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BEFORE THE ARIZONA CORPORATION COMMISSION

CARL KUNASEK
COMMISSIONER-CHAIRMAN
JIM IRVIN
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COMMISSIONER

Arizona Corporation Commission
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IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY AND FOR RELATED APPROVALS, AUTHORIZATIONS AND WAIVERS	Docket No. E-01933A-98-0471 Docket No. E-01933A-97-0772 Docket No. RE-00000C-94-0165
IN THE MATTER OF THE FILING OF TUCSON ELECTRIC POWER COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A..A.C. R14-2-1061, ET SEQ.	**NEW WEST ENERGY CORPORATION'S NOTICE OF FILING TESTIMONY OF ROBERT NICHOLS**
IN THE MATTER OF COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA	

Intervenor New West Energy Corporation gives notice that it is filing the testimony of its witness Robert Nichols.

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RESPECTFULLY SUBMITTED this 28th day of July, 1999.

JENNINGS, STROUSS & SALMON, P.L.C.

By ______________________

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TESTIMONY OF ROBERT NICHOLS

Q. Please state your name and your position with New West Energy.

A. My name is Robert Nichols. I am Director of Finance and Administration with New West Energy. My resume is attached as Exhibit RSN-1

Q. Please describe New West Energy and the purpose of New West Energy's intervention in this proceeding.

A. New West Energy is an Energy Service Provider (ESP) that operates as a power marketer in the state of California. New West Energy has applied to this Commission for authority to participate in competitive markets in Arizona. The purpose of New West Energy's intervention is to analyze the settlement agreement and to make suggestions to the Commission on changes which would better facilitate the development of competitive markets and avoid cross subsidization of competitive services by non-competitive services.

Q. Would you summarize your testimony?

A. In this testimony I make four recommendations for conditions to approval of the settlement agreement:

1. The Commission should conduct a cost of service study to determine that the unbundled prices properly reflect the cost of service and to insure that no cross-

subsidization exists. The settlement could be approved on an interim basis, with the cost of service study to follow in the next six months.

2. The stranded cost recovery period should end on the same date for all utilities. Currently the SRP stranded cost recovery and the APS stranded cost recovery will end no later than the end of 2004. It is important for the development of competitive markets that stranded cost recovery is phased out in a reasonable time frame.

3. The proposed transmission and distribution prices are excessive, as evidenced by the fact that the unbundled transmission and distribution prices are 17.6% higher than TEP's own statement of costs in its last rate case. Reducing the transmission and distribution elements of price to more accurately reflect costs will allow the floating portion of the CTC to increase without increasing overall prices. This will facilitate the goal of phasing out the CTC by 2004.

4. Certain costs that are properly related to the provision of competitive services should be credited to the direct access customers through the energy portion of the price. This would include competitive parts of demand-side management, and services such as load forecasting, customer service representatives, customer account managers, etc. These are services that will be provided by an ESP; the customer should not have to pay twice by paying for these services in the non-bypassable non-competitive charges.

The need for a rate case based on current test year data

Q. Please discuss the need for complete and cost-based unbundling for TEP's rates?

A. It is important that cost shifting between the competitive and non-competitive services does not occur. That is, non-competitive services should not subsidize competitive services. This is consistent with the Commission objective to provide an opportunity for full generation competition as soon as possible. (Decision No. 60977, dated June 22, 1999, page 10, lines 7-8). If cross-subsidization is allowed, this will slow the transition to a competitive deregulated electricity marketplace in Tucson.

Q. Please discuss the need for TEP to conduct a cost of service study?

A. TEP's last cost of service study was conducted for the test year ending December 31, 1994. Under Decision No. 59594, dated March 29, 1995, TEP was allowed to set rates based on a blended cost of capital determined by applying a hypothetical capital structure. The hypothetical capital structure was a temporary device designed to maintain the financial integrity of TEP. Things have changed since the 1995 Commission order.

Q. What has changed since the 1995 Commission Rate Order?

A. Prior to this rate Order, the Commission allowed 60% debt and 40% equity hypothetical capital structure. Under Decision No. 59594, the Commission found that TEP's financial health improved. As such, the Commission adopted a capital structure of 37.5 % equity and 62.5 % debt (Decision No. 59594, dated March 29, 1996, pages 6 and 7). It is reasonable to assume, and in fact it is true, that TEP's equity position has increased since the 1995 Decision. To be consistent with the Commission's prior order, the Commission should revisit TEP's hypothetical capital structure to determine if the current hypothetical capital structure is just and reasonable. The proposed settlement agreement retains the hypothetical capital structure adopted in 1996.

Q. Do you have any other examples of why a cost-of-service study is important?

A. The settlement agreement calls for a rate decrease of 1% in 1999 and 2000 (Direct Testimony, James S. Pignatelli, page 12, lines 11 through 19). These rates appear to be negotiated in the proposed settlement agreement. The Commission can use a cost-of-service study to determine whether the negotiated rate decrease as proposed in the settlement agreement is just and reasonable.

Q. Are there any other issues that will be addressed in a cost-of-service study?

A. I will discuss our concerns with how Transmission and Distribution rates were developed in the proposed settlement agreement later in my testimony. Additionally, the Commission can address all the regulatory asset issues that will be addressed later in my testimony.

Q. Does this mean that the settlement agreement should not be approved?

A. No. The appropriate method for the Commission to set prices going forward is to conduct a rate case during which all parties can carefully scrutinize the cost of service for each unbundled component as well as the need, or the extent of the need, to maintain a hypothetical capital structure for TEP.

However, New West Energy recognizes the interim need to set prices through a negotiated settlement. It is New West Energy's recommendation that the Commission adjust the settlement as is appropriate under the current circumstances, and start competition in the TEP service territory. Then, the Commission can conduct a proper cost of service study and conduct a proper rate case. In the event that the rate case determines that adjustments should be made, then they should be made on a prospective basis.

Q. When should the Commission conduct the rate case?

A. We recommend that the appropriate filings be made by TEP within three months of approval of the settlement agreement, with the actual rate case starting within six months of approval of the settlement agreement.

Phase out the CTC by 12/31/2004, to match APS and SRP.

Q. What was the last Commission order regarding Stranded Cost Recovery for the Affected Utilities in Arizona?

A. On April 14, 1999, the Commission approved Decision No. 61677 that ordered Affected Utilities to choose from one of five options to recover stranded costs. The five options are as follows: (1) Net Revenues Lost methodology, (2) Divestiture/Auction methodology; (3) Financial Integrity Methodology; (4) Settlement Methodology and (5) the Alternative Methodology.

In the proposed settlement agreement TEP chose the fourth option to recover stranded costs: The Settlement Methodology. (James S. Pigantelli's direct testimony, dated June 30, 1999, page 3, lines 3-6).

Q. When will TEP recover all of its stranded costs under the proposed settlement agreement?

A. The settlement agreement proposed two methods to recover stranded costs, a Floating CTC and a Fixed CTC mechanism. The floating CTC mechanism will terminate on December 31, 2008. The fixed CTC mechanism will terminate when it has recovered $450 million, or on December 31, 2008.

Q. When will Arizona Public Service and Salt River Project expect to collect all of their stranded costs?

A. Both Arizona Public Service Company and Salt River Project have proposed to collect all of their stranded costs by 2004. This is consistent with the Commission objective limit the duration of the transition period to recover stranded costs between three to six years (Decision No. 60977, dated June 22, 1998, page 9, lines 16-20).

Q. Does the proposed settlement agreement meet the Commission's transition objective?

A. No.

Q. What does New West Energy recommend for TEP's transition period?

A. To be consistent with APS, SRP and follow the Commission objectives for stranded cost recovery, New West Energy recommends that TEP recover all of its floating CTC by 12/31/2004.

Q. What is the definition of the Floating CTC under the proposed settlement agreement?

A. Floating CTC is equal to the difference between the customer's bundled rate and the sum of the following: (1) the Market Generation Credit, (2) the adder, (3) distribution, (4) transmission, (5) meter services, (5) meter reading services, (6) billing and collection, (7) DSM, (8) customer information and life-line discount charge, (9) uncollectible accounts, (10) ancillary services, (11) fixed must-run generation, and (12) fixed CTC.

Q. What costs will be recovered under the Fixed CTC as proposed in the settlement agreement?

A. The stranded costs recovered through the Fixed CTC consist of approximately $200 million of regulatory assets and approximately $250 million of above market generating assets. Based on TEP's response to New West Energy's data request No. 2, TEP has identified that the Commission has ordered recovery for regulatory assets at $142M.

Q. What is New West Energy recommendation for TEP's fixed CTC recovery?

A In the interim, New West Energy recommends that the fixed CTC only include properly approved regulatory assets by the Commission. This total is $142 million. The recovery of the remaining $308 million ($248 million of the above market generation and $60 million of deferred taxes) of stranded costs should be collected as part of the floating CTC.

Q. Is New West Energy questioning the level of stranded costs to be recovered under the fixed CTC mechanism?

A. No. To give TEP the incentive to mitigate stranded costs, New West Energy recommends that TEP recover all other costs through the proposed floating CTC mechanism. This is consistent with the Commission objective to have an incentive that will result in a maximum mitigation effort by the Affected Utilities (Decision No. 60977, dated June 22, 1998, page 9, lines 3-4).

Q. What is the financial impact of New West Energy's Stranded Cost Recovery recommendation?

A. Based on TEP's response to New West Energy Data Request No. 1, TEP estimated its total stranded costs to be $683 million under a market price forecast developed by TEP. This is shown in Exhibit RSN-2. Under New West Energy's proposed recommendations that included reducing the T&D rate component to 2.165 cents per kWh, the recovery of stranded cost will be $652M on a net present value basis. This is shown in exhibit RSN-2. The difference in value is $31M.

Proposed distribution prices are excessive

Q. Please discuss the proposed Transmission and Distribution (T&D) prices per the settlement agreement.

A. Transmission prices are regulated by the Federal Energy Regulatory Commission (FERC) and are not subject to the Commission jurisdiction. To be consistent with how TEP presents prices, the T&D prices are combined. Since the transmission prices have not been updated recently, the only increase is in the distribution price.

Distribution pricing in TEP's settlement agreement is defined as system benefits, customer service, metering and billing, uncollectibles, distribution and other charges (Direct testimony, James S. Pignatelli, page 10, lines 22 through 27). Transmission pricing is defined as the FERC regulated prices. The proposed settlement agreement calls for transmission and distribution charges to be set at an average cost of 2.6 cents/kWh (Direct testimony of James S. Pignatelli, dated June 30, 1999, page 10, lines 27 and 28).

Q. How do the proposed combined distribution and transmission prices differ from TEP's current combined transmission and distribution prices?

A. In the proposed settlement agreement, the T&D revenue requirement has increased from \$154 million (2.211 cents/kWh) under Decision No. 59594, dated March 29, 1996 to \$205 million (2.6 cents/kWh) under the proposed settlement agreement. This is an increase of \$51 million to the transmission and distribution revenue requirement. This has increased the average combined transmission and distribution price by almost 18%. While at the same time TEP's overall retail rates have declined 2.1% or $13 million (Decision No. 61104, dated August 28, 1998, page 2).

Q. Why have TEP's average distribution and transmission prices increased by 17.6% since 1994, while overall prices are falling?

A. In the short time frame available to analyze the settlement, it is not possible to give a complete answer. According to data request responses from TEP, only the distribution component of the rate has been updated using a sort of pro-forma analysis that is based on a Business Unit Reporting (BUR) study. No historical test year was used and the distribution prices under the agreement are well above the levels that would be set in a rate case. In fact, the proposed distribution prices are higher than those proposed by TEP in the November 1998 Settlement.

Q. What does New West Energy recommend the T&D price should be?

A. As stated above, TEP's T&D charges are excessive. To be consistent with prior Commission ratemaking orders (Decision Nos. 59594 and 61104), TEP should be allowed to recover an average rate of $0.0221/kWh (T&D rates in the 1995 were 2.21 cents/kWh). With no cost shifting, this rate should be adjusted downward by 2.1% to reflect the overall rate reductions consistent with Decision No. 61104. As such, New West Energy recommends that the average T&D rate be $0.0216/MWh. See Exhibit RSN-4.

Q. How does this price adjustment impact prices and the recovery of stranded costs?

A. By keeping the distribution price at the 1994 level, customers will pay the CTC for five years as opposed to nine years and TEP can recover stranded costs by the end of 2004. This adjustment will allow customers to benefit by more than $200 million over the stranded cost recovery period proposed by TEP.

Increase the proposed market generation to better reflect the cost to serve direct access customers

Q. How will TEP credit customers who choose direct access?

A. Per the settlement agreement, the Market Generation Credit (MGC) is a credit that will be passed on to direct access customers.

Q. What are the components of the MGC?

A. The MGC includes the market price of electricity, distribution losses and an adder.

Q. How will the MGC be calculated per the settlement agreement?

A. The MGC will be calculated monthly in advance and stated as both an on-peak and off-peak value. The on-peak value component will be the product of the Palo Verde NYMEX futures price and one plus the appropriate line loss factor plus an adder. When TEP's system is constrained, the MGC will include the variable cost credit of TEP's must-run generation. The off-peak component shall be determined in the same manner as the on-peak component, except that the Palo Verde futures price will be adjusted by the ratio of off-peak to on-peak hourly prices from the California Power Exchange of the same month from the preceding year.

The purpose of the adder is to estimate the cost of supplying power to a specific customer or customer group and stratum relative to the value of the NYMEX futures price used in the calculation of the market price for a 100 percent load factor.

Q. Does the proposed MGC cover all the costs of serving a retail customer?

A. No. Kevin Higgins states that the adder was "a compromise determined through negotiation." As such, many of the costs of providing competitive electricity to retail customers are not included. For example, the MGC calculation does not reflect the other costs to provide competitive electricity service such as, customer account management, customer service representatives, and financing costs for purchasing power from the wholesale market. (e.g., see California Public Utilities Commission Decision (CPUC) No. 99-06-058, dated June 10, 1999, Revenue Allocation Proceeding for PG&E, SCE and SDG&E, page 24). If these costs are not included, direct access customers pay for them by way of distribution rates although direct access customers make no use of the utility's procurement, load forecasting, scheduling, customer and marketing services.

Q. Does New West Energy recommend any changes to the proposed MGC per the settlement agreement?

A. Yes, New West Energy recommends that the MGC reflect the costs of customer account managers, load forecasting, advertising, rate design, customer service representatives, and financing costs for purchasing power from the wholesale market. A&G costs should be allocated to each category as well. (see CPUC Decision No. 99-06-058). These costs should be included as part of the adder

To ensure that a dynamic marketplace begins quickly, New West Energy recommends that the Commission allow for an additional .15 cents/kWh credit to cover the following services: load forecasting, customer account management, advertising, rate design, customer service representatives and financing costs for procuring power from the wholesale market. This will prevent direct access customers from having to pay for these services twice. With New West Energy's proposed rate case TEP should submit tariffs for each service to be credited back to direct access customers. This .15 cents/kWh credit is an interim credit pending resolution of TEP's next rate case.

Q. Are there any other competitive services that should be credited back to direct access customers?

A. Yes. Economic demand-side management is one of the services provided by ESP's. Today TEP recovers about $3.3 million in rates for DSM programs. Since these services are provided by ESPs, direct access customers who purchase power and energy services from ESPs will pay for DSM services twice, once through a system benefits charge and again directly to their ESP.

Q. What is New West Energy's recommendation regarding TEP's competitive DSM?

A. New West Energy recommends that direct access customers be credited for competitive demand-side services. Based on TEP's current recovery of $3.1 million annually, this equates to .045 cents/kWh.

Q. Please summarize New West Energy's recommended changes to the proposed MGC?

A. The TEP proposed MGC is grossed up for losses and includes the "negotiated" adder which will cover some of the cost of shaping load. New West Energy proposes an additional credit of .195 cents/kWh to be included with the TEP proposed adder. This credit is composed of .045 cents/kWh for DSM and .15 cents/kWh to cover the cost of load forecasting, customer service representatives, customer account managers, rate design, advertising and financing costs for procuring power from the wholesale market. The additional credits to the MGC as proposed by New West Energy will come from the distribution component of the bundled price. This means that the timing and recovery of TEP's stranded costs will not be impacted by crediting customers for these services.

Conclusions

Q. Can you please summarize New West Energy's recommendations?

A. New West Energy recommends the following:

1. New West Energy recommends that the Commission bring competition to Tucson as soon as possible.

2. Since TEP's last cost-of-service study was completed in 1994, New West Energy recommends that Commission order TEP to file a rate case as soon as possible.

3. TEP's stranded cost recovery mechanism should meet the objective of the Commission and match the recovery periods for APS and SRP. To that end, TEP should recover all of its floating CTC costs by no later than 12/31/2004.

4. The proposed T&D average rate of 2.6 cents per kwh in the settlement agreement seems high. Based on 1994 test year figures and recent rate decreases ordered by the Commission, TEP should be allowed to recover 2.165 cents per kwh. The remainder of these charges should be collected in the floating CTC.

5. TEP should only be allowed to recover regulatory assets that have accounting order from the Commission through the proposed fixed CTC mechanism. All other stranded costs should be collected in the floating CTC.

6. The MGC must cover all the costs that are avoided by the Affected Utility. The proposed settlement agreement includes generation costs, but does not address additional costs that will be avoided by TEP.

Q. Does this conclude your direct testimony?

A. Yes.

EXHIBIT RSN-2

New West Energy
TEP's Estimate of Stranded Cost Recovery
Per Settlement Agreement
TEP's response to Data Request NWE-1

Average Standard Offer Rate	4Q 1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
T&D Tariff	2.60	2.58	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57
Fixed CTC	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93		
MGC	3.01	3.01	3.01	3.17	3.30	3.47	3.58	3.76	3.85	3.91	4.01	4.12
Ancillary Services	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Fixed Must-run generation	0.43	0.43	0.45	0.50	0.50	0.51	0.48	0.46	0.46	0.46	0.45	0.45
Floating CTC	0.99	0.97	0.91	0.71	0.58	0.40	0.32	0.16	0.07	0.01	-	-
Total Avg. Retail Rate	8.20	8.16	8.11	8.12	8.12	8.12	8.12	8.12	8.12	8.12	7.27	7.38
Retail MWH Consumption	1,781,685	7,962,610	8,105,407	8,268,139	8,426,162	8,591,155	8,755,232	8,916,705	9,078,629	9,249,612	9,409,722	9,576,824
T&D Tariff	$ 46,323,810	$ 205,435,338	$ 208,308,960	$ 212,491,172	$ 216,552,363	$ 220,792,684	$ 225,009,462	$ 229,159,319	$ 233,320,765	$ 237,715,028	$ 241,829,855	$ 246,124,377
Fixed CTC	$ 16,569,671	$ 74,052,273	$ 75,380,285	$ 76,893,693	$ 78,363,307	$ 79,897,742	$ 81,423,658	$ 82,925,357	$ 84,431,250	$ 86,021,392	$ -	$ -
MGC	$ 53,628,719	$ 239,674,561	$ 243,972,751	$ 262,100,006	$ 278,063,346	$ 298,113,079	$ 313,437,306	$ 335,268,108	$ 349,527,217	$ 361,659,829	$ 377,329,852	$ 394,565,149
Ancillary Services	$ 4,276,044	$ 19,110,264	$ 19,452,977	$ 19,843,534	$ 20,222,789	$ 20,618,772	$ 21,012,557	$ 21,400,092	$ 21,788,710	$ 22,199,069	$ 22,583,333	$ 22,984,378
Fixed Must-run Generation	$ 7,661,246	$ 34,239,223	$ 36,474,332	$ 41,340,695	$ 42,130,810	$ 43,814,891	$ 42,025,114	$ 41,016,843	$ 41,761,693	$ 42,548,215	$ 42,343,749	$ 43,095,708
Floating CTC	$ 17,638,682	$ 77,237,317	$ 73,759,204	$ 58,703,787	$ 48,871,740	$ 34,364,620	$ 28,016,742	$ 14,266,728	$ 6,355,040	$ 924,961	$ -	$ -
Total Avg. Retail Rate	$ 146,098,170	$ 649,748,976	$ 657,348,508	$ 671,372,887	$ 684,204,354	$ 697,601,786	$ 710,924,838	$ 724,036,446	$ 737,184,675	$ 751,068,494	$ 684,086,789	$ 706,769,611
CTC Revenues	$ 34,208,352	$ 151,289,590	$ 149,139,489	$ 135,597,480	$ 127,235,046	$ 114,262,362	$ 109,440,400	$ 97,192,084	$ 90,786,290	$ 86,946,353	$ -	$ -
% open to Competition	20%	20%	100%	100%	100%	100%	100%	100%	100%	1	1	1
Stranded Cost Recovery	$ 6,841,670	$ 30,257,918	$ 149,139,489	$ 135,597,480	$ 127,235,046	$ 114,262,362	$ 109,440,400	$ 97,192,084	$ 90,786,290	$ 86,946,353		
Discount factor	1.1103	1.0537	0.949	0.8548	0.7698	0.6934	0.6245	0.5624	0.5066	0.4562		
NPV of Stranded Cost Rev	$ 7,596,307	$ 31,882,768	$ 141,533,375	$ 115,908,726	$ 97,945,539	$ 79,229,521	$ 68,345,530	$ 54,660,828	$ 45,992,335	$ 39,664,926		
NPV	$ 682,759,854											
Discount rate Pre-tax ROR	11.03%											

New West Energy
NWE's Proposal for TEP's Stranded Cost Recovery
Per Settlement Agreement
TEP's response to Data Request NWE-1

Average Standard Offer Rate	4Q 1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
T&D Tariff	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17
Fixed CTC	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30		
MGC	3.01	3.01	3.01	3.17	3.30	3.47	3.58	3.76	3.85	3.91	4.01	4.12
Ancillary Services	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Fixed Must-run generation	0.43	0.43	0.45	0.50	0.50	0.51	0.48	0.46	0.46	0.46	0.45	0.45
Floating CTC	2.06	2.02	1.96	1.75	1.62	1.44	-	-	-	-	-	-
Total Avg. Retail Rate	8.20	8.16	8.12	8.12	8.12	8.12	6.77	6.93	7.02	7.08	6.87	6.98
Retail MWH Consumption	1,781,685	7,962,610	8,105,407	8,268,139	8,426,162	8,591,155	8,755,232	8,916,705	9,078,629	9,249,612	9,409,722	9,576,824
T&D Tariff	$ 38,573,480	$ 172,390,507	$ 175,462,062	$ 179,005,209	$ 182,426,407	$ 185,998,506	$ 189,550,773	$ 193,046,663	$ 196,552,318	$ 200,254,100	$ 203,720,481	$ 207,338,240
Fixed CTC	$ 5,345,055	$ 23,887,830	$ 24,316,221	$ 24,804,417	$ 25,278,486	$ 25,773,465	$ 26,265,696	$ 26,750,115	$ 27,235,887	$ 27,748,836	$ -	$ -
MGC	$ 53,628,719	$ 239,674,561	$ 243,972,751	$ 262,100,006	$ 278,063,346	$ 298,113,079	$ 313,437,306	$ 335,268,108	$ 349,527,217	$ 361,659,829	$ 377,329,852	$ 394,565,149
Ancillary Services	$ 4,276,044	$ 19,110,264	$ 19,452,977	$ 19,843,534	$ 20,222,789	$ 20,618,772	$ 21,012,557	$ 21,400,092	$ 21,788,710	$ 22,199,069	$ 22,583,333	$ 22,984,378
Fixed Must-run Generation	$ 7,661,246	$ 34,239,223	$ 36,474,332	$ 41,340,695	$ 42,130,810	$ 43,814,891	$ 42,025,114	$ 41,016,843	$ 41,761,693	$ 42,548,215	$ 42,343,749	$ 43,095,708
Floating CTC	$ 36,613,627	$ 160,446,592	$ 158,460,707	$ 144,279,026	$ 136,082,516	$ 123,283,074	$ -	$ -	$ -	$ -	$ -	$ -
Total Avg. Retail Rate	$ 146,098,170	$ 649,748,976	$ 658,159,046	$ 671,372,887	$ 684,204,354	$ 697,601,786	$ 592,291,445	$ 617,481,821	$ 636,865,824	$ 654,410,049	$ 645,977,415	$ 667,983,474
CTC Revenues	$ 41,958,682	$ 184,334,422	$ 182,776,928	$ 169,083,443	$ 161,361,002	$ 149,056,539	$ 26,265,696	$ 26,750,115	$ 27,235,887	$ 27,748,836	$ -	$ -
% open to Competition	20%	20%	100%	100%	100%	100%	100%	100%	100%	1	1	1
Stranded Cost Recovery	$ 8,391,736	$ 36,866,884	$ 182,776,928	$ 169,083,443	$ 161,361,002	$ 149,056,539	$ 26,265,696	$ 26,750,115	$ 27,235,887	$ 27,748,836		
Discount factor	1.1103	1.0537	0.949	0.8548	0.7698	0.6934	0.6245	0.5624	0.5086	0.4582		
NPV of Stranded Cost Rev	$ 9,317,345	$ 38,846,636	$ 173,455,305	$ 144,532,527	$ 124,215,700	$ 103,355,804	$ 16,402,927	$ 15,044,265	$ 13,797,700	$ 12,659,019		
NPV	$ 651,627,227											
Discount rate Pre-tax ROR	11.03%											

New West Energy
NWE's Proposal for TEP's Stranded Cost Recovery
Per Settlement Agreement
TEP's response to Data Request NWE-1

Average Standard Offer Rate	4Q 1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
T&D Tariff	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17
Fixed CTC	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30		
MGC	3.01	3.01	3.01	3.17	3.30	3.47	3.58	3.76	3.85	3.91	4.01	4.12
Ancillary Services	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Fixed Must-run generation	0.43	0.43	0.45	0.50	0.50	0.51	0.48	0.46	0.46	0.46	0.45	0.45
Floating CTC	2.06	2.02	1.96	1.75	1.62	1.44	-	-	-	-	-	-
Total Avg. Retail Rate	8.20	8.16	8.12	8.12	8.12	8.12	6.77	6.93	7.02	7.08	6.87	6.98

	4Q 1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Retail MWH Consumption	1,781,685	7,962,610	8,105,407	8,268,139	8,426,162	8,591,155	8,755,232	8,916,705	9,078,629	9,249,612	9,409,722	9,576,824
T&D Tariff	$ 38,573,480	$ 172,390,507	$ 175,482,062	$ 179,005,209	$ 182,426,407	$ 185,998,506	$ 189,550,773	$ 193,046,663	$ 196,552,318	$ 200,254,100	$ 203,720,481	$ 207,338,240
Fixed CTC	$ 5,345,055	$ 23,887,830	$ 24,316,221	$ 24,804,417	$ 25,278,486	$ 25,773,465	$ 26,265,696	$ 26,750,115	$ 27,235,887	$ 27,748,836	$ -	$ -
MGC	$ 53,628,719	$ 239,674,561	$ 243,972,751	$ 262,100,006	$ 278,063,346	$ 298,113,079	$ 313,437,306	$ 335,268,108	$ 349,527,217	$ 361,659,829	$ 377,329,852	$ 394,565,149
Ancillary Services	$ 4,276,044	$ 19,110,264	$ 19,452,977	$ 19,843,534	$ 20,222,789	$ 20,618,772	$ 21,012,557	$ 21,400,092	$ 21,788,710	$ 22,199,069	$ 22,583,333	$ 22,984,378
Fixed Must-run Generation	$ 7,661,246	$ 34,239,223	$ 36,474,332	$ 41,340,695	$ 42,130,810	$ 43,814,891	$ 42,025,114	$ 41,016,843	$ 41,761,693	$ 42,548,215	$ 42,343,749	$ 43,095,708
Floating CTC	$ 36,613,627	$ 160,446,592	$ 158,460,707	$ 144,279,026	$ 136,082,516	$ 123,283,074	$ -	$ -	$ -	$ -	$ -	$ -
Total Avg. Retail Rate	$ 146,098,170	$ 649,748,976	$ 658,159,048	$ 671,372,887	$ 684,204,354	$ 697,601,786	$ 592,291,445	$ 617,481,821	$ 636,865,824	$ 654,410,049	$ 645,977,415	$ 667,983,474
CTC Revenues	$ 41,958,682	$ 184,334,422	$ 182,776,928	$ 169,083,443	$ 161,361,002	$ 149,056,539	$ 26,265,696	$ 26,750,115	$ 27,235,887	$ 27,748,836	$ -	$ -
% open to Competition	20%	20%	100%	100%	100%	100%	100%	100%	100%	1	1	1
Stranded Cost Recovery	$ 8,391,736	$ 36,866,884	$ 182,776,928	$ 169,083,443	$ 161,361,002	$ 149,056,539	$ 26,265,696	$ 26,750,115	$ 27,235,887	$ 27,748,836		
Discount factor	1.1103	1.0537	0.949	0.8548	0.7698	0.6934	0.6245	0.5624	0.5066	0.4562		
NPV of Stranded Cost Rev	$ 9,317,345	$ 38,846,636	$ 173,455,305	$ 144,532,527	$ 124,215,700	$ 103,355,804	$ 16,402,927	$ 15,044,265	$ 13,797,700	$ 12,659,019		
NPV	$ 651,627,227											
Discount rate Pre-tax ROR	11.03%											