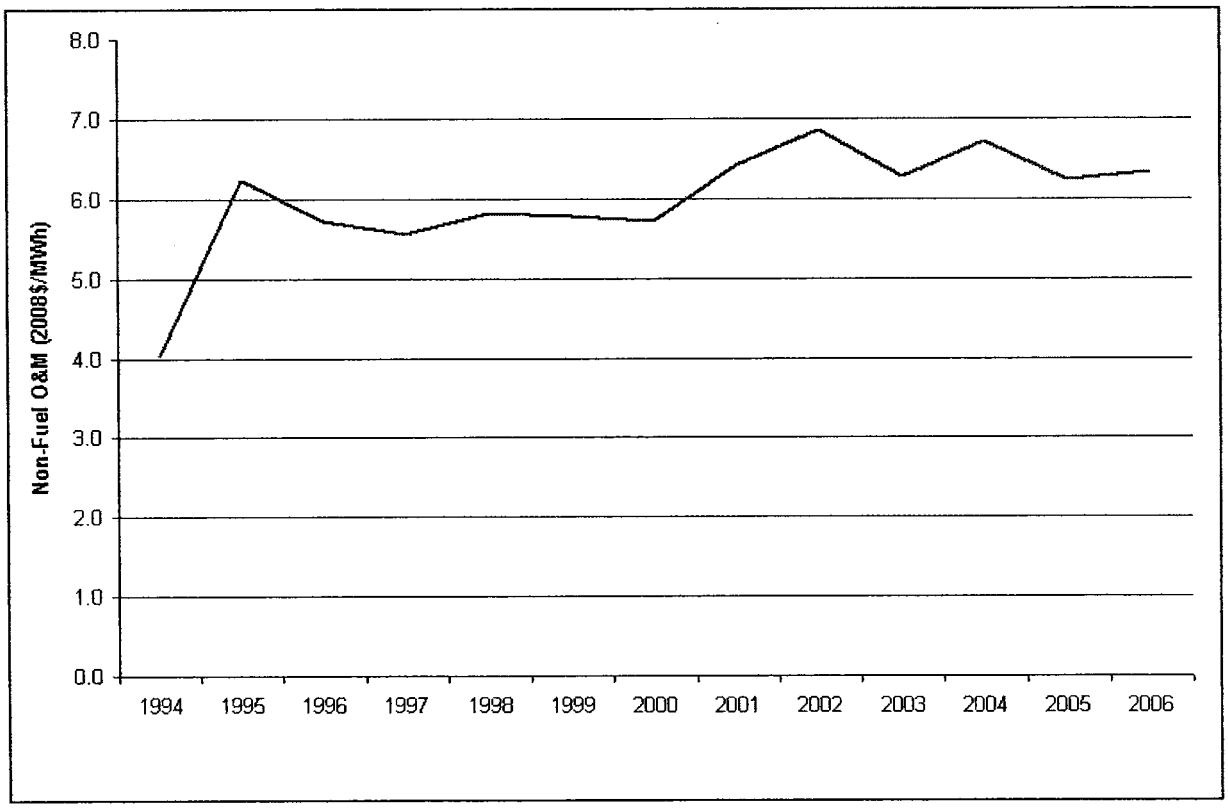
- No U.S. coal plant with a modern SO_2 emission scrubber has ever retired. TEP's coal plants that were analyzed all have SO_2 scrubbers (see Exhibit 27).

EXHIBIT 27
TEP's Coal Plants

Plant	Unit	Net Summer Dependable Capacity (MW)	TEP Share (%)	On-Line Date	Age in 2008	SO_2 Scrubber
Four Corners	4	784	7.0	1969	39	Yes
	5	784	7.0	1970	38	Yes
Navajo	1	750	7.5	1974	34	Yes
	2	750	7.5	1975	33	Yes
	3	750	7.5	1976	32	Yes
San Juan	1	327	50.0	1973	35	Yes
	2	316	50.0	1980	28	Yes
Springerville	2	380	100.0	1990	18	Yes
Total		4,841	20.2			

- Only 3 major U.S. coal-fired power plants have completely retired (Breed, Gannon and Mohave), and in each case the circumstances were unique.
- My analysis already includes all existing and prospective environmental regulations including potential future CO_2 emission regulations. Since environmental issues could be a cause of retirement, it is significant that this issue has already been addressed.
- There is no evidence of non-fuel cost increases noticeably greater than general inflation at large U.S. coal units (see Exhibit 28) nor is there a record of significant performance deterioration, e.g., rising heat rates.

EXHIBIT 28
Historical Coal Non-Fuel O&M (2008$/MWh)



[1] Source is SNL Financial (www.snl.com), (accessed March 19, 2008).

- Ben Johnson, a witness for the Residential Utility Consumer Office, rightly points out that power plants can last from 40 to 60 years or beyond.

> *"For instance, the typical base load generating plant has a useful life of 40 or more years, and it is not unheard of for a generating plant to be still operating 60 or more years after it was constructed."*[15]

[15] Page 29 of his direct testimony.

Q. What did you assume for life extension costs?

A. I used non-fuel O&M cost estimates provided by TEP. Other than these costs, I did not add additional costs for life extension. EIA AEO 2006 adds $6.3/kW-yr (2006$) to the costs of plants greater than 30 years for life extension.[16] If I add these costs, my estimate of fair market value of TEP's coal plants decreases 1.7 percent. Even if EIA's costs are too low and actual costs are double this level (a concern given EIA's costing problems discussed later), and if none are already in TEP's costs (which seems improbable since most TEP units recently turned 30 years old), the effect on value is still small.

Q. Why did you not make that adjustment?

A. I did not make that adjustment because I did not want to double count activities already in TEP's costs. I also believed my overall estimate of fair market value was likely conservatively low. Specifically, I believe my $2.83 billion estimate is likely to be low if it were updated even if I added $6.3/kW-yr for life extension costs at year 30. However, I have not estimated the increase in value.

Q. Why might your estimate of fair market value be too low?

A. One important reason is that since my testimony was filed, ICF has raised its estimate of the costs of new units [redacted] as shown in Exhibit 29.

[16] Source: Page 77, Annual Energy Outlook (AEO) 2006, Energy Information Administration.

EXHIBIT 29
CHANGES IN ICF CAPITAL COST ASSUMPTIONS (2008$)

Plant Technology	July 2007 Testimony[1]	March 2008 ICF View[2]	% Change
	2008$/kW	2008$/kW	2008$/kW
Scrubbed Coal[3]	[redacted]		
Combined Cycle[4]			
Combustion Turbine[5]			

1: Direct testimony of Judah L. Rose filed before Arizona Corporation Commission. July 2, 2007. Docket No. E-01933A-07.
2: Reflects ICF view of capital costs in Arizona for different generation technologies.
3: Reflects Super-Critical Pulverized Coal Power Plant all-in capital cost in the first online year of 2013.
4: Reflects 2x1 GE 7FA frame combined cycle all-in capital cost in the first online year of 2010.
5: Reflects GE 7FA frame combustion turbine all-in capital cost in the first online year of 2009.

This is important since marginal costs of producing electricity reflect in part the costs of building new units in response to growing electricity demand. Higher marginal costs raise wholesale power prices which raises the value of existing units.

Q. Why else might your fair market value be too low?

A. Natural gas prices are even higher than expected and extremely high. This is the largest cost and price driver in the wholesale power market. 2008 natural gas prices are estimated likely to be approximately $10/MMBtu at Henry Hub based on current NYMEX futures prices. In contrast, my forecast was [redacted] in 2008 dollars.

Q. How important is record high natural gas pricing to the value of TEP's coal units?

A. Natural gas pricing is very important. To quote Mr. Frank Radigan:

> *"For a low cost generating unit (e.g., a coal unit) selling in the market where the clearing price is set by natural gas, the value can be tremendous."*[17]

[17] Page 6, lines 6 and 7.

Q. What other factors support high market values for TEP's plants?

A. I cite two. First, there is little construction of new power plants in the desert southwest. The capacity under construction equals 1,260 MW.[18] This lack of construction decreases competition at the summer peak in particular, a period when the value of generation capacity is the greatest. Second, electricity demand continues to grow. Over the last five years from 2001 to 2006, electricity demand in AZ-NM SNV has grown an average of 5.6 percent per year. This remarkably high demand growth means demand levels double every 13 years. If there is a delay in infrastructure investment of 6 to 7 years, (e.g., due to regulatory disputes, etc.), the grid needs to be doubled in size in 6 to 7 years. This is a period shorter than the lead time for many types of units. Droughts can further exacerbate this problem by causing WECC-wide and local wholesale price increases at the time companies are trying to catch up. This sensitivity is in part related to local hydro (Hoover and Glen Canyon dams) as well as even greater reliance on hydro in parts of the interconnected-WECC marketplace (e.g., Pacific Northwest, California). My analysis did not allow for large shortages of generation supply in the desert southwest in spite of it being a real threat. Thus, my valuation may be significantly understated.

Q. What other evidence exists that the RCND does not account for fair market value?

A. There are several important points in this regard:

- In my more than 25 years of valuing power plants, I have never seen a plant's fair market value estimated and successfully defended using replacement cost less accounting based estimates of depreciation.
- While the RCND approach is the wrong approach, at least there is an effort to avoid the confusion between accounting and valuation by starting with replacement cost instead of original cost. Replacement cost is an improvement over original cost because it attempts to correct for the numerous problems with using

[18] Global Energy New Entrants Plant Report for Arizona and New Mexico as of 3/19/2008. Includes 24 MW of renewable.

accounting value to estimate market value. For example, Ross, Westerfield and Jaffe in Corporate Finance (4th ed.), Irwin 1996, p.24, a commonly used finance textbook, states:

> *Value versus Cost*
>
> *The accounting value of a firm's assets is frequently referred to as the carrying value or the book value of the assets. Under* ***generally accepted accounting principles (GAAP),*** *audited financial statements of firms in the United States carry the assets at cost. Thus, the terms carrying value and book value are unfortunate. They specifically say "value," when in fact the accounting numbers are based on cost. This misleads many readers of financial statements to think that the firm's assets are recorded as true market values. Market value is the price at which willing buyers and sellers trade the assets. It would be only a coincidence if accounting value and market value were the same. In fact, the management's job is to create a value for the firm that is higher than its cost. (emphasis added)*
>
> *Many people use the balance sheet. The information each may wish to extract is not the same. A banker may look at a balance sheet for evidence of accounting liquidity and working capital. A supplier may also note the size of accounts payable and therefore the general promptness of payments. Many users of financial statements, including manages and investors want to know the value of the firm, not its cost. This is not found on the balance sheet. In fact, many of the true resources of the firm do not appear on the balance sheet; good management, proprietary assets, favorable economic conditions, and so on.*

One example of the problem of using accounting data is its failure to factor in the effects of monetary inflation on market value. While I have noted above that the comparison of an existing unit and a new unit is imperfect due to lead times for new units and other factors, at least the RCND has avoided one aspect of the confusion between accounting value and market value by starting with replacement costs.

- Not so with depreciation. Whereas the RCND replaces original cost with replacement cost, practically no effort was made to overcome the problem of using accounting depreciation.

As described in a textbook on accounting, Anthony and Reece, 1975,[19]

> *Most fixed assets have a limited useful life; that is, they will be of use to the company over a limited number of future accounting periods. A fraction of the cost of a fixed asset is properly chargeable as an expense in each of the accounting periods in which the asset is used by the company. The accounting process for this gradual conversion of fixed assets into expense is called depreciation.*

Thus, the first step in depreciation is to determine the useful life of the asset. Industry accounting treatment assigned 30 to 40 year book lives for coal plants and conducts depreciation on that basis. In contrast, the average age of U.S. coal plants is already almost 40 years, and hence, half of U.S. coal power plant capacity is about to exceed the industry's maximum book life for coal plants. Put another way, the accounting estimates of book life and the associated accounting depreciation have indisputably turned out to be very wrong. In spite of this glaring problem, there is no evidence of any meaningful effort to re-determine the useful life and redo the allocation based on value and remaining life. It is as if actuarial

[19] Page 198.

tables based on human life expectancy from the 17th century were still being used. As one would expect, accounting estimates of existing coal plant's book value less depreciation are approaching zero nationwide. However, in actuality, no major existing coal plants are planned to be retired, and they have long remaining useful lives. Furthermore, these operations can generate "tremendous" market revenues. Hence, using accounting depreciation without major adjustment must be an incorrect means of determining fair market value.

- This entire case is evidence of the discrepancy between accounting book value and market price and highlights the large remaining value of TEP's coal plants. If this were not so, parties would be indifferent to market-based versus cost-based accounting rates.
- Numerous other evidence exists of inappropriateness of relying on accounting measures of coal lifetimes. Without regard to the merit of environmentalists concerns, decades of attacks on existing coal power plants emphasize the underlying concern that existing coal-fired power plants will not be retired any time soon due to what Mr. Radigan himself describes as the existing coal plant's "tremendous value".[20]

III. NEW UNIT CONSTRUCTION COSTS.

Q. What does Mr. Radigan say about new power plant construction costs?

A. Mr. Radigan says ICF over-estimates new unit construction costs. Specifically, Mr. Radigan states "all these studies indicate that the construction cost estimates used by the company are overstated on the order of 25 – 35 percent."[21] Further, he presents the data contained in Exhibit 30 which he claims shows much lower construction costs for new units than ICF estimates. For example, he presents new coal plant construction cost

[20] Page 6, line 7.
[21] Page 5, lines 24-25.

estimates that are as much as 96 percent below the ICF estimates contained in my direct testimony.

EXHIBIT 30
Mr. Radigan's New Plant Replacement Cost Estimates

Plant	Source	Capital Costs Reported by Mr. Radigan	Capital Costs Reported by Mr. Radigan in 2008$[6,7]	July 2007 ICF Capital Costs in 2008$[6,7]	% Difference From ICF Estimate
Coal	Michigan 21st Century Plan	1,551[1]	1,632	[redacted]	[redacted]
	EIA AEO 2006[5]	1,167[2]	1,308	[redacted]	[redacted]
	Maryland Energy Future	2,700[3]	2,768	[redacted]	[redacted]
Natural Gas Combined Cycle	Northwest Power and Conversation (sic) Council	586	617	[redacted]	[redacted]
	AEO EIA	556[3]	623	[redacted]	[redacted]
	University of Chicago	590[2]	680	[redacted]	[redacted]
Natural Gas Combustion Turbine	AEO EIA	388[3]	435	[redacted]	[redacted]
	Northwest Power and Conversation (sic) Council	420	442	[redacted]	[redacted]
Average				[redacted]	[redacted]

[1] 2006$
[2] 2004$
[3] 2007$
[4] 2003$
[5] Note that EIA AEO numbers reported by Mr. Radigan do not include contingency factors reported by the same document. Also EIA AEO capital costs exclude AFUDC and therefore do not represent the all-in cost.
[6] Source for 2003-2007 inflation escalation is Bureau of Economic Analysis National Income and Products Table Implicit Price Deflators for Gross Domestic Product. Inflation numbers are 2.87% from 2003 to 2004, 3.23% from 2004 to 2005, 3.16% from 2005 to 2006, and 2.67% from 2006 to 2007.
[7] From 2007 to 2008 inflation is assumed as 2.5%

Q. What is your reaction to Mr. Radigan's estimates?

A. Mr. Radigan's estimates with one exception are outdated and in error. Indeed, Mr. Radigan is so misinformed about construction costs that the opposite is true; ICF's estimate is not too high but is too low. Since my testimony was filed, new unit construction costs have continued to rise. ICF has raised its estimated new unit capital costs by [redacted] above those used in my mid-2007 valuation based on the latest market evidence. New unit construction cost is an important input even in a discounted cash flow (i.e., income) analysis since construction costs are a

component of marginal costs of producing power. Marginal costs drive wholesale power prices, and hence, plant fair market value. Specifically, higher new unit construction costs raise the value of existing units in a market with growing electricity demand. In that sense, even though only the income method can be used for fair market valuation, one can hypothesize that RCND has its origins in a recognition that fair market value correlates with new unit costs. Further, when originally considered, the gross mismatch between accounting depreciation and the actual required adjustment to new unit costs needed to estimate value may not have been properly appreciated due to inexperience with modern coal power plants. This correlation between new unit costs and value also explains Mr. Radigan's emphasis on estimated new unit construction costs.

Q. What is the evidence supporting your new unit replacement cost estimates?

A. Evidence supporting my capital investment cost estimates for new units and/or higher updated estimates includes:

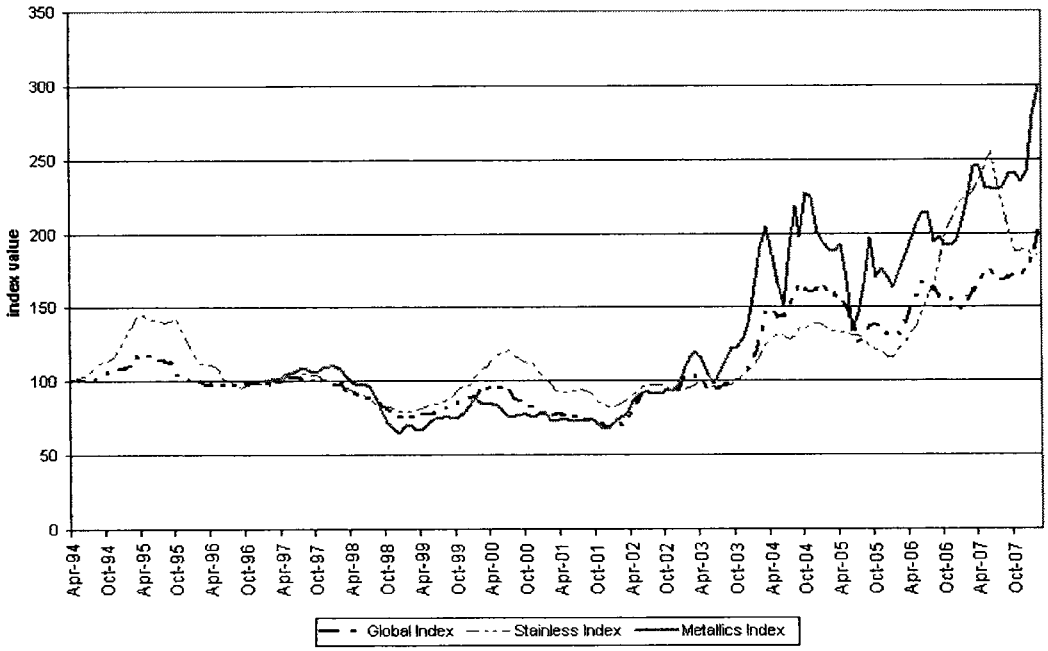
- Mr. Radigan's single up-to-date source, the November 2007 Maryland Public Service Commission study, corroborates my estimate for coal plants, and in fact is higher than the cost assumption I used in my direct testimony for new coal power plants. Hence, it is not only supportive of the estimates used, but also supportive of the need to update and raise the estimates I used in my July testimony. His other sources are either out-of-date, misinformed or both.
- The capital cost of the Springerville Unit 3 coal power plant in Arizona was over $2,200/kW.[22] This plant came on-line as of 2006, and began construction in 2003, well before the recent run up in costs. Adjusting for general inflation to express this cost in 2008 dollars results in a cost of $2,464/kW. This is [redacted] my estimate in spite of the plant avoiding the recent run up in costs. It is certainly not 25 to 35 percent below my estimate as Mr.

[22] Source: http://www.tristategt.org/Aboutus/gen-springerville.cfm

Radigan claims. This is a very material datum since it is the only new Arizona coal plant in nearly 2 decades. Furthermore, this is the only major new coal power plant built in the region tracked by Handy Whitman Index (HW) that includes Arizona since 1990 when Springerville Unit #2 came on line.

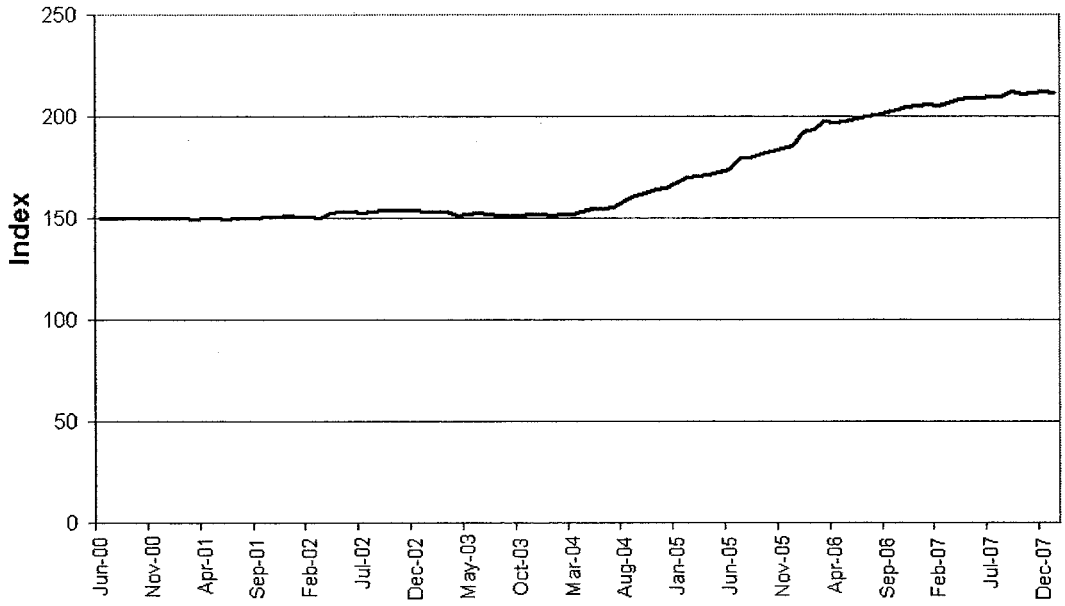
- The large increase in material costs for new plants including steel and cement is public information and well documented (see Exhibits 31 and 32).

EXHIBIT 31
CRUspi Steel Price Index



[1] Source: http://cruonline.crugroup.com/Steel/CRUspi.aspx (accessed March 10, 2008)
[2] Index value for Global and Stainless (April, 1994 = 100).
[3] Index value for Metallics (Jan, 1997 = 100).

EXHIBIT 32
Cement Index



[1] Source: http://www.bls.gov/ (accessed March 11, 2008).

- The recent increase in the cost of new natural gas peaking unit power plants has been reflected in the Cost of New Entrant - CONE used by PJM, the largest U.S. power market operator. This estimate has been approved by FERC for use in PJM's Reliability Pricing Model (RPM).
- Recent well publicized studies of power industry capital cost increases refute Mr. Radigan (IHS/CERA[23], Brattle[24], Standard & Poor's[25], New York Times[26]).
- Mr. Radigan cites the U.S. EIA capital costs. Unfortunately, the estimates he used were incomplete in a manner that understates the costs. Also, EIA has recently updated and raised its cost estimates. However, a proper investigation would have

[23] HIS/CERA Capital Cost Index, 2008, "North American Power Generation Construction Costs Rise 27 Percent in 12 Months to New High: IHS/CERA Power Capital Costs Index." IHS Press release, February 14, 2008, can be accessed at ""http://energy.ihs.com/News/Press-Releases/2008/North-American-Power-Generation-Construction-Costs-Rise-27-Percent-in-12-Months-to-New-High-IHS-CERA.htm.

[24] The Brattle Group, 2007, "Rising Utility Construction Costs: Sources and Impacts" Brattle Group report prepared for The Edison Foundation, September 2007. The report can be accessed at: "www.edisonfoundation.net/Rising_Utility_Construction_Costs.pdf"

[25] Standard & Poor's, 2007, "Increasing Construction Costs Could Hamper U.S. Utilities' Plans To Build New Power Generation." Standard & Poor's Ratings Direct, June 12, 2007.

[26] The New York Times, 2007, "Costs Surge for Building Power Plants." The New York Times, July 10, 2007.

revealed the unfortunate fact that EIA construction cost estimates are systematically too low.

- Mr. Radigan suggests a coal plant cost of $1,167/kW (2004$) based on EIA AEO 2006. This is less than half my estimate. The same document actually suggests $1,249/kW of total overnight costs (2004$) including contingency factor for new scrubbed coal power plants. If the AFUDC adder of 14% and inflation escalation is included, all-in capital cost becomes $1,597/kW. EIA AEO 2008 suggests $1,534/kW (2006$) total overnight cost for new scrubbed coal power plants. If the inflation and 14% AFUDC applied all-in capital cost becomes $1,842/kW (2008$). Thus, his own source needs to be raised [redacted] to even be comparable to ICF's. Even then, a full investigation would have clearly indicated that even when corrected, EIA cost estimation is too low.
- A similar problem exists *vis~a~vis* new natural gas-fired power plants. The EIA overnight cost estimates again fail to include either contingency factor or Allowance For Funds Used During Construction (AFUDC). According to EIA AEO 2006, total overnight cost (2004$) including contingency factor for new combined cycle power plants is $584/kW (2004$). If 7% AFUDC and inflation is applied all-in capital cost for combined cycles becomes $698/kW in 2008 dollars. This compares with an all-in capital cost of $806/kW (2008$) including AFUDC and contingency derived from EIA AEO 2008[27] using the same methodology.
- A proper review of EIA indicates a real increase of 15 percent in capital costs for both new combined cycle and coal plants reported from EIA AEO 2008 versus costs from EIA AEO 2006 (Exhibit 33).

[27] Based on email communication with EIA. Note that EIA 2008 total overnight cost including project contingency factor is $717/kW in 2006$.

EXHIBIT 33

EIA All-In Capital Costs for New Units (2008$/kW)[28,29]

Technology	AEO 2008[30]	AEO2006	Difference
Scrubbed Coal	1,842	1,597	+15.3%
Combined Cycle	806	699	+15.3%
Combustion Turbine	548	475	+15.4%

- There are no up-to-date construction cost estimates corroborating Mr. Radigan for future coal plants anywhere in the U.S. that is backed by detailed engineering studies and sworn testimony. Special deference should be given to such data sources in light of the difficulties in price discovery in this sector.
- Exhibit 34 complies estimates of new unit costs from sworn testimony and based on detailed engineering studies and equipment quotations. Specifically.
  - My recent public testimony on behalf of Duke Carolinas in the 1,600 MW Cliffside coal power plant CPCN (Certificate of Public Convenience and Necessity) case in North Carolina indicating very large capital cost increases was not disputed. Duke submitted a higher cost estimate than shown in Exhibit 34 after the completion hearings due to lower economies of scale.

[28] Source for 2004-2007 inflation escalation is Bureau of Economic Analysis National Income and Products Table Implicit Price Deflators for Gross Domestic Product. Inflation numbers are 3.23% from 2004 to 2005, 3.16% from 2005 to 2006, and 2.67% from 2006 to 2007. 2007 to 2008 inflation is assumed as 2.5%.

[29] Includes 4% AFUDC for combustion turbines, 7% AFUDC for combined cycles, 14% FUDC for coal power plants.

[30] Based on ICF email communication with EIA.

EXHIBIT 34
Selected New Unit Capital Costs

Company	Plant	State	Size (MW)	Technology / Fuel	Proposed Online Year	Capital Cost (2008$/kW)
FPL	Glades	Florida	1,960	Ultra Super Critical Coal	2012-2013	2,372[1]
AEP-SWEPCO	Arsenal Hill	Louisiana	500	Gas CC	2010	949[2]
AEP	Turk	Arkansas	600	Ultra Super Critical Coal	2011	2,900[3]
Duke	Edwardsport IGCC	Indiana	630	IGCC Coal	2012	2,875[4]
Duke	Cliffside	North Carolina	800	Super Critical Coal	2012	2,037[5]
Entergy	Little Gypsy	Louisiana	530	CFB Petcoke	2011	2,715[6]
OG&E	Red Rock	Oklahoma	950	Ultra Super Critical Coal	2011	1,827[7]

[1] Florida Public Service Commission, Petition for Determination of Need for Glades Park 1 and 2 Electrical Power Plants in Glades County, By Florida Power & Light Company. Docket No. 070098-EI Black and Veatch preliminary cost estimate page 6-6.
[2] Supplemental testimony of Judah Rose for Southwestern Electric Power Company, December 2007 Before the Louisiana Public Service Commission. Docket No. U-29702. Assumes inflation of 2.5% per year.
[3] Page 14, Final Recommendation of the Administrative Law Judge, Louisiana Public Service Commission. February 29, 2008. Docket No. U-29702 Consolidated with Docket No. U-27866 Subdocket-B SWEPCO Application for Approval of Capacity Acquisition – Hempstead Facility. Cost is derived based on SWEPCO's share and inflation of 2.5% per year.
[4] Duke Energy Press Release, 25 January 2008, "Indiana Department of Environmental Management Issues Air Permit for Duke Energy Coal Gasification Power Plant."
Site accessed on 10 March 2008: http://www.duke-energy.com/news/releases/2008012501.asp
[5] North Carolina Utilities Commission, February 2008, "Advanced Clean Coal Cliffside Unit Cost Estimate Docket No. E-7 Sub.790."
[6] SNL News, 12 July 2007, "Cost estimates climb for Entergy's Little Gypsy repowering project."
[7] SNL News, 11 October 2007, "Oklahoma formally denies preapproval for Red Rock coal plant, developers walk away."

- The capital cost estimates for the proposed new Glades coal plant provided by Florida Power and Light (FPL) based on detailed engineering studies and contained in sworn testimony are $2,372/kW (2008$) and greatly exceed Mr. Radigan's estimates. Glades was also the largest proposed coal power plant contained in the set of estimates proposed here, and hence, their economies of scale lowered the costs.
- The capital cost estimates provided by Oklahoma Gas and Electric (OG&E), and American Electric Power (AEP) for new coal power plants based on detailed engineering studies and contained in sworn testimony on Oklahoma in 2007 for the 950 MW Red Rock coal plant are $1,827/kW in

2008$. The plant has not been approved, and hence, an updated cost is not available.

- The capital cost estimates provided by AEP based on detailed engineering studies and contained in sworn testimony for the 600 MW Turk coal fired power plant in Arkansas are $2,900/kW in 2008$ and exceed most of Mr. Radigan's estimates.
- The capital cost estimates provided by Duke Indiana based on detailed engineering studies and contained in sworn testimony for the 630 MW Edwardsport IGCC coal fired plant in Indiana are $2,875/kW in 2008$ and exceed most of Mr. Radigan's estimates.
- The capital cost estimates provided by Entergy based on detailed engineering studies and contained in sworn testimony for the 530 MW Little Gypsy solid fuel (coal and petroleum coke) plant in Louisiana are $2,715/kW in 2008$ and exceed most of Mr. Radigan's estimates.
- The capital cost estimates provided by AEP based on detailed engineering studies and contained in sworn testimony for the 500 MW Arsenal Hill natural gas combined cycle power plant in Louisiana are $949/kW in 2008$ and exceed most of Mr. Radigan's estimates. This is an updated estimate.

• The high costs for existing units in regions with excess capacity including the recent OG&E purchase of the Redbud combined cycle power plant in Oklahoma of nearly $700/kW which is higher than[31] any combined cycle cost contained in the testimony of Mr. Radigan.

[31]Source: Press release from Kelson Holdings dated January 22, 2008.

Q. Why might your July 2007 estimate of construction cost be [redacted] higher than Ms. Kissinger's?

A. I highlight two potential sources of this difference. First, Ms. Kissinger uses the HW index values for 2006 not 2007. Second, the HW data appears to be based on historical costs incurred not costs for contracting for new units which will be incurred in the future. There can be a large difference between these two types of estimates in periods of rapid inflation in costs.

IV. MR. RADIGAN'S VIEW OF THE INCOME APPROACH.

Q. What is your understanding of the role of fair market value in this case?

A. I am not a lawyer, but my understanding is that a fair value rate base (FVRB) may need to be determined, and that an accurate estimate of fair market value at a minimum is a consideration in setting FVRB. I also understand that if TEP's generation revenues equal the Market Generation Credit (MGC), the value of its plants would be similar to the fair market value as I have calculated it.

Q. What valuation approaches are in general use in the U.S. power industry?

A. There are two. The first is accounting based and equals original cost less accumulated depreciation. This is used for regulated utilities subject to cost of service regulation. The second is fair market value which is generally used for plants selling into the wholesale power market and earning based on these revenues. Fair market value also appears relevant to FVRB determination based on my non-lawyer review of the 2007 Chaparral decision of the Arizona Court of Appeals.[32]

[32] 1 CA-CC 05-0002, February 13, 2007, In the court of appeals State of Arizona Division One, Chaparral City Water Company, an Arizona Corporation v. Arizona Corporation Commission, an agency of the State of Arizona and Residential Utility Consumer Office. Docket No. W-02113A-04-0616.

Q. What does Mr. Radigan say about valuing TEP's power plants?

A. He states:

> *In the Company's study, its coal portfolio is valued at $2.634 billion or $2,689/kW in real 2006 dollars and accounts for nearly 93% of the total portfolio value. While that result may be meaningful, if one is contemplating selling the units to a third party, it is inappropriate for a regulated market where the utility is generally not allowed to keep profits from interacting in the wholesale market, but rather has to credit the profits against other fuel costs. Thus, using this market method to determine a fair value for rate base would overstate the valuation.*[33]

Q. What is your reaction?

A. If my approach is not valid, it means that fair market value is not an input into determining the fair value rate base. In this circumstance, since the only other accepted measure is original cost less depreciation, how is the fair value rate base different from the original cost rate base? Further, even if a utility nets power sales profits against fuel costs, its base rates still need to be set based on a fair value rate base. This cannot be set without knowing the fair market value, and therefore, an assessment in which the plant owner is assumed not to net the profits against fuel is clearly required. Even if Mr. Radigan is right that the fair value rate base might be below the fair market value rate base, it is still important to know what the fair market value is in order to give it proper due consideration.

[33] Page 6, lines 7-14.

V. WHOLESALE POWER MARKET VOLATILITY.

Q. What does Mr. John Antonuk say on behalf of the ACC staff regarding market price volatility?

A. He states:

> *By determining the generation component of rates based upon an index, ratepayers will be subjected to the short-term volatility of the wholesale market*[34]*. . . The indices that TEP proposes to use to set the MGC are relatively short-term. They do not accurately reflect the prices attainable by building a supply portfolio that takes advantage of long-term bilateral agreements from suppliers in the market. Relying on short-term market indicators was one of the characteristics of the failed California market, and it is a particularly troubling aspect of TEP's market alternative.*[35]

Q. What is your reaction?

A. I have two reactions. The first relates to price volatility. The spot wholesale electricity priced can be volatile on an annual basis as shown in Exhibit 35. This volatility primarily reflects volatility in natural gas prices and scarcity of generation supply. However, there are mechanisms to limit the volatility while still using short-term market indices. One example that is relatively easy to implement is to set the price index or MGC to be equal to a rolling average such as a 3 year rolling average. The 3 year rolling average has 49 percent lower volatility compared to annual spot prices when measured using annual stand deviation, respectively. There is some virtue in using these indices since spot markets are relatively liquid, spot prices are subject to FERC price caps and numerous new protections

[34]Page 13, lines 11-12
[35]Page 21, lines 23-26; Page 22, lines 1-2

exist in this market. A second example would be to use a mix of forward contract hedges of mixed duration to decrease the volatility. A fraction of the load could be hedged at one point and another fraction later. My second reaction is that one of the failings of the California market was to use both market pricing and caps on rates which led to utility bankruptcy. Accordingly, it is absolutely imperative to ensure proper mechanisms for pass through of purchase power costs. It is not therefore necessary to avoid market pricing to avoid a California repeat, just avoid price caps.

EXHIBIT 35
Palo Verde Wholesale Power Prices

Year	Palo Verde Spot On-Peak Price ($/MWh)	Three Year Rolling Average ($/MWh)
1998	29.25	NA
1999	31.32	NA
2000	115.62	58.73
2001	122.52	89.82
2002	32.62	90.25
2003	48.06	67.73
2004	47.95	42.88
2005	67.37	54.46
2006	57.66	57.66
2007	61.56	62.20
Average	61.39	65.47
Standard Deviation	33.08	16.74

VI. WHOLESALE POWER MARKET CONDITIONS.

Q. What does Ben Johnson say on behalf of the Residential Utility Consumer Office related to the wholesale power market and TEP's proposal?

A. He states:

> *Q. Can you explain your concern that TEP is simply assuming that rates under its market approach would be fair and reasonable?*
>
> *A. Yes. Even if one interpreted the Settlement Agreement as the Commission's expression of support for Standard Offer rates being based on market-priced generation, this policy*

does not, and cannot, override the constitutional requirement for fair and reasonable rates. Nor does a policy preference for competition automatically ensure that competition will, in fact, exist. Nor is there anything about this policy that would require the Commission to adopt TEP's proposed "market" approach.

Q. Can competitive market data be used to determine just and reasonable rates?

A. I doubt it, at least given the current status of competitive markets. In its FERC Form 1 TEP has admitted that retail electric competition is essentially non-existent in its service area. As explained by TEP:

"As a result of the energy crisis in California in 2000 and 2001 and the volatility of natural gas prices, the competitive retail market in Arizona that was anticipated in 1999 did not materialize. In addition, a 2005 Arizona Court of Appeals ruling held certain portions of the ACC's retail competition rules invalid. Currently, none of TEP or UNS Electric's customers are receiving energy from other providers; however we cannot predict if retail competition will enter the Arizona market. [TEP FERC Form 1, p. K-18]"

TEP paints a more encouraging picture of competition at the wholesale level:

"Competition in wholesale markets has greatly escalated due to increased participation by utilities, non-utility generators, independent power producers and other wholesale power marketers and brokers. [id.]"

But, even if competition in wholesale spot markets is escalating, that doesn't mean the wholesale market is fully mature, or that the Commission can rely entirely on market price information to establish retail prices that are fair and reasonable. Among other problems, there is not sufficient market data available for the price of power generated over long time periods, stretching 10 or more years into the future. For instance, the data included in the MGC calculations is focused on short term, or spot-market, transactions; none of the underlying index data extends even 5 years into the future. Yet, the actual costs incurred by TEP are being incurred on a long term, relatively stable basis extending over multiple decades.

Q. What is your reaction?

A. I am not a lawyer, but I note FERC has given market based rate authority to TEP and it too has a just and reasonable standard. Also, Mr. Johnson ignores the specific points made in my direct testimony describing the improvements in the wholesale power market. One is also left to wonder how high a standard he has for a wholesale market to be a basis for rates. The specific points about improvements in market conditions that I made in my direct testimony that he ignored included:

- Capacity additions in the WECC primarily in the 1999-2003 period

- FERC anti-manipulation rules
- FERC market behavior rules
- The Energy Policy Act of 2005 with increases scope for penalties (i.e., up to one million dollars per violation per day) and recent applications of this authority
- The creation of an ERO with reliability rules
- Potential for joint investigation by FERC and CFTC
- FERC EQR system
- Index oversight improvements
- FERC market power reviews and recent favorable decisions concerning TEP relative to other Arizona entities
- FERC price caps for short-term markets
- FERC Section 203
- Cal ISO LMP in 2009
- California Resource Adequacy
- Litigation settlements
- Special circumstances related to TEP including scale size in the market

VII. FUEL AND PURCHASE POWER ADJUSTMENT CLAUSES.

Q. What does Marylee Diaz Cortez, a witness on behalf of Residential Utility Consumer Office, say about fuel and purchase power adjustment?

A. She argues for a purchase power and fuel clause that applies only to the costs associated with load growth. She argues that only 20 percent of TEP's costs are sufficiently volatile to justify an automatic fuel and purchase power clause. She specifically says she believes market purchases are only "somewhat less stable than coal prices.[36]"

[36] Page 28, line 14

Q. What is your reaction?

A. First, the view expressed by Ms. Cortez contradicts the testimony of Mr. Antonuk and Mr. Johnson. It cannot be that short-term market prices are volatile as described by Mr. Antonuk and Mr. Johnson and not volatile enough as stated by Ms. Cortez. There is potential for unit outages, unexpected fuel and emission allowance costs and very high power market prices that require flexible and fast cost recovery in order to prevent utility illiquidity. Second, Ms. Cortez's proposal is at odds with the nearly ubiquitous use of fuel and purchase power adjustment mechanisms on the federal and state levels. Third, to the extent TEP's coal capacity buffers fuel and purchase power volatility, this highlights the high value of TEP's existing coal plants.

Q. Does that conclude your testimony?

A. Yes.

TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-07-0402 et al.

RESIDENTIAL UTILITY CONSUMER OFFICE'S ("RUCO")
RESPONSE TO TUCSON ELECTRIC POWER COMPANY'S
FOURTH SET OF DATA REQUESTS

TEP 4-4: Please fully describe all outreach efforts undertaken by RUCO to speak with TEP's customers to discuss customers' opinions regarding the Proposed Settlement Agreement, including (i) the proposed base rate increase; (ii) reliability and quality of service; (iii) TEP's proposed TOU tariffs, (iv) TEP's proposed Inverted Block Rate Structure; (v) low-income customers' rate treatment; (vi) the Purchase Power and Fuel Adjustment Clause; and (vii) the rate moratorium.

Response: William A. Rigsby

None.

EXHIBIT
TEP 11
admitted

TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-07-0402 et al.

RESIDENTIAL UTILITY CONSUMER OFFICE'S ("RUCO")
RESPONSE TO TUCSON ELECTRIC POWER COMPANY'S
FOURTH SET OF DATA REQUESTS

TEP 4-5: In regard to TEP Data Request 4-4 above, please indicate the number of TEP customers RUCO contacted, the date on which those customers were contacted and under which specific tariffs the customers take service.

Response: William A. Rigsby

Not applicable. See response to TEP 4-4.

TEP 4-6: Please provide any written comments from customers or any notes of verbal customer comments. Please specifically identify the number of complaints that RUCO has received from TEP residential consumers regarding the terms of the Proposed Settlement Agreement. Please provide a copy of any such complaints and any subsequent RUCO correspondence.

Response: William A. Rigsby

Not applicable. See response to TEP 4-4.

TEP 4-7: Please admit that RUCO attended and participated in the discussions and negotiations that resulted in the Proposed Settlement Agreement.

Response: William A. Rigsby

Admit.

TEP 4-8: Does the Proposed Settlement Agreement provide any benefits to TEP's residential customers? If so, please list and explain each such benefit.

Response: William A. Rigsby

Yes.

1) Expanded TOU rates
2) Expanded DSM program and spending
3) Rate Case Moratorium
4) Equitable rate spread
5) Rate increase exemption for low-income tariffs
6) Customer credits for Short-term sales revenue, customer credit for 10% of wholesale trading profits, and customer credit for 50% of the revenues realized from the sale of SO2 emission allowances.