OPEN MEETING ITEM

EXCEPTION

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BEFORE THE ARIZONA CORPORATION COMMISSION

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Arizona Corporation Commission
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DOCKETED BY

JIM IRVIN
Commissioner - Chairman
RENZ D. JENNINGS
Commissioner
CARL J. KUNASEK
Commissioner

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. RE-00000C-94-0165 **TEP'S COMMENTS/EXCEPTIONS TO PROPOSED ORDER ADOPTING RULE AMENDMENTS**

On July 24, 1998, the Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission") issued a Proposed Order on Proposed Emergency Rulemaking regarding the Retail Electric Competition Rules, R14-2-1601, *et seq.* ("Proposed Rules"). Tucson Electric Power Company ("TEP" or "Company") hereby submits its Comments/Exceptions to the Proposed Rules attached to the Proposed Order.

A. **General Exceptions**

TEP has commented on previous drafts of the Proposed Rules on May 22, July 6, and July 22, 1998. Copies of TEP's comment letters are attached hereto as Exhibits A, B, and C, respectively, and are hereby incorporated by reference to the extent such comments have not been incorporated into the Proposed Rules or reiterated herein. Additionally, the Proposed Rules contain unresolved operational and implementation issues (such as a lack of standardized service acquisition and ISA agreements and CC&N requirements), some of which the Company will address herein. Finally, the Company believes that the Proposed Rules should be "cleaned-up" prior to adoption.

As a matter of general concern relating to the CC&N application process, TEP notes that instead of incorporating necessary details and requirements in Proposed Rule R14-2-1603, the Commission has recently issued a CC&N application form for new ESPs. It appears that the Commission is attempting to promulgate additional rules through the form, as opposed to incorporating the substantive requirements set forth in the application form into the Proposed Rules. TEP does not believe this is appropriate, as many of the provisions in the application form appeared for the first time without comment or input from the Affected Utilities.

B. Exceptions to Article 16. Retail Electric Competition

1. R14-2-1601. Definitions.

17. Change "generation of wholesale electric power" to "receipt of wholesale electric power."

20. Change "of the interconnected" to "to the interconnected."

27. Add "distribution" after "maintain."

37. "Standard Offer" should be defined as "the Bundled Service offered to all consumers in the Affected Utility's service territory at regulated rates by the Affected Utility or the UDC including Metering, Meter Reading, Billing, Collection Services and other Customer Information Services." This change will eliminate confusion regarding the regulatory treatment of the listed services associated with the standard offer requirement.

2. R14-2-1603 Certificates of Convenience and Necessity.

TEP is concerned that the Proposed Rule does not address the settlement process between ESPs and UDCs. The primary settlement issues that we are concerned with involve the process by which the UDC determines whether the actual power used by the ESPs' customers is greater than, equal to or less than the power scheduled and delivered by the ESP and the reconciliation of resulting differences. This includes issues relating to pricing of such power variances.

G.6. With respect to Service Acquisition Agreements, it must be made clear that such agreements must be with a UDC and will be required for any entity that is requesting access to the UDC's system. This shall include Aggregators and self-aggregation loads.

3. R14-2-1604. Competitive Phases.

A.1. TEP believes that utilizing a single "non-coincident" peak has unintended consequences. Only customers with 1 MW minimum demand should be eligible for direct access. Given TEP's customer base, the non-coincident peak criterion would expand the direct access eligibility from the 1 MW customer base to well beyond the 20 percent of TEP's 1995 system retail peak demand. It would also have the affect of making the 40 kW aggregation meaningless, as well as impose additional burdens to administer. As the 20 percent cap could be easily reached, there will

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be customers that have loads in excess of 1 MW that will not be able to access the competitive market during the transition period.

A.2. In the third sentence, TEP suggests replacing "month" with "six months." Doing so will better characterize a customer whose load or usage is more consistently at least 40 kW or 16,500 kWh.

4. __R14-2-1607. Recovery of Stranded Cost of Affected Utilities.__

A. Delete "by means such as expanding wholesale or retail markets, or offering a wider scope of services for profit, among others." As is, this sentence suggests that the Affected Utility use profits from "expanding [its] wholesale or retail markets," or a "wider scope of services" to mitigate stranded costs. It is unclear whether the markets and services mentioned are regulated or unregulated (*i.e.*, competitive). TEP anticipates that most, if not all, new products and services in the electric industry will develop in the unregulated, competitive marketplace. The very nature of "unregulated" means that the Commission will __not__ require that profits from such activities be used to offset costs in the regulated arena.

F. TEP disagrees with the self-generation exclusion set forth in Paragraph F. If the Proposed Rule is not modified to ensure that customers who choose to self-generate are responsible for stranded costs just as any other existing customer, a potentially large and improper economic incentive for self-generation will be created. This is due to the ability of such customers to avoid stranded cost charges. The result of the Proposed Rule as written will be to significantly increase uneconomic self-generation while increasing stranded cost burdens on customers who purchase their power in the competitive marketplace. TEP proposes the following change:

> A Competitive Transition Charge may be assessed only from customer purchases made in the competitive market using the provisions of this Article. Any reduction in electricity purchases from an Affected Utility resulting from demand-side management or the use of renewable resources shall not be used to calculate or recover any Stranded Cost from a customer.

5. __R14-2-1608. System Benefits Charge.__

TEP believes that either this section, or the definition of System Benefits Charge, should incorporate competitive access implementation and evaluation program costs in the System Benefits Charge. The Proposed Rules do not mention who will be responsible for paying for competitive access implementation costs. TEP believes that all Affected Utility customers should pay for the costs of implementing and evaluating the new marketplace, because a) restructuring was ordered by the Commission, and b) all customers and "market-players" potentially stand to benefit from it.

6. **R14-2-1609. Solar Portfolio Standard.**

TEP requests that for purposes of this Proposed Rule, it should be made clear that an ESP may take credit and be in compliance with this standard if it utilizes an affiliate that is engaged in the solar industry. For example, Staff specifically recognized this relationship in subsection J by inserting "affiliate" with respect to the manufacturing credit. It should also be applicable to other sections of the Proposed Rule where a credit may be taken such as the Early Installation Credit in subsection C.

A. and B. TEP believes that in order to allow for proper advances in technology and to ensure that money is invested in proven technologies, the percentage should be decreased from 1/2 of one percent to in 1999 to 1/10th of 1 percent and then increase this percentage by 1/10th of one percent each year until the one percent level is achieved.

7. **R14-2-1610. Transmission and Distribution Access.**

A. Add at the end of the paragraph "in accordance with FERC Orders 888 and 889."

G. TEP believes that the use of Scheduling Coordinators must be a mandatory requirement for all ESPs (including Aggregators and Self-Aggregators who are not required to use an ESP) under this Proposed Rule. In order for open access to occur, there needs to be a Scheduling Coordinator to fill the role as an intermediary between the competitive market and the system control areas. Without the Scheduling Coordinator, the control areas will be unable to properly schedule power which could jeopardize system reliability. TEP also believes that the Rules should specify minimum requirements for the Scheduling Coordinators such as a 24 hour a day, seven day a week

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operation and a license. This concept has been supported by the Commission working group studying this issue.

8. <u>R14-2-1613. Service Quality, Consumer Protection, Safety and Billing Requirements.</u>

A. The re-definition of the term "utility" is incorrect in some instances. (See comments on Article 2 below.)

J.1. After "shall provide access to meter" delete the remainder of the sentence and insert "*reading data* to other Electric Service Providers serving the same consumer *when authorized by the consumer*."

J.10. Change "and" to "or" after Affected Utility.

9. <u>R14-2-1616. Separation of Monopoly and Competitive Services.</u>

C. The following should be added at the end of the paragraph: "Generation Cooperatives will be subject to the same limitations that its member Distribution Cooperatives are subject to." This is necessary to prevent AEPCO from competing in the retail electric market while its distribution cooperatives are allowed to offer competitive services to their members.

10. <u>R14-2-1617. Electric Affiliate Transaction Rules.</u>

TEP believes that this section should <u>not</u> be adopted at this time. There needs to be further input by the Affected Utilities with respect to the implications of these Proposed Rules from both a financial and operational perspective, as well as an assessment as to whether the Proposed Rules give a competitive advantage to non-Affected Utilities. Notwithstanding TEP's position and without waiver thereof:

A.1. TEP believes that this section can be eliminated because the provisions of A.2 contain all of the necessary safeguards. It is also unclear as to its purpose in light of A.2.

A.6. TEP believes that there is no purpose to be served by this provision except to disadvantage smaller corporate entities such as TEP. It makes a presumption that separation is appropriate in all instances when the Commission has always had the ability to review affiliate relationships under the Affiliate Rules. What this does is to deny day-to-day expertise necessary to efficiently carry out responsibilities to different entities. So long as proper allocation and conflict policies are in effect, this provision is unnecessary. At the very least, the Proposed Rule should provide for a waiver by the Commission upon a demonstration by the Affected Utility that appropriate procedures have been implemented that ensure that the utilization of common board members and corporate officers does not allow for the sharing of confidential information with affiliates or otherwise circumvent the purpose of this Proposed Rule.

D. This is an example of something that applies to Affected Utilities that should also apply to new market entrants. Otherwise, new market entrants are being provided a competitive advantage.

11. <u>R14-2-1618. Disclosure Information.</u>

TEP currently does not possess the means necessary to automatically produce the Information Disclosure Label outlined in the Proposed Rule. Significant time, money and resources will need to be expended in order to accomplish this requirement. TEP suggests that this requirement be deleted from the Proposed Rules at this time so that further comment and study can be undertaken.

C. <u>Exceptions to Article 2. Electric Utilities</u>

1. <u>Definitional Inconsistency</u>

Notwithstanding the language in A.A.C. R14-2-1613.A that attempts to change the use of the term "utility" in the existing rules to accommodate the proposed revisions, the Proposed Rules improperly use several terms throughout such as the word "utility." In such instances, different terminology must be utilized. TEP suggests the following word changes when the term "utility" is used:

- "UDC/ESP" should be used in the title of 208.A.
- "entity" should be used in 208.A.2.
- "UDC" should be used in 208.A.3. and 211.A.1.
- "billing agent" or some other term should be used in 209.A.1, 2, 3, 4, 5 and 7; 210.A.1, 2, 3, 5 and 6; 210.C.4; 210.D.2; 210.E.1, 2 and 3; and 210.F.1, 2 and 3.
- "provider" should be used in 209.B.1.
- "MSP" should be used in 209.C.1; 209.E.1 and 2; 209.F.1; 210 E.1. and 210.I.3.
- "MRSP" should be used in 210.A.1 and 210.E.3.
- "ESP" should be used in 210.F.3; 210.G 2, 3, 4 and 5; 210.H.1, 2, 3, 4, 5 and 7; and 210.I.1.

2. R14-2-203 Establishment of Service.

D.4. After the first sentence, another sentence should be added that provides that if a request is made in less than 15 days prior to the next regular read date, service will be established at the next regular read date thereafter.

3. R14-3-209 Meter Reading

A.6. and 8 Change "Affected Utility" to "UDC".

B.1. Delete " owned and/or maintained by the utility,".

4. R14-2-210 Billing and Collection

A.3 and 5. TEP is concerned that estimated bills may be required to facilitate customers who choose to use load profiles rather than real-time meters. Information concerning actual usage, ESP deliveries and the estimated load will all need to be reconciled in order to render a correct bill rather than an estimated bill. The fact that these pieces of information may be coming from a variety of parties may require estimates to facilitate timely bills. TEP, therefore, suggests that language be added to these sections which allows estimates to be used when necessary to facilitate timely billing for customers using load profiles.

B.1. Delete "and the readings of two or more meters will not be combined unless otherwise provided in the utility's tariffs. This provision does not apply in the case of aggregation as described in R14-2-1601" and add "in the appropriate tariffs." TEP is suggesting deletion of the second sentence because it suggests that aggregation would allow customers to combine their peaks for billing purposes. This may result in cost shifting to other customers and should, therefore, be addressed in the UDC rate case.

D. Conclusion

Although a significant number of issues have been addressed in the Proposed Rules, there is still significant work to be done on the Proposed Rules. TEP believes that all of these issue could be addressed within the next 60 days so that the Proposed Rules could still be adopted prior to the January 1, 1999 start date. Many of these issues are crucial for retail electric competition to be possible (such as the Service Acquisition Agreement, the ISA Agreement, the CC&N criterion, the Scheduling Coordinator and ISA protocols) without jeopardizing system reliability. Accordingly, the Company requests that the Commission complete the work on the Proposed Rules as outlined in these Comments/Exceptions before it moves to adopt them, which as a result of the emergency filing with the Secretary of State, will become effective immediately.[1]. Properly considered Rules are in the best interest of the public and will help to ensure a smooth transition to a competitive marketplace.

RESPECTFULLY SUBMITTED this 31st day of July, 1998.

TUCSON ELECTRIC POWER COMPANY

By: ______________________

Bradley S. Carroll
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[1] The Company also questions whether adoption of the Proposed Rules on an emergency basis is permissible under the Administrative Procedures Act.

Original and ten copies of the foregoing filed this 31st day of July, 1998, with:

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Copy of the foregoing hand-delivered this 31st day of July, 1998, to:

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Copy of the foregoing mailed This 31st day of July, 1998, to:

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EXHIBIT A

Tucson Electric Power Company

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May 22, 1998

Via Facsimile and U.S. Mail
Ray Williamson, Acting Director
Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Re: Tucson Electric Power Company's Comments on Staff's May 19, 1998 Statement of Position on Retail Electric Competition

Dear Mr. Williamson:

Tucson Electric Power Company ("TEP" or "Company") is in receipt of the May 19, 1998 Statement of Position on Retail Electric Competition ("Position") and appreciates the opportunity to provide comments in respect thereof. Given the time constraints, these comments do not represent an exhaustive analysis of the Position, but a general overview of what the Company considers the most critical issues. We reserve the right to further analyze the issues and respond more fully when such analysis is completed.

General Comments

TEP commends Staff for taking the initiative to redefine the principals governing the introduction of retail electric competition in Arizona in light of the various knowledge and experience that has been garnered since the adoption of the Electric Competition Rules ("Rules") on December 26, 1996. Much has happened including, but not limited to, the various workshops that have taken place, the generic stranded cost hearings held this past February, the proposed legislation in Arizona and the experiences of other jurisdictions such as California which have gone down this path. It is clear that the Position put forth by Staff is designed to enable the Commission and the various stakeholders to move more rapidly with respect to some of the crucial issues that must be resolved in order to make retail electric competition a reality in Arizona. However, given the proposed timetables, options and requirements set forth in the Position, modifications are necessary and a greater degree of specificity must be provided with respect to financial and operational considerations. Moreover, to the extent that it may not be possible to provide specificity with respect to some issues in a short timeframe, there at least must be a recognition of such issues and a timetable for the resolution thereof.

A. <u>Stranded Cost</u>

General

TEP believes that all Affected Utilities must have a reasonable opportunity to recover 100 percent of their unmitigated stranded costs regardless of the method selected. However, despite the assertion on page one of the Position that "Affected Utilities are not required to divest generation assets," unless Affected Utilities elect divestiture, they do not have an opportunity to recover all of their stranded costs. This constructively constitutes a forced divestiture despite the semantical assertion. In effect, the Position puts the Commission in the shoes of management by forcing this decision. No other state has adopted legislation or rules that conditioned full stranded cost recovery on divestiture of generation assets. It is management's prerogative, and, indeed, its responsibility to shareholders, to decide this issue.

Divestiture Option

TEP supports a divestiture option for Affected Utilities. The Position proposes "unmitigated stranded costs shall include reasonable costs associated with sale of generation assets." TEP supports this proposal in concept. Given the unique financial and ownership structure of the Company's generating assets, however, the proposal must provide greater specificity regarding the type of costs that will be recoverable. For example, the Company may not be able to divest its leasehold interest in its leveraged leases without incurring premiums, penalties or other payments to the Lessors and Debt Participants. Any such payments should be included as elements of stranded costs. In addition, a significant portion of the Company's generating assets is financed with tax-exempt two-county debt, which may have to be redeemed upon transfer of the assets. The Company should be able to recover the higher average interest cost if low cost debt must be redeemed. Similarly, costs associated with the transfer of the Company's fuel and transportation contracts and interests in jointly-owned generating facilities must be accounted for in determining the costs associated with divestiture. Furthermore, all tax ramifications of a divestiture should be recoverable by the Affected Utility. Finally, the definition should reference "book value" as opposed to just "value."

Staff's Position would prohibit any Affected Utility from purchasing generation assets of another Affected Utility. TEP believes in the absence of a clear demonstration of the potential of market dominance by the acquirer, the prohibition needlessly limits the market for such assets and may limit the value received, thereby increasing stranded cost. The prohibition may also violate the interstate commerce clause of the U.S. Constitution. Affected Utilities have unique knowledge of the value inherent in generation assets within the region, and the assets have potentially more value to Affected Utilities due to system and regulatory considerations. Limiting the potential buyers is contrary to the concept of a competitive market, and provides a competitive advantage to out of state interests who are pushing for divestiture. Because the Commission must approve any sale of the assets, it will be in a position to determine the existence or potential of market dominance as part of the proceeding.

The Position does not address the possibility that no acceptable bids will be received for the generating assets, or that the Commission does not approve a submitted divestiture plan. Under such circumstances, the Company should be provided with another option that provides a reasonable opportunity for recovery of 100 percent of unmitigated stranded costs.

In its current form, the Position may negatively impact the financial viability of TEP during and after the divestiture process. The Company's ability to maintain adequate cash flows is imperative. Customers will begin to leave the Company's system on January 1, 1999. Transition charges associated with such losses will be estimated and held in trust until divestiture of the generating assets is completed. Yet, until the divestiture of its generating assets is completed, the Company will continue to have payment obligations associated with the assets (including fuel, lease payments, interest and O&M expense). The establishment of the trust essentially withholds revenues that are necessary to meet those payment obligations. In addition, TEP's Credit Agreement with its bank lenders contains covenants relating to interest coverage and financial leverage, both of which are measured based on cash flows available to the Company. The loss of revenue associated with the establishment of a competitive transition charge ("CTC") trust would impair the Company's ability to meet the financial covenants, and could result in a default under the Credit Agreement. That result would obviously have a negative impact on the ability of the Company to conduct its business and to participate in the divestiture process.

In order to complete the divestiture of its generating assets, the Company may be required to (1) redeem debt obligations associated with the assets, (2) compensate substitute lessees for assuming the Company's obligations under its leveraged leases, and/or (3) pay premiums or penalties to Lessors, Debt Participants, fuel and transportation providers or participants in jointly-owned facilities, all as discussed previously. The cash required to make such payments may exceed the proceeds received by the Company from the divestiture of the assets. Consequently, funding would be required to finance the potential cash requirement.

The additional funds could be obtained by the local distribution company (*i.e.*, TEP, following divestiture) through one or more financings. The financing would be dependent on the CTC the Company receives for its stranded costs. Lenders would look to the CTC cash payments as a source for the payment of interest and principal on the new loan(s). The loan terms (including the amount, interest rate, and maturity) would be determined by the size and term of the CTC and, of key importance, assurance that the CTC is an irrevocable obligation, subject to change only for true-up. One means of obtaining such assurance is through an irrevocable order of the Commission. Additional assurance and enhanced financing ability would result if an approved Commission order created a property right in the transition property for the benefit of a special purpose entity. Bonds secured with such property rights could probably be issued by the special purpose entity on more favorable terms than the LDC would receive, thereby reducing costs to customers.

TEP believes that the January 1, 2000 date for competition of divestiture is unreasonable. Under optimal circumstances, the average time for divestiture, including all FERC and other approvals, has been 18 months to two years. TEP has in place very complex contractual and other financial structures which could take at least two years to address in the event TEP chooses to divest its generation assets. These structures include sale and leaseback transactions, coal sales agreements, coal transportation contracts, remote coal plant joint operating agreements, tax exempt local furnishing bonds, pollution control revenue bonds and wholesale power and transmission agreements. TEP is also a participant in joint projects that currently require three-years notice of divestiture. Additionally, as the Affected Utility will be required to provide regulated generation services to most of its existing customer base until January 1, 2001, the Affected Utility should have a reliable source of generation until that time. To require divestiture prior to that will force the Affected Utility to procure the generation in the market which could be more costly and raise rates. Therefore, TEP suggests that the latest date for divestiture should be January 1, 2001 unless otherwise approved by the Commission.

TEP also supports a requirement that existing employees continue to operate any divested plants for two years after plant sales take place in order to maintain operating continuity.

Finally, the Position must state that the recovery period for the CTC must be sufficient to allow for the opportunity for 100 percent recovery and to support any securitization and that regulatory assets are recoverable as part of the CTC or distribution charge, as appropriate.

Special Contracts

Special contracts were approved by the Commission to retain load for the benefit of all customers of the Affected Utility and are included in customer class cost allocations. The concept of retaining load and providing some fixed margin has benefited all customers and been supported by the Commission. TEP's shareholders should not be responsible for stranded cost associated with these contracts, especially to the extent there could be no allocation of such costs pursuant to class cost allocations. Under the Position, special contract customers would not be required to pay their share of stranded costs while other customers will pay their full share. Unless modified, Staff's Position may result in a write-off for TEP and not provide TEP the opportunity for 100 percent stranded cost recovery. Further, it will be unlikely to negotiate a contract extension that contains a stranded cost assessment. This will result in large customers escaping their obligation to pay their fair share of stranded costs while captive customers such as residential consumers will be forced to pay. Additionally, there are write-off implications that are more fully discussed below.

Non-Divestiture Option

It appears that with the exception of regulatory assets, this option does not provide for any stranded cost recovery. TEP believes that this provision is not a viable option for those Affected Utilities whose management determines that it is not in their best interest to divest <u>and</u>

would constitute a taking without due process or just compensation. Such a position is unprecedented in the electric deregulation initiatives proposed at the federal and state levels. TEP believes that it would be more appropriate for the Commission to allow an opportunity for full stranded cost recovery under this option through a net lost revenues or similar approach during a defined recovery period.

It is also unclear from the Position whether the Commission has the authority to require the transfer of generation assets to an unregulated affiliate. From TEP's perspective, this is of particular concern to those assets under lease where the lessors hold the consent rights to transfer.

Financial Viability Option

The Commission has a legal obligation to prescribe just and reasonable rates and allow for a reasonable return on the fair value of a utility's property. This is not discretionary. This option could be interpreted to mean that the Commission will provide sufficient revenues to provide one dollar over bankruptcy or sufficient revenues to meet financial obligations but no return to shareholders. The option is also vague and needs considerably more specificity. TEP would support this option if it provided for sufficient revenues for an Affected Utility to reach and maintain an investment grade credit rating and not require any FAS 71 write-offs.

Accounting and FAS 71 Considerations

While the Position states that it has the objective of providing an opportunity for 100 percent recovery of stranded cost, it is unclear from the Position whether Staff is proposing a plan that will actually provide this opportunity, or whether the Position will be structured so that it can be recognized by utilities following the accounting guidelines of FAS 71 and related accounting literature that applies to rate regulated enterprises. Failure to meet the FAS 71 criteria in any material way would result in significant write-offs that would financially cripple the Company and cause defaults under various credit agreements.

For recovery of costs to be recognized in the Affected Utilities' financial statements, the recovery must have the following characteristics:

- Cash flows must come from regulated revenues, rather than competitive revenues, even if it is probable that such competitive revenues will be earned by the entity. The cash flows can come from rates charged directly as a tariffed rate, or as a competitive transition charge, or through proceeds from securitized bonds which will be paid off through regulated revenues. In addition, the cash flows must be certain enough to warrant reliance upon them as a recovery mechanism. This certainty level should be interpreted as 80 percent (or better) probability of occurrence. Note that this does not constitute a guarantee of recovery.

- Recovery periods of five years or less appear to provide sufficient timely recovery to provide reasonable certainty that the utility will receive its costs. If the plan provides for recovery over a five-to-ten year period, the plan *may* be considered adequately timely, but recovery over a period in excess of ten years may not be sufficiently timely. The longer the recovery period, the greater the need for a true-up mechanism to allow the utility's cost recovery to be re-evaluated and modified. In the alternative, a greater amount of "head room" within the rate or increased evidence that the costs will be recovered by the end of the stated recovery period would be needed to avoid recognizing a write-off.

- A direct correlation between the costs incurred and the revenues being provided must exist. Setting rates, for example, based on a financial viability measure as proposed earlier by Staff in this Docket would be an approach to ratemaking based on factors other than cost of service. This would not fulfill the requirements of FAS 71 and may require write-offs, depending upon how it is implemented.

It is unclear from the Position what the length of the recovery period would be, whether the recovery plan uses only regulated revenues as a recovery mechanism and whether the determinations of amounts recoverable are directly related to costs incurred. These points are especially unclear for the option to transfer generation assets to an unregulated affiliate. There is no guidance in the "non-divestiture" option as to whether any stranded cost recovery is contemplated, nor as to how the Commission would determine a value to ascribe to assets so transferred. It would be extremely difficult, if not impossible, for a utility to make an informed judgment as to the appropriate path to take, without further clarification of these issues. If the "non-divestiture" option is intended to preclude stranded cost recovery, all stranded costs would be written off immediately.

In addition, there are two issues which present potential write-offs for the Affected Utilities. First, under the divestiture option, the Staff proposes to put funds in a trust until generation assets have been divested. The interest earned on the funds are used to reduce stranded cost. While there is little detail to this plan, it appears possible that this plan could be construed as an indirect disallowance, which would require the utilities to write-off the amounts of the stranded cost at least equal to the anticipated return on the funds. The trust arrangement appears to represent a penalty provision to the divesting utilities. Under other circumstances, the utilities would collect the rates directly from customers and keep any earnings thereon. This disallowance would be avoided with the omission of the proposed trust arrangement.

The special contract provision would likely cause write-offs. The Position states that customers under special contract will be exempt from the CTC and that the amounts are not collectible from other customers. Since the amounts would therefore be collectible from no one, those amounts would likely have to be written off immediately.

In addition to the trust fund related FAS 71 concerns noted above, there are trust fund administrative concerns as well. This trust fund appears to be more administratively costly than the benefit it provides. The following issues must be addressed before such a plan could be implemented:

- How would the transition charge be collected?
- Does the collection method change after divestiture of generation assets has occurred and is there a trust account maintained thereafter?
- What happens to uncollectable amounts while such amounts are due to the trust account?
- Who administers the trust account?
- If this charge is on the same bill as all other customer charges, would the funds would come first to the utility or the ESP? Separate arrangements would have to be made to forward the funds to a Commission-controlled trust account.

To summarize, the Position would avoid causing write-offs under FAS 71 if the Position provided an "opportunity" (of 80 percent probability or higher) for recovery of 100 percent of stranded cost over ten years or less, and was based solely on regulatory cash flows. In addition, the trust arrangement should be omitted from the plan and the CTC should be made recoverable from all parties, including those under special contracts. Further, the recovery plan must be designed based on the specific costs of the entity, rather than some other method, such as the maintenance of financial viability.

B. Affiliate Rules

In November 1997, the Commission approved cost allocation procedures for shared resources, such as payroll system, accounting department personnel, etc., between TEP and its commonly-controlled affiliates, as a part of the approval of the formation of TEP's holding company. An absolute prohibition of shared services and savings may not be in the public interest if it increases the costs of regulated activities. Would these requirements now set aside those procedures and force UniSource Energy/TEP to provide separate accounting and other operating departments, separate information systems (payroll, general ledger, accounts payable, etc.) for TEP versus unregulated affiliates? This is a large and unnecessary cost to incur. Competitive companies, including likely new entrants to this market, share administrative costs between business units as a common practice, without hindering competition. The Staff should reconsider this proposal and, at a minimum, grandfather cost allocation arrangements which have been previously approved by the Commission. Alternatively, the Commission should allow the routine use of cost allocation procedures, provided that such procedures are not established to benefit one commonly-controlled entity over another.

The Position further states, "costs associated with restructuring the Affected Utilities into separate corporate affiliates shall be borne by the shareholders." TEP believes that any costs mandated by the Commission associated with implementing competition should be borne by customers since they are the ones receiving the benefits of competition. These costs would include, but not be limited to, those related to installing new computer systems, capital expenditures to assure reliability, capital expenditures to implement any pilot program, system control room expenses, metering and customer information systems.

Other issues include:

- Do the new market entrants have to comply with these provisions? If not, it provides them with a competitive advantage.
- If the Commission establishes a value of the competitive assets below the book value of the assets, would that be included as a stranded cost?
- The provision for offering the same terms and conditions to competitors should apply only to the Affected Utility's distribution service territory. Otherwise, new entrants receive a competitive advantage.

C. <u>Implementation of Competition</u>

Timing and Customer Selection

There needs to be a clear definition of what 1 MW means. TEP believes the Position should clearly state that a minimum net hourly load of 1 MW is required.

TEP does not support load profiling. There are many reasons load profiling is not a solution to open access including economic efficiency, system reliability, proper allocation of costs to customers and proper allocation of costs to third-party suppliers. These issues are explained in detail in the Commission report submitted by the Unbundled Services and Standard Offer Working Group November 3, 1997. The Company believes that all customers that want to access the competitive market must have a real time meter. This position is feasible given that the majority of customers will not have competitive access until the year 2001.

TEP also does not support the option to aggregate customers with > 20 kW loads or the residential pilot program as there are many unresolved technical issues in order to aggregate customers > 20 kW. These issues were described in TEP's filing "Second Set of Comments on Proposed Rule Regarding Retail Electric Competition." dated December 4, 1996. The basic premise is that it is far more difficult technically to serve individual residential customers than it is to serve several large customers. In its report TEP states:

> "Energy management systems, communication systems, billing systems and general system operations will need to undergo significant changes and improvements before the number of independent system transactions dramatically increase. A full choice competitive environment will result in local area control rooms that facilitate transactions between specific suppliers and specific customers and require that the local area control room be able to follow specific customer loads and their respective suppliers moment to moment. If a customer's supplier does not deliver power, then that specific customer will be required to cut its load or purchase alternative supplies. This change from managing a handful of suppliers for one customer (total retail load) to a brokering role between many separate customers and suppliers will require significant changes to existing energy management systems as well as more phone lines and people to facilitate customer transactions."

Considering the time frame of the phase-in and the additional requirements to include residential customers in their own phase-in program on a quarterly basis, the technical issues become even more crucial to resolve before direct access implementation. TEP believes that it could implement the requirements for customers over 1 MW. However, TEP strongly objects to the aggregation of customers 20 kW and above. The Position negates any attempt to phase-in competition in an orderly manner in order to accomplish meter installation, development of billing systems and other operational protocols.

The addition of 20 kW customers will dramatically increase the number of customers having choice. The number is not ever clearly known to TEP because our system has few demand meters for the small customers; however, the 20 kW requirement could potentially allow large homeowners to qualify, bringing the number into the tens of thousands. Additionally, one half of one percent of our residential customers is just under 1500 customers. These customers would require a new computer system to accurately track loads. Without such a system, which has yet to be designed, system reliability could be affected. Moreover, due to the lack of demand meters, load profiling would be very difficult to implement. Therefore, TEP believes that before any load profiling is utilized, that demand meters be installed on a statistically valid sample of customers and 24 months of data be obtained. For these reasons the residential pilot program could not be implemented by 7/1/99.

Targeted Rate Decrease

The level of any required rate decrease should be determined based on a balance of the recovery of 100 percent of stranded costs, term limits on any such recovery and rate cap requirements. Although TEP recognizes the need to share significant operational savings with customers as evidenced by its pending shared savings proposal, any mandated decrease beyond this is requiring shareholders to fund a decrease for customers. For TEP, a three-to-five percent rate decrease could be as much as $30 million of revenues or up to $18 million after tax. This represents more than half of TEP's earnings today and is not acceptable to TEP.

D. Metering and Billing

Metering

The Position states, "Competitive metering shall be offered to customers having access to competitive electric power services as of 1/1/99. These services can be provided by the Affected Utility, the ESP or their Agents." Yet it also states in the Affiliate Rules, " ...Affected Utilities create separate corporate affiliates for competitive activities and monopoly activities. The Affected Utilities will transfer competitive assets to a separate affiliate at a value determined by the Commission to be fair and reasonable." It is unclear if metering must be moved to an affiliate or if it should remain with the LDC. This issue is also linked to the Standard Offer requirements. Does the LDC have standard offer metering obligations even if metering is determined to be competitive? Must the LDC purchase metering services as well as generation services?

There needs to be a clear definition of what "competitive metering" is. The Subcommittee working on metering is still working out the details concerning competitive versus regulated services. There is still an issue concerning current transformers and potential transformers as far as who should own this equipment and who should have access. Because of these issues, TEP believes that metering should remain with the LDC during the transition period.

Billing

Since there will be a need to implement a new billing system in order to accommodate direct access, the customers should be responsible for the cost of any upgrades or a new system. Customer information should be closely monitored and only companies to which the customer gives access should receive any customer information.

The Position provides for the Affected Utility to determine the appropriate termination procedure. A significant number of joint use issues exist prior to termination of service delivery that must be resolved before joint billing can be instituted:

- Who determines credit policy (how much deposit or alternative credit support is required)?
- If a customer makes a partial payment, which party gets paid?
- Who bears the cost and responsibility of collections?
- How are the costs of providing the billing service allocated back to the other party (such as the LDC bills for the ESP)?

- Who determines that the various parties (LDC or ESP) have the billing system capability to ensure that the appropriate amounts are billed to customers, collected, credited to and remitted to the appropriate ESP or other provider? Are there minimum standards which must be met?
- Shouldn't all competitive CC&N's be contingent upon an "interconnection" agreement with the LDC?

Again, as with metering, billing should remain with the LDC during the transition in order to resolve these very significant issues.

E. Local Distribution Company Services

Standard Offer

The Position states, "There shall be no additional constraints for a consumer switching to or from Standard Offer Service." TEP believes that there should be some limit as to how many times a customer may switch from standard offer service per year. There should be some limit as to how many ESPs the customer switches to or from. It would be unreasonably difficult to perform system planning and to purchase power if the customer base is switching back and forth from Standard Offer Services to market without limitation as to frequency of such changes. This would encourage customers to "game" the system depending on market prices, seasonal rates and the purchased power pass through to customers. It will create a constant need to amend standard offer tariffs in response to market gaming. Further, as there are administrative costs associated with a customer switching, a nominal charge to cover the cost should be permitted.

The Standard Offer Section of the proposal states that a customer may change service provider at the end of a billing cycle. We suggest that this be changed to every third billing cycle. The experience in California has shown that it takes 60 days just to perform the process.

The utility should be allowed to arrange standard offer purchases through a subsidiary, subject to Commission approval, in order to minimize the cost of power acquisition. Further, it should be explicit that the costs of purchasing energy competitively to supply the standard offer is fully recoverable under an energy adjustment clause. The LDC should not be at risk for those costs due to rate caps or rate reductions. Staff should be aware that purchasing power under variable contracts with "ratchet-down" provisions tends to be expensive.

The Position is silent concerning rate design issues. There needs to be some guidelines for companies who sell generation. Allocation procedures that were used in the past will have to be refined given the changes in the corporate structure. A Company that divests generation should be given an opportunity to file a rate structure that reflects the new corporate and market structure and new business and financial risks.

Thus, the Commission must recognize that procuring energy for standard offer customers raises additional issues. The Commission could set standard offer service as a direct pass through in which case the LDC takes no risk. Alternatively, the LDC could accept a certain level of risk if it was permitted to share in any profits associated with the procurement of power as measured by relevant benchmarks.

F. Transmission and Dispatch

The Electric System Reliability and Safety Work Group has been discussing infrastructure issues relative to direct access for well over a year. As a part of these discussions a document laying out the functions of Scheduling Coordinators, Transmission Providers/Control Area Operators and an entity called the Independent Scheduling Administrator ("ISA") has been drafted. This document is supported by the stakeholders taking part in the discussions as a roadmap for implementing direct access in Arizona. As such, this document should be included in the Position to formally adopt the ISA model for Arizona direct access purposes. Enclosed is a copy of the ISA model.

Coincident with the start of direct access on 1/1/99, scheduling coordinators ("SC") shall provide for any aggregation of customers' schedules prior to submission to the respective Control Area Operator and the ISA. These schedules must have a minimum net hourly load of 1 MW. The SC must receive certification from the ISA prior to operating in Arizona.

The list of potential functions for an Independent System Operator ("ISO") in the Position should be modified as follows:

1. Administration of grid-wide tariff that eliminates pancaked rates;

2. Managing congestion and establishing congestion pricing;

3. Coordinate the planning and transmission expansion with existing regional planning (RTG) and operating groups;

4. Security Coordinator;

5. Provision and pricing of ancillary services;

6. Provide for Alternative Dispute Resolution (ADR) process;

7. Operate the Open Access Same-time Information System (OASIS);

8. Resolve "seams" issues; and

9. Follow WSCC/NERC (NAERO) standards.

The Commission should require the ISA to be operational prior to implementation of Direct Access on 1/1/99. Furthermore, the Commission should require formation of an ISO by 1/1/01. For both the ISA and the ISO, timetables should be established by the Commission to accomplish this.

In regards to the treatment of must run units, the Affected Utilities, with approval by the ISA, should determine which generation units are must run for distribution reliability in order to mitigate market power. The price of power from such units should be determined by the appropriate Commission.

Finally, the Commission should support the Affected Utilities with respect to modifications needed to their FERC tariffs.

Other Considerations

The Position is silent with respect to any intergovernmental agreement ("IGA") between the Commission and SRP. TEP has been consistent in its position since 1996 that SRP should implement competition consistent with the Commission's plan. TEP reiterates this position again.

Conclusion

Through these comments, the Company has attempted to provide all stakeholders Staff with constructive recommendations based upon its financial circumstances and its operational experience. The submission of this Position by Staff at this time is indicative of Staff and the Commission's goal to bring retail electric competition to Arizona as quickly as possible. In order to meet that goal, it is crucial that the Position that Staff will ask the Commission to consider and ultimately adopt must provide a greater degree of specificity with respect to crucial operational and financial concerns of the Affected Utilities. It also must not advantage some stakeholders at the expense of other stakeholders based upon arbitrary or political considerations. This means making some tough choices now because they cannot be put off until later. As all parties are very serious about meeting this goal in a timely manner, this Position may represent the last opportunity to do so. If principles of equity and fairness are ignored, protracted litigation may result. Such litigation could potentially set back the introduction of competition in this State indefinitely. The Company urges Staff to consider what the Company has recommended and incorporate such recommendations into the final Position and to answer questions posed by the Company through a cooperative resolution of the issues raised. Only after such a full and complete response to our concerns will TEP support the adoption of the Position.

Thank you again for the opportunity to provide these comments. Representatives of the Company would be happy to meet with you or provide additional information prior to the submission of the final Position on May 29. If you have any questions, please do not hesitate to contact me.

Sincerely,

Bradley S. Carroll
Counsel, Regulatory Affairs

SC/ISA/TP/CAO FUNCTIONS
For 1/1/99 Implementation

Scheduling Coordinators (SC's) & Qualified Wholesale Transmission Customer — **Independent Scheduling Administrator (ISA)** [People] [Computer Interface] — **Transmission Providers (TP's) Control Area Operator (CAO's)**

	SC's	ISA	TP's & CAO's
Future		1. Participate in the processes of: ▪ Operating Studies used to determine TTC ▪ Maintenance schedules of Transmission [1] ▪ Control Area Operator TTC determination 2. Define, review and oversight of committed use. (Implementation of Western Interconnection ATC document)	1. Production of: ▪ Operating studies for TTC determined ▪ Determine TTC and allocate to path owners ▪ Publish Transmission maintenance schedules[1]
Day Ahead	1. Forecast load requirements for day-ahead 2. Acquires necessary transmission and distribution 3. Arranges for appropriate ancillary services 4. Submits balanced schedules (load + loss = gen) to ISA & CAO simultaneously and provides necessary NERC/WSCC tags	1. Responsible for calculation of ATC (Implementation of Western Interconnection ATC document) 2. Operate over arching state-wide OASIS ▪ All ATC posted here ▪ All loads scheduled here ▪ All Xmiss reservations requests made here [1] ▪ Ancillary Services posted here ▪ Secondary transmission posted here 3. Receives copy of transmission schedule and update ATC after receipt of confirmed schedule 4. Receives additional requests for transmission and update ATC 5. Monitor release of ATC	2. Process, review SC's schedules, submit existing contract schedules to ISA, submit generation participants schedules to ISA 3. Posts ancillary services to ISA's OASIS 4. Processes additional schedules from transmission reservation updates 5. Participates in activities for checkout/settlement process for previous day 6. Publish next day operating plan to ISA
Current Day	5. Additional schedules submitted to ISA & CAO with tags 6. Responds to contingencies and curtailments as directed by control areas (7 X 24 ops)	6. Receives and posts curtailment information 7. Provides appeals process for transmission use denials and curtailment orders	7. Manage Real-time operations and specify curtailment and contingency actions [1] 8. Processes additional schedules from transmission reservation updates
After the Fact	7. Required to participate in checkout/settlement process and provide metering information 8. Provides meter data	8. Facilitate ADR process 9. Participates in checkout/settlement process, as needed	9. Responsible for the checkout/settlement process

[1] Presumption: Once a Scheduling Coordinator receives transmission access, distribution access will not be a problem. However, if there is distribution congestion, there may be a role for the ISA in overseeing distribution congestion management and distribution access.

EXHIBIT B

Tucson Electric Power Company

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July 6, 1998

HAND DELIVERED

Ray Williamson, Acting Director
Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Re: Tucson Electric Power Company's Comments on Staff's First Draft of Proposed Revisions of the Retail Electric Competition Rules
Docket No. RE-00000-94-0165

Dear Mr. Williamson:

Tucson Electric Power Company ("TEP" or "Company") is in receipt of the First Draft of the Proposed Revisions of the Retail Electric Competition Rules dated June 25, 1998 ("Proposed Revisions") and appreciates the opportunity to provide comments in respect thereof. Given the time constraints, these comments do not represent an exhaustive analysis of the Proposed Revisions, but rather a general overview of what the Company considers the most critical issues. TEP reserves the right to further analyze the issues and respond more fully when such analysis is completed. TEP further incorporates by reference its other comments filed in this Docket with respect to the issues set forth in the Proposed Revisions and urges Staff to review those comments.

The format for TEP's comments will track the rules as set forth in the Proposed Revisions. The rule number and name will be cited, as well as each section or paragraph. Where appropriate, the Company has provided suggested language for each section. The fact that the Company has not commented on a particular section should not be construed as the Company's acceptance or agreement with such section.

General Comments

TEP commends Staff for taking the initiative to redefine and further clarify the principles governing the introduction of retail electric competition in Arizona. The Commission, however, should review the various provisions of the Proposed Revisions with regard to the financial and operational burdens they will impose on the Affected Utilities and whether or not it is even possible to implement such provisions in the short time frames contemplated. Moreover, many of the Proposed Revisions provide new Energy Service Providers ("ESPs") an unfair market advantage in that the Rules impose a substantial degree of additional regulation on the Affected Utilities and their affiliates, while not placing similar restrictions on the new market entrants.

The Commission has been regulating the Affected Utilities for many years under traditional regulation. Yet, the Proposed Revisions focus heavily on re-regulating Affected Utilities while ignoring critical public interest considerations regarding certification and regulation of new ESPs. In its zeal to bring competition to Arizona, the Commission should remember that, unlike the Affected Utilities, new ESPs have everything to gain and very little to lose. Given the Affected Utilities' experience in providing electric services as vertically integrated utilities to Arizona customers for many years, the Company believes that a greater degree of deference should be given to the Affected Utilities' operational, reliability and financial concerns, as opposed to the numerous requirements that have been urged by specious interests without regard to feasibility and cost. Finally, the Proposed Revisions impose financial responsibilities of restructuring on Affected Utility shareholders. TEP believes that the cost of *Commission mandated* requirements should be borne by those entities that are benefiting from restructuring and not by shareholders.

R14-2-1601. Definitions.

9. and **30.** These definitions do not comply with TEP's FERC Open Access Transmission Tariff ("OATT"). The split between transmission and distribution is unique to each company based upon FERC definitional criteria set froth in Order 888. For TEP's OATT, 69 kV and above is regulated as transmission and 69 kV and below is distribution for TEP. The Commission should, where possible, correlate its requirements with FERC. Therefore, TEP suggests the following definitions:

> 9. "Distribution Primary Voltage" is voltage as defined under the Affected Utility's FERC Open Access Transmission Tariff, except for Metering Service Providers, for which "Distribution Primary Voltage" is voltage at or above 600 volts (600V) through and including 25 kV.
>
> 30. "Transmission Primary Voltage" is defined under the Affected Utility's FERC Open Access Transmission Tariff.

12. This should include ("ESP") after the term "Energy Service Provider."

R14-2-1602. Filing of Tariff by Affected Utilities.

Although the Affected Utilities have already complied with this provision, the Proposed Revisions, as well as the recently adopted stranded cost order, may require amendments to this filing, as well as additional tariff filings.

R14-2-1603. Certificates of Convenience and Necessity.

A. TEP believes that the phrase "or self aggregation" should be deleted from the last sentence of this Paragraph, as it is not a competitive function. TEP also objects to the deletion of the last sentence regarding application for a CC&N. TEP currently has a CC&N to provide generation, transmission and distribution services in its service territory. TEP will still be required to provide such services during the transition period, as well as into the future through Standard Offer. To the extent TEP provides competitive services through its affiliates, such affiliates should be required to apply for a CC&N. However, the Affected Utility should not be required to reapply for a CC&N to provide services within its service territory. It is simply unnecessary.

E. In the last sentence, after the word "shall" insert "be allowed to enter into transactions with Arizona retail customers for terms no greater than the term of their interim approval and . . ."

F. Section 3 provides that a "service acquisition agreement" must be entered into with the UDC. There is no discussion of the terms and conditions to be included in the agreement. This is a critical component of the competitive process in that, without such agreements, there are likely to be a significant number of disputes between the UDCs and the ESPs, such as credit arrangements or other credit support issues.

R14-2-1604. Competitive Phases.

General. TEP believes that if customers want to access the competitive marketplace, they should be required to have real-time meters. TEP does not believe that load profiling is appropriate. However, to the extent load profiling is required to be used, it should only be used during the transition period. It should also be noted that the concept of load profiling is inconsistent with the billing requirement to bill on actual usage.

B. After the first sentence, add "Self-Aggregation is also allowed pursuant to the minimum and combined load demands set forth in this Rule."

C. TEP opposes the residential phase-in program set forth in Paragraph C. Under the Proposed Revisions, *all* customers will be afforded retail access on January 1, 2001. The Proposed Revisions already contain a very ambitious agenda for the introduction of competition on January 1, 1999 for customers of 1 MW and above, as well as those 40 kW customers that aggregate. TEP believes that it needs time to develop the systems and load profiles, as well as to procure and install the real time meters, that will be necessary to include residential customers. Two additional years will not only enable the Affected Utilities to accomplish this, but to gain actual experience. Additionally, as an offset, Paragraph D is intended to provide rate reductions to such customers during the two-year period. As residential customers have not been shown to be terribly interested in receiving competitive generation supply in those jurisdictions that have retail access, and given the amount of work to be done in the next two years, the Commission should not further complicate this process with a residential phase-in program to start contemporaneously with other retail access.

If, however, the Commission is determined to have some residential retail access prior to 2001, TEP strongly suggests that the phase-in not start until January 1, 2000 for the following reasons: (1) it will give the Affected Utilities, the Commission and other parties one full year of retail access to gain some experience, and (2) in the interim, the Affected Utilities could institute a study on residential customers using a small number of real-time meters during that year to create accurate load profiles. Based upon experience in California, TEP is opposed to load profiling as it often leaves the incumbent utility with the customers with the worst load profiles. A January 1, 2000 start date would allow time to accurately develop load profiles and to develop the necessary billing systems to be implemented.

Another simplifying alternative for a residential phase-in could be to continue metering and billing as monopoly services during the transition period. This would eliminate a significant portion of the technical difficulties with residential phase-in and aggregation.

Finally, regardless of when the residential phase-in will start, TEP requests that it not be in the summer months because of the peak demand in the summer and the inefficiencies of load profiling.

F. The last sentence incorrectly references the Rules and should be changed to reflect the Proposed Revisions.

<u>R14-2-1606. Services Required to Be Made Available by Affected Utilities.</u>

A. The current version of the Proposed Revisions creates confusion as to whether an Affected Utility or a UDC can provide metering, meter reading, billing and customer information services. The Proposed Revision clearly states that these services are competitive and an Affected Utility or UDC cannot provide competitive services. However, the Proposed Revision also states that the "Affected Utility shall make available to all consumers in its service area Standard Offer bundled generation, transmission, ancillary, distribution and other necessary services at regulated rates." Therefore, a question exists as to whether the UDC must acquire these services for its Standard Offer customers from the market. TEP suggests that Paragraph A should be changed to clarify these issues as follows:

> A. The Affected Utilities shall be responsible to provide Standard Offer Services until January 1, 2001. Thereafter, UDCs will provide Standard Offer Services. Such services shall include the following:
>
> 1. Generation and or Purchased Power Costs
> 2. Transmission
> 3. Ancillary Services
> 4. Distribution
> 5. Metering and Meter Reading

6. Billing
7. Customer Information

C. *Standard Offer Tariffs.* TEP is concerned that the Proposed Revisions do not allow the UDC or Affected Utility to recover costs incurred during the transition to a competitive market. All customers must pay for the transition costs to competition. TEP suggests the following changes to allow for proper cost recovery:

> C.2. Affected Utilities may file proposed revisions to such rates. It is the expectation of the Commission that the rates for Standard Offer Service will not increase, relative to existing rates. **However, if as a result of implementing competition there are increased transaction costs, the UDC may file a tariff to recover these additional costs.** Any rate increase proposed by an Affected Utility for Standard Offer Service must be fully justified through a rate case proceeding.

F. In order to secure purchased power, the UDC may have to create a new department or contract this work to a power marketer. The Proposed Revision should take into account the cost of providing purchased power service and whether the UDC outsources this requirement or creates its own internal department. TEP proposes the following change:

> F. After January 1, 2001, power will be purchased by the UDC to serve Standard Offer customers pursuant to mechanisms approved by the Commission. The UDC will be required to file an initial power purchase plan on or before September 1, 2000.

G. The UDC should always have access to customer data from the ESP since it will be responsible for calculating all wires-related charges.

<u>R14-2-1607. Recovery of Stranded Cost of Affected Utilities.</u>

A. TEP believes this should simply state that "Affected Utilities shall take reasonable cost-effective measures to mitigate or offset stranded costs." The word "every" should be deleted because it is too subjective. The rest of the paragraph should be deleted because wholesale sales are non-jurisdictional and should not be used to reduce stranded costs. The Commission currently allocates costs to the wholesale jurisdiction, so there is no reason to include FERC jurisdictional sales for retail stranded cost mitigation purposes. Finally, as the Proposed Revisions require the Affected Utilities to put all competitive services in separate affiliates, it will not be possible to mitigate by offering a wider scope of services for profit. All mitigation will have to come from the Affected Utility's ability to reduce costs internally.

F. TEP disagrees with the self-generation exclusion set forth in Paragraph F. If the Rule is not modified to ensure that customers who choose to self-generate are responsible for stranded costs just as any other existing customer, a potentially large and improper economic incentive for self-generation will be created. This is due to the ability of such customers to avoid stranded cost charges. The result of the Rule as written will be to significantly increase uneconomic self-generation while increasing stranded cost burdens on customers who purchase their power in the competitive marketplace. TEP proposes the following change:

> F. A Competitive Transition Charge may be assessed only from customer purchases made in the competitive market using the provisions of this Article. Any reduction in electricity purchases from an Affected Utility resulting from demand-side management or the use of renewable resources shall not be used to calculate or recover any Stranded Cost from a customer.

<u>R14-2-1608. System Benefits Charges.</u>

D. The cite should read "R14-2-1606(J)" and not "(I)."

<u>R14-2-1609. Solar Portfolio Standard.</u>

<u>General</u>. A UDC is also an ESP; it should be exempted from this provision to the extent that the UDC does not provide competitive generation services. For example, if TEP was to divest of its generation and was only a UDC, by virtue of the requirement to provide Standard Offer Service and procure generation, it would be required to comply with this Rule. This Rule should be for ESPs providing generation.

C.4. "Solar electric generator" could be read to apply to all generators, including central solar thermal or photovoltaic plants that are not distributed to customer sites. TEP suggests changing this to "Any *distributed* electric generator."

E. The 30 cents per kWh penalty should be paid directly to the Affected Utility or UDC and the investment thereof monitored by the Commission. Otherwise, all ESPs will be required to satisfy the requirement on their own which is likely to be inefficient and difficult to monitor.

J. The sentence that reads "In order to avoid double-counting of the same equipment, solar electric generators that are sold to other Electric Service Providers..." should be changed to, "In order to avoid double-counting of the same equipment, solar electric generators that are *used by* Electric Service Providers...." This change is suggested because the business arrangement could be something other than a sale (*e.g.*, equipment could be leased) and an ESP could also own the manufacturing.

<u>Additional Comments</u>. TEP believes that the Commission should retain flexibility to take into account all facts and circumstances and to make appropriate adjustments to the standard as needed. Therefore, the Company believes it is unnecessary and potentially harmful, to change the existing permissive language in the Rule to mandatory language or anything that decreases the Commission's flexibility in the future. For example, **B.2.** changes a "may" to a "shall" on imposing a penalty and also eliminates "change" in favor of "increase." **E.** eliminates "up to 30 cents" and mandates 30 cents. Additionally, TEP believes line 2 of **J.** should read "ESP or its

affiliate" as in most situations, including TEP's, the manufacturing plant would be separated into an affiliate and not contained in the ESP itself. This is also consistent with the Proposed Revisions on separation of competitive and other services from the Affected Utility or UDC into another corporate entity. Finally, the last sentence of K. is missing the word "may."

R14-2-1610. Transmission and Distribution Access.

General. TEP believes this Rule should state that the overriding objective should be to maintain the reliability and the safety of the transmission and distribution systems.

A. TEP believes that the last sentence should be eliminated. This issue has been a controversial issue that needs further review and legal analysis. It is not clear whether the Commission has the jurisdiction to assign rights on the transmission system on a pro rata basis or any other basis.

F. The last sentence states that "proposed rates for the recovery of such [ISA/ISO] costs shall be filed with the FERC and the Commission." Since the first sentence of the paragraph indicates the Commission's intent to allow recovery of prudently incurred costs in establishment and operation of the ISA/ISO, the Paragraph should expressly state that, if FERC does not approve recovery, the Commission will allow recovery.

I. TEP believes that this paragraph needs further discussion and comment and should be eliminated. First, to the extent the Commission examines must run generation units in a distribution context, it will do so when examining the unbundled distribution tariff. Second, there is a FERC jurisdictional question with respect to the phrase "regulate the price of power from these units." Third, to the extent the Commission is encouraging divestiture of generation assets, this phrase could negatively affect the market price offered in an auction process of such units. To the extent this happens and depresses the value of the asset, it will increase stranded costs. Finally, the Commission will have oversight authority of the contracts for must run generation in the context of the sale of the assets, as well as through rate cases for the UDC.

R14-2-1612. Rates.

The lettering for the paragraphs is incorrect.

R14-2-1613. Service Quality, Consumer Protection, Safety and Billing Requirements.

General. It is unclear whether (1) the UDC is required to collect the ESP's billable charges from the ESP for presentation on the UDC's bill, or (2) the UDC is required to calculate the ESP's billable charge, on behalf of the ESP, for presentation on the bill. Significant time, money and resources will need to be expended by TEP if it is required to calculate any price structure that an ESP may bill for, including real-time pricing. TEP believes it will take a minimum of 12 months and several million dollars of new computer systems.

C. and D. The word "provider(s)" should be "ESPs."

C. The provision should state that the "ESP shall be responsible for maintaining the written notification."

D. The phrase "a large portion of their system" at the end of the paragraph needs further definition.

M. Unbundled Billing Elements.

Standard Offer Service Customers. The billing for Standard Offer Service customers can be accommodated by TEP's existing Customer Information System ("CIS"). The CIS's ability to provide this support is based upon: (1) current tariff rates for generation, and (2) all other costs (*i.e.*, CTC, fuel or purchase adjustor, distribution services, transmission service, metering services, meter reading services, billing and collection, and System Benefits charges) being calculated as a flat charge or as a factor of consumption.

Competitive Electric Service Customers. The capacity to calculate charges for competitive electric services on behalf of ESPs is not currently available within TEP's billing resources. The means to uniquely bill for services provided during each meter read interval will add considerable complexity to the billing procedures and need to be supported. Significant time and effort is required on TEP's part to provide the features needed. While TEP will strive to make this service available as soon as possible, it is not anticipated these services will be available on January 1, 1999.

R14-2-1616. Separation of Monopoly and Competitive Generation Assets.

A. TEP may not be able to comply with the asset separation requirements due to covenants and other restrictions in its leases and other credit obligations. This issue for TEP has been raised in most of the filings made with the Commission dealing with this issue. Further, this requirement may constitute an infringement by the Commission on management's authority in violation of current case law.

R14-2-1617. Electric Affiliate Transaction Rules.

General. In November 1997, the Commission approved cost allocation procedures for shared resources, such as payroll system, accounting department personnel, etc., between TEP and its commonly controlled affiliates, as a part of the approval of the formation of TEP's holding company. The Proposed Revisions are in conflict with many such procedures. Competitive companies, including likely new entrants to this market, share administrative costs between business units as a common practice without hindering competition. The Rules should grandfather cost allocation arrangements which have been previously approved by the Commission.

The Proposed Revisions are also silent as to who bears the costs of complying with these Rules. TEP believes that any costs mandated by the Commission associated with implementing competition (including these Rules) should be borne by customers, since they are the ones receiving the benefits of competition. These costs would include, but not be limited to, those related to installing new computer systems, capital expenditures to assure reliability, capital expenditures to implement any pilot program, system control room expenses, metering and customer information systems.

TEP believes that this Rule requires modification and, because of its significant impact on the corporate structure of the Company, would like the opportunity for further comment and discussion. TEP recommends not adopting this Rule at this time.

A.1. TEP believes that this section can be eliminated because the provisions of A.2. contain all of the necessary safeguards. It is also unclear as to its purpose in light of A.2.

A.6. TEP believes there is no purpose to be served by this provision except to disadvantage smaller corporate entities such as TEP. It makes a presumption that separation is appropriate in all instances when the Commission has always had the ability to review affiliate relationships under the Affiliate Rules. There is no practical reason to limit board and officer roles to two entities when by serving on one entity (such as the holding company) gives effective oversight and control over all entities. What this does, however, is to deny day-to-day expertise necessary to efficiently carry out responsibilities to different entities. So long as proper allocation and conflict policies are in effect, this provision is unnecessary. At the very least, the Rule should provide for a waiver by the Commission upon a demonstration by the Affected Utility that appropriate procedures have been implemented that ensure that the utilization of common board members and corporate officers does not allow for the sharing of confidential information with affiliates or otherwise circumvent the purpose of this Rule.

A.7.a. This provision is the opposite of the condition imposed by the Commission in approving TEP's holding company. If the Commission is concerned about activities between affiliated entities providing undue advantage to one party or another, it could require that all material transactions between affiliated entities be recorded at fair market value.

B. This Paragraph is missing or the Rule needs to be re-lettered.

C.2. As discussed earlier, shareholders should not bear this expense. This is a Commission mandated cost that is designed to benefit competitors and customers.

D.1. This is another example of something that applies to Affected Utilities that should also apply to new market entrants. Otherwise, they are being provided a competitive advantage.

R14-2-1618. Information Disclosure Label.

TEP currently does not possess the means necessary to automatically produce the Information Disclosure Label outlined in the Proposed Revisions. Significant time, money and resources will need to be expended in order to accomplish the requirement. TEP suggests that this requirement be deleted from the Proposed Revisions at this time so that further comment and study can be made.

The creation of an Information Disclosure Label represents an onerous task. Depending upon the level of precision required, the following activities may need to occur:

1. All energy acquisition transactions (scheduled and spot) and corresponding prices be recorded for the intervals in which energy is provided to a customer.
2. All sources of energy be monitored and recorded for the intervals in which energy is used by a customer.
3. All fuel mixes and emission characteristics be monitored and recorded for the intervals in which energy is used by a customer.
4. All line losses be monitored and recorded for the interval in which energy is used by a customer.
5. All load serving entities monitor and record energy used on its own system for the interval in which energy is used by a customer.
6. The necessary information be captured and provided by the entities providing the service.

TEP estimates it will require a minimum of 18 months and several million dollars to provide the Information Disclosure Label as outlined. TEP believes it can provide a more general information brochure outlining TEP's performance in several of the areas requested by January 1, 1999. The brochure would provide an encapsulation of the criteria outlined, for TEP as a whole, based upon a historical perspective.

R14-2-210. Billing and Collection.

General. To the extent that billing and collection services are competitive, there is no need for regulation. For example, terms for levelized billing and deferred payments should be between the customer and the supplier. To the extent the customer is unhappy with the terms or service, he/she could switch. However, if these services are to remain under regulation, they should stay with the UDC.

TEP believes that there should be some limit as to how many times a customer may switch from Standard Offer Service per year. There should be some limit as to how many ESPs the customer switches to or from. It would be unreasonably difficult to perform system planning and to purchase power if the customer base is switching back and forth from Standard Offer Services to market without limitation as to frequency of such changes. This would encourage customers to "game" the system depending on market prices, seasonal rates, time-of-use rates and the purchased power pass through to customers. It will create a constant need to amend Standard Offer tariffs in response to market gaming. Further, as there are administrative costs associated with a customer switching, a nominal charge to cover the cost should be permitted.

TEP further suggests that this be limited to every third billing cycle. Switching should only be allowed on regular metering dates to minimize the cost of facilitating switching. The experience in California has shown that it takes 60 days just to perform the process.

Conclusion

If it is Staff's intention to adopt the Proposed Revisions on an emergency basis, given the immediate financial and operational impact such rules will have on the Affected Utilities, the Commission should only adopt those provisions necessary to ensure compliance with the January 1, 1999 start date. Those Proposed Revisions not crucial to the start date should not be adopted at this time to allow for further discussion and comment before Affected Utilities are required to make significant financial, corporate, restructuring and resource expenditures. Staff should also consider repealing, suspending or modifying other rules that are in conflict with these Rules such as the Resource Planning Rules and the Affiliate Interest Rules. Representatives of the Company would be happy to meet with Staff prior to the finalization of the Proposed Revisions to discuss any of the issues raised in these comments.

Sincerely,

Bradley S. Carroll
Counsel, Regulatory Affairs

BSC/kj

cc: Docket Control (Original and 10 copies)

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July 22, 1998

VIA FACSIMILE AND HAND-DELIVERED

Ray Williamson, Acting Director
Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Re: Tucson Electric Power Company's Comments on Staff's Second Draft of Proposed Revisions of the Retail Electric Competition Rules
Docket No. RE-00000-94-0165

Dear Mr. Williamson:

Tucson Electric Power Company ("TEP" or "Company") is in receipt of the Second Draft of the Proposed Revisions of the Retail Electric Competition Rules dated July 10, 1998 ("Proposed Rules") and appreciates the opportunity to provide comments in respect thereof. Given the time constraints, these comments do not represent an exhaustive analysis of the Proposed Rules, but rather a general overview of what the Company considers the most critical issues.

<u>R14-2-1604. Competitive Phases.</u>

A.1. TEP believes that the addition of "non-coincident" peak has unintended consequences. TEP has always interpreted this section to require a 1 MW minimum demand for customers to be eligible. This change would expand the one MW customer base well beyond the 20 percent threshold. It would also have the affect of making the 40 kw aggegration meaningless, as well as impose additional burdens to administer. TEP supports going back to the original language of this Proposed Rule.

A.2. In the third sentence, TEP suggests replacing "month" with "six months." Doing so better characterizes a customer whose load or usage is more consistently at least 40 kw or 16,500 kwh.

R14-2-1607. Recovery of Stranded Cost of Affected Utilities.

A. Delete "by means such as expanding wholesale or retail markets, or offering a wider scope of services for profit, among others." As is, this sentence suggests that the Affected Utility use profits from "expanding [its] wholesale or retail markets," or a "wider scope of services" to mitigate stranded costs. It is unclear whether the markets and services mentioned are regulated or unregulated (*i.e.*, competitive). TEP anticipates that most, if not all, new products and services in the electric industry will develop in the unregulated, competitive marketplace. The very nature of "unregulated" means that the Commission will not require that profits from such activities be used to offset costs in the regulated arena.

F. If this statement means that a customer can avoid the Competition Transition Charge ("CTC") by bypassing the transmission and distribution system, including through means which are uneconomic, TEP believes it is unwise to include such a statement. Giving customers the opportunity to avoid the CTC will strongly incent them to do so, and unfairly shift costs to customers who remain on the T&D system. Therefore, TEP suggests the Commission explicitly exclude T&D bypass as an acceptable means of reducing or avoiding CTC responsibility. TEP also suggests the Commission be specific regarding which types of demand reduction are and are not acceptable for reducing a customer's CTC responsibility.

R14-2-1608. System Benefits Charge.

TEP believes that either this section, or the definition of System Benefits Charge, should incorporate competitive access implementation and evaluation program costs in the System Benefits Charge. The Proposed Rules do not mention who will be responsible for paying for competitive access implementation costs. TEP believes that all Affected Utility customers should pay for the substantial costs of implementing and evaluating the new marketplace, because a) restructuring was ordered by the Commission, and b) all customers and market players potentially stand to benefit from it.

R14-2-1617. Electric Affiliate Transaction Rules.

General. TEP believes that this section should not be adopted at this time. There needs to be further input by the Affected Utilities with respect to the implications of these Proposed Rules from both a financial and operational perspective, as well as an assessment as to whether they give a competitive advantage to non-Affected Utilities.

A.1. TEP believes that this section can be eliminated because the provisions of A.2. contain all of the necessary safeguards. It is also unclear as to its purpose in light of A.2.

A.6. TEP believes there is no purpose to be served by this provision except to disadvantage smaller corporate entities such as TEP. It makes a presumption that separation is appropriate in all instances when the Commission has always had the ability to review affiliate relationships under the Affiliate Rules. There is no practical reason to limit board and officer roles to two entities when by serving on one entity (such as the holding company) gives effective oversight and control over all entities. What this does, however, is to deny day-to-day expertise necessary to efficiently carry out responsibilities to different entities. So long as proper allocation and conflict policies are in effect, this provision is unnecessary. At the very least, the Proposed Rule should provide for a waiver by the Commission upon a demonstration by the Affected Utility that appropriate procedures have been implemented that ensure that the utilization of common board members and corporate officers does not allow for the sharing of confidential information with affiliates or otherwise circumvent the purpose of this Rule.

D. This is an example of something that applies to Affected Utilities that should also apply to new market entrants. Otherwise, new market entrants are being provided a competitive advantage.

R14-2-1618. Disclosure Information.

TEP currently does not possess the means necessary to automatically produce the Information Disclosure Label outlined in the Proposed Rule. Significant time, money and resources will need to be expended in order to accomplish this requirement. TEP suggests that this requirement be deleted from the Proposed Rules at this time so that further comment and study can be undertaken.

R14-2-210. Billing and Collection.

All references to "LDCs" should be changed to "UDCs".

Conclusion

TEP also requests that Staff re-evaluate TEP's July 6, 1998 comment letter with respect to other comments not specified above and not included in the July 10, 1998 Second Draft.

Please do not hesitate to contact me if you have any questions.

Sincerely,

Bradley S. Carroll
Counsel, Regulatory Affairs

BSC/kj

cc: Docket Control (Original and 10 copies)