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BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
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DOCKETED BY

JIM IRVIN
COMMISSIONER-CHAIRMAN
RENZ D. JENNINGS
COMMISSIONER
CARL J. KUNASEK
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01345A-98-0473
IN THE MATTER OF THE FILING OF ARIZONA PUBLIC SERVICE COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1601 et seq.	DOCKET NO. E-01345A-97-0773
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS PLAN FOR STRANDED COST RECOVERY	DOCKET NO. E-01933A-98-0471
IN THE MATTER OF THE FILING OF TUCSON ELECTRIC POWER COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1601 et seq.	DOCKET NO. E-01933A-97-0772
IN THE MATTER OF COMPETITION IN THE PROVISIONS OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. RE-00000C-94-165

Notice of Filing

The Residential Utility Consumer Office ("RUCO") provides notice of filing the Testimony of Richard Rosen on the Arizona Public Service and Tucson Electric Power Settlement Agreements in the above-referenced Dockets.

RESPECTFULLY SUBMITTED this 30th day of November, 1998.

Scott S. Wakefield
Chief Counsel

An original and ten copies of the foregoing filed this 30th day of November, 1998 with:

Docket Control Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

COPIES of the foregoing hand delivered/ faxed/e-mailed/mailed this 30th day of November, 1998 to:

Jerry Rudibaugh, Chief Hearing Officer
Hearing Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Paul Bullis, Chief Counsel
Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

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

Barbara Klemstine
Arizona Public Service
Law Department, Station 9909
P.O. Box 53999
Phoenix, AZ 85072-3999

Walter W. Meek, President
Arizona Utility Investors Association
2100 North Central Ave., Suite 210
Phoenix, AZ 85004

Terry Forthun, President
Arizona State AFL-CIO
588 North 7th Street, Suite 200
Phoenix, AZ 8504-581

Norman J. Furuta
Department of the Navy
900 Commodore Drive, Building 107
P.O. Box 272 (Attn: Code 90C)
San Bruno, CA 94066-0720

Barbara S. Bush
Coalition for Responsible Energy Educ.
315 West Riviera Drive
Tempe, AZ 85252

Rick Lavis
Arizona Cotton Growers Assoc.
439 E. Broadway Rd
Phoenix, AZ 85040

Karen Glennon
19037 N. 44th Avenue
Glendale, AZ 85308

Columbus Electric Cooperative
P.O. Box 631
Deming, NM 88031

Dixie Escalante Rural Electric Assoc.
CR Box 95
Beryl, UT 8474

Garkane Power Association
P.O. Box 790
Richfield, UT 84701

Morenci Water and Electric Company
P.O. Box 68
Morenci, AZ 85540

Michael Curtis
Martinez & Curtis, PC
2712 North 7th Street
Phoenix, AZ 85006
Attorneys for Arizona Municipal Power Users Association

Rick Gilliam
Land and Water Fund of the Rockies
2260 Baseline Road, Suite 200
Boulder, CO 80302

David C. Kennedy
Law Offices of David C. Kennedy
2001 N. 3rd Street, Suite 212
Phoenix, AZ 85004-1439

Thomas C. Horne
Michael S. Dulberg
Horne, Kaplan & Bistrow, P.C.
40 North Central Avenue, Suite 2800
Phoenix, AZ 85004

Sam Defraw (Attn: Code 16R)
Rate Intervention Division
Naval Facilities Engineering Command
200 Stovall Street, Room 0S12
Alexandria, VA 22332-2300

Steve Brittle
Don't Waste Arizona, Inc.
6205 South 12th Street
Phoenix, AZ 85040

Ajo Improvement Company
P.O. Drawer 9
Ajo, AZ 85321

Continental Divide Electric Cooperative
P.O. Box 1087
Grants, NM 87020

Mohave Electric Cooperative
P.O. Box 1045
Bullhead City, AZ 86430

Arizona Dept. of Commerce
Energy Office
3800 North Central Ave., 12th Floor
Phoenix, AZ 85012

Betty Pruitt
Arizona Community Action Assoc.
2627 N. 3rd Street, Suite 2
Phoenix, AZ 85004

Bradley Carroll
Tucson Electric Power Company
P.O. Box 711
Tucson, AZ 85702

Mick McElrath
Cyprus Climax Metals Co.
P.O. Box 22015
Tempe, AZ 85285-2015

A.B. Baardson
Nordic Power
4281 North Summerset
Tucson, AZ 85715

Dan Neidlinger
3020 North 7th Drive
Phoenix, AZ 85015

Patricia Cooper
AEPCO
P.O. Box 670
Benson, AZ 85602-0670

Marv Athey
Trico Electric Cooperative
P.O. Box 35970
Tucson, AZ 85740

Wayne Retzlaff
Navopache Electric Cooperative
P.O. Box 308
Lakeside, AZ 85929

Craig Marks
Citizens Utilities Company
2901 North Central Ave., Suite 1660
Phoenix, AZ 85012

Jack Shilling
Duncan Valley Electric Coop.
P.O. Box 440
Duncan, AZ 85534

Barry Huddleston
Destec Energy
P.O. Box 4411
Houston, TX 77210-4411

Choi Lee
Phelps Dodge Corporation
2600 North Central Avenue
Phoenix, AZ 85004-3014

Creden Huber
Sulphur Springs Valley Electric Coop.
P.O. Box 820
Willcox, AZ 85644

Wallace Kolberg
Southwest Gas Corporation
P.O. Box 98510
Las Vegas, NV 89193-8510

Michael Rowley
c/o Calpine Power Services
50 West San Fernando, Suite 550
San Jose, CA 95113

Jessica Youle
Salt River Project
PAB 300
P.O. Box 52025
Phoenix, AZ 85072-2025

Clifford Cauthen
Graham County Electric Cooperative
P.O. Drawer B
Pima, AZ 85543

Joe Eichelberger
MAGMA Copper Company
P.O. Box 37
Superior, AZ 85273

Steve Kean
Enron
P.O. Box 1188
Houston, TX 77251-1188

Jay I. Moyes
Meyer Hendricks Bivens & Moyes, P.A.
P.O. Box 2199
Phoenix, AZ 85001-2199

Steve Montgomery
Johnson Controls
2032 West 4th Street
Tempe, AZ 85281

Terry Ross
Center for Energy and Economic Devel.
P.O. Box 288
Franktown, CO 8016-0288

Louis Stahl
Streich Lang
2 North Central Avenue
Phoenix, AZ 85004

Ellen Corkhill
AARP
5606 North 17th Street
Phoenix, AZ 85016

Andrew Gregorich
BHP Copper
P.O. Box M
San Manuel, AZ

Jim Driscoll
Arizona Citizen Action
2430 S. Mill, Suite 237
Tempe, AZ 85282

John Jay List
General Counsel
National Rural Utilities Coop. Finance Corp.
2201 Cooperative Way
Herndon, VA 21071

Robert Julian
PPG
1500 Merrell Lane
Belgrade, MT 59714

Robert S. Lynch
340 E. Palm Lane, Suite 140
Phoenix, AZ 85004-4529

Michael Block
Goldwater Institute
Bank One Center
201 North Central Avenue
Concourse Level
Phoenix, AZ 85004

Carl Robert Aron
Itron, Inc.
2818 North Sullivan Road
Spokane, WA 99216

Ken Saline
K.R. Saline & Associates
60 North Pasadena, Suite 101
Mesa, AZ 85201-6764

Sheryl Johnson
Texas-New Mexico Power Co.
400 International Plaza
Fort Worth, TX 76109

Phyllis Rowe
Arizona Consumers Council
6841 N. 115th Place
Phoenix, AZ 85014

Larry McGraw
USDA-RUS
6266 Weeping Willow
Rio Rancho, NM 87124

William Baker
Electrical District No. 6
P.O. Box 16450
Phoenix, AZ 85011

Wallace Tillman
Chief Counsel
National Rural Electric Coop. Association
4301 Wilson Blvd.
Arlington, VA 22203-1860

C. Webb Crockett
Fennemore Craig
3003 North Central Ave., Suite 2600
Phoenix, AZ 85012-2913
Attorneys for ASARCO, Cyprus Climax Metals, Enron and AAEC

Douglas Oglesby
Vantus Energy Corporation
353 Sacramento St., Suite 1900
San Francisco, CA 94111

Stan Barnes
Copper State Consulting Group
100 West Washington St., Suite 1415
Phoenix, AZ 85003

Douglas Nelson
Douglas C. Nelson, PC
7000 N. 16th Street, Suite 120-307
Phoenix, AZ 85020

Lawrence Robertson, Jr.
Munger Chadwick PLC
333 North Wilmot, Suite 300
Tucson, AZ 85711-2634
Attorneys for PG&E Energy Services

Michael Grant
Gallagher & Kennedy
2600 North Central Avenue
Phoenix, AZ 85004
Attorneys for AEPCO

Lex Smith
Michael Patten
Brown & Bain PC
P.O. Box 400
Phoenix, AZ 85001-0400
Attorneys for Morenci Water & Electric,
Ajo Improvement & Phelps Dodge

Steve Wheeler
Thomas Mumaw
Snell & Wilmer
One Arizona Center
400 E. Van Buren
Phoenix, AZ 85004-0001
Attorneys for APS

Elizabeth Firkins
International Brotherhood of
Electrical Workers L.U. #1116
750 S. Tucson Blvd
Tucson, AZ 85716-5698

Carl Dabelstein
2211 E. Edna Avenue
Phoenix, AZ 85022

Jesse Sears, Assistant Chief Counsel
City Attorney's Office
200 W. Washington, Suite 1300
Phoenix, AZ 85003-1611

Russell Jones
33 N. Stone Ave., Suite 2100
P.O. Box 2268
Tucson, AZ 85702
Attorneys for Trico Electric Coop.

Myron Scott
1628 E. Southern Ave., No. 9-328
Tempe, AZ 85282-2179
Attorneys for Arizona for a Better Environment

Tom Broderick
6900 E. Camelback Rd #700
Scottsdale, AZ 85251

Albert Sterman
Arizona Consumers Council
2849 North Central Avenue
Tucson, AZ 85716

Suzanne Dallimore
Antitrust Unit Chief
Department of Law Building
Attorney General's Office
1275 W. Washington
Phoenix, AZ 85007

Vinnie Hunt
City of Tucson
Department of Operations
4004 S. Park Avenue, Building #2
Tucson, AZ 85714

William Sullivan
Martinez & Curtis PC
2716 N. 7th Street
Phoenix, AZ 85006
Attorneys for Mohave Electric Cooperative
and Navopache Electric Cooperative

Jeff Woner
K.R. Saline & Associates
160 N. Pasadena
Mesa, AZ 85201

Larry K. Udall
Arizona Municipal Power Users Assoc.
2712 North 7th Street
Phoenix, AZ 85006-1090

William Murphy
200 W. Washington, Suite 1400
Phoenix, AZ 85003-1611

Christopher Hitchcock
P.O. Box 87
Bisbee, AZ 85603-0087
Attorneys for Sulphur Springs Valley
Electric Coop.

Andrew Bettwy
Debra Joluc Walley
Southwest Gas Corporation
5241 Spring Mountain Road
Las Vegas, NV 89102

Barbara Goldberg
Office of the City Attorney
3939 Civic Center Blvd
Scottsdale, AZ 85251

Bradford Borman
PacifiCorp
201 S. Main, Suite 2000
Salt Lake City, UT 84140

Marcia Weeks
18970 N. 116th Lane
Surprise, AZ 85374

Timothy Michael Toy
Winthrop, Stimson, Putnam & Roberts
One Battery Park Plaza
New York, NY 10004-1490

Raymond Heyman
Darlene Wauro
Roshka Heyman & Dewulf PLC
Two Arizona Center
400 North 5th Street, Suite 1000
Phoenix, AZ 85004
Attorneys for New Energy Ventures, LLC

Peter Glaser
Doherty Rumble & Butler PA
1401 New York Ave., NW, Suite 1100
Washington, DC 20005

Timothy Hogan
Arizona Center for Law in the Public Interest
202 E. McDowell Rd, Suite 153
Phoenix, AZ 85004

John Travers
William H. Nau
272 Market Square, Suite 2724
Lake Forest, IL 60045

Stephanie Conaghan
Duane, Morris & Heckscher LLP
1667 K Street N.W., Suite 700
Washington, DC 20006-1608

By Cheryl Fraulob
Cheryl Fraulob

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BEFORE THE ARIZONA CORPORATION COMMISSION

DOCUMENT CONTROL

JIM IRVIN
Commissioner – Chairman
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Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01933A-98-0471
IN THE MATTER OF THE FILING OF TUCSON ELECTRIC POWER COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1602 et seq.	DOCKET NO. E-01933A-97-0772
IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01345A-98-0473
IN THE MATTER OF THE FILING OF ARIZONA PUBLIC SERVICE COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-160 et seq.	DOCKET NO. E-01345A-97-0773
IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. U-00000C-94-165

DIRECT TESTIMONY OF

DR. RICHARD A. ROSEN

On the APS and TEP Settlement Agreements

On behalf of the
Residential Utility Consumer Office

November 30, 1998

EXECUTIVE SUMMARY

My initial review of the proposed Settlement Agreements between the ACC Staff, Arizona Public Service Co. (APS) and Tucson Electric Power (TEP) leads me to conclude that both Agreements should be rejected in their current form. The key reasons why the Agreements should be rejected are:

1. The Agreements were negotiated without significant input by most of the parties to this docket and, thus, they do not represent a reasonable balance of stakeholder interests.
2. The Agreements include entirely new policies and proposals that have not received any attention thus far by parties to these dockets, and therefore, have not been adequately analyzed in the context of this docket.
3. The Agreements will not achieve the Commission's goal of establishing a competitive retail market for power in Arizona. Furthermore, the rate decreases promised to standard offer customers from these Agreements are substantially smaller than those rate decreases that have accompanied retail competition in most other states.
4. Both Agreements will likely lead to ratepayers over-paying (paying more than 100 percent) of stranded costs for both Companies, especially for APS.
5. Both Agreements set the generation credit for customers leaving the Standard Offer Service at the cost of <u>wholesale</u> power, and, therefore, no reasonable level of <u>retail</u> competition is likely to ever result.
6. The proposed sale of generating assets to APS from TEP would likely lead to the ability of APS to exercise additional horizontal market power, particularly in light of the load pockets that are likely to exist in Arizona. This would unjustifiably raise the cost of electric generation to ratepayers in Arizona, and, perhaps, in neighboring regions as well.

7. The transfer of generation assets from TEP to APS and the transfer of generation assets from APS to its unregulated marketing affiliate should both occur at a fair market value. None of these assets should be transferred at their net book value.

8. The proposal that TEP become the owner of the high voltage transmission grid within Arizona does not seem workable, and it might increase transmission rates to the Salt River Project, AEPCO, and WAPA ratepayers. In addition, the ACC does not have jurisdiction to implement this proposal, because they do not have jurisdiction over SRP and WAPA.

9. The APS Agreement would likely allow APS to over-earn profits, by keeping the return on equity at inappropriately high levels. APS' and TEP's transmission and distribution rates should be re-set utilizing cost-of-service principles from the ground up, and a new return on equity should be established.

10. Based on a detailed study of potential load pockets in Arizona, the Commission must determine which generating units of APS and TEP are must-run units, and an appropriate market-based price cap mechanism for the units should be proposed to FERC, which has jurisdiction.

11. The Commission must approve the correct procedure for TEP's divestiture of its power plants not being transferred to APS, including how the plants should be grouped or "bundled" for sale to different generation owners. Neither APS nor its subsidiaries should be allowed to bid for TEP's other power plants.

12. The Commission must review the reasonableness of TEP's proposed interim transition charge until its divestiture process has been completed.

13. In case TEP does not decide to divest it's remaining generating units, the Commission must further define the net lost revenues methodology ahead of time that TEP is planning to use to compute stranded costs.

14. The Commission should not grant all of the waivers being requested by TEP and APS.

I. QUALIFICATIONS

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Dr. Richard A. Rosen. My business address is Tellus Institute, 11 Arlington Street, Boston, MA 02116-3411.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a B.S. in Physics and Philosophy from MIT, an M.S. in Physics from Columbia University, and a Ph.D. in physics from Columbia University. Currently I am a senior research director at Tellus Institute, as well as executive vice-president of the Institute. I am also the manager of the Institute's Electricity Program.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF TELLUS INSTITUTE.

A. Tellus Institute is a non-profit organization specializing in energy, natural resource, and environmental research. Within Tellus Institute, the Energy Group focuses on energy and utility research areas which include demand forecasting, conservation program analysis, electric utility dispatch and reliability modeling, least-cost utility planning and integrated resource planning, avoided cost analysis, financial analysis, cost of service and rate design, non-utility generation issues, bidding systems, incentive regulation, cost-of-capital analysis, and utility industry restructuring.

Q. PLEASE ELABORATE ON TELLUS' EXPERIENCE WITH ELECTRIC UTILITY SYSTEM SUPPLY PLANNING.

A. The Energy Group has had wide experience assessing utility system supply options on both a service area and a regional basis. These assessments have encompassed all types of generation plant, transmission plant, purchases of capacity and energy, fuel purchases and contracting, central station district heating and decentralized cogeneration plants, and alternative sources of energy such as wind, biomass, and solar energy connected to electricity grids. These assessments have dealt with the technical, economic, environmental, regulatory, and financial aspects of supply planning, including the relationships between supply planning, load forecasting, rate design, and revenue requirements. Tellus Institute also has reviewed the prudence of many past supply planning decisions by utilities.

Q. PLEASE REVIEW YOUR EXPERIENCE IN THE AREA OF UTILITY PLANNING.

A. Power supply system modeling, integrated resource planning, and electric industry restructuring has been the major focus of my activities for the past 18 years. My research and testimony in this area began in 1980, and I have testified in numerous cases involving generation planning and the integration of demand and supply technologies on a least-cost basis. For example, I submitted extensive generation planning testimony in the 1980 CAPCO Investigation in Pennsylvania in Case No. I-79070315, and in the 1981 Limerick Investigation as well (Case No. I-80100341). In early 1982, I prepared a major report for the Alabama Attorney General's Office entitled "Long-Range Capacity Expansion Analysis for Alabama Power Company and the Southern Company System," and I filed testimony in Docket No. 18337 before the Alabama Public Service Commission. In addition, I testified on the excess capacity issue regarding Susquehanna unit 1 in the 1983 Pennsylvania Power and Light Co. Rate Case (No. R-822169). In 1987, I testified before the Federal Energy Regulatory Commission on NEPOOL's Performance Incentive Program on behalf of the Maine Public Utilities Commission in Docket No. ER-86-694-001. In 1989, I testified before the Pennsylvania Public Utility Commission on excess capacity and ratemaking treatment regarding Philadelphia Electric Co.'s Limerick 2 nuclear unit. This work was performed on behalf of the Pennsylvania Office of Consumer Advocate in Docket No. R-891364. I also testified in Vermont in Docket No. 5330 on the cost-effectiveness of the proposed purchased power contract between the Vermont utilities and Hydro-Quebec.

Due to my extensive regulatory experience in the public interest, as outlined above, in 1988 I was chosen to serve a 3-year term on the Research Advisory Committee of the National Regulatory Research Institute, an appointment made by the public utility commissioners serving on the NRRI Board of Directors. In addition, within the last 2 years, I have been the project manager on contract research that the Tellus Institute has performed for the U.S. Department of Energy, the U.S. Environmental Protection Agency, the National Association of Regulatory Utility Commissioners (NARUC), the New England Governors' Conference, and the National Council on Competition in the Electric Industry.

In the last 2 years, I have spent most of my time analyzing electric utility restructuring issues.

I testified before the New Hampshire Public Utilities Commission on issues affecting the design of the state's pilot programs (Docket No. 96-150 and market power (Docket No. DE 97-251), and I testified before the New York Public Service Commission on stranded costs, market structures, and other issues related to the ConEd's, NYSEG's, and RG&E's restructuring plans. In early 1998, I testified on the full range of policy issues connected with the establishment of stranded cost policies by a state PUC in Arizona Docket No. U-000-94-165. I also have worked or testified on other restructuring issues such as unbundling, stranded costs, retail margins, Standard Offer service, market power, and wholesale market prices in Nevada, New Jersey, Illinois, Texas, Missouri, Delaware, Pennsylvania, and Michigan. The remainder of my experience is summarized in my resume, which is attached as Exhibit___(RAR-1).

II. BACKGROUND

Q. HAVE YOU TESTIFIED IN ANY OF THESE DOCKETS BEFORE?

A. Yes, I have testified in the stranded cost dockets previously.

Q. WOULD YOU PLEASE OUTLINE SOME OF THE KEY PROCEDURAL ASPECTS OF YOUR INVOLVEMENTS IN THESE DOCKETS IN ADDITION TO THE FILING OF YOUR STRANDED COST POLICY TESTIMONY IN JANUARY OF 1998?

A. Yes. TEP and APS filed proposed unbundled tariffs on December 30, 1997 and February 13, 1998 respectively. In response to these filings, RUCO issued data requests to both TEP and APS on July 24, 1998, as well as a follow-up request on September 30, 1998. TEP and APS then filed their separate stranded cost plans on August 21, 1998. RUCO issued data requests about these plans to TEP on August 31, September 1, and September 4, and to APS on August 31, 1998. RUCO then filed comments on both stranded cost plans with the Commission on September 21, 1998.

The two new proposed Settlement Agreements were filed at the Commission on November 5, 1998. RUCO followed up these filings by issuing data requests for APS on November 10, 11, 18, and 25 and to TEP on November 6, 12, and 13, 1998.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Tellus Institute was retained by the Residential Utility Consumer Office to analyze the various filings related to the unbundled service tariffs, stranded cost recovery proposals for APS and TEP, and various other aspects of their restructuring proposals. One purpose of my testimony is to suggest ways in which the proposed plans could be modified to more closely adhere to the various rules and policies the ACC adopted in the various restructuring dockets, and to principles of fairness. Another purpose of my testimony is to suggest ways in which Arizona's transition to competition in the supply of electricity-related services could be made more successful than the proposed settlement is likely to be. Finally, my testimony will indicate why more time is needed for the parties to analyze the details of the proposed Agreements. One reason why more time is needed is that this Agreement was still incomplete, at least up until November 24, 1998, when I received a copy of Mr. Davis' testimony.

Q. SHOULD THE COMMISSION APPROVE THE TWO PROPOSED SETTLEMENT AGREEMENTS IN THEIR CURRENT FORM?

A. No, the Arizona Corporation Commission should not approve the two proposed Settlement Agreements in their current form. The Agreements should be rejected.

Q. WHY SHOULD THE COMMISSION CONSIDER REJECTING OR AT A MINIMUM CHANGING THESE TWO SETTLEMENT AGREEMENTS WHICH THE COMMISSION STAFF, TEP, AND APS FOUND ACCEPTABLE?

A. These two Settlement Agreements were developed quickly, with very limited input from parties other than TEP, APS and the ACC staff. In light of this, it is not surprising that other parties might be able to offer critical beneficial suggestions for improvement of the important issues dealt with in these Agreements. Furthermore, even a quick review of these Settlement Agreements has uncovered many serious problems with them. The key problem is that the Agreements will not achieve the Commission's restructuring goals. In particular, as with restructuring agreements reached in California, Massachusetts, Rhode Island, and New Hampshire, little or no retail competition will result from these Agreements. There are many issues that need considerable more analysis before the Commission will have sufficient information on which to make a decision.

Q. IS THE PROCEDURAL SCHEDULE ISSUED BY THE ACC ON NOVEMBER 25, 1998 REASONABLE IN LIGHT OF THE IMPORTANT ISSUES RAISED IN THE PROPOSED SETTLEMENT AGREEMENTS?

A. No. The case schedule for these docket numbers as ordered by the ACC on November 25, 1998 is unreasonable. The compressed case schedules ordered by the ACC on November 25, 1998 should be replaced with case schedules which are greatly extended by several months.

The current schedule does not allow for adequate discovery and analysis of the proposed Settlement Agreements prior to the filing of testimony. Due to the inability of the Residential Utility Consumer Office to adequately address the issues raised by these filings, and the inability of other stakeholders to participate meaningfully in this proceeding, the public interest will not be well served by an Order issued based upon this inadequate record.

Q. GIVEN THE VERY BRIEF PERIOD OF TIME (ABOUT THREE WEEKS) THAT YOU HAVE BEEN ABLE TO REVIEW THE TWO PROPOSED SETTLEMENT AGREEMENTS, WHAT NEW PROPOSALS HAVE BEEN MADE IN THOSE AGREEMENTS FOR THE FIRST TIME THAT, THEREFORE, REQUIRE CONSIDERABLE FURTHER ANALYSIS?

A. Given that I have only been able to review these two proposed Settlement Agreements for about three weeks, and given that they contain many new proposals that have not previously been discussed among all the parties to these cases, I find that substantially more analysis is required of, at least, the following <u>new</u> proposals:

1. The proposal that TEP transfer certain generation assets directly to APS in return for certain APS transmission system assets.
2. The proposal that TEP's generating assets transferred to APS should be valued at $165 million.
3. The proposal that APS' current generating assets should be transferred at net book value to an unregulated APS marketing subsidiary.
4. The proposal that TEP should become the owner of all transmission system assets within Arizona.
5. The proposal that APS should freeze its rate of return on equity at its current level.

6. The proposal that TEP should have primary control over the divestiture process for its remaining generating units and that these units could be sold as a single bundle.
7. The proposal that the market generation credits for Standard Offer Service customers for both APS and TEP be set on the basis of <u>wholesale</u> market prices and not <u>retail</u> market prices in order to achieve retail competition.
8. The proposal that price caps for APS' must-run generating units be set based on current cost-of-service levels, and not market-based wholesale prices.

III. THE TWO SETTLEMENT AGREEMENTS

<u>APS</u>

Q. PLEASE SUMMARIZE THE SETTLEMENT AGREEMENT BETWEEN APS AND ACC STAFF.

A. *Market generation credits.* Under the Settlement Agreement, APS customers who choose to receive generation service from a non-APS Energy Service Provider ("direct access customers") would receive a market generation credit (MGC) in lieu of APS generation service. The credit would be based on the NYMEX prices for electricity futures at the Palo Verde Exchange in southern California and the California Power Exchange prices, plus a line loss adjustment and an adder. It would be calculated for each month of a given calendar year during November of the preceding year.

"True-Up" of CTC. The NYMEX Palo Verde electricity futures prices used to set the CTC for each month, which would be from November of the preceding year, would be compared with the NYMEX futures prices during the last three days before the month in question. Differences, positive or negative, would be considered over- or under-recovery of monthly

stranded costs, and would be accumulated. The accumulated amount would be spread over the direct access sales of the following year (pp. 2-3; Exhibit A).

Adjustment for line loss. The projected market price of power, based on the NYMEX futures price, would be multiplied by 1 plus a line loss factor to account for losses during transmission and distribution.

Adder. To calculate the market generation credit, APS would apply an adder of approximately 3 mills (thousandths of a dollar) per kWh to the projected wholesale generation price based on the NYMEX Palo Verde futures price. The adder reflects additional components of the wholesale price of power. The adder would be adjusted for each rate class according to the differences between the class load factor and the system average load factor.

Redesigned rates effective January 1, 2001. The Settlement Agreement would allow APS to file a new rate case by September 1, 1999 and would require the ACC to rule that new APS rates be effective January 1, 2001. These rates would be "revenue neutral" and would not change APS' currently authorized cost of capital. However, APS' rate case filing would propose to "realign Standard Offer and unbundled rates in accordance with appropriate cost allocation and rate design principles."

Regulatory asset recovery. APS would be allowed to recover 100 percent of regulatory assets.

Exchange of assets with TEP. The Settlement Agreement would give APS and TEP "all requisite approvals necessary" for a transaction in which APS would sell its 345 kV and 500 kV transmission assets to TEP and buy TEP's 279 MW of ownership interests in the Four Corners Generating Plant and Navajo Generating Plant.

Transfer of generation assets to APS' unregulated affiliate. APS is proposing to transfer its generating plant assets to its unregulated marketing affiliate at net book value.

Standard Offer rates. In Arizona, "Standard Offer...means Bundled Service offered...to all consumers...at regulated rates" (A.A.C. R14-2-1601(38)). Presumably, under the Settlement Agreement, APS' current rates would become its rates for Standard Offer service. The rates for Standard Offer service would then decline by 1 percent in 1999 and again by 1 percent in 2000. Standard Offer rates for residential customers only would decline by a further 1 percent in 2001 and again in 2002. The annual reductions would be larger than 1 percent if the cost savings incentive formula in ACC Decision 59601 yielded a reduction of greater than 1 percent. Also, APS is proposing to cap the rates of its must-run generating units on a cost-of-service basis.

Unbundled rates. It is not entirely clear whether unbundled rates (with the MGC in place of generation) would match Standard Offer rates. The Settlement Agreement merely states that "the Company's unbundled rates will reflect the embedded cost of service for all functions as approved by the Commission" (p. 2). The unbundled rates would decline in 1999 and 2000 to the same degree that the Standard Offer rates would decline, but would not decline in 2001 and 2002, as Standard Offer residential rates would.

Customer transition charge (CTC). The customer transition charge, described primarily in Exhibit A, would apply to direct access customers, that is, to customers paying unbundled rates. Through the end of the year 2004, it would recover the difference between the Standard Offer generation rate (implicit in the Standard Offer tariffs) and the market generation credit. However, it is not clear whether it would be calculated for all customers in one aggregated group or separately for the customers on each tariff. The CTC would not be allowed to drop below zero.

Conditions for collection of CTC. The CTC would be contingent on APS divesting its transmission assets but not contingent on APS divesting its generation assets. In addition, if the ACC concluded that APS had significant market power and had manipulated the market price for power in the region, it could terminate the CTC.

Resolution of litigation. The Settlement Agreement would require APS to withdraw all litigation against the ACC, and would, instead, direct APS to help the ACC overcome any litigation by other parties in opposition to the ACC's Electric Competition Rules.

TEP

Q. PLEASE SUMMARIZE THE PROPOSED SETTLEMENT AGREEMENT WITH TEP.

A. *Unbundled service rates.* The Settlement Agreement describes changes to the unbundled service rates TEP filed in its December 31, 1997 filing in ACC Docket No. E-01933A-97-0772. The new unbundled service rates were to be submitted to the ACC by November 15, 1998. According to the Settlement Agreement, they were to reflect a new TEP cost of service study already approved by the ACC and a rate reduction of 1.1%. Since stranded costs cannot be accurately calculated until a final result of unbundling the generation component of current rates is known, more time will be required to analyze this new filing.

Recovery of positive stranded costs. TEP's stranded costs, both its regulatory assets and its other positive stranded costs, are to be completely recovered from ratepayers over a period of 6-8 years from the date that the final stranded cost amount is calculated. In fact, Exhibit C to the filing, which was delayed until November 10, 1998, provides a precise estimate for the final stranded costs of $821 million net present value (NPV), but the year in which the present value (PV) dollars is expressed is not clear. This exhibit also computes a CTC of 1.82 cents per kWh for 8 years beginning in 2001. The basis for these results needs to be reviewed.

Market generation credit. In lieu of generation service, direct access customers will receive a "market generation credit" for each kilowatt-hour they use. This credit will be revised each quarter based on the prices of wholesale electricity futures, which will be adjusted upward by a credit of 2.6-4 mills (thousandths of a dollar) per kilowatt-hour, depending on the customer class involved. These additional costs are intended to reflect ancillary services, capacity reserves, and other generation costs at the wholesale level.

Interim stranded cost recovery. Until the divestiture of all generation assets has either succeeded or failed, and the stranded cost of each is known, TEP will continue to collect its annual strandable costs from both Standard Offer and direct access customers. This will most likely be from 1999-2000. Standard Offer customers will pay those stranded costs through their Bundled Service rates, while direct access customers will pay them through an interim transition charge intended to equal the difference between the Standard Offer generation rate and the market price of generation. These stranded costs paid during 1999 and 2000 will add to the $821 million estimate of stranded costs to be paid from 2001-2008, making a total stranded cost recovery that will probably exceed $1.0 billion (NPV) as estimated under this agreement.

Recovery of negative stranded costs. For those assets with negative stranded costs, TEP would be entitled to "borrow" the negative stranded cost amounts for the purpose of purchasing transmission assets in Arizona. In the meantime, TEP would pay its customers the equivalent of interest on the "loan" from ratepayers by reducing jurisdictional rates by an amount equal to the return on the negative stranded cost amount multiplied by TEP's cost of capital. At some unspecified future time, TEP would begin to repay the "principal" over a period of ten years. This appears to be an internal financing mechanism for new transmission investments. It is not clear why TEP is mixing up financing issues for transmission and stranded cost recovery issues in this way. This issue needs considerable further analysis.

Transco monopoly on transmission in Arizona. The Agreement calls for TEP's transmission affiliate, Transco, to become the only builder and owner of transmission facilities in the state of Arizona. The potential impact of this proposal on the transmission rates of other utilities and coops in Arizona also requires further analysis.

Asset swap with APS. TEP would sell its interest in the Navajo and Four Corners generation facilities to APS for $165 million, and would buy all of APS' transmission assets with voltages of 345 kV and above for $168 million. The potential impact of this sale of generation plant to APS on horizontal market power in the region requires substantial analysis before it is approved. In addition, a process needs to be established for Commission review of the reasonableness of the $165 million price for those generation assets of TEP. The transfer price must reflect a reasonable market price in order that TEP ratepayers do not subsidize APS ratepayers, or vice versa.

Auction. TEP would auction those generation assets that it would not sell to APS. The degree of control that TEP should be allowed to have over the auction process needs significant review.

Failed auction. If the ACC did not find any of the bids acceptable for any of these other generating units, it could declare a failed auction and allow TEP to keep the generating asset. In that case, the stranded cost of the generating asset would be determined through a "net lost revenues" method. The Agreement provides few details of the precise "net lost revenues" method to be employed. These details must be specified as part of any reasonable settlement, e.g., the time period over which stranded costs would be calculated.

Failure to divest. If TEP chose not to divest for some reason other than a failed auction, it would be allowed stranded cost recovery sufficient to maintain financial viability, but would not be guaranteed 100% recovery of positive stranded costs. However, the Agreement contains no clear criteria for what constitutes "financial viability." These criteria must be clearly stated.

Waivers. The Settlement Agreement would codify waivers of various ACC regulations. Many of these waivers would obviate the requirement that TEP or its affiliates reveal to the ACC certain information about those affiliates. Whether this proposal is reasonable or not requires detailed analysis. However, on their face, some of the waivers do not appear to be justified.

Resolution of litigation. The Settlement Agreement would require TEP to withdraw all litigation against the ACC, and would, instead, direct TEP to help the ACC overcome any litigation by other parties in opposition to the ACC's Electric Competition Rules.

IV. CONCLUSIONS AND RECOMMENDATIONS

APS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE PROPOSED APS SETTLEMENT AGREEMENT.

A. 1. Based on my previous testimony in this docket, APS has a negative strandable cost amount. Therefore, it is not appropriate for APS to collect only additional positive amounts of stranded costs from customers, as APS would under the Settlement Agreement. Rather, the Commission should determine to what extent APS may have negative stranded costs, and APS should then fully return its negative stranded costs to customers through a wires credit. Anything short of this would constitute excess retention by APS of ratepayers' money, and would be completely inequitable. The Commission needs to review APS' claim that its stranded costs are positive in a properly adjudicated hearing.

2. Little or no competition would occur in APS' service territory as long as the terms of the Settlement Agreement remained in effect. This is because the Settlement Agreement calls for a market generation credit that approximates the *wholesale* price of generation. Retail competitors would not be able to match this *wholesale* price. Experience to date in Massachusetts, New Hampshire, Rhode Island, and California has amply demonstrated that if the market generation credit approximates the wholesale price, little or no competition

results. In addition to the modest *wholesale* adder of approximately 3 mills proposed in the Settlement Agreement, the market generation credits should incorporate a *retail* adder for each customer class, which accounts for the additional costs of providing *retail* generation service. In my January 1998 testimony in ACC Docket No. RE-00000C-94-0165, I estimated that the retail adders in Arizona should be 0.82-1.18 cents per kWh for small customers such as residential customers and 0.64-0.85 for large customers such as industrial customers. I suggest starting with the upper ends of these ranges because they were conservatively estimated, and because utilizing the upper end of the range would facilitate the onset of retail competition. The size of the retail adder could be reduced in the future if retail competition proves to be successful.

3. Ratepayers must be assured that transferring certain of TEP's generating units to APS will not increase APS' ability to exercise horizontal market power. Such assurance is not likely to be possible, but certainly cannot be made until a detailed study of horizontal market power within Arizona can be completed. Such a study would probably take at least a few months before this aspect of the proposed settlement could even be intelligently discussed and considered by the Commission. This study must also include an analysis of the extent to which Phoenix and Tucson are load pockets, and therefore the hours in which any generation unit owned by APS would be a must-run unit. If it becomes apparent from such a study that horizontal market power could be exercised by APS, then appropriate mitigation measures must be put into place.

4. Allowing APS to retain its currently authorized cost of capital in the rate case filing of September 1, 1999 would likely be highly inequitable, given that interest rates have fallen significantly in recent years. A new, appropriate cost of capital must be established in APS' next rate case that should be used to re-set APS' transmission and distribution rates on a traditional cost-of-service basis from the "ground up."

5. The unbundling process should result in rates for distribution, transmission, and customer service charges that are the same for all Standard Offer and unbundled customers within the same customer class. Therefore, all rate reductions for 2001 and 2002 should apply equally to Standard Offer and unbundled rates. In addition, the 2-4 percent rate decreases scheduled for the Standard Offer rates are far too small to be a reasonable outcome of this Settlement process. This is especially true since the Settlement locks the ratepayers into paying a cost of capital in the next rate case that is too high. Just reducing the current return on equity to a more up-to-date and reasonable level might cause Standard Offer rates to drop by more than 4 percent. In addition, the restructuring process should yield rate decreases of a minimum of 10 percent beyond the level of just and reasonable rates under traditional cost-of-service regulation.

6. APS should not be allowed to transfer its generating assets to an unregulated subsidiary at their net book value. To the extent that these assets have negative stranded costs, this would allow this subsidiary to profit at ratepayer expense. Thus, not only is the proposed Settlement asking ratepayers to pay positive stranded costs through the CTC for 2000-2004, but the Agreement does not credit ratepayers with these over-payments of stranded costs by requiring the unregulated APS marketing affiliate to reimburse these stranded costs, since overall stranded costs are negative. Whether stranded costs are negative or positive generating assets should only be spun-off to an unregulated affiliate at fair <u>market value</u>, not at net book value.

7. The Commission must determine which APS generating units are must-run units based on a detailed analysis of APS' load pockets. These units should have the wholesale price of power sold capped not at cost-of-service as provided for in the proposed Settlement Agreement, but at a long-term levelized market price for wholesale power. If this is not done, the "price signals" seen by customers of these units will be distorted, and some customers could end up with subsidized rates. This is a situation that restructuring was designed to avoid, not perpetuate.

Stranded Cost Recovery

Q. WHAT WILL LIKELY BE THE VALUE OF APS' TOTAL STRANDED COSTS?

A. RUCO's Comments on APS' stranded cost filing (submitted September 21, 1998 in ACC Docket No. E-01345A-98-0473) present an estimate of APS' strandable costs at the beginning of 1999. The estimate is *negative* \$1.1 billion as revised to cover the period 1999-2020. With the phasing in of competition, these potential benefits of APS continuing to use its generating resources to serve its customers on a cost-of-service basis could become stranded, and APS' ratepayers may not benefit from future use of APS' generating assets unless the Commission takes appropriate action to protect them. Ratepayers would lose these benefits if APS' generating assets are transferred to an unregulated affiliate at net book value instead of at a fair market value. My estimate above for APS' total stranded costs uses exactly the same model and data I relied upon in my January testimony in ACC's competition Docket, No. RE-00000C-94-0165. The only difference is that my earlier estimate, negative \$838 million, had been computed beginning in 1998, and the revised figure is for a period beginning 1 year later. Any stranded cost recovery should be based on up-to-date estimates of stranded costs carefully examined in a litigated proceeding, or based on the actual sale prices of APS generation assets, or on a combination of both.

Q. HOW CAN APS' POTENTIALLY STRANDED BENEFITS/COSTS BE PROPERLY RECOVERED?

A. In the case of APS, it is the *customers*, rather than the Company, that need to recover potentially stranded benefits. The Settlement Agreement can be adapted to accomplish these important ends. APS would simply award all customers a per-kWh stranded cost recovery credit, sufficient to return the total stranded cost amount in present value over some period of time to be determined by the ACC. This credit should be trued up periodically as either actual market prices become known, or generating plants are divested and their sales prices become known. This could include use of the fair market value that the ACC should set for the plant assets being transferred to APS' unregulated marketing subsidiary.

Q. WOULD THIS BE FAIR TO APS?

A. Yes. It would be entirely fair to APS. The Company would enter the competitive wholesale marketplace through its unregulated subsidiary with no Stranded Costs, which by definition would set it on a path to continued normal rates of return over the long run. In addition, APS would still have tremendous advantages such as an initial 100 percent share of the retail market, economies of scale, and proximity to its customers.

Q. WHAT IS THE BASIS FOR THE INAPPROPRIATE STRANDED COST RECOVERY PROPOSAL IN THE SETTLEMENT AGREEMENT?

A. The stranded cost recovery proposal in the Settlement Agreement would collect overestimates of APS' *annual* stranded cost amounts during the next six years when they are positive. In contrast, a proper stranded cost recovery would instead collect the amount of the Company's *total* stranded cost, which is the net present value of the stream of annual stranded cost amounts over the remaining life of APS' generating assets.

The overestimated annual stranded cost amounts to be collected under the Settlement Agreement would very likely remain positive through the year 2004, which is when APS would stop collecting them. These positive amounts contrast sharply with my estimate for total stranded costs, because under the proposal ratepayers would never get to be credited with the negative annual stranded costs that will likely occur after 2004. This is true even if the total stranded costs for APS are much less negative (closer to zero) then I believe they are. If APS has made any recent computation of its stranded costs, I have not yet had the opportunity to review it. Setting the proper level of stranded costs in these dockets is equivalent to setting the overall rate of return on equity in a full rate case. It must be done with equal care and caution, as very large amounts of money are at stake each year in the future.

Market Generation Credit (MGC)

Q. WHAT SHOULD THE MAGNITUDE OF THE MARKET GENERATION CREDIT BE?

A. The market generation credit should be at least as high as the retail market price of generation service. It should be set at the high end of a reasonable range of retail market prices. Otherwise, alternative generation suppliers will not be able to match or beat the price of APS generation service. If the MGC is not somewhat higher than the retail market price, little or no competition will result, just as we have seen this year in California, Massachusetts, New Hampshire, and Rhode Island. Most ratepayers probably need to receive <u>at least</u> 5 percent overall savings on their electric bills before they would be induced to switch suppliers.

Q. IS THE MGC PROPOSED IN THE SETTLEMENT AGREEMENT AT LEAST AS HIGH AS A REASONABLE ESTIMATE OF THE RETAIL MARKET PRICE OF GENERATION?

A. No. The market generation credit proposed in the Settlement Agreement is significantly lower than a reasonable estimate of the retail price of generation service, for two reasons.

First, it is a wholesale, rather than a retail, price. The adder of roughly 3 mills per kWh to be included in the MGC is only enough to cover some additional wholesale generation-related costs, if that. No retailing costs have been included, not even the retailing costs (generation-related A&G) that are currently included in APS' retail rates. Yet, alternative suppliers will necessarily have even higher retailing costs than APS has had under monopoly conditions.

Second, the market generation credit proposed in the Settlement Agreement is based on the NYMEX futures price, which equally weights the prices of electricity between 6 a.m. and 10 p.m, Monday through Friday. The hours not thus included are represented by the NYMEX multiplied by a "light load ratio" which is less than one. (See Exhibit A to the Settlement Agreement for more detail.) In reality, the average wholesale price of a kilowatt-hour is higher than the NYMEX indicates because prices are highest at the times when the most kilowatt-hours are sold. The MGC must be adjusted for APS' load shape, separately, for each customer class.

Q. WHAT DO YOU RECOMMEND TO CORRECT APS' PROPOSED MARKET GENERATION CREDIT?

A. I recommend two simple modifications of the Settlement Agreement to correct APS' market generation credit. The first is the application of a customer class-specific retail adder on top of the wholesale market generation credit which APS proposes. As a first approximation of the appropriate retail adder, I suggest the use of the adders I presented in pages 28-39 of my January, 1998 testimony in ACC Docket No. RE-00000C-94-0165. Since these were conservatively estimated, I believe it would be best to begin with the high ends of the ranges I derived. These are 1.18 cents per kWh for small customers and 0.85 cents per kWh for medium-large customers.

My second recommendation is to start with a more realistic wholesale price. The wholesale market price of generation used in the calculation of the MGC for each customer class should reflect the load curve of that class, rather than a flattened load curve such as that implicit in the formula proposed in the Settlement Agreement's Exhibit A.

Transfer of Generation Assets

Q. IS THERE A PROBLEM WITH LEAVING GENERATING UNITS UNDER THE CONTROL OF APS, EVEN IF THEY ARE FORMALLY OWNED BY AN UNREGULATED AFFILIATE?

A. Yes. The more generation capacity APS owns, the more able it is to raise electricity prices in Arizona through the exercise of market power. The Company already owns a large portion of the generating capacity in Arizona. Under the terms of the proposed APS and TEP Settlement Agreements, APS would be authorized not only to keep the generating assets it currently owns but also to obtain even more from TEP. In addition, many of its generating units may prove to be must-run units in order to preserve system reliability once an analysis of potential load pockets is done within APS' service territory.

Q. WHAT ACTION DO YOU RECOMMEND TO ADDRESS THE ISSUE OF POTENTIAL APS HORIZONTAL MARKET POWER?

A. The amount of generation plan that APS could safely own without being able to exercise horizontal market power must be reviewed so that ratepayers can be assured that transferring additional amounts of generation to APS will not inappropriately increase APS' ability to exercise horizontal market power. Such assurance can not be made until a detailed study of potential horizontal market power within Arizona and neighboring regions can be completed. Such a study would probably take at least a few months before this aspect of the proposed settlement could be intelligently discussed and considered by the Commission. In the alternative, strict price controls for all of APS' generation would have to be kept in place indefinitely, but this would hamper the development of a competitive wholesale market.

Therefore, I recommend that the ACC leave sufficient time for a study of the impact on electricity prices in Arizona of allowing APS to retain its generating assets, and of allowing it to acquire additional generating assets from TEP prior to deciding these cases. As noted, this study would require several months, at least, to be performed adequately. This study should be coupled to a thorough study of APS' potential load pockets. This is because the existence of load pockets can substantially accentuate problems with horizontal market power. Finally, the must-run generating units will require price caps for the indefinite future as APS has proposed, and as FERC has approved for must-run units in California. However, the price caps should be at a market-based level of prices assuming that all generation is transferred to APS' unregulated subsidiary at a fair market value. This is so that the price caps reflect the same underlying basis of value assigned to these generating units for transfer purposes, and for the purpose of setting stranded costs.

TEP

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE PROPOSED TEP SETTLEMENT AGREEMENT.

A. The summary of my conclusions and recommendations regarding the proposed TEP Settlement Agreement is as follows:

1. Since new unbundled rates were to be presented to the Commission on or about November 15, 1998, no final determination can be made of either the appropriate interim transition charge for 1999-2000, or the final transition charge for the period 2001-2008, until the parties to the docket have an opportunity to review that new filing, particularly the new proposed generation component of rates, and the new estimate for generation-related administrative and general costs. Resolving the proper values for these two components of rates is critical for computing the two stranded cost recovery charges.

2. The new, late filed Exhibit C contains an estimate of $821 million (NPV) in stranded costs for the period 2001-2008 that is completely undocumented.

The parties need an opportunity to review the basis for this estimate, and to review the reasonableness of the proposed translation of that estimate into the proposed 1.82 cents per kWh CTC for the period 2001-2008. Even more importantly, no calculation has been made of the proposed ITC for the period 1999-2000, and no Settlement Agreement should be approved by the Commission until such a figure is proposed and reviewed by the parties.

3. The proposed market generation credit is simply based on a wholesale price of power not a retail price for power. The wholesale price is much too low to allow for retail competition, and, thus, is anti-competitive. As I testified to in my stranded cost testimony in January 1998, a much higher retail price for power must be used for pricing standard offer generation service. By pricing the generation credit at a wholesale price, no alternative provider can price their power lower, by definition, and, therefore, no competition will result. This is what has already happened in California, Massachusetts, Rhode Island, and New Hampshire. This error must be rectified.

4. TEP should keep its mechanism for collecting stranded costs from ratepayers completely separate from any process that it proposes for financing new transmission investments. Thus, any net income from generation asset sales should not directly be used to fund new transmission investments. In addition, any new transmission investments should pass traditional least cost planning criteria before the Commission should allow such investments to be made. The Commission needs to make sure that TEP will not create new uneconomic investments in transmission, which would be like stranded generation costs.

5. TEP should not be allowed to become the sole or primary owner of all transmission in Arizona until the details of the state or regional ISO are worked out so that ratepayers can be assured that this proposal will not allow TEP to exercise

vertical market power. In addition, TEP's proposal must be studied as to the likely rate impact that it might have for non-investor owned utilities within Arizona, especially for coops and the Salt River Project. Since TEP's cost of capital is higher than their cost of capital, selling their transmission assets to TEP could increase the cost of transmission to the coops and to Salt River.

6. TEP should not be allowed to sell any of its generating assets to APS unless ratepayers can be assured that doing so will not increase APS' ability to exercise horizontal market power. Such assurance can not be made until a detailed study of horizontal market power within Arizona can be completed. Such a study would probably take at least a few months before this aspect of the proposed settlement could be intelligently discussed and considered by the Commission. One aspect of such a study necessarily involves a transmission system analysis to determine to what extent Phoenix and Tucson are load pockets. This will also bear on a determination of which generation units are must-run units.

7. Prior to TEP's divestiture of its generating units, the Commission must determine both which is the best way to group or "bundle" the plants for sale to best mitigate potential market power problems, and what type of price cap will be placed on the must-run generating units. (Note that this price cap must ultimately be FERC approved.) Since both of these determinations will likely offset the sale price of the generating units, they clearly must be made prior to the solicitation of bids.

8. If TEP fails to divest some of its generating units for any reason, the "net lost revenues" methodology that it claims will be used to compute stranded cost administratively must be specified in detail before the proposed Settlement should be approved.

9. The Commission should not grant all of the waivers requested by TEP from the Commission's rules.

Market Generation Credit (MGC) and Interim Transition Charge (ITC)

Q. WHAT MARKET PRICE OF GENERATION SHOULD BE USED IN CALCULATING THE MARKET GENERATION CREDIT AND INTERIM TRANSITION CHARGE FOR TEP CUSTOMERS?

A. The market generation credit for each customer class should be at least as high as the full retail market price of generation service for each class. Otherwise, alternative generation suppliers will not be able to match or beat the price of TEP generation service provided under the Standard Offer. If this is not done, very little competition will result, just as has occurred in California, Massachusetts, New Hampshire, and Rhode Island.

The interim transition charge is simply the difference between TEP's Standard Offer generation rate and the market generation credit, as indicated on page 3 of the Agreement. If the market generation credit is too small, then the interim transition credit will also be too large—it will collect more than TEP's annual stranded costs correctly calculated.

For confirmation of this last point, consider the concept of stranded cost. It is, of course, based on the difference between the utility's cost of generation service and the price the utility can garner in the competitive retail market for its generation. That competitive market price is the *retail* market price, because the competition that TEP will face is for retail generation sales within its own service area. TEP has a tremendous competitive advantage because it is the known provider and customers have to do some work to switch to any other provider. Therefore, if TEP just matched the retail market price, it would hold onto most, if not all, of its generation customers. Thus, the generation credit should be somewhat higher than the expected retail market price if the Commission wants competition to actually begin. (It should be at the high end of a reasonable range, keeping in mind, though, that most customers will not switch without at least being guaranteed a 5 percent saving on their total rate.)

Q. IS TEP'S PROPOSED MARKET PRICE OF GENERATION A RETAIL MARKET PRICE?

A. No. TEP's market price of generation is far lower than the retail price of generation service, for two reasons.

First, it is a wholesale, rather than a retail, market price. The adder of 2.6-4 mills per kWh which TEP proposes to add to the wholesale market price is only enough to cover some additional wholesale generation-related costs, if that. No retailing costs have been included at all; not even the level of costs embedded in TEP's current level of generation-related A&G.

Second, TEP's proposed market price of generation, which is ultimately based on the palo Verde Index, may reflect a flatter, less expensive load curve than that of some or all Arizona customer classes.

Q. WHAT DO YOU RECOMMEND TO CORRECT THE MARKET PRICE OF GENERATION USED IN SETTING TEP'S MARKET GENERATION CREDIT AND INTERIM TRANSITION CHARGE?

A. To correct this serious problem, I recommend at least two simple modifications of the Settlement Agreement. The first is the application of a retail adder on top of the wholesale market price of generation and the wholesale adder which TEP proposes. As a first approximation of the appropriate retail adder, I suggest the use of the adders I presented in pages 28-39 of my January, 1998 testimony in ACC Docket No. U-0000-94-165. Since these were conservatively estimated, I believe it would be best to begin with the high ends of the ranges I derived. These are 1.18 cents per kWh for small customers and 0.85 cents per kWh for medium-large customers.

The second modification I recommend is that the wholesale market price of generation used in the calculation of the MGC and ITC for each rate schedule be a weighted average of the spot market prices and ancillary services, with the price for each hour weighted in proportion to the load curve of the corresponding group of customers.

"Net Lost Revenues" Method of Estimating Stranded Costs

Q. UNDER THE PROPOSED TEP SETTLEMENT AGREEMENT, WHEN WOULD THE "NET LOST REVENUES" METHOD BE EMPLOYED?

A. The TEP Settlement Agreement proposes on pages 3 and 5 that the "net lost revenue" method of estimating stranded costs be used to calculate the stranded costs of those generation assets for which a failed auction is declared.

Q. IS THE "NET LOST REVENUES" METHOD APPROPRIATE FOR THIS PURPOSE?

A. Yes. The net lost revenues method is a valid framework for administratively calculating stranded costs. However, the details of its implementation have a considerable impact on the results.

Q. WHAT ACTION DO YOU RECOMMEND TO FACILITATE A REASONABLE ESTIMATION OF STRANDED COSTS BY MEANS OF THE "NET LOST REVENUES" METHOD?

A. I recommend that the stranded cost estimates be examined in a fully litigated proceeding for TEP, and rejected or revised if necessary, before being approved.

I also recommend that the ACC and its staff be careful not to pre-approve any parameters of the specific net lost revenues estimation methodology if those parameters would tend to lead to an overestimation of stranded costs. For example, a proper final estimation of stranded costs generally requires the use of a retail market price of generation rather than a wholesale market price of generation, just as a proper calculation of the interim transition charge requires the use of a retail market price, as discussed above in the section about the MGC and the ITC. In addition, stranded costs must be calculated over a sufficiently long period of time. If the ACC were to approve the provision (on page 2 of the Settlement Agreement and on sheets 1 and 4 of Exhibit B) calling for the use of a wholesale market price in setting the ITC now, this precedent might be difficult to overcome when the time arrived to estimate the final stranded costs of TEP assets.

Asset Swap with APS

Q. WHAT IS YOUR OPINION OF THE PROPOSED ASSET SWAP BETWEEN APS AND TEP?

A. I am aware of two major problems with the swap, from the perspective of TEP ratepayers: First, it may undervalue TEP's generating assets. If APS is willing to pay $165 million in a swap, then it is probably willing to pay at least as much in an auction for those assets—and some other party might be willing to pay more. The Commission will have to make an administrative determination of whether or not $165 million is a fair market price for those assets. A hearing process must be included in the proposed Agreement to accomplish this.

Second, the further accumulation of generation assets by APS increases the potential for APS to raise generation prices through the exercise of horizontal market power. This is already a serious risk of a competitive wholesale market in Arizona, even without APS acquiring additional generation assets. This is because Phoenix (and, perhaps, Tucson) is most likely a significant load pocket, given transmission constraints in the region. In addition, APS already owns a significant fraction of all generation in the state. Thus, any additional ability on the part of APS to unjustifiably raise prices within Arizona will affect TEP's current ratepayers also, since retail competition has begun.

Impact of Negative Stranded Costs on Individual Generation Assets

Q. WHAT ARE STRANDED COSTS?

A. Annual stranded costs are defined as the difference between a utility's annual generation-related revenue requirements under traditional regulation, and the annual market value of that generation. Total stranded costs are defined as the net present value of the stream of annual stranded costs over the remaining lifetime of the utility's generation assets. Stranded costs can be positive or negative.

Q. HOW SHOULD NEGATIVE STRANDED COSTS FOR INDIVIDUAL GENERATION ASSETS BE TREATED?

A. The stranded cost amounts for all generation assets should be combined into one total, and that total should be recovered solely by the ratepayers if it is negative. If the total is positive, the appropriate manner to share recovery of stranded costs shall be litigated at the Commission.

Q. WHAT IS WRONG WITH TEP "BORROWING" THE STRANDED COSTS ASSOCIATED WITH GENERATION ASSETS THAT HAVE NEGATIVE STRANDED COSTS?

A. TEP should acquire capital for its new investments through the capital markets, not through "loans" from ratepayers such as that described at the end of the Settlement Agreement's section VI (page 4). If TEP is proposing to acquire capital this way, it is probably because a lender would consider the risk too high to justify a loan at TEP's target rate of return. This suggests the "loan" by ratepayers to TEP would be a bad risk. If TEP went bankrupt at any time during the long span before the loan is to be repaid, the ratepayers would have paid disproportionately more of the positive stranded costs than they had received of the negative stranded costs, and their future recovery of the negative stranded costs might be in jeopardy.

TEP Ownership of State-wide Transmission System

Q. SHOULD TEP EMBARK ON MAJOR NEW INVESTMENTS IN TRANSMISSION?

A. No, it is not likely that it would be in the public interest for TEP to significantly expand its transmission system investments. The Settlement Agreement states that "it is the intent of Staff and, by its approval of this Agreement, the Commission, that TEP's transmission company affiliate be the sole builder and owner of transmission assets in the state (page 7)." It also directs that TEP's transmission affiliate "will acquire all transmission facilities owned by TEP, APS, SRP, AEPCO and others."

TEP is already severely short of equity and impaired in its ability to raise capital, because of ongoing financial problems. It therefore seems poorly suited to the task of making and maintaining major new investments in transmission assets. This entire proposal requires much more flushing out and review by all parties before it can even be seriously considered by the Commission. This is especially true since the ACC does not even regulate the transmission systems of SRP and WAPA.

Q. WHAT IMPACT WOULD A TEP-OWNED TRANSCO STATEWIDE TRANSMISSION MONOPOLY HAVE ON THE COST OF TRANSMISSION IN ARIZONA?

A. This is difficult to predict, but there is an important reason why it might increase the cost of transmission to large parts of Arizona. Transco, TEP's transmission affiliate, would have a higher cost of capital than the current owners of many of the transmission facilities in

Arizona. This is true, in part, because TEP's past financial troubles increase the perceived risk of lending to a TEP affiliate, and in part because SRP and the cooperatives, current owners of some of Arizona's transmission assets, receive low-cost financing and certain tax treatments which reduce their cost of capital.

Waivers

Q. THE PROPOSED SETTLEMENT AGREEMENT HAS ALLOWED FOR WAIVERS FOR MANY OF THE ACC'S RULES FOR TEP. DO YOU HAVE ANY COMMENTS ON THE WAIVERS PROPOSED?

A. Yes. The Agreement proposes that waivers be granted for complying with R14-2-701, et seq., the Integrated Resource Planning Rules. To the extent that these waivers could apply to generation, then they could be granted. However, to the extent that the waivers would apply to future transmission (or distribution) system investments, then they should be denied. IRP procedures ought to continue to be applied to transmission investments using the projected market price for generation as the basis for doing least-cost transmission system planning.

In addition, the Agreement calls for a waiver from the Decision No. 59594 requirement that a Mid-Year DSM and Renewables Report be filed. I am not aware of why the restructuring process should cause the need for these reports to change. Similarly, a waiver should not be granted from the Decision No. 58497 requirements to file an avoided cost report. Even after divestiture is completed, there will be a market price for incremental supplies of power for different DSM-related load shapes. This information will still be useful to help ensure that new DSM investments are cost-effective.

Q. ARE THERE ANY OTHER WAIVERS THAT YOU ARE OPPOSED TO THE ACC GRANTING?

A. Yes. I oppose the granting of several other waivers which TEP has requested. Specifically, I object to the waiver of condition numbers 19, 20, 21, and 28 in Decision No. 60480.

Conditions 19, 20, and 21 restrict TEP's actions in certain ways, for the purpose of improving TEP's debt-heavy capital structure. TEP requests a waiver of these conditions, claiming that its capital structure will be dramatically redefined after divestiture. While divestiture would likely improve TEP's capital structure, it is premature to waive these conditions at this time. After any Commission-authorized divestiture is completed, waiver of these conditions may be appropriate. However, it is premature to grant these waivers at this time.

Condition 28 prevents TEP's parent company and sister companies from investing amounts greater than $60 million in any single investment without Commission approval. This condition was also designed to protect TEP's customers from further deterioration of TEP's capital structure. The Commission may approve any such investment, but it is inappropriate to waive the condition in its entirety.

V. CONCLUSION

Q. ARE THE TWO PROPOSED SETTLEMENT AGREEMENTS AN IMPROVEMENT OVER APS' AND TEP'S ORIGINAL STRANDED COST RECOVERY FILINGS?

A. No. The proposed Settlement Agreements are worse for Arizonans because they correct none of the major problems of the original stranded cost filings, while they create many new problems. Many of these new proposals and problems could lead to higher electricity prices in Arizona than need be the case. In summary, the proposed Settlement Agreements would not lead to retail competition, especially for small customers. They would very likely over-charge customers for stranded costs, they would over-charge customers for their Standard Offer rates, and they would very likely lead to greater market power on the part of APS. Because the two proposed Settlement Agreements leave so many problems either unsolved or insufficiently addressed, they both should be rejected by the Commission. This is especially necessary in light of the insufficient time which most parties to these dockets have had to properly analyze the numerous new issues raised by the proposed Agreements.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.