

TUCSON ELECTRIC POWER COMPANY

**DOCKET NO. E-01933A-07-0402
DOCKET NO. E-01933A-05-0650**

**DIRECT TESTIMONY
OF
BEN JOHNSON, PH.D.**

**ON BEHALF OF
THE
RESIDENTIAL UTILITY CONSUMER OFFICE**

FEBRUARY 29, 2008

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1 TESTIMONY

2 OF BEN JOHNSON, PH.D.

3 On Behalf of

4 The Residential Utility Consumer Office

5 Before the

6 Arizona Corporation Commission

7
8 Docket No. E-01933A-07-0402

9 Docket No. E-01933A-05-0650

10
11
12 **Introduction**

13
14 **Q. Would you please state your name and address?**

15 A. Ben Johnson, 3854-2 Killlearn Court, Tallahassee, Florida.

16
17 **Q. What is your present occupation?**

18 A. I am a consulting economist and president of Ben Johnson Associates, Inc.®, an economic
19 research firm specializing in public utility regulation.

20
21 **Q. Have you prepared an appendix that describes your qualifications in regulatory and
22 utility economics?**

23 A. Yes. Appendix A, attached to my testimony, will serve this purpose.

24
25 **Q. What is your purpose in making your appearance at this hearing?**

26 A. Our firm has been retained by the Residential Utility Consumer Office ("RUCO") to assist with

1 RUCO's evaluation of the three methodologies proposed by Tuscon Electric Power Company
2 (TEP) for setting rates related to generating electricity.

3 Following this introduction, my testimony has four sections. In the first section, I briefly
4 summarize some of the history leading to this proceeding. In the second section, I summarize
5 the three rate setting methodologies proposed by TEP, focusing on the development of rates for
6 generation services. In the third section, I discuss several problems with TEP's filing. In this
7 section I point out how TEP's forecasted rates are flawed, and could lead the Commission to the
8 wrong conclusion when evaluating the merits of TEP's proposed rate-setting methodologies. I
9 also discuss how market-based generation rates may result in rates that are not just and
10 reasonable – a problem that also applies to TEP's hybrid proposal. In the fourth and final
11 section, I summarize my conclusions and recommendations.

12
13 **Q. As background information, can you please briefly summarize the history of this**
14 **Commission's Electric Competition rules?**

15 A. The Commission adopted its Electric Competition Rules (Rules) in 1996. [See, Decision No.
16 59943] The Rules were intended to "set forth a framework for the inevitable transition from a
17 non-competitive to a competitive environment". [Id., p. 2]

18 Among other things, the Rules required TEP to file estimates of its stranded costs, and
19 required commission approval of any charges intended to recover stranded costs. [R14-2-
20 1607(G) and (H)] In September 1999, the Commission revised the Rules to require TEP to
21 divest its generation assets and to purchase its power for Standard Offer Service from the
22 competitive market. [R14-2-1615(A) and R14-2-1606(B)] The Rules also declare that rates set
23 by the market for competitive services are deemed just and reasonable. [R14-2-1611(A)]

1 **Q. Now, can you briefly summarize this Commission's efforts to foster competition as they**
2 **relate specifically to Tucson Electric Power?**

3 A. On June 22, 1998 the Commission issued its Stranded Cost Order, which required TEP to file a
4 plan for stranded cost recovery. [Decision No. 60977] On August 10, 1998, TEP filed its
5 Stranded Cost Recovery Plan. On June 9, 1999, TEP, RUCO and several other parties entered
6 into Settlement Proposal, which was intended to resolve various disputed issues concerning
7 TEP's proposed Stranded Cost Recovery Plan. [See, Decision 62103, p. 2] On November 30,
8 1999, the Commission adopted the Settlement Agreement, with modifications. [Decision
9 62103]

10 The Settlement Agreement required TEP to transfer its generation assets to a subsidiary
11 by December 31, 2002. [Settlement Agreement § 3.1] The Settlement Agreement also
12 reaffirmed rate reductions of 1 percent in 1999 and again in 2000, and a rate freeze thereafter
13 through December 31, 2008. [Settlement Agreement § 5.1] In exchange, the Settlement
14 Agreement provided mechanisms for the recovery of TEP's stranded costs, thereby shielding
15 TEP from the anticipated adverse financial impact of allowing competitors to supply electricity
16 in TEP's service area.

17

18 **Q. Can you explain how TEP's stranded costs were to be recovered under the Settlement**
19 **Agreement?**

20 A. Yes. TEP's frozen rates would include a fixed Competitive Transition Charge (CTC) and a
21 floating CTC. [Settlement Agreement § 2.1] The fixed CTC was set at 0.93 cents/kWh and
22 would terminate after recovery of \$450 million of stranded costs, or on December 31, 2008,
23 whichever occurred first. [Id.] The floating CTC was intended to recover an estimated
24 additional \$233 million in stranded costs. The floating CTC would be determined in part by a
25 Market Generation Credit (MGC) based upon a market-index futures price. The MGC and CTC
26 were inversely related; an increase in the MGC results in a decrease in the CTC, and vice versa.

1 In other words, the floating CTC would decrease as the market price of power increased (as
2 estimated by the MGC market index). The Settlement Agreement acknowledged that the
3 floating CTC could actually be negative, if short term wholesale prices increase, in which case
4 "the negative value would be credited to the customers' monthly bill". [Decision 62103, p. 5]
5 The Settlement Agreement provides for termination of the floating CTC on December 31, 2008.
6 [Id.]

7
8 **Q. Are there any other major provisions of the Settlement Agreement that you would like to**
9 **mention at this point?**

10 A. Yes. The Settlement Agreement also provided for a review of TEP's rates in 2004. The purpose
11 was to facilitate a Commission investigation into whether TEP's Standard Offer rates, or its
12 overall unbundled rates had been set too high, and should be reduced. [Settlement Agreement, §
13 5.2]

14
15 **Q. Can you now discuss the next significant event leading up to this proceeding?**

16 A. On September 10, 2002 the Commission issued its "Track A Order", which modified portions of
17 the Rules and Decision 62103. [Decision No. 65154] Specifically, the Track A Order granted
18 TEP a waiver from the requirement to divest its generation assets and the requirement to
19 purchase energy on the competitive market. [Id., pp. 32-33] The Commission stated:

20 In retrospect, it was a good idea to delay divestiture and competitive
21 procurement in the APS and TEP Settlement Agreements, given what has
22 happened in the last two or so years, including the experience in California; the
23 market volatility and illiquidity; and the lack of public confidence in the
24 transition to electric deregulation and ability of regulators to prevent price
25 spikes, ensure reliable service, and prevent bankruptcies. Even today, there is
26 not agreement amongst economists, much less regulators, as to why ...what
27 happened in California, happened, and how to prevent a similar or related
28 occurrence.

29 It is clear that the Commission and all parties expected benefits from
30 retail competition, yet there is no active retail Competition, so actual benefits
31 are still unknown. It is said that consumers will benefit from wholesale
32 competition, but not without the proper market structure and regulatory
33 framework that will support it. It was anticipated that at the time that APS and

1 TEP divested, ESPs would be providing direct access to retail customers. In
2 actuality, no retail competition exists; market power is held by the incumbent
3 utilities; no RTO is in effect; transmission constraints exist that potentially
4 exacerbate market abuse; the GAO has issued a negative report on FERC's
5 ability to manage competitive markets; both TEP and APS recognize a problem
6 - one wants to postpone its divestiture while the other is affected by its parent's
7 and affiliates' adverse financial considerations; proposed new generation may
8 be cancelled if it is not able to find a market; more protections are needed
9 against self-dealing and inappropriate affiliate transactions; and investigations
10 are ongoing into market manipulations and improprieties. Contrary to what APS
11 argues, these changes relate to the question of divestiture, especially to our
12 willingness to transfer our ratemaking jurisdiction over generation assets to
13 FERC, given its recent history regulating the wholesale market and the
14 conclusions contained in the recent GAO report. [Id., p. 22]
15
16

17 **Q. Have the Commission's Competition Rules also been the subject of some controversy?**

18 A. Yes. Various parties challenged the Rules, and several Certificates of Convenience and
19 Necessity (CC&Ns) that were issued to potential competitors pursuant to the Rules. Primarily at
20 issue was Rule R14-2-1611 which provides: "Market determined rates for Competitive
21 Services, as defined in R14-2-1601 shall be deemed to be just and reasonable."

22 In resolving this dispute, the Court of Appeals of Arizona noted that the Arizona
23 Constitution requires the Commission to "prescribe ... just and reasonable rates and charges to
24 be made and collected by public service corporations" and to "ascertain the fair value of the
25 property within the State of every public service corporation doing business therein." [Phelps
26 Dodge v. AEPCO, 83 P.3d 573, ¶ 18 (App. 2004)] The Court of Appeals concluded that the
27 Commission violated these portions of the Arizona Constitution by approving CC&N's for
28 competitive electric providers without first determining and considering fair value. [Id., ¶ 24]
29 As well, the Court rejected the Commission's sweeping replacement of traditional ratemaking
30 principles with market-based pricing, concluding that "the Commission may not abdicate its
31 constitutional responsibility to set just and reasonable rates by allowing competitive market
32 forces alone to do so". [Id., ¶ 32]
33
34

1 **Q. Previously you mentioned that TEP's rates were supposed to be reviewed in 2004. Did**
2 **that review occur?**

3 A. Yes. In 2004 TEP filed the rate review required by Decision No. 62103, claiming a revenue
4 deficiency of \$111 million. The Staff, RUCO and other parties disputed TEP's alleged revenue
5 deficiency, contending that this computation was greatly overstated. However, no party
6 concluded that TEP was over-earning, which was the key issue under consideration. Hence, the
7 proceeding was suspended and no action was taken by the Commission.

8

9 **Q. What happened after the 2004 rate review?**

10 A. In 2005, TEP filed a Motion for Declaratory Order, seeking clarification of whether TEP would
11 be entitled to charge Standard Offer generation rates based on the MGC in 2009 and beyond.
12 After several parties filed opposition to the Motion for Declaratory Order, the Administrative
13 Law Judge issued a procedural order suggesting TEP file its request for relief in a different
14 form. TEP then filed a Motion to Amend Decision No. 62103. That Motion was assigned
15 Docket No. E-01933A-05-0650. In April 2006, the Commission issued Decision No. 68669,
16 which ordered that a hearing be held to consider amending Decision No. 62103 and the
17 Settlement Agreement. TEP then filed testimony in which it claimed that the Settlement
18 Agreement provided that TEP could begin charging market-based rates beginning in 2009 in
19 accordance with the MGC provisions of the Settlement Agreement. TEP's testimony also
20 presented two proposals for generation rates beginning in 2009, a market-phase in proposal and
21 a traditional cost of service proposal that included an \$850 million regulatory asset.

22

23 **Q. What was RUCO's position on TEP's Motion to Amend Decision No. 62103?**

24 A. RUCO opposed TEP's claim that the Settlement Agreement required the use of the MGC
25 mechanism to establish Standard Offer generation rates in 2009. RUCO also opposed the two
26 alternatives TEP had proposed, and suggested that the Commission should establish rates based

1 on a traditional cost of service rate case, to be effective in 2009. RUCO filed testimony and a
2 legal memorandum in support of its position¹. Other parties likewise disagreed with TEP's
3 contention that generation rates for Standard Offer service would be based on the MGC in 2009.
4 During the hearing on the Motion to Amend in March 2007, TEP offered another alternative for
5 setting generation rates based on a hybrid of cost-based and market-based rates.

6
7 **Q. What was the disposition of TEP's Motion to Amend?**

8 A. The Commission issued Decision No. 69568 in May 2007. The Commission did not decide the
9 issue of how rates would be established in 2009, but ordered TEP to file a rate application that
10 included all of its rate proposals for side-by-side comparison. The Commission ordered that the
11 rate application would be consolidated with the docket on the Motion to Amend. In July 2007,
12 TEP filed the rate application that is the subject of my testimony.

13
14 **Q. How does your testimony differ from that RUCO offered in response to the Motion to**
15 **Amend?**

16 A. The testimony and legal memorandum RUCO presented in the Motion to Amend docket
17 explained why the Commission was not required to establish TEP's rates based on the MGC
18 methodology beginning in 2009. My testimony is meant to evaluate the relative merits of TEP's
19 various proposals based on the assumption that the Commission agrees it is not required to use
20 the MGC methodology as TEP has claimed it is.

21
22
23
24

1 Direct Testimony of Marylee Diaz Cortez, filed January 7, 2007 in Docket No. E-0933A-05-0650 (with attached
2 legal memorandum); and Surrebuttal Testimony of Marylee Diaz Cortez, filed February 8, 2007 in the same
3 docket. Ms. Diaz Cortez also testified at the hearing in March 2007. The entire record in Docket No. E-01933A-
4 05-0650 has been consolidated with the Rate Application, per Decision No. 69568.

1 **TEP's Generation Proposals**

2
3 **Q. Could you now summarize TEP's proposals regarding the treatment of generation assets**
4 **and its proposals for rates related to generating electricity?**

5 A. TEP proposes three different rate making methodologies, which differ in their treatment of
6 TEP's generating plants, and in the development of rates related to generation. The methods are:
7 the "Market Methodology", the "Cost-of-Service Methodology", and the "Hybrid
8 Methodology".

9
10 **Q. Can you briefly describe TEP's proposed Market Methodology?**

11 A. Yes. TEP claims that, beginning January 1, 2009, it is entitled to charge market-based rates for
12 generation service.²

13 TEP has presented the Market Methodology to the Commission because it
14 believes that when the rate increase moratorium in the 1999 Settlement
15 Agreement is lifted on January 1, 2009, it is entitled to (i) a rate increase for
16 transmission and distribution service; and (ii) charge rates for generation service
17 based upon the market-based methodology set forth in the 1999 Settlement
18 Agreement. [Pignatelli Direct Testimony, p. ii]
19

20 The Market Methodology put forward by TEP is premised on this interpretation of the 1999
21 Settlement Agreement. TEP seems to be claiming it has a legal right to charge customers for
22 generation based on a "market-based proxy, the Market Generation Credit ("MGC")" as set
23 forth in the 1999 Settlement Agreement". TEP's support for its Market proposal is based almost
24 entirely on its legal theory and its claims concerning the 1999 Settlement Agreement. In its
25 direct case, TEP made no real effort to demonstrate that its Market proposal is in the public
26 interest, treats customers fairly, or results in fair and reasonable rates.

27 While TEP claims it is entitled to charge market-based rates consistent with its Market
28 proposal, it does provide two alternatives for Commission consideration. The Cost-of-Service

2 As discussed above, RUCO disagrees with TEP's position and has set forth the basis for that disagreement in Docket No. E-01933A-05-0650.

1 and Hybrid Methodologies are presented to "help the Commission evaluate our proposals for
2 amending the 1999 Settlement Agreement and Decision No. 62103 in furtherance of settlement
3 discussions and negotiations among the parties to the 1999 Settlement Agreement". [Id., p. 7]
4

5 **Q. How would rates for transmission and distribution services be developed under the
6 Market Methodology?**

7 A. Transmission and distribution rates would be based on a traditional cost of service approach
8 recovering TEP's actual costs and allowing it to earn a fair return on the transmission and
9 distribution portion of its fair value rate base. [See, Id., p. i]
10

11 **Q. Can you now explain how rates for generation service would be determined under the
12 Market Methodology?**

13 A. Under the Market Methodology, TEP proposes to set prices for generation service using the
14 MGC computations set forth in its Settlement Agreement.

15 Market prices for generation service would be calculated using the existing
16 Market Generation Credit ("MGC") rate schedule (Rate Schedule MGC-1) from
17 TEP's 1999 Settlement Agreement as modified by Decision No. 65754 (March
18 20, 2003). This Schedule is attached to my testimony as Exhibit DGH-11, and
19 incorporated herein. This MGC value is derived from a Palo Verde market index
20 published by Platts, a McGraw-Hill publication. [Hutchins Direct Testimony, p.
21 47]
22

23 The Settlement Agreement provides that the MGC is calculated 30 days prior to each calendar
24 estimation month using the most recent 3 day average of the Platts Long-Term Forward
25 Assessment for Palo Verde Forward prices. [See, Schedule MGC-1, p. 2] These are "spot"
26 prices for large blocks of electricity transferred from one utility to another on a short term basis.
27

28 **Q. Are there any other aspects of the Market Methodology you would like to mention at this
29 point?**

30 A. Yes. There is one other point I would like to mention. Under the Market Methodology, TEP's

1 rate base would include an Implementation Cost Regulatory Asset (ICRA) of \$14.2 million to
2 recover "direct costs incurred to implement competition in compliance with the 1999 Settlement
3 Agreement". [Id., p. 5] The largest component of the \$14.2 million ICRA is computer software
4 costs. [Kissinger Direct Testimony, p. 8] The \$14.2 million ICRA also includes costs incurred
5 by funding and developing two entities (Desert Star and WestConnect) which were formed to
6 provide more open access to the Arizona transmission grid. [Id., p. 10] Other costs include
7 consulting fees, and accounting, legal, administrative, and payroll expenses. [Id., pp. 8-10]

8
9 **Q. What is the rate impact of TEP's proposed Market Methodology?**

10 A. By the Company's calculations, the Market Methodology would result in an immediate 21.9%
11 increase "based on current projections for wholesale market power prices". [TEP Application, p.
12 2]

13
14 **Q. Can you now summarize TEP's proposed Cost-of-Service Methodology?**

15 A. If the Commission rejects the Market Methodology (e.g. because it would result in
16 unreasonably high rates), TEP nevertheless wants a rate increase of a similar magnitude. It
17 proposes to accomplish this by implementing a modified version of traditional rate making.
18 Nominally, transmission, distribution and generation rates would all be based on cost of service
19 principles. [Id.] Significantly, however, TEP proposes to include both a \$47.5 Million ICRA in
20 its rate base, and to recover an additional \$788 million which it refers to as a Termination Cost
21 Regulatory Asset (TCRA) [Id., p. 7]. The effect of the proposed TCRA, if approved, would be
22 to increase rates to nearly the same level as its Market proposal.

23
24 **Q. What is included in the \$47.5 million ICRA?**

25 A. The \$47.5 million ICRA includes the \$14.2 million discussed previously, plus additional costs
26 that TEP incurred in buying out certain coal contracts, and refinancing costs associated with

1 certain generation assets. [Id., pp. 11-12]

2
3 **Q. Can you now explain the \$788 million TCRA?**

4 A. TEP claims that the TCRA reflects its estimate of the "financial impact of meeting its
5 obligations under the 1999 Settlement Agreement and transitioning back to cost-of-service
6 ratemaking in 2009". [TEP Application, p. 7] The TCRA would be recovered through a TCRA
7 Charge at an average rate of \$0.0126 per kWh. [Id.] TEP explains the TCRA as follows:

8 The TCRA represents economic harm that will have been suffered by TEP if the
9 1999 Settlement Agreement is not honored and generation service rates are
10 based solely on cost-of-service principles. The TCRA will place TEP in the
11 position it would have been but for the 1999 Settlement Agreement. The amount
12 of the TCRA included in the Company's rate request under the Cost-of-Service
13 Methodology is \$788 million, which is based on the \$111 million revenue
14 deficiency proved in the 2004 Rate Review. Applying this revenue deficiency,
15 the Company has determined that it will have foregone revenues in an amount
16 that will reach \$788 million by May 2008. The cumulative balance of the
17 foregone revenues will grow to \$921 million by December 2008. However,
18 because TEP believes that the continuation of the collection of CTC revenues
19 beyond May 2008 is a partial mitigation of the losses that TEP has suffered as a
20 result of the 1999 Settlement Agreement not being honored in full, the
21 Company is proposing the lower \$788 million balance for the TCRA. [Pignatelli
22 Direct Testimony, p. 20]

23
24 **Q. Are there any other aspects of TEP's proposed Cost-of-Service Methodology that you
25 would like to mention?**

26 A. Yes. Under this methodology TEP is proposing to implement a Purchased Power and Fuel
27 Adjustment Clause (PPFAC). Mr. Pignatelli explains:

28 TEP does not currently employ a PPFAC. However, in light of the volatile fuel
29 and purchased power costs experienced in recent years, TEP should have a
30 PPFAC mechanism in place to provide for the timely recovery of fuel and
31 purchased power costs incurred in serving its customers. A PPFAC would serve
32 the best interests of TEP and its customers. [Id.]

33
34 Mr. Hutchens further explains:

35 TEP relies on significant quantities of natural gas and purchased power to meet
36 its retail load. Although TEP has served the majority of its load with company-
37 owned generating resources, it relies on natural gas and purchased power to
38 meet a growing percentage of its customer demand. This gas and power is

1 purchased at market prices, so TEP should be allowed to recover these costs.
2 [Hutchens Direct Testimony, p. 30]

3
4 In addition, TEP proposed that its Certificate of Convenience and Necessity ("CC&N") be
5 restored to its former exclusive status.

6
7 **Q. What is the rate impact of TEP's proposed Cost-of-Service Methodology?**

8 A. By the Company's calculations, the Cost-of-Service Methodology would result in a 23.0%
9 increase "based on current expectations for future power supply costs". [TEP Application, p. 3]
10 As I will discuss later in my testimony, a large portion of this proposed increase is directly
11 attributable to the proposed TCRA.

12
13 **Q. Can you describe the Company's proposed Hybrid Methodology?**

14 A. TEP's Hybrid Methodology selectively combines elements of the Cost of Service and Market
15 Methodologies. Under this approach, transmission, distribution and some generation rates
16 would be based on traditional cost of service principles. However, TEP's interest in certain
17 generation assets would be removed from rate base and designated as wholesale assets. [Id.]

18 The assets excluded from rate base under the Hybrid Methodology are (i) the
19 Company's interest in Navajo Generating Station Units 1, 2 and 3, and (ii) the
20 Company's interest in Four Corners Generating Station Units 4 and 5 (the
21 "excluded generation assets"). These excluded generation assets will be
22 dedicated to wholesale market transactions, although the power could be used to
23 supply TEP's retail customers at prices reflecting wholesale market conditions.
24 In that circumstance, the cost to supply TEP's retail customers from those
25 excluded generation assets would be recovered through the PPFAC and not base
26 rates. [Id., p. 7]

27
28 Notably, TEP is not seeking recovery of any portion of the proposed \$788 million TCRA under
29 its proposed Hybrid Methodology, although it does seek recovery of the full \$47.5 Million
30 ICRA. The Hybrid Methodology also includes a PPFAC. [Pignatelli Direct Testimony, p. ii]
31 Further, TEP proposes that if its Hybrid Methodology is adopted, TEP's exclusive CC&N would
32 be partially restored. Specifically, TEP proposes that only customers with a demand in excess
33 of 3MW would be permitted to obtain generation service from a competitive provider.

1 **Q. What is the rate impact of TEP's proposed Hybrid Methodology?**

2 **A.** By the Company's calculations, the Hybrid method would result in a 14.9% increase "based on current
 3 expectations for future power supply costs". [TEP Application, p. 3] This is much less than the impact of
 4 the Cost of Service Approach, primarily because the Hybrid Approach doesn't include the TCRA. It is
 5 less than the impact of the Market Approach, because fewer generating plants would be moved out of the
 6 rate base and thus a larger portion of its generation-related rates would continue to be based on
 7 traditional rate setting principles – a much smaller fraction of its generating costs would be tied to the
 8 MGC calculations.

9
 10 **Q. Has TEP provided a comparison of the rate effects of the three different methodologies?**

11 **A.** Yes. In response to Staff data request 5.11, TEP provided a forecast of unbundled rates for the three
 12 methodologies for the years 2009 through 2015, in comparison to the test year unbundled rates. As
 13 shown in the following table, TEP's total test year unbundled rates were 8.42 cents per kWh. Total 2009
 14 rates under the Cost-of-Service, Market and Hybrid Methodologies are forecast to be 23.4%, 21.4% and
 15 15.3% greater than the current unbundled rates, respectively.

¢ / kWh	TEP's	2009 Forecast Rates		
	Test Year	Cost of Service	Market	Hybrid
Distribution	1.98	1.58	1.58	1.58
Transmission	0.78	0.70	0.70	0.70
Must-Run & Ancillary	0.64	0.55	0.55	0.55
Fixed CTC	0.97	NA	NA	NA
Floating CTC	(2.67)	NA	NA	NA
MGC	6.66	NA	7.39	NA
DSM	0.06	NA	NA	NA
Generation Non-Fuel	NA	2.99	NA	2.62
PPFAC	NA	3.31	NA	4.25
TCRAC	NA	1.26	NA	NA
Total	8.42	10.39	10.22	9.71
Percent Increase		23.4%	21.4%	15.3%

18

19

1 As shown in the following table, total 2015 rates under the Cost-of-Service, Market and Hybrid
 2 Methodologies are forecast by TEP to be 34.5%, 16.6% and 25.0% greater than test year rates,
 3 respectively.

¢ / kWh	TEP's	2015 Forecast Rates		
	Test Year	Cost of Service	Market	Hybrid
Distribution	1.98	1.58	1.58	1.58
Transmission	0.78	0.70	0.70	0.70
Must-Run & Ancillary	0.64	0.55	0.55	0.55
Fixed CTC	0.97	NA	NA	NA
Floating CTC	(2.67)	NA	NA	NA
MGC	6.66	NA	6.99	NA
DSM	0.06	NA	NA	NA
Generation Non-Fuel	NA	2.99	NA	2.62
PPFAC	NA	4.24	NA	5.07
TCRAC	NA	1.26	NA	NA
Total	8.42	11.33	9.82	10.53
Percent Increase		34.5%	16.6%	25.0%

6 This forecast suggests the market approach will be less onerous in future years than it is initially.
 7 However, this is tied to the forecast (or assumption) that the MGC will only slightly increase from the
 8 test year level of 6.66 cents to 6.99 cents in 2015. Needless to say, there is no assurance that this
 9 forecast will come to pass. If natural gas prices continue to escalate, or growth in demand for electricity
 10 in California and the Western United States outstrips growth in new supply, spot market prices at Palo
 11 Verde could increase dramatically, causing the MGC to escalate far above the level shown in this
 12 forecast.

1 **Critique of TEP's Generation Proposals**
2

3 **Q. Let's turn to the next section of your testimony. As you offer your critique of TEP's**
4 **proposals regarding generation rates, to what degree do you consider the aspects of TEP's**
5 **proposals relating to the exclusivity of its CC&N?**

6
7 A. My comments below are applicable to the aspects of TEP's proposals relating to the pricing of
8 generation regardless of whether the Commission were to decide to restore any exclusivity to
9 TEP's and CC&N. Essentially, I have set aside those aspects of TEP's proposal relating to its
10 CC&N, and I am evaluating only the generation pricing of its proposals. I understand that the
11 issue of whether the Commission wants to maintain a competitive retail generation market
12 structure is under consideration in other dockets, and I do not believe that it would be necessary
13 for the Commission to resolve that issue for TEP in this proceeding. The determination of how
14 TEP's Standard Offer Service is priced is not dependent on any particular resolution of the
15 CC&N question, and any of TEP's pricing mechanisms could theoretically exist whether TEP's
16 CC&N was exclusive or not. While I recognize that the issue of whether the Commission will
17 permit retail electric competition is a significant one, the Commission can evaluate TEP's
18 proposed generation pricing alternatives without having decided whether retail competition will
19 be permitted or not. I recommend that the Commission not make a decision on the future status
20 of TEP's CC&N in this proceeding.

21
22 **Q. Can you briefly identify some of your concerns with respect to TEP's proposals relating to**
23 **market-based generation rates?**

24 A. Yes. TEP's proposed Market Methodology is based on some incorrect assumptions – that it is
25 entitled to charge market-based generation rates, and that the resulting rates will be just and
26 reasonable. Moreover, TEP's forecast rate comparisons are flawed, and could lead the
27 Commission to incorrect conclusions when evaluating the relative merits of the the proposals.

1 Finally, TEP's Market Methodology will result in widely fluctuating rates that can easily exceed
2 levels that are just and reasonable. And, even if rates were to average out to a reasonable level
3 over a long period of time (something that has not been demonstrated), the very fact that the
4 rates would fluctuate so widely from month-to-month and year-to-year is a reason for
5 concluding that the proposed Market-based rates would not be just and reasonable.

6
7 **Q. Can you briefly explain your first concern, TEP's assumption that it is entitled to charge**
8 **market-based generation rates?**

9 A. TEP contends that it has the right to charge customers for electrical generation on the basis of
10 the MGC formula set forth in the 1999 Settlement Agreement. Since it assumes it already has
11 the right to do this, TEP makes little or no effort to argue that this is would be fair, or that the
12 resulting rates would be just and reasonable. As the Commission knows, RUCO strongly
13 disagrees with this assumption. As explained in various pleadings submitted to the
14 Commission, RUCO has a fundamentally different interpretation of the 1999 Settlement
15 Agreement; and, even if TEP's interpretation had some validity, it would not negate the need to
16 demonstrate that the resulting rates will be just and reasonable – something TEP has not even
17 attempted.

18
19 **Q. Doesn't the MGC portion of the 1999 Settlement Agreement expire on December 31,**
20 **2008?**

21 A. Yes, it certainly appears that way to me in my reading of the Agreement as a non-lawyer. The
22 purpose of the MGC was to develop the floating CTC, and under the terms of the Settlement
23 Agreement, the floating CTC will expire on December 31, 2008. Logically, after the CTC
24 expires, the MGC will become unnecessary, and thus the provisions relating to the MGC would
25 become moot. I don't see any provisions in the Settlement Agreement that specifically
26 contemplate using the MGC for any purpose other than developing the floating CTC.

1 **Q. Does TEP agree that the Settlement Agreement calls for the expiration of the MGC at the**
2 **end of 2008?**

3 A. No. TEP contends that the Settlement Agreement is silent as to the expiration of the MGC.
4 "While the Floating CTC terminates on December 31, 2008, the agreement set no expiration
5 date for the MGC rate". [Pignatelli Direct Testimony, p. 14] Perhaps more importantly, TEP
6 claims that the MGC is of general applicability – it isn't simply a component used in computing
7 the floating CTC, and that the Settlement Agreement "requires TEP to charge the MGC rate for
8 generation service". [Id.]

9 In searching the text of the Settlement Agreement, I did not find any references to the
10 MGC except in the section 2, "Stranded Cost Recovery" (pages 4-7 of Attachment No. 1 to
11 Decision 62103). For instance, it says: "The Floating CTC shall be calculated using a Market
12 Generation Credit CMGC") methodology ... and will terminate on December 31, 2008."

13 Similarly, I did not find any statement in the Settlement Agreement concerning how standard
14 offer generation service would be priced, or that prices would be based on spot market prices.
15 In fact, at page 8, under Section 4 Unbundled Rates, there is a provision that states

16 TEP's rates shall be fully unbundled into separate charges for: (a) distribution;
17 (b) transmission; (c) metering; (d) billing; (e) ancillary services; (f) fixed must-
18 run generation; (g) system benefits; and (h) standard offer generation, the sum
19 of TEP's standard offer which shall not exceed a customer's current bundled
20 rates.

21
22 This language certainly doesn't provide support for the view that the Settlement Agreement
23 mandates a substantial increase in rates above the then-existing level of bundled rates. To the
24 contrary, my impression of this language as a non-lawyer is that the intent was to ensure that
25 standard offer customers (those who continue to purchase energy from TEP) would not face
26 any increase in their rates as a result of the unbundling process or other provisions of the
27 Agreement.

28
29

1 **Q. Can you explain your concern that TEP is simply assuming that rates under its market**
2 **approach would be fair and reasonable?**

3 A. Yes. Even if one interpreted the Settlement Agreement as the Commission's expression of
4 support for Standard Offer rates being based on market-priced generation, this policy does not,
5 and cannot, override the constitutional requirement for fair and reasonable rates. Nor does a
6 policy preference for competition automatically ensure that competition will, in fact, exist. Nor
7 is there anything about this policy that would require the Commission to adopt TEP's proposed
8 “market” approach.

9 It is clear from the decision of the Court of Appeals in the *Phelps Dodge* case that the
10 Commission is responsible for ensuring that all of the rates charged by TEP are just and
11 reasonable – including generation rates. The Commission has broad discretion in deciding
12 whether to implement competitive retail generation rates, but any such action to move in that
13 direction must be consistent with the requirements of the Arizona constitution – the
14 Commission must ensure that rates remain just and reasonable. Yet there is no assurance that
15 market prices will be just and reasonable. The Commission cannot simply assume that market
16 rates will satisfy the just and reasonable standard, particularly under a proposal that will result
17 in a substantial increase in rates above levels that were previously found to be just and
18 reasonable.

19
20 **Q. Can you now explain how TEP's rate forecasts might lead the Commission to the wrong**
21 **conclusion regarding the relative merits of each approach?**

22 A. Yes. As I explained earlier, TEP estimates that its proposed Market, Cost-of-Service and Hybrid
23 methods will result in rate increases of 21.9%, 23.0% and 14.9%, respectively. TEP's rate
24 comparisons give the impression that the Hybrid approach is less costly for consumers. The
25 hybrid approach appears to be the most favorable because it doesn't include the \$788 million
26 TCRA. The Cost of Service approach would show even lower costs, if the TCRA were excluded

1 from that approach as well. Clearly, these comparisons hinge on the relevance, appropriateness,
2 and magnitude of the TCRA. If the TCRA were rejected the comparison would shift in favor of
3 the cost of service approach; similarly, even if the concept of a TCRA were accepted, but TEP's
4 calculations were rejected, and a much smaller TCRA were approved, the comparison would
5 look strikingly different.

6
7 **Q. Are there other flaws in TEP's comparison of forecast rates?**

8 A. Yes. The rates forecast by TEP under each of its proposed methodologies are based upon a
9 particular view of disputed facts, and they are based on a particular set of market projections,
10 and they do not adequately portray the potential for significantly different outcomes, depending
11 on future market volatility and uncertainties.

12
13 **Q. Can you please explain how the forecast rates are based on the Company's particular view
14 of disputed facts?**

15 A. Yes. Key components of each forecast are dependent on a variety of different revenue
16 requirement and ratemaking calculations that are disputed by other parties. These disputes are
17 particularly significant with regard to the proposed TCRA that TEP proposes to include as part
18 of the Cost-of-Service Methodology. The TCRA is based entirely on calculations that are
19 inherently controversial and speculative. As TEP's witness explains, the \$788 million TCRA "is
20 based on the \$111 million revenue deficiency *proved* in the 2004 Rate Review". [Pignatelli
21 Direct Testimony, p. 20, emphasis added] However, the \$111 million revenue deficiency was
22 merely alleged by TEP, it was never proven, nor did the Commission ever make any findings of
23 fact concerning the existence, or magnitude of a revenue deficiency at that time. In fact, the
24 Staff and RUCO provided evidence which suggested a revenue deficiency of \$111 million did
25 *not* exist. To the extent these other parties believed a revenue deficiency existed, they believed
26 it was significantly less than the amount claimed by TEP. The Commission concluded that

1 proceeding without making any determination regarding TEP's revenue requirements.

2
3 **Q. What would be the effect of removing the TCRA from TEP's cost of service rate forecast?**

4 A. As shown in the table below, removing the TCRA would bring rates down to levels that are
5 much closer to the existing rates. Rates would increase by 8.4% in 2009, gradually trending up
6 to a total 19.5% increase by 2015. It should be noted that these calculations assume that TEP
7 prevails on all disputed revenue requirement issues, and that the proposed PPFAC is accepted –
8 contrary to RUCO's recommendations in this proceeding. If RUCO's positions were adopted
9 instead, rates would be substantially lower throughout this time period, and much closer to the
10 existing level of rates.
11

¢ / kWh	TEP's Cost of Service Forecast Rates			
	Test Year	2009	2012	2015
Distribution	1.98	1.58	1.58	1.58
Transmission	0.78	0.70	0.70	0.70
Must-Run & Ancillary	0.64	0.55	0.55	0.55
Fixed CTC	0.97	NA	NA	NA
Floating CTC	(2.67)	NA	NA	NA
MGC	6.66	NA	NA	NA
DSM	0.06	NA	NA	NA
Generation Non-Fuel	NA	2.99	2.99	2.99
PPFAC	NA	3.31	3.72	4.24
Total	8.42	9.13	9.54	10.07
Percent Increase		8.4%	13.3%	19.5%

13 **Q. Can you please comment on TEP's request that it be “compensated” for harm it allegedly**
14 **suffered as a result of the 1999 Settlement Agreement – the underlying premise of the**
15 **TCRA proposal?**

16 A. Yes. TEP's TCRA calculations are based purely on its perspective, without considering the
17 perspective of customers. The Court of Appeals in *Phelps Dodge* has clearly stated that a "just
18 and reasonable" analysis must ensure that rates are fair to both consumers and the regulated

1 Company.

2 Even if the Commission were willing to compensate TEP for any impacts of a perceived
3 failure to abide by the 1999 Settlement Agreement, it should not rely on TEP's claims
4 concerning its revenue deficiency during past years. Those calculations are highly speculative
5 and they are inconsistent with the analogous calculations developed during the 2004 rate review
6 by the Staff and other parties. There is simply no way of knowing whether, in the absence of
7 the rate freeze provided by the 1999 Settlement Agreement, the Commission would have
8 approved a rate increase during this time period, and if so what the magnitude of such an
9 increase would have been.

10 There is no "entitlement" to increase rates in the future merely because TEP believes
11 rates were too low in the past, or that a revenue deficiency existed during portions of the time
12 period when its rates were frozen. Furthermore, it is a matter of pure speculation to conjecture
13 whether the Commission would have computed any specific revenue deficiency, or that it would
14 have approved a rate increase, or what the magnitude of such an increase would have been, if
15 rates had not been frozen during this time period.

16
17 **Q. You mentioned that TEP's rate forecasts don't adequately portray significant differences**
18 **in volatility and risk. Can you please explain this concern?**

19 A. Yes. As I explained, under TEP's proposed Market Methodology, generation rates would be
20 based on the MGC, which will fluctuate from month to month. Under the proposed Market
21 Methodology, rates paid by TEP's customers' will depend heavily on a rate component that will
22 fluctuate from month to month; in fact, according to TEP's forecasts, the MGC will represent
23 approximately 70% of the total rate paid by TEP's customers. Yet, the MGC can fluctuate
24 dramatically, in response to fluctuations in natural gas prices, and imbalances in supply and
25 demand conditions. Recent history has shown the magnitude of these fluctuations can be very
26 dramatic, despite the fact that the fact that the actual cost of generating most of the power used

1 by TEP's customers is relatively stable.

2 Exhibit DGH-12, attached to Mr. Hutchen's direct testimony, shows monthly MGC
3 values from January 2000 through February 2007. For convenience, I've reproduced the data in
4 the table below. As shown, during this time period the MGC for non-industrial customers has
5 been as low as \$18.56 per month in March 2002, and as high as \$315.63 per month in August
6 2001 – a difference of more than 1,500%.

1

	MGC	MGC		MGC	MGC
Date	Industrial	Other	Date	Industrial	Other
01/00	24.17	25.10	08/03	51.02	52.96
02/00	22.78	23.65	09/03	42.43	44.04
03/00	21.37	22.17	10/03	41.23	42.81
04/00	29.21	30.30	11/03	38.37	39.84
05/00	27.14	28.15	12/03	37.19	38.62
06/00	28.57	29.62	01/04	39.90	41.43
07/00	54.37	56.36	02/04	45.46	47.20
08/00	73.47	76.22	03/04	42.69	44.33
09/00	60.99	63.27	04/04	40.71	42.26
10/00	75.40	78.24	05/04	35.71	37.06
11/00	51.61	53.55	06/04	44.61	46.30
12/00	55.63	57.71	07/04	55.68	57.79
01/01	60.67	62.97	08/04	55.68	57.80
02/01	59.58	61.84	09/04	55.47	57.58
03/01	52.51	54.50	10/04	41.46	43.05
04/01	201.36	209.07	11/04	47.91	49.75
05/01	170.89	177.42	12/04	60.08	62.39
06/01	176.53	183.25	01/05	53.17	55.20
07/01	272.88	283.31	02/05	49.60	51.50
08/01	304.02	315.63	03/05	49.60	51.50
09/01	193.18	200.57	04/05	49.74	51.64
10/01	33.16	34.41	05/05	54.94	57.04
11/01	33.87	35.14	06/05	50.01	51.91
12/01	35.87	37.23	07/05	51.76	53.73
01/02	25.44	26.39	08/05	60.60	62.90
02/02	22.03	22.85	09/05	60.04	62.33
03/02	17.90	18.56	10/05	77.38	80.34
04/02	20.08	20.83	11/05	95.49	99.15
05/02	24.08	24.96	12/05	79.70	82.76
06/02	28.56	29.60	01/06	86.97	90.31
07/02	31.02	32.15	02/06	74.26	77.11
08/02	36.45	37.78	03/06	56.70	58.88
09/02	30.16	31.27	04/06	48.86	50.74
10/02	28.61	29.68	05/06	43.69	45.37
11/02	28.34	29.40	06/06	47.99	49.83
12/02	33.11	34.35	07/06	55.86	58.01
01/03	32.65	33.87	08/06	56.08	58.24
02/03	39.38	40.87	09/06	69.32	71.98
03/03	42.12	43.71	10/06	48.37	50.23
04/03	56.18	58.31	11/06	43.80	45.48
05/03	39.03	40.49	12/06	59.44	61.73
06/03	37.34	38.75	01/07	59.25	61.51
07/03	50.89	52.82	02/07	50.14	52.06

2

Admittedly, these extreme fluctuations occurred during an unusual time period, which everyone

3

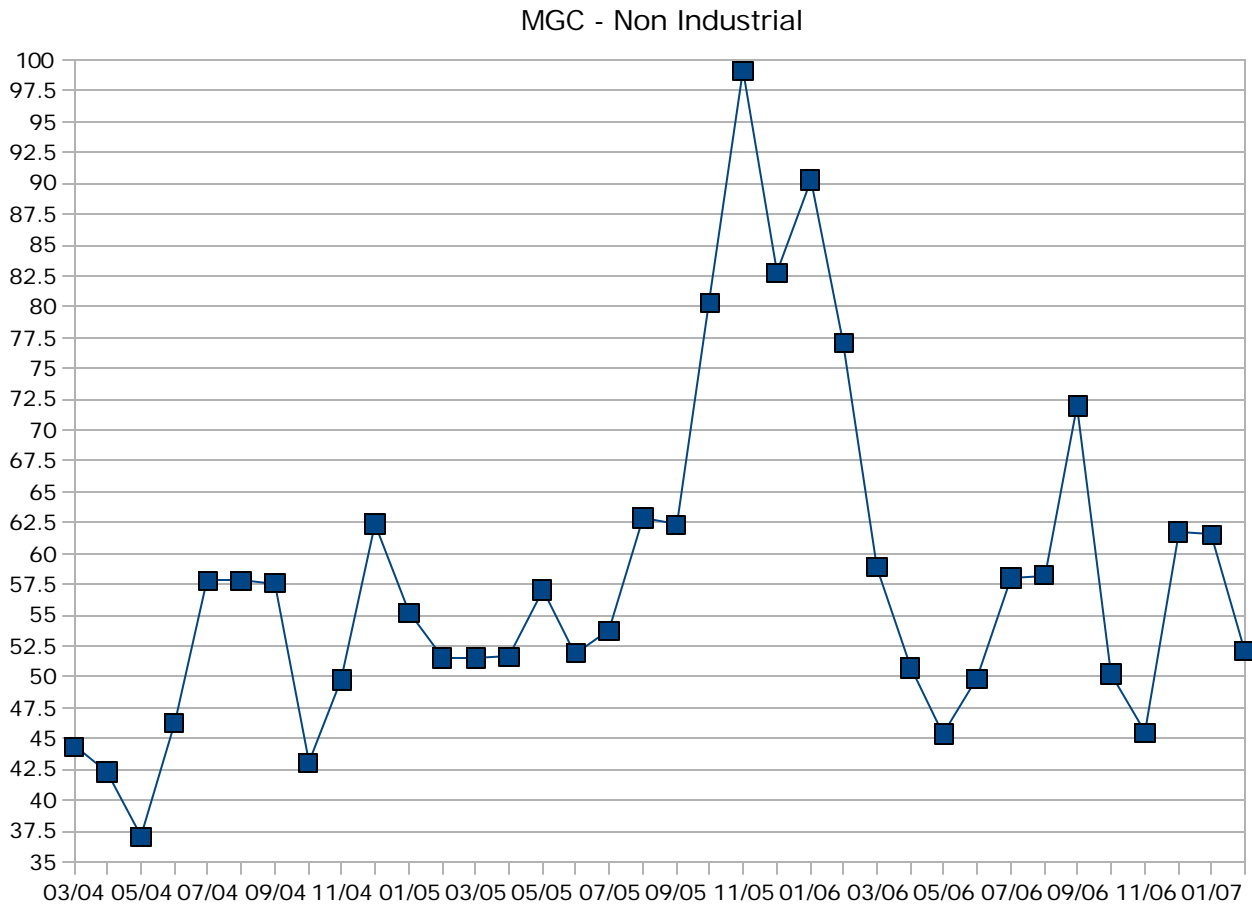
hopes will never be repeated. But, there are no guarantees that a milder version of the

4

supply/demand imbalances that occurred during during the 2001 California energy crisis will

1 never occur again. In fact, even during the past few years, when market conditions have been
2 relatively calm, the MGC has demonstrated a tendency to fluctuate rather dramatically. The
3 graph below shows the MGC data for the most recent 3 year period – a period which excludes
4 the 2001 California energy crisis. During this time period, the MGC for non industrial
5 customers fluctuated from a low of \$37.06 per month in May of 2004, to a high of \$99.15 in
6 October, 2005. This period includes month to month price increases of more than 30%, month
7 to month price decreases of more than 25%, and an overall increase from May 2004 to October
8 2005 of more than 160%

9



11

12

1 **Q. Why are you concerned about volatility of the MGC?**

2 A. Under the Company's market proposal, the majority of consumers' rates would be determined
3 by the MGC, and thus fluctuations in the MGC would translate into widely fluctuating rates to
4 be paid by TEP's customers. Even if the average level of MGC-based generation rates were
5 comparable to those that would be charged under traditional cost of service ratemaking over a
6 ten or twenty year period, the instability and unpredictability of rates on a month-to-month or
7 year-to-year basis would still make the market approach completely unacceptable to the vast
8 majority of customers.

9 It is important to realize that most people are risk averse most of the time – they prefer
10 stability and predictability, and they particularly dislike unpleasant surprises. While some
11 people enjoy gambling small amounts in the hope of gaining a large amount, this is a limited
12 exception to the more general rule: given a choice, most people prefer stability and certainty
13 when it comes to important financial matters – that's why there is a thriving market for
14 insurance, and that's why investors demand higher returns where risk and uncertainty exists.

15 Given that electricity is such a vital service – one that customers cannot simply do
16 without if the price is too high, or too volatile, it is not reasonable to force customers to pay
17 rates that fluctuate widely. Fluctuating rates would wreak havoc on the budgets of both
18 residential and business customers – making it difficult to plan ahead, and potentially forcing
19 them into dire straits if prices suddenly escalate above anticipated levels. While some local
20 businesses may be able to recoup higher electric costs by simply raising their prices, others
21 would find this impossible to do. Unlike TEP, many local businesses do not enjoy any
22 substantial degree of monopoly power; firms will experience a sharp drop in sales if they
23 attempt to increase prices, as customers buy less of their products, or purchase from businesses
24 located in Phoenix or elsewhere. Thus, they would not be in a position to simply increase or
25 decrease their prices each month, in response to increases or decreases in TEP's rates.

26 Similarly, widely fluctuating electric rates would create problems for many residential

1 customers. Volatile electric rates would obviously have an adverse impact on senior citizens
2 who are living on a fixed income, but they would also cause a problem for the vast majority of
3 residential customers, who cannot expect their employer to increase their pay every time
4 electric rates increase. And, even if the highs and lows eventually average out, it simply isn't
5 fair to force customers to deal with this sort of extreme uncertainty with respect to something as
6 important, and unavoidable, as their monthly electric bill. Customers need a reasonable degree
7 of predictability with respect to the cost of electricity; so they can make reasonable plans, know
8 how much of their monthly budget they need to set aside for their electric bill, and how much
9 will be available for food, clothing, and other expenses.

10 As noted by the Court of Appeals in *Phelps Dodge*, Arizona courts "have consistently
11 held that 'just and reasonable rates' are those that are fair to both consumers and public service
12 corporations". [83 P. 3d 573, ¶ 30] The Arizona Supreme Court has held:

13
14 In determining what is a reasonable price to be charged for services by a public
15 service corporation, an examination must be made not only from the point of
16 view of the corporation, but from that of the one served, also. A reasonable rate
17 is not one ascertained solely from considering the bearing of the facts upon the
18 profits of the corporation. The effect of the rate upon persons to whom services
19 are rendered is as deep a concern in the fixing thereof as is the effect upon the
20 stockholders or bondholders. A reasonable rate is one which is as fair as
21 possible to all whose interests are involved. [Id.]
22

23 When considering whether rates are just and reasonable, the Commission should not only be
24 concerned with the overall magnitude or average level of rates. It must take all relevant factors
25 into consideration, including the degree of volatility and predictability of the rates. From the
26 consumers' perspective, rates that can vary 10, 20 or 30 percent from one month to the next
27 cannot be considered just and reasonable. The Commission has recently expressed its concern
28 about volatility in electric rates. In APS's most recent rate case, the Commission retained an
29 annual 4 mil per kWh cap on the amount APS' power supply adjustor could change, and
30 rejected Staff's proposal to allow the adjustor to move an unlimited amount each month. [See,

1 Decision No. 69663 at p. 112]

2
3 **Q. What about from TEP's perspective? Is the Company facing severe fluctuations in its**
4 **generation costs from month-to-month?**

5 A. No. As explained by RUCO witness Marylee Diaz Cortez, the primary source of TEP's power is
6 from coal plants that it owns, or leases on a long term basis. During the test year, TEP
7 generated 81% of power from coal fired plants. [Diaz Cortez Direct Testimony, f.n. 5, p. 27]
8 Another 6.3% was generated from plants that are fueled with natural gas, and just 12.6% was
9 acquired through open market purchases. [Id.]

10 Clearly, the vast majority of TEP's generating costs are relatively stable and predictable,
11 compared to the MGC rate. To the extent TEP faces uncertainties with respect to the cost of
12 generating electricity from coal, that uncertainty primarily exists during the years when a plant
13 is being planned and constructed, and a source of coal is being obtained. Once the plant is built
14 and contracts have been signed for a long term coal supply, the cost of generating power is quite
15 stable and predictable.

16 Admittedly, the costs of generating electricity with natural gas is not as predictable on a
17 long term basis – natural gas cannot generally be purchased on a fixed-price, long term basis,
18 and the cost of fuel is a larger proportion of the total cost of a gas plant (the cost of plant
19 construction is generally lower). But, as I said, only a small minority of TEP's generation is
20 subject to this uncertainty – because the vast majority of its power comes from coal plants,
21 where costs are much more predictable.

22 In effect, TEP's market proposal would force its customers to suffer from precisely the
23 sort of volatility that TEP itself has prudently avoided. While there have been periods when
24 natural gas may have looked very attractive from a total cost of production perspective, TEP has
25 not bet heavily on this fuel source, and thus it has minimized the risks and uncertainties of
26 natural gas prices, which fluctuate widely from month to month and year to year in response to

1 global energy markets. Gas prices are strongly influenced by crude oil prices, as well as energy
2 supply and demand conditions around the globe, and thus by political developments in Russia,
3 Venezuela and the Middle East – factors that are completely beyond the control of TEP, this
4 Commission, or Arizona rate payers. Yet, TEP is asking its customers to pay electric prices that
5 are tied directly to volatile market indexes that are heavily influenced by those same
6 uncertainties.

7
8 **Q. You have been discussing the potential volatility of prices under the Market proposal.**

9 **Would electric prices also vary under the two alternative approaches proposed by TEP?**

10 A. Yes. Both the Cost-of-Service and Hybrid Methodologies include a PPFAC, which would vary
11 over time. However, the PPFAC would be updated annually, while the MGC is modified every
12 month. Also, as shown in the table above, the PPFAC under both the Cost-of-Service and
13 Hybrid Methodologies would comprise a significantly smaller percentage of overall rates than
14 the MGC under the Market Methodology, and thus rates would not be nearly as volatile, even if
15 the PPFAC is approved. However, it is worth noting that RUCO does not agree with the PPFAC
16 proposal. As explained by Ms. Diaz Cortez, RUCO believes the proposed PPFAC does not meet
17 the Arizona Court of Appeals' eligibility requirements for an automatic adjustment mechanism.
18 RUCO therefore recommends the Commission reject TEP's request for a PPFAC.

19
20 **Q. Can competitive market data be used to determine just and reasonable rates?**

21 A. I doubt it, at least given the current status of competitive markets. In its FERC Form 1 TEP has
22 admitted that retail electric competition is essentially non-existent in its service area. As
23 explained by TEP:

24 As a result of the energy crisis in California in 2000 and 2001 and the volatility
25 of natural gas prices, the competitive retail market in Arizona that was
26 anticipated in 1999 did not materialize. In addition, a 2005 Arizona Court of
27 Appeals ruling held certain portions of the ACC's retail competition rules
28 invalid. Currently, none of TEP or UNS Electric's customers are receiving
29 energy from other providers; however we cannot predict if retail competition

1 will enter the Arizona market. [TEP FERC Form 1, p. K-18]

2
3 TEP paints a more encouraging picture of competition at the wholesale level:

4
5 Competition in wholesale markets has greatly escalated due to increased
6 participation by utilities, non-utility generators, independent power producers
7 and other wholesale power marketers and brokers. [id.]
8

9 But, even if competition in wholesale spot markets is escalating, that doesn't mean the
10 wholesale market is fully mature, or that the Commission can rely entirely on market price
11 information to establish retail prices that are fair and reasonable.

12 Among other problems, there is not sufficient market data available for the price of
13 power generated over long time periods, stretching 10 or more years into the future. For
14 instance, the data included in the MGC calculations is focused on short term, or spot-market,
15 transactions; none of the underlying index data extends even 5 years into the future. Yet, the
16 actual costs incurred by TEP are being incurred on a long term, relatively stable basis extending
17 over multiple decades. For instance, the typical base load generating plant has a useful life of 40
18 or more years, and it is not unheard of for a generating plant to be still operating 60 or more
19 years after it was constructed.

20 The Commission must ensure that rates are fair to both producers and consumers, that
21 rates are reasonably adequate to cover the full cost of producing power over a typical plant's
22 entire life cycle, and that rates do not greatly exceed those fully compensatory levels, in order to
23 ensure that customers are also treated fairly. It is hard to see how the Commission can reconcile
24 all of these concerns if it were going to tie rates purely to short term market prices – prices that
25 only extend a few years into the future, leaving great uncertainty about the adequacy or
26 excessiveness of price levels in future years – during the later part of the life cycle of a newly
27 constructed plant.

28 In any event, regardless of whether or not it is theoretically possible to develop just and
29 reasonable rates by relying in part on wholesale market price data, the specific proposal offered

1 by TEP is clearly not up to the task.

2
3 **Q. Should the Commission also consider the actual circumstances facing TEP and its**
4 **customers – including the specific history and costs associated with its generating plants,**
5 **in determining whether rates are just and reasonable?**

6 A. Yes, I believe it should. TEP's existing generating plants were all constructed as part of an
7 integrated Generation, Transmission and Distribution utility. This is particularly significant
8 with respect to its coal plants, which required long construction lead times and involve very
9 long operating lives. While these plants offer cost stability, they require investments that stretch
10 over many decades – risks that have historically been borne in part by TEP's customers under
11 the traditional rate making process.

12 Under the traditional ratemaking process, TEP's customers have been required to
13 reimburse the reasonable and prudent costs incurred by the utility, including the cost of plants
14 that were constructed by the utility to serve its native load, regardless of whether those plants
15 happened to have higher or lower costs than other plants built by other utilities during the same
16 time period, and regardless of whether the resulting total cost of electricity happened to be
17 higher or lower than the spot market price of electricity available for short term purchase from
18 other utilities. Thus, for example, customers were required to pay the full cost of coal-based
19 power, even if short term blocks of natural gas-based power happened to be available on the
20 open market at a lower cost during at a particular point in time.

21 The equitable principles behind this long-standing arrangement helps explain why the
22 Commission was concerned about the possibility of “stranded” costs, and why it provided the
23 CTC mechanism, to ensure that customers – not TEP – would be responsible for paying for any
24 costs that otherwise might have been “stranded” during a transition to retail competition. In
25 effect, customers were expected to be “guarantors” to ensure that TEP would have an adequate
26 opportunity to recover the full cost of its existing generating plants, even if the cost of power

1 generated by those plants happened to be higher than the going market price.

2 Moreover, traditional rate making shifts a disproportionate share of the costs of plants
3 onto customers during the early years of a plant's operating life cycle, through the depreciation
4 and return on rate base procedures. Rather than charging a “levelized” price which remains
5 constant over the plant's entire life cycle, or an escalating price that increases with the general
6 level of prices, under traditional cost-based ratemaking principles, rates are highest in the early
7 years, and lowest in the final year's of the plant's life cycle – when the plant is largely, if not
8 entirely depreciated. In a sense, under standard rate making practices, the cost of newly
9 constructed plants is “front-loaded” onto customers, forcing them to pay a disproportionately
10 high portion of the life cycle cost in years right after a new plant goes into service. This burden
11 was offset by the expectation that customers would get the benefit of lower prices in the final
12 years of the plant's life cycle, when the plant is almost entirely depreciated, and thus a relatively
13 small amount would appear in the rate base.

14 Given this historical practice, it would clearly be unfair and unreasonable to force
15 customers to pay high spot-market based rates now, despite having helped share the burdens
16 and risks associated with TEP's existing generating plants, and despite having paid higher-than-
17 average rates during the early years immediately after these plants went into operation. Stated
18 another way, just as it would not have been fair to TEP to simply ignore the problem of stranded
19 costs if spot market prices are much lower than TEP's actual costs, it would not be fair to
20 customers to simply ignore the analogous problem in the other direction, if spot market prices
21 are high relative to TEP's actual costs.

1 **Recommendations**

2

3 **Q. Let's turn to the final section of your testimony. What do you recommend the**
4 **Commission do with regard to TEP's proposed treatment of generating costs?**

5 A. I recommend that the Commission reject both the Market and Hybrid Methodologies. The
6 linchpin for all of TEP's generation proposals is its claim that it is entitled to charge MGC-based
7 rates for generation starting on January 1, 2009. Yet, the 1999 Settlement Agreement does not
8 say anything about how rates will be computed after 2008 – it only indicates that the rate freeze
9 will end, suggesting an opportunity for TEP to request changes in its rates, and an opportunity
10 for other parties to submit evidence concerning what they believe would be reasonable for the
11 Commission to do in response to such a request.

12 Significantly, TEP ties its claim to provisions in the 1999 Settlement Agreement
13 concerning the MGC, but the MGC is only used to calculate the floating CTC, which provided a
14 mechanism for recovery of stranded costs from customers who start purchasing from
15 competitive energy providers. Since the MGC is not mentioned elsewhere in the Agreement
16 and is not used for any other purpose, there is no logical basis for assuming that the MGC will
17 live on, after the floating CTC expires. It would be doubly unreasonable for the MGC to live on
18 indefinitely, and to effectively control the level of rates paid by captive customers, considering
19 that TEP never even experienced a rush of customers leaving its system to purchase from
20 competing energy providers, and thus it never actually suffered from the problem of stranded
21 costs which led to creation of both the MGC and the CTC in the first place.

22 I would also note that, the Commission should keep in mind that its responsibilities go
23 far beyond simply resolving a dispute over language in a legal document. There are overriding
24 public policy considerations which must concern the Commission, and the proper resolution of
25 this issue should take those public policy considerations into account. However the 1999
26 Settlement Agreement is interpreted, it cannot, and should not, be the only factor considered by

1 the Commission, because that document does not in any way supersede this Commission's
2 obligations to ensure that rates are just and reasonable. That constitutional obligation requires
3 the Commission to take appropriate steps to ensure that customers are treated fairly, regardless
4 of how that document is worded.

5
6 **Q. What methodology should the Commission use to set generation rates?**

7 A. The Market and Hybrid methodologies should not be used, because they will result in
8 excessive, unreasonably volatile rates, which would impose an unnecessary and unreasonable
9 burden on customers.

10 I recommend the Commission use a traditional cost-of-service methodology in setting
11 all rates, including generation rates. However, RUCO recommend the Commission reject TEP's
12 proposed TCRA Charge, because it is based upon incorrect premises is further explained by
13 RUCO witness Marylee Diaz Cortez. Further, TEP's TCRA calculations are highly speculative,
14 and they are based upon disputed claims regarding an alleged revenue deficiency – claims that
15 were never resolved by the Commission. For all these reasons, the TCRA proposal should be
16 rejected.

17
18 **Q. Does this conclude your testimony prefiled on February 29, 2008?**

19 A. Yes, it does.

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Appendix A
Qualifications

Present Occupation

Q. What is your present occupation?

A. I am a consulting economist and President of Ben Johnson Associates, Inc.®, a firm of economic and analytic consultants specializing in the area of public utility regulation.

Educational Background

Q. What is your educational background?

A. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. The title of my Master's Thesis is a "A Critique of Economic Theory as Applied to the Regulated Firm." Finally, I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics. The title of my doctoral dissertation is "Executive Compensation, Size, Profit, and Cost in the Electric Utility Industry."

Clients

Q. What types of clients employ your firm?

A. Much of our work is performed on behalf of public agencies at every level of government involved in utility regulation. These agencies include state regulatory

1 commissions, public counsels, attorneys general, and local governments, among others.
2 We are also employed by various private organizations and firms, both regulated and
3 unregulated. The diversity of our clientele is illustrated below.

4

5 Regulatory Commissions

6

7 Alabama Public Service Commission—Public Staff for Utility Consumer Protection

8 Alaska Public Utilities Commission

9 Arizona Corporation Commission

10 Arkansas Public Service Commission

11 Connecticut Department of Public Utility Control

12 District of Columbia Public Service Commission

13 Idaho Public Utilities Commission

14 Idaho State Tax Commission

15 Iowa Department of Revenue and Finance

16 Kansas State Corporation Commission

17 Maine Public Utilities Commission

18 Minnesota Department of Public Service

19 Missouri Public Service Commission

20 National Association of State Utility Consumer Advocates

21 Nevada Public Service Commission

22 New Hampshire Public Utilities Commission

23 North Carolina Utilities Commission—Public Staff

24 Oklahoma Corporation Commission

25 Ontario Ministry of Culture and Communications

26 Staff of the Delaware Public Service Commission

27 Staff of the Georgia Public Service Commission

28 Texas Public Utilities Commission

29 Virginia State Corporation Commission

30 Washington Utilities and Transportation Commission

- 1 West Virginia Public Service Commission—Division of Consumer Advocate
- 2 Wisconsin Public Service Commission
- 3 Wyoming Public Service Commission

4 Public Counsels

- 5
- 6 Arizona Residential Utility Consumers Office
- 7 Colorado Office of Consumer Counsel
- 8 Colorado Office of Consumer Services
- 9 Connecticut Consumer Counsel
- 10 District of Columbia Office of People's Counsel
- 11 Florida Public Counsel
- 12 Georgia Consumers' Utility Counsel
- 13 Hawaii Division of Consumer Advocacy
- 14 Illinois Small Business Utility Advocate Office
- 15 Indiana Office of the Utility Consumer Counselor
- 16 Iowa Consumer Advocate
- 17 Maryland Office of People's Counsel
- 18 Minnesota Office of Consumer Services
- 19 Missouri Public Counsel
- 20 New Hampshire Consumer Counsel
- 21 Ohio Consumer Counsel
- 22 Pennsylvania Office of Consumer Advocate
- 23 Utah Department of Business Regulation—Committee of Consumer Services

24

25 Attorneys General

- 26
- 27 Arkansas Attorney General
- 28 Florida Attorney General—Antitrust Division
- 29 Idaho Attorney General
- 30 Kentucky Attorney General
- 31 Michigan Attorney General

- 1 Minnesota Attorney General
- 2 Nevada Attorney General's Office of Advocate for Customers of Public Utilities
- 3 South Carolina Attorney General
- 4 Utah Attorney General
- 5 Virginia Attorney General
- 6 Washington Attorney General

7

8 Local Governments

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- 10 City of Austin, TX
- 11 City of Corpus Christi, TX
- 12 City of Dallas, TX
- 13 City of El Paso, TX
- 14 City of Galveston, TX
- 15 City of Norfolk, VA
- 16 City of Phoenix, AZ
- 17 City of Richmond, VA
- 18 City of San Antonio, TX
- 19 City of Tucson, AZ
- 20 County of Augusta, VA
- 21 County of Henrico, VA
- 22 County of York, VA
- 23 Town of Ashland, VA
- 24
- 25 Town of Blacksburg, VA
- 26 Town of Pecos City, TX

27

1 Other Government Agencies

2

- 3 Canada—Department of Communications
- 4 Hillsborough County Property Appraiser
- 5 Provincial Governments of Canada
- 6 Sarasota County Property Appraiser
- 7 State of Florida—Department of General Services
- 8 United States Department of Justice—Antitrust Division
- 9 Utah State Tax Commission

10

11 Regulated Firms

12

- 13 Alabama Power Company
- 14 Americall LDC, Inc.
- 15 BC Rail
- 16 CommuniGroup
- 17 Florida Association of Concerned Telephone Companies, Inc.
- 18 LDDS Communications, Inc.
- 19 Louisiana/Mississippi Resellers Association
- 20 Madison County Telephone Company
- 21 Montana Power Company
- 22 Mountain View Telephone Company
- 23 Nevada Power Company
- 24 Network I, Inc.
- 25 North Carolina Long Distance Association
- 26 Northern Lights Public Utility
- 27 Otter Tail Power Company
- 28 Pan-Alberta Gas, Ltd.
- 29 Resort Village Utility, Inc.
- 30 South Carolina Long Distance Association
- 31 Stanton Telephone

- 1 Teleconnect Company
- 2 Tennessee Resellers' Association
- 3 Westel Telecommunications
- 4 Yelcot Telephone Company, Inc.

5

6 Other Private Organizations

7

- 8 Arizona Center for Law in the Public Interest
- 9 Black United Fund of New Jersey
- 10 Casco Bank and Trust
- 11 Coalition of Boise Water Customers
- 12 Colorado Energy Advocacy Office
- 13 East Maine Medical Center
- 14 Georgia Legal Services Program
- 15 Harris Corporation
- 16 Helca Mining Company
- 17 Idaho Small Timber Companies
- 18 Independent Energy Producers of Idaho
- 19 Interstate Securities Corporation
- 20 J.R. Simplot Company
- 21 Merrill Trust Company
- 22 MICRON Semiconductor, Inc.
- 23 Native American Rights Fund
- 24 PenBay Memorial Hospital
- 25 Rosebud Enterprises, Inc.
- 26 Skokomish Indian Tribe
- 27 State Farm Insurance Company
- 28 Twin Falls Canal Company
- 29 World Center for Birds of Prey

30

1 ***Prior Experience***

2

3 **Q. Before becoming a consultant, what was your employment experience?**

4 A. From August 1975 to September 1977, I held the position of Senior Utility Analyst
5 with Office of Public Counsel in Florida. From September 1974 until August 1975, I
6 held the position of Economic Analyst with the same office. Prior to that time, I was
7 employed by the law firm of Holland and Knight as a corporate legal assistant.

8

9 **Q. In how many formal utility regulatory proceedings have you been involved?**

10 A. As a result of my experience with the Florida Public Counsel and my work as a
11 consulting economist, I have been actively involved in approximately 400 different
12 formal regulatory proceedings concerning electric, telephone, natural gas, railroad, and
13 water and sewer utilities.

14

15 **Q. Have you done any independent research and analysis in the field of regulatory
16 economics?**

17 A. Yes, I have undertaken extensive research and analysis of various aspects of utility
18 regulation. Many of the resulting reports were prepared for the internal use of the
19 Florida Public Counsel. Others were prepared for use by the staff of the Florida
20 Legislature and for submission to the Arizona Corporation Commission, the Florida
21 Public Service Commission, the Canadian Department of Communications, and the
22 Provincial Governments of Canada, among others. In addition, as I already mentioned,
23 my Master's thesis concerned the theory of the regulated firm.

24

1 **Q. Have you testified previously as an expert witness in the area of public utility**
2 **regulation?**

3 A. Yes. I have provided expert testimony on more than 250 occasions in proceedings
4 before state courts, federal courts, and regulatory commissions throughout the United
5 States and in Canada. I have presented or have pending expert testimony before 35
6 state commissions, the Interstate Commerce Commission, the Federal Communications
7 Commission, the District of Columbia Public Service Commission, the Alberta, Canada
8 Public Utilities Board, and the Ontario Ministry of Culture and Communication.

9

10 **Q. What types of companies have you analyzed?**

11 A. My work has involved more than 425 different telephone companies, covering the
12 entire spectrum from AT&T Communications to Stanton Telephone, and more than 55
13 different electric utilities ranging in size from Texas Utilities Company to Savannah
14 Electric and Power Company. I have also analyzed more than 30 other regulated firms,
15 including water, sewer, natural gas, and railroad companies.

16

17 ***Teaching and Publications***

18

19 **Q. Have you ever lectured on the subject of regulatory economics?**

20 A. Yes, I have lectured to undergraduate classes in economics at Florida State University
21 on various subjects related to public utility regulation and economic theory. I have also
22 addressed conferences and seminars sponsored by such institutions as the National
23 Association of Regulatory Utility Commissioners (NARUC), the Marquette University
24 College of Business Administration, the Utah Division of Public Utilities and the
25 University of Utah, the Competitive Telecommunications Association (COMPTEL), the

1 International Association of Assessing Officers (IAAO), the Michigan State University
2 Institute of Public Utilities, the National Association of State Utility Consumer
3 Advocates (NASUCA), the Rural Electrification Administration (REA), North Carolina
4 State University, and the National Society of Rate of Return Analysts.

5

6 **Q. Have you published any articles concerning public utility regulation?**

7 A. Yes, I have authored or co-authored the following articles and comments:

8

9 “Attrition: A Problem for Public Utilities—Comment.” *Public Utilities Fortnightly*,
10 March 2, 1978, pp. 32-33.

11

12 “The Attrition Problem: Underlying Causes and Regulatory Solutions.” *Public Utilities*
13 *Fortnightly*, March 2, 1978, pp. 17-20.

14

15 “The Dilemma in Mixing Competition with Regulation.” *Public Utilities Fortnightly*,
16 February 15, 1979, pp. 15-19.

17

18 “Cost Allocations: Limits, Problems, and Alternatives.” *Public Utilities Fortnightly*,
19 December 4, 1980, pp. 33-36.

20

21 “AT&T is Wrong.” *The New York Times*, February 13, 1982, p. 19.

22

23 “Deregulation and Divestiture in a Changing Telecommunications Industry,” with
24 Sharon D. Thomas. *Public Utilities Fortnightly*, October 14, 1982, pp. 17-22.

25

1 “Is the Debt-Equity Spread Always Positive?” *Public Utilities Fortnightly*,
2 November 25, 1982, pp. 7-8.

3
4 “Working Capital: An Evaluation of Alternative Approaches.” *Electric Rate-Making*,
5 December 1982/January 1983, pp. 36-39.

6
7 “The Staggers Rail Act of 1980: Deregulation Gone Awry,” with Sharon D. Thomas.
8 *West Virginia Law Review*, Coal Issue 1983, pp. 725-738.

9
10 “Bypassing the FCC: An Alternative Approach to Access Charges.” *Public Utilities*
11 *Fortnightly*, March 7, 1985, pp. 18-23.

12
13 “On the Results of the Telephone Network's Demise—Comment,” with Sharon D.
14 Thomas. *Public Utilities Fortnightly*, May 1, 1986, pp. 6-7.

15
16 “Universal Local Access Service Tariffs: An Alternative Approach to Access
17 Charges.” In *Public Utility Regulation in an Environment of Change*, edited by
18 Patrick C. Mann and Harry M. Trebing, pp. 63-75. Proceedings of the Institute of
19 Public Utilities Seventeenth Annual Conference. East Lansing, Michigan: Michigan
20 State University Public Utilities Institute, 1987.

21
22 With E. Ray Canterbery. Review of *The Economics of Telecommunications: Theory*
23 *and Policy* by John T. Wenders. *Southern Economic Journal* 54.2 (October 1987).

24

1 “The Marginal Costs of Subscriber Loops,” A Paper Published in the Proceedings of
2 the Symposia on Marginal Cost Techniques for Telephone Services. The National
3 Regulatory Research Institute, July 15-19, 1990 and August 12-16, 1990.

4

5 With E. Ray Canterbery and Don Reading. “Cost Savings from Nuclear Regulatory
6 Reform: An Econometric Model.” *Southern Economic Journal*, January 1996.

7

8 ***Professional Memberships***

9

10 **Q. Do you belong to any professional societies?**

11 A. Yes. I am a member of the American Economic Association.

12