0000121592

Transcript Exhibit(s)

Docket #(s): RE-00000C-94-0165

E-01345A-97-0773

E-01345A-98-0473

Exhibit # : AECC1, AECC2

EXHIBIT
AECC-1
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
Chairman
JIM IRVIN
Commissioner
WILLIAM A. MUNDELL
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS PLAN FOR 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 COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. RE-00000C-94-0165

DIRECT TESTIMONY OF KEVIN HIGGINS

Fennemore Craig
3003 North Central Avenue, Suite 2600
Phoenix, Arizona 85012-2913
Attorneys for Cyprus Climax Metals Company, ASARCO Incorporated and Arizonans for Electric Choice and Competition

DIRECT TESTIMONY OF KEVIN C. HIGGINS

Q. Please state your name and business address.

A. Kevin C. Higgins, 39 Market Street, Suite 200, Salt Lake City, Utah, 84101.

Q. By whom are you employed and in what capacity?

A. I am employed by Energy Strategies, Inc. (ESI) as a senior associate. ESI is a private consulting firm specializing in the economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Arizonans for Electric Choice and Competition[1].

Q. What are your qualifications to testify in this proceeding?

A. My academic background is in economics, and I have completed all course work and examinations toward the Ph.D. in Economics at the University of Utah, and have served on the adjunct faculties of both the University of Utah and Westminster College. Prior to joining ESI, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I testified regularly before the Utah Public Service Commission on matters involving structural change in the provision of energy services, including introduction of retail competition in the natural gas industry, implementation of rules governing small power production and cogeneration, joint ownership of electric transmission facilities, and the merger between major electric utilities. From 1991 to 1994, I was chief of staff to the

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[1] Arizonans for Electric Choice and Competition is a coalition of energy consumers in favor of competition and includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multihousing Association, Arizona Rock Products Association, Arizona Restaurant Association, Arizona Association of General Contractors, Arizona Retailers Association, Boeing, Arizona School Board Association, National Federation of Independent Business, Arizona Hospital Association, Lockheed Martin, Abbot Labs, and Raytheon.

chairman of the Salt Lake County Commission, one of the larger municipal governments in the western U.S., where I was responsible for development and implementation of a broad spectrum of public policy. In 1995, I joined ESI, where I assist private and public-sector clients in the area of energy-related economic and policy analysis, including the provision of expert testimony. A more detailed description of my qualifications is contained in Exhibit KCH-1, attached to this testimony.

Q. **What has been your involvement in the electric industry restructuring effort in Arizona?**

A. For much of 1996, I was involved in the workshop process conducted by the Arizona Corporation Commission to develop rules governing the implementation of retail access. In 1997, I participated in the Working Group process established by the Commission, serving as a consumer representative on the Stranded Cost Working Group; as part of that effort, I participated in each of the Working Group's three subcommittees. I also participated actively in the Reliability & Safety, Customer Selection, ISO, and Unbundled Services & Standard Offer Working Groups established by the Commission. Concurrently, I have been actively involved in the Desert STAR independent system operator (ISO) feasibility assessment, participating on the Steering Committee, in the Pricing and Operations Working Groups, and on the Legal & Negotiating Committee.

In 1998, I provided direct and rebuttal testimony before this Commission on stranded cost recovery in the electric competition hearing, and submitted testimony on the previously-proposed Arizona Public Service (APS) and Tucson Electric Power settlements at the end of that year. I also provided extensive comments to the SRP Board as part of its effort to implement retail competition. I have also been very involved in addressing transmission access issues; I serve on the Board of the Arizona Independent Scheduling Administrator (AISA) and have been chairing its Operating Committee, which is responsible for drafting the AISA's Protocols Manual.

Q. What is the purpose of your testimony today?

A. My testimony addresses the Settlement Agreement between AECC, RUCO, Arizona Community Action Association, and APS. I believe this settlement is in the public interest and I recommend that the Commission approve it.

Q. On what basis are you familiar with the Settlement Agreement?

A. On behalf of AECC, I helped to negotiate the Settlement Agreement.

Q. Why do you believe the Settlement Agreement is in the public interest?

A. The Settlement Agreement provides a comprehensive resolution to many of the difficult issues associated with effecting a transition to retail competition in APS' distribution territory. The Settlement Agreement resolves these issues fairly, providing significant benefits to customers in the form of rate reductions and viable competitive options. Stranded cost recovery is resolved through a compromise that allows APS to recover $350 million (present value) in stranded cost through 2004, while incurring a $234 million (nominal) disallowance. The Competitive Transition Charge (CTC) that is levied to recover stranded cost declines each year through 2004, as does the regulatory asset payment by competitive customers, which is included in the unbundled distribution charge. The combination of a declining CTC and a declining regulatory asset payment (via the unbundled distribution charge) results in a progressively smaller regulatory cost hurdle for customers to access the competitive market. Simultaneously, Standard Offer rates decline each year of the transition through 2003. Further, the Settlement Agreement commits APS to assuring non-discriminatory access to the transmission system through active support of the formation of the Desert STAR ISO and adherence to the AISA protocols.

Q. How is your testimony organized?

A. I will address key terms of the Settlement Agreement generally in the order in which they appear in the agreement. I will explain why, from a customer perspective, I believe these terms are fair and reasonable.

Implementation of retail access

Q. How does the implementation of retail access in the Settlement Agreement compare with the implementation in the Commission's proposed Electric Competition Rules?

A. The start date for opening retail access to all customers is the same – January 1, 2001. During the phase-in, Section 1.1 of the Settlement Agreement allows for an additional 140 MW of competitive load being made available by APS for eligible non-residential customers. This additional 140 MW restores the non-residential share of the phase-in amount that these customers lost in December 1998 when the Commission raised the residential set-aside from the 4 percent that had been originally proposed in the Rules to 10 percent. (Because the total amount of load eligible for competition had not been increased in the Rules, raising the residential set-aside had the effect of lowering the amount of load eligible for competition for other customers.) The Settlement Agreement does not impact the 10 percent set-aside for residential customers. Thus, the Settlement Agreement increases the total amount of load that is eligible for competition during the phase-in, while providing the level of residential participation required by the proposed Rules.

Rate matters

Q. What rate changes result from the Settlement Agreement?

A. Two major rate changes are implemented: Standard Offer rates will decline in a specified amount each year through 2003 (Section 2.2), and unbundled tariffs are issued for competitive service (Section 2.1). The unbundled tariff rates also decline a specified amount each year (Exhibit A, Schedules A and B).

The Settlement Agreement establishes regulated retail rates through July 1, 2004.[2] Subsequently, rates are to be established pursuant to a general rate case, which APS will file by June 30, 2003 (Section 2.7).

Q. **What is the reduction in Standard Offer rates?**

A. For all residential customers, there will be successive 1.5 percent reductions in Standard Offer rates in July 1999, July 2000, July 2001, July 2002, and July 2003, for a cumulative reduction of 7.5 percent. The same rate reduction will apply to all non-residential Standard Offer rates for service provided below 3 MW. For industrial-type service, i.e., 3 MW or greater, Standard Offer rates will decline as follows: 1.5 percent in July 1999 and July 2000, 1.25 percent on July 2001, and .75 percent in July 2002, for a cumulative reduction of 5 percent.

Q. **How does the Standard Offer rate reduction in this Settlement Agreement compare with the rate reduction that had been proposed in the (expired) Settlement Agreement that APS had negotiated with Staff in late 1998?**

A. The rate reductions in this Settlement Agreement are greater for all Standard Offer customers. The previous settlement would have reduced residential rates 1 percent each year from July 1999 through July 2002, for a total of about 4 percent – compared with 7.5 percent in the current agreement. Furthermore, under the previous agreement, non-residential rates would have declined 1 percent in July 1999 and July 2000 for a total of about 2 percent – compared with 7.5 percent for commercial-size customers and 5 percent for industrial-size customers under the current agreement.

Q. **Please describe the unbundled tariffs that are issued as part of the Settlement Agreement.**

A. The unbundled tariffs will provide direct access service for each major category of APS customer: residential, general service, extra-large general service, and contract

[2] The exception is the CTC, which is set through December 31, 2004.

(when contracts terminate). The unbundled components in each tariff consist of basic delivery, distribution, system benefits, and the CTC. In addition, there are unbundled billing credits for metering, meter reading, and billing when those services are provided by the customer's electric service provider (ESP).

Q. How are APS' regulatory assets recovered in the unbundled tariff?

A. Full recovery of regulatory asset is included in the distribution charge of each unbundled tariff.

Q. How are transmission and ancillary services costs recovered?

A. APS will not bill retail customers directly for transmission service and ancillary services. Instead, these services will be billed, when appropriate, to the scheduling coordinators who will be submitting hourly load and resource schedules on behalf of ESPs. Eventually, these costs likely will be passed on to retail customers by their respective ESPs. The rates that APS intends to charge scheduling coordinators for transmission and ancillary services have been provided to me as part of the settlement negotiations. They are generally comparable to the rates now found in APS' Open Access Transmission Tariff (OATT) approved by FERC.

Q. Why are there separate unbundled tariffs for BHP Copper, Cyprus Bagdad, and Ralston Purina?

A. These customers take service today under special contracts. The unbundled tariffs for these customers would govern direct access service upon termination of the current contracts. Consistent with the proportionality provision of the proposed Rules, the unbundled rates for these customers are calculated to continue, at the time each contract terminates (2001), the level of contribution to stranded cost recovery that is included in the respective current bundled-service contract rates. Thereafter, the CTC and regulatory asset payments decline at the same rate as that of the extra-large general service tariff. All the other unbundled rates for these customers – basic service charge, system benefits, and the non-regulatory asset portion of distribution service – are the same as that of the unbundled tariff for extra-large general service.

Q. What is the basis for the reduction in the unbundled tariffs in future years?

A. The rates in the unbundled tariffs are set in advance through July 1, 2004. A major advantage of this approach is that it provides direct access customers with price certainty regarding the regulated portion of their bills. The CTC and distribution rates are reduced each year during the transition period in accordance with Schedule A and Schedule B, respectively, of Exhibit A. The CTC declines January 1 of each year and is calculated to recover $350 million in present value when levied against the kWh expected to be delivered to all retail load in the APS distribution territory from January 1, 1999 through December 31, 2004.[3] There are two main reasons for the annual decline in the CTC: (1) increased kWh sales, which lowers the per-unit cost of stranded cost recovery, and (2) smaller amounts of annual stranded cost in future years, based on APS' net revenues lost calculation.

The unbundled distribution rates also decline on January 1 for each year of the transition period. This decline results from the annual reduction in the regulatory asset portion of the distribution charge. The percentage decline in the regulatory asset portion of the distribution charge is the same for all direct access customers; by January 2004, the regulatory asset portion of the distribution charge will be approximately 35 percent lower than in 1999.

Q. What are the implications for the competitive market of the declining CTC and declining regulatory asset portion of the distribution charge?

A. The competitive market will benefit from this design feature. The combination of a declining CTC and a declining regulatory asset payment (via the unbundled distribution

[3] For the years 1999 and 2000, the contribution to the $350 million stranded cost recovery will be applied to 20 percent of the kWh delivered to all retail load, consistent with the assumptions used in APS' calculation of its stranded cost. See Exhibit B.

charge) results in a progressively smaller regulatory cost hurdle for customers to access the competitive market each year. My assessment of the unbundled tariffs is that at current market prices they will allow customers to benefit from competition right away, and benefit even more in the future. For example, I estimate that an ESP serving a commercial customer in 2000 would have a margin of 5.1 mills per kWh between the wholesale price and the Standard Offer rate from which to offer the customer savings. In 2001, this margin grows to 6.1 mills – even as the Standard Offer declines. By way of comparison, under the previously-proposed settlement (1998), the comparable margin was 2.2 mills for all years. Of course, under the current Settlement Agreement, as the market price of power changes, so does the margin – up or down.

Q. How are Standard Offer and unbundled rates established after July 1, 2004?

A. As I indicated above, rates after that time are to be established pursuant to a general rate case, which APS will file by June 30, 2003 (Section 2.7). The timing of the general rate case is significant: APS' regulatory assets are scheduled to be fully amortized by July 1, 2004. In addition, the CTC expires six months later. All things being equal, customers would be entitled to significant rate reductions following the regulatory asset amortization and the CTC expiration. At the same time, to the extent that APS may experience increased costs associated with its regulated service, the utility can seek to recover such costs as part of the general rate case. Further, certain adjustment clauses (Section 2.6), discussed below, are scheduled to be implemented beginning July 1, 2004.

Q. Please explain the adjustment clauses that appear in Section 2.6.

A. Section 2.6 identifies four categories of cost that are to be recovered through two basic types of adjustment clauses beginning July 1, 2004. The first type of adjustment clause applies to cost items (1) and (2) of Section 2.6; it is associated with the costs of providing Standard Offer service, and is applicable only to Standard Offer rates. Note that cost item (1) – obligations associated with "provider of last resort" and Standard Offer service – is intended to apply to *deviations* in the cost of providing Standard Offer service above or below the amount recovered in base rates after July 1, 2004. By that time, APS will be acquiring all of its resources for Standard Offer service from the wholesale market. The cost of such acquisitions may be greater than or less than the cost built into rates; consequently, the adjustment clause may be either positive or negative. Prior to July 1, 2004, there is no adjustment clause, and APS is at risk for recovering the obligations in cost item (1).

The second basic type of adjustment clause is applicable to all customers – Standard Offer and competitive. It pertains to cost item (3), compliance with the Electric Competition Rules, and cost item (4), system benefits costs that are not included in rates as of June 30, 1999.

Q. Does applying an adjustment clause to APS' costs of complying with the Electric Competition Rules constitute a "blank check" for the utility?

A. Applying an adjustment clause to this cost item is not intended to be a blank check for the utility. Before costs can be included in the adjustment clause(s), they must be found by the Commission to be reasonable and prudent. The parties to this agreement are not waiving their rights to review, and if necessary, challenge the reasonableness, prudence, or proper classification of any of the costs that APS proposes to recover through the adjustment clause(s).

<u>Regulatory assets and stranded costs</u>

Q. What is the basis for the $350 million in stranded cost recovery provided in Section 3.3 of the Settlement Agreement?

A. It is based on a compromise among the parties. A present value of $350 million corresponds to about 66 percent of the $533 million in stranded cost calculated by APS.

Q. Does the Settlement Agreement assure recovery of the $350 million?

A. Yes, it does. Section 3.3 provides that the recovery of stranded cost will be tracked in accordance with the CTC values shown in Exhibit B, which in turn, correspond to the CTC that will be levied on customers, as shown in Exhibit A, Schedule A. The values in Exhibit B will recover a present value of $350 million in stranded cost if the amount of retail kWh delivered in the APS distribution territory is equal to APS' forecast. If a greater amount of kWh is delivered than forecast, it will result in more than $350 million being collected during the transition period; if fewer kWh are delivered, it will result in less being collected. Section 3.3 provides that, as of December 31, 2004, any excess recovery or under recovery of the $350 million is to be applied to the adjustment mechanism set forth in Section 2.6 (3).

Q. Does the Settlement Agreement provide for full recovery of APS' regulatory assets?

A. Yes. For Standard Offer customers, the recovery of regulatory assets is included in the Standard Offer rate. For retail access customers, full payment for regulatory asset recovery is included in the distribution charge of each unbundled tariff.

<u>Corporate structure</u>

Q. Why does Section 4.1 of the Settlement Agreement provide APS a two-year extension for forming its competitive affiliate?

A. My understanding is that such an extension will allow APS to save significant costs in effecting the separation; such savings will reduce the amount that APS will seek to recover in the adjustment clause described in Section 2.6 (3).

Q. Section 4.4 of the Settlement Agreement states that its approval by the Commission shall be deemed to include certain specific determinations in support of an APS application to FERC for exempt wholesale generator (EWG) status. Does this provision bind the parties or the Commission to any position in any future

proceedings before FERC regarding its regulation of APS' wholesale generation rates?

A. No. If the APS affiliate is successful in being designated an EWG by FERC, it does not mean that FERC would necessarily relinquish its regulation of the affiliate's wholesale generation rates. In fact, if FERC were to determine that the APS generation affiliate had significant market power, one would expect FERC to impose price caps on the affiliate's wholesale generation sales. In Section 4.6 of the Settlement Agreement, the parties reserve their rights under Sections 205 and 206 of the Federal Power Act to appear before FERC and argue their respective positions with respect to the rates of any APS affiliate formed under Article IV of the Settlement Agreement.

Miscellaneous – Transmission Access

Q. **What provisions are made to ensure non-discriminatory access to the transmission system?**

A. Over the past two years, stakeholders in the southwest have been negotiating the terms of transmission access. The long-term resolution of this issue lies in the formation of the Desert STAR Independent System Operator, and the interim solution requires implementation of the AISA protocols and its oversight. Section 7.6 of the Settlement Agreement requires APS to actively support the AISA and the formation of the Desert STAR Independent System Operator. In addition, APS agrees to modify its OATT to be consistent with any FERC-approved AISA protocols, and to file such changes within ten days of Commission approval of the Settlement Agreement. I believe these provisions are the appropriate steps for ensuring non-discriminatory access to the transmission system

Miscellaneous – Code of Conduct

Q. **What is the purpose of the code of conduct provisions in Section 7.7 of the Settlement Agreement?**

A. In my opinion, the establishment of effective rules governing affiliate relationships is an integral part of successfully implementing retail competition. In the proposed Electric Competition Rules, this function had been fulfilled, in part, by the "Affiliate Transactions" section. Unfortunately, however, the "Affiliate Transactions" section was deleted from the proposed Rules and replaced with a requirement that Affected Utilities file a code of conduct within ninety days of the adoption of the Rules. The code of conduct is intended to prevent anti-competitive abuses and must be approved by the Commission.

The Settlement Agreement contemplates that APS' code of conduct filing will proceed in accordance with the Commission's proposed Rules. The parties to the Settlement Agreement are free to participate in any such proceeding and to advocate their own positions at such time. In the meantime, APS will adhere to a voluntary, interim code of conduct that will be served on the parties within thirty days of Commission approval of the Settlement Agreement.

I believe that given the deletion of the "Affiliate Transactions" section of the proposed Rules, the approach taken in the Settlement Agreement is the most reasonable way to address code of conduct issues without further delaying the start of competition.

<u>Conclusion</u>

Q. In conclusion, what is your recommendation to the Commission regarding the Settlement Agreement?

A. I believe that the Settlement Agreement is in the public interest. The Settlement Agreement provides a comprehensive resolution to many of the difficult issues associated with effecting a transition to retail competition in APS' distribution territory. The Settlement Agreement resolves these issues fairly, providing significant benefits to customers in the form of rate reductions and viable competitive options. The combination of a declining CTC and a declining regulatory asset payment (via the unbundled distribution charge) results in a progressively smaller regulatory cost hurdle for customers to access the competitive market each year. Simultaneously, Standard Offer rates decline each year of the transition through 2003. Further, the Settlement Agreement commits APS to assuring non-discriminatory access to the transmission system through active support of the formation of the Desert STAR ISO and adherence to the AISA protocols.

I recommend that the Settlement Agreement be approved by the Commission.

Q. Does this conclude your direct testimony?

A. Yes, it does.

KEVIN C. HIGGINS
Senior Associate, Energy Strategies, Inc.
39 Market St., Suite 200, Salt Lake City, UT 84101
(801) 355-4365

Vitae

PROFESSIONAL EXPERIENCE

Senior Associate, Energy Strategies, Inc., Salt Lake City, Utah, February 1995 to present. Responsible for energy-related economic and policy analysis, regulatory intervention, and strategic negotiation on behalf of industrial, commercial, and public sector interests.

Adjunct Instructor in Economics, Westminster College, Salt Lake City, Utah. September 1981 to May 1982; September 1987 to May 1995. Taught in the economics and M.B.A. programs. Awarded Adjunct Professor of the Year, Gore School of Business, 1990-91.

Chief of Staff to the Chairman, Salt Lake County Board of Commissioners, Salt Lake City, Utah, January 1991 to January 1995. Senior executive responsibility for all matters of county government, including formulation and execution of public policy, delivery of approximately 140 government services, budget adoption and fiscal management (over $300 million), strategic planning, coordination with elected officials, and communication with consultants and media.

Assistant Director, Utah Energy Office, Utah Department of Natural Resources, Salt Lake City, Utah, August 1985 to January 1991. Directed the agency's resource development section, which provided energy policy analysis to the Governor, implemented state energy development policy, coordinated state energy data collection and dissemination, and managed energy technology demonstration programs. Position responsibilities included policy formulation and implementation, design and administration of energy technology demonstration programs, strategic management of the agency's interventions before the Utah Public Service Commission, budget preparation, and staff development. Supervised a staff of economists, engineers, and policy analysts, and served as lead economist on selected projects.

Utility Economist, Utah Energy Office, January 1985 to August 1985. Provided policy and economic analysis pertaining to energy conservation and resource development, with an emphasis on utility issues. Testified before the state Public Service Commission as an expert witness in cases related to the above.

Acting Assistant Director, Utah Energy Office, June 1984 to January 1985. Same responsibilities as Assistant Director identified above.

Research Economist, Utah Energy Office, October 1983 to June 1984. Provided economic analysis pertaining to renewable energy resource development and utility issues. Experience includes preparation of testimony, development of strategy, and appearance as an expert witness for the Energy Office before the Utah PSC.

Operations Research Assistant, Corporate Modeling and Operations Research Department, Utah Power and Light Company, Salt Lake City, Utah, May 1983 to September 1983. Primary area of responsibility: designing and conducting energy load forecasts.

Instructor in Economics, University of Utah, Salt Lake City, Utah, January 1982 to April 1983. Taught intermediate microeconomics, principles of macroeconomics, and economics as a social science.

Teacher, Vernon-Verona-Sherrill School District, Verona, New York, September 1976 to June 1978.

EDUCATION

Ph.D. Candidate, Economics, University of Utah (coursework and exams completed, 1981).

> Fields of Specialization: Public Finance, Urban and Regional Economics, Economic Development, International Economics, History of Economic Doctrines.

Bachelor of Science, Education, State University of New York at Plattsburgh, 1976 (cum laude).

Danish International Studies Program, University of Copenhagen, 1975.

SCHOLARSHIPS AND FELLOWSHIPS

University Research Fellow, University of Utah, Salt Lake City, Utah 1982 to 1983.
Research Fellow, Institute of Human Resources Management, University of Utah, 1980 to 1982.
Teaching Fellow, Economics Department, University of Utah, 1978 to 1980.
New York State Regents Scholar, 1972 to 1976.

EXPERT TESTIMONY

"In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in Utah," Utah Public Service Commission, Case No. 80-999-06, pp. 1293-1318. Prefiled testimony submitted January 13, 1984 (avoided costs), May 9, 1986 (security for levelized contracts) and November 17, 1986 (avoided costs); cross-examined February 29, 1984 (avoided costs), April 11, 1985 (standard form contracts), May 22-23, 1986 (security for levelized contracts) and December 16-17, 1986 (avoided costs).

"In the Matter of the Investigation of Demand-Side Alternatives to Capacity Expansion for Electric Utilities," Utah Public Service Commission, Case No. 84-999-20. Prefiled direct testimony submitted June 17, 1985. Prefiled rebuttal testimony submitted July 29, 1985; Cross-examined August 19, 1985.

"In the Matter of the Application of Sunnyside Cogeneration Associates for Approval of the Cogeneration Power Purchase Agreement," Utah Public Service Commission, Case No. 86-2018-01. Rebuttal testimony submitted July 16, 1986; cross-examined July 17, 1986.

"In the Matter of the Investigation of Rates for Backup, Maintenance, Supplementary, and Standby Power for Utah Power and Light Company," Utah Public Service Commission, Case No. 86-035-13; prefiled direct testimony submitted January 5, 1987. Case settled by stipulation approved August 1987.

"Cogeneration: Small Power Production," Federal Energy Regulatory Commission, Docket No. RM87-12-000. Statement delivered March 27, 1987, on behalf of State of Utah, in San Francisco.

"In the Matter of the Application of Utah Power and Light Company for an Order Approving a Power Purchase Agreement," Utah Public Service Commission, Case No. 87-035-18. Oral testimony delivered July 8, 1987.

"In the Matter of the Application of Mountain Fuel Supply Company for Approval of Interruptible Industrial Transportation Rates," Utah Public Service Commission, Case No. 86-057-07. Prefiled direct testimony submitted January 15, 1988; cross-examined March 30, 1988.

"In the Matter of the Application of Utah Power & Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. and Authorizing the Issuance of Securities, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith," Utah Public Service Commission, Case No. 87-035-27; prefiled direct testimony submitted April 11, 1988; cross-examined May 12, 1988 (economic impact of UP&L merger with PacifiCorp).

"In the Matter of the Review of the Rates of Utah Power and Light Company pursuant to The Order in Case No. 87-035-27," Utah Public Service Commission, Case No. 89-035-10. Rebuttal testimony submitted November 15, 1989; cross-examined December 1, 1989 (rate schedule changes for state facilities).

"In the Matter of the Investigation of the Reasonableness of the Rates and Tariffs of Mountain Fuel Supply Company," Utah Public Service Commission, Case No. 89-057-15. Pre-filed direct testimony submitted July 1990. Surrebuttal testimony submitted August 1990.

"In the Matter of the Application of Mountain Fuel Supply Company for an Increase in Rates and Charges," Utah Public Service Commission, Case No. 95-057-02. Prefiled direct testimony submitted June 19, 1995. Rebuttal testimony submitted July 25, 1995. Surrebuttal testimony submitted August 1995.

"Questar Pipeline Company," Federal Energy Regulatory Commission, Docket No. RP95-407. Direct testimony prepared, but withheld subject to settlement. Settlement approved July 1, 1996.

"In the Matter of the Application of PacifiCorp, dba Pacific Power & Light Company, for Approval of Revised Tariff Schedules and an Alternative Form of Regulation Plan," Wyoming Public Service Commission, Docket No. 2000-ER-95-99. Prefiled direct testimony submitted April 8, 1996.

"In the Matter of Arizona Public Service Company's Rate Reduction Agreement," Arizona Corporation Commission, Docket No. U-1345-95-491. Direct testimony prepared, but withheld consequent to issue resolution. Agreement approved April 18, 1996.

"In the Matter of the Petition of Sunnyside Cogeneration Associates for Enforcement of Contract Provisions," Utah Public Service Commission, Docket No. 96-2018-01. Prefiled direct testimony submitted July 8, 1996.

"In the Matter of Consolidated Edison Company of New York, Inc.'s Plans for (1) Electric Rate Restructuring Pursuant to Opinion No. 96-12; and (2) the Formation of a Holding Company Pursuant to PSL, Sections 70, 108, and 110, and Certain Related Transactions," New York Public Service Commission, Case 96-E-0897. Testimony filed April 9, 1997. Cross examined May 5, 1997.

"In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Arizona Corporation Commission, Docket No. U-0000-94-165. Direct and rebuttal testimony filed January 21, 1998. Cross-examined February 25, 1998.

"Hearings on Customer Choice," Salt River Project Board of Directors, written and oral comments provided June 22, 1998; June 29, 1998; July 9, 1998; August 7, 1998; and August 14, 1998.
"Hearings on Pricing," Salt River Project Board of Directors, written and oral comments provided November 9, 1998.

OTHER RELATED ACTIVITY

Board Member, Arizona Independent Scheduling Administrator Association, October 1998 to present.

Acting Chairman, Operating Committee, Arizona Independent Scheduling Administrator Association, October 1998 to present.

Member, Desert Star ISO Investigation Working Groups: Operations, Pricing, and Governance April 1997 to present.

Participant, Independent System Operator and Spot Market Working Group, Arizona Corporation Commission, April 1997 to September 1997.

Participant, Unbundled Services and Standard Offer Working Group, Arizona Corporation Commission, April 1997 to October 1997.

Participant, Customer Selection Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Stranded Cost Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Electric System Reliability & Safety Working Group, Arizona Corporation Commission, November 1996 to present.

Consultant to business customers, "In the Matter of Competition in the Provision of Electric Services Throughout the State of Arizona," Arizona Corporation Commission, Docket No. U-0000-94-165. Preparation of comments and participation in staff workshops. Rule on retail electric competition adopted December 23, 1996.

Chairman, Salt Palace Renovation and Expansion Committee, Salt Lake County/State of Utah/Salt Lake City, multi-government entity responsible for implementation of planning, design, finance, and construction of an $85 million renovation of the Salt Palace Convention Center, Salt Lake City, Utah, May 1991 to December 1994.

State of Utah Representative, Committee on Regional Electric Power Cooperation, a joint effort of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, January 1987 to December 1990.

Member, Utah Governor's Economic Coordinating Committee, January 1987 to December 1990.

Chairman, Standard Contract Task Force, established by Utah Public Service Commission to address contractual problems relating to qualifying facility sales under PURPA, March 1986 to December 1990.

Chairman, Load Management and Energy Conservation Task Force, Utah Public Service

Commission, August 1985 to December 1990.

Alternate delegate for Utah, Western Interstate Energy Board, Denver, Colorado, August 1985 to December 1990.

Articles Editor, Economic Forum, September 1980 to August 1981.

EXHIBIT
AECC-2
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
Chairman
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Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS PLAN FOR STRANDED COST RECOVERY	DOCKET NO. E-01345A-98-0473
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REBUTTAL TESTIMONY OF KEVIN HIGGINS

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REBUTTAL TESTIMONY OF KEVIN C. HIGGINS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Kevin C. Higgins, 39 Market Street, Suite 200, Salt Lake City, Utah, 84101.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Energy Strategies, Inc. (ESI) as a senior associate. ESI is a private consulting firm specializing in the economic and policy analysis applicable to energy production, transportation, and consumption.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. My testimony is being sponsored by Cyprus Climax Metals Company, ASARCO Incorporated and Arizonans for Electric Choice and Competition (collectively, hereinafter, "AECC")[1].

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I have filed direct testimony supporting the Settlement Agreement.

Q. WHAT ISSUES WILL YOU BE ADDRESSING IN YOUR REBUTTAL TESTIMONY?

A. I will address the following areas in response to the direct testimony of other parties: (1) unbundled rates for Standard Offer customers, (2) viability of the competitive market for direct access customers, (3) the "shopping credit" for contract customers, and (4) market power.

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[1] Arizonans for Electric Choice and Competition is a coalition of energy consumers in favor of competition and includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multihousing Association, Arizona Rock Products Association, Arizona Restaurant Association, Arizona Retailers Association, Boeing, Arizona School Board Association, National Federation of Independent Business, Arizona Hospital Association, Lockheed Martin, Abbot Labs, and Raytheon.

UNBUNDLED RATES FOR STANDARD OFFER CUSTOMERS

Q. A NUMBER OF PARTIES HAVE MAINTAINED THAT THE SETTLEMENT AGREEMENT DOES NOT PROVIDE FOR THE UNBUNDLING OF STANDARD OFFER RATES. IS THIS VIEW CORRECT?

A. No. Section 2.1 of the Settlement Agreement plainly states: "Bills for Standard Offer service shall indicate individual unbundled service components to the extent required by the Electric Competition Rules." The proposed Rules spell out these unbundled billing requirements in R14-2-1612.N. The customer's bill is the most accessible source of pricing information for customers and requiring the inclusion of unbundled pricing information in the Standard Offer bill has been an important objective in the transition to competition. Thus, AECC sought to ensure that this provision was reinforced in the Settlement Agreement. A number of witnesses seem to have missed or disregarded this provision in their review of the Settlement Agreement, and assert that there is no requirement in the Agreement to unbundle Standard Offer rates.[2] This assertion, however, is incorrect.

VIABILITY OF THE COMPETITIVE MARKET

Q. A NUMBER OF PARTIES HAVE ARGUED THAT THE "SHOPPING CREDIT" IN THE SETTLEMENT AGREEMENT IS TOO LOW FOR VIABLE COMPETITION TO TAKE PLACE. DO YOU WISH TO COMMENT ON THIS POINT?

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[2] See, e.g., Direct testimony of Harry J. Kingerski (Enron), pp. 7-16, esp. p. 12, lines 1-7; Direct testimony of Lee Smith (Staff), p. 4, lines 16-18.

A. Certainly a higher "shopping credit" makes competitive alternatives more attractive and competition more viable. In negotiating the Settlement Agreement, AECC sought to achieve the maximum shopping credit achievable while still providing customers the benefit of reduced Standard Offer rates. This consideration is important because the simplest way to increase the shopping credit would be to refrain from reducing Standard Offer rates. However, it is not in customers' interests to forego guaranteed Standard Offer rate reductions in order to maintain a higher shopping credit. Therefore, I disagree with the suggestion of Mr. Williamson that consideration be given to obtaining a higher shopping credit through lowering the Standard Offer reductions.[3]

I believe that Standard Offer rate reductions and a viable competitive market can coexist. The Settlement Agreement seeks a balance by providing for annual reductions in the direct access unbundled tariffs that meet or exceed the Standard Offer reductions, which results in annual increases of the shopping credit. At the time the Settlement Agreement was executed in May, the shopping credit for all classes of customers provided sufficient "head room" for viable competition, given the prices in the NYMEX Palo Verde futures market, which averaged 25.5 mills per kwh (shaped to include off-peak periods) for the upcoming year. This price in May was in the middle range of the prices of the preceding nine months, which fluctuated between an approximate low of 24.3 mills in September 1998 to an approximate high of 27.0 mills in November 1998.

Q. SINCE THE COMPLETION OF THE SETTLEMENT AGREEMENT, HAVE WHOLESALE MARKET PRICES INCREASED?

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[3] See Direct testimony of Ray Williamson (Staff), p. 8, line 26.

A. Yes, they have. We have now entered the summer season, generally a period of relatively high wholesale market prices in Arizona. This year is no exception, and NYMEX Palo Verde futures prices have risen some eleven percent since mid-May to an average of 28.5 mills per kwh (shaped to include off-peak periods) for the upcoming year. This price increase certainly squeezes, and in some cases, eliminates competitive margins, particularly for customers in the industrial class (over 3 MW), although many small to middle-sized commercial customers (under 500 kw) can still realize savings in the competitive market, even at these higher prices.

Q. PLEASE PROVIDE AN EXAMPLE THAT SHOWS THE POTENTIAL FOR COMMERCIAL CUSTOMER SAVINGS AT THESE HIGHER PRICES.

A. The situation for a 500-kw customer with a 50 percent load factor is illustrated in Exhibit KCH-R1, Schedule 1, which shows the "incremental competitive margin" at these higher prices. The "incremental competitive margin" is a measure of "head room" and refers to the margin available for the ESP to cover its own costs and to offer savings to the customer below the Standard Offer rate. With the NYMEX Palo Verde market at 28.5 mills, the incremental competitive margin for this customer is about 4 percent of the Standard Offer price in 2000, and 5 percent in 2001. For a smaller commercial customer, the margin is greater, as shown in Schedule 2, which illustrates the case of a 200-kw customer. This customer would have an incremental competitive margin of 11 percent in 2000, and 12 percent in 2001. The reason for the higher margin is that Standard Offer rates for commercial customers are significantly higher at lower usage levels, making the competitive option more attractive.

Q. ARE THERE WAYS TO MITIGATE THE TYPE OF PRICE RISK ASSOCIATED WITH THE RECENT JUMP IN WHOLESALE MARKET PRICES?

A. Yes. The Settlement Agreement provides a price hedge for customers by offering them the option of Standard Offer service at rates that are guaranteed to decline through June 30, 2004. Apart from the Standard Offer service option, price risk can be mitigated through a CTC that "floats" inversely with market prices (with appropriate "head room" built in). While I see merit in this approach, it was not the direction the parties ultimately pursued in the Settlement Agreement because parties sought certain advantages inherent in a fixed CTC approach.

Q. WHAT ARE THE ADVANTAGES TO THE FIXED CTC APPROACH VERSUS A FLOATING CTC?

A. Under the fixed CTC arrangement in the Settlement Agreement, market participants are provided certainty regarding regulatory price parameters in advance, including the total amount of stranded cost, the level of CTC, the rates for unbundled services, etc. This is certainly advantageous, but there are also risks because the participants may be advantaged or disadvantaged when there are changes in market prices. The squeeze in competitive margins resulting from the recent surge in market prices is an example of the latter.

Q. DO YOU EXPECT ANY RELIEF FROM THE SQUEEZE ON COMPETITIVE MARGINS?

A. Forecasting prices is a hazardous endeavor, and there are absolutely no guarantees as to the direction prices will move. Last summer, temperatures were relatively mild. Nonetheless, July NYMEX prices for the upcoming year rose ten percent over the levels in May of that year, then subsided later in the summer. If the current NYMEX futures market were to follow a similar seasonal pattern, one might expect a softening of wholesale prices toward the end of this summer. This timing would coincide with the start-up of retail competition. Regardless of the direction prices move, some relief would come when the shopping credit is increased on January 1, 2000, due to the scheduled reduction in both the CTC and the regulatory asset charge (included in the unbundled distribution rate).

Q. DO YOU HAVE ANY COMMENTS ON THE PROPOSAL BY MS. SMITH FOR INCREASING THE SHOPPING CREDIT?

A. Yes. Ms. Smith proposes to increase the shopping credit by reducing the CTC in varying amounts for different customer classes, and deferring collection of the shortfall until after July 1, 2004, subject to a wholesale market price test.[4] Taken in isolation, Ms. Smith's proposal generally favors the objectives AECC pursued in negotiation. As I have indicated above, AECC endeavored to achieve the highest feasible shopping credit in its negotiations with APS. A significant part of this negotiation addressed stranded costs and the size of the CTC. In agreeing to settle at a stranded cost figure of $350 million,

[4] Direct testimony of Lee Smith (Staff), p. 14, line 21 to p. 17, line 22.

the parties adopted a compromise position, relinquishing, for the purposes of settlement, positions on stranded cost that they otherwise advocated. AECC, of course, preferred a smaller amount of stranded cost and a lower CTC. In contrast, APS sought a much higher stranded cost recovery and therefore a higher CTC would have resulted. Thus, the Settlement Agreement must be viewed in total, as a package resulting from those settlement negotiations.

Q. YOU STATED THAT MS. SMITH'S PROPOSAL FOR LOWERING THE CTC "GENERALLY" FAVORS THE OBJECTIVES AECC PURSUED IN NEGOTIATION. ARE THERE SPECIFIC ASPECTS OF HER PROPOSAL THAT DIFFER FROM AECC'S NEGOTIATING OBJECTIVES?

A. Yes. While the near-term benefit of a lower CTC (in isolation) is appealing for customers, the potential deferral of stranded cost recovery beyond 2004 involves a trade-off between near-term and longer-term costs and benefits. In other words, there is something to be said for getting stranded cost recovery over with sooner rather than later. A related issue is the credit toward stranded cost recovery that is attributable to customers who remain on the Standard Offer. Given that a fixed amount ($350 million) is to be recovered, lowering the CTC in the early years (for potential deferral to later years) could have the perverse effect of under-crediting stranded cost recovery from Standard Offer customers in the earlier period. This point is most obvious in the case of 1999. Although the Settlement Agreement strives to implement retail access as soon as feasible, it will be, at best, late 1999 before competition can occur. Yet application of the CTC toward stranded cost recovery will apply retroactively back to January 1 – with all customers, of course, on the Standard Offer. With that point in mind, it is preferable for as much stranded cost recovery to be attributable to 1999 as possible, alleviating the burden in future years, rather than lowering the CTC for 1999 – at the cost of a higher CTC later.

SHOPPING CREDIT FOR CONTRACT CUSTOMERS

Q. DO YOU WISH TO COMMENT ON MS. SMITH'S DISCUSSION OF THE SHOPPING CREDIT FOR CONTRACT CUSTOMERS?

A. Yes. Ms. Smith states that she calculates a shopping credit for contract customers of 3.5 cents – which exceeds her calculation of the shopping credit for customers in the Extra-Large General Service class. She states that this does not seem appropriate and could be construed as prior discrimination.[5]

I strongly disagree with Ms. Smith's assessment. The treatment of contract customers in the Settlement Agreement follows the proportionality provision in the proposed Rules and implements the requirement in the Commission's Stranded Cost Order that states that "No customer or customer class shall receive a rate increase as a result of stranded cost recovery by an Affected Utility . . . ."[6] In the Settlement Agreement, this objective is met by setting unbundled rates for these customers that continue the level of contribution to stranded cost recovery that is implicit in the customers' current bundled-service contract rates. This approach is essentially the same one used by FERC in determining stranded cost for contract customers under its jurisdiction.

[5] Direct testimony of Lee Smith (Staff), p. 21, lines 1-12.
[6] Arizona Corporation Commission Decision No. 61677 (April 27, 1999) Docket No. RE-00000C-94-0165.

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Q. DOES MS. SMITH CORRECTLY REPRESENT THE SHOPPING CREDIT FOR CONTRACT CUSTOMERS?

A. No. The shopping credit for contract customers is not 3.5 cents as she has calculated, but ranges from 2.7 to 3.1 cents, the lowest shopping credit range of all customer classes.[7] The shopping credit, as Ms. Smith uses the term, is equal to the difference between the customer's rate for Standard Offer service and the direct access unbundled pricing components (i.e., unbundled costs exclusive of generation, transmission, and ancillary services). In calculating the shopping credit for contract customers, Ms. Smith apparently uses the E-34 tariff as the customers' Standard Offer rate; such an application, however, is not correct, because contract customers do not pay the E-34 rate for Standard Offer service – their Standard Offer rates are the *contract* rates they pay for bundled service. To measure whether a contract customer can benefit from retail access you need to compare the costs of the competitive option with the customer's contract price with the utility. The contract customer's shopping credit, therefore, is the difference between the bundled price for power in the contract and the direct access unbundled pricing components, which, as I have stated, ranges from 2.7 to 3.1 cents per kwh.

Q. WHAT WOULD BE THE CONSEQUENCES OF ALTERING THE PROVISIONS OF THE SETTLEMENT AGREEMENT THAT ADDRESS DIRECT ACCESS SERVICE FOR CONTRACT CUSTOMERS?

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[7] Ms. Smith's calculation of the shopping credit for the Extra-Large Customer Class does not appear to include the primary voltage discount that will apply to the unbundled distribution rate for the majority of these customers. Applying this discount would increase her shopping credit calculation for this class by about 1 mill to 3.1 cents.

A. This provision is an integral component of the Settlement Agreement. AECC would not have agreed to a settlement without a satisfactory resolution of this issue. Further, a simple inspection of the unbundled tariffs for contract customers would reveal that the overwhelming number of kilowatt-hours in this group comes from copper mines – one of which has already announced a major shut down due to the depressed state of the industry. Altering the Settlement to the detriment of contract customers would send a disastrous signal to the copper industry that its participation in retail access would only be permissible if it were accompanied by an increase in rates administered by the Commission.

MARKET POWER

Q. WITNESSES FROM ENRON HAVE RAISED MARKET POWER CONCERNS. DO YOU WISH TO COMMENT ON THIS ISSUE?

A. Yes. As Arizona moves forward with retail competition regulators must be vigilant with regard to market power, both vertical (which pertains to the relationship between generation, transmission, distribution, and retailing) and horizontal (which pertains to market dominance in the provision of a competitive service, e.g., generation). Such ongoing regulatory vigilance is necessary irrespective of the Settlement Agreement. Concerns about market power are not exacerbated by the Settlement Agreement. To the contrary, the agreement takes steps to alleviate such concerns.

Q. HOW DOES THE SETTLEMENT AGREEMENT TAKE STEPS TO ALLEVIATE MARKET POWER CONCERNS?

A. Vertical market power concerns will be greatly alleviated with the formation of a Regional Transmission Organization (RTO) as proposed by FERC in its Notice of Public Rulemaking dated May 13, 1999. The Settlement Agreement (Section 7.6) obligates APS to support the formation of the Desert STAR Independent System Operator (ISO) – which is being designed to meet the requirements of an RTO that would serve the Southwest. On behalf of retail customers, I have been very involved with other stakeholders in this effort, along with Mr. Delaney (Enron) and APS.

Further, since it is widely recognized that Desert STAR will not be ready in time to facilitate the initiation of retail access in Arizona, stakeholders have formed the Arizona Independent Scheduling Administrator (AISA), which is intended to ensure non-discriminatory access to the transmission system during the interim. The Settlement Agreement requires APS to actively support the formation of the AISA and to modify its open access transmission tariff (OATT) to be consistent with any FERC-approved AISA protocols.

Q. ARE YOU PERSONALLY FAMILIAR WITH THE DEVELOPMENT OF THE AISA?

A. Yes. I serve on the AISA Board, representing retail customers, and have been very active on its Operating Committee, which has prepared draft protocols for implementing retail access. Mr. Delaney (Enron) also serves on the Board, and both Enron and APS have been actively involved in the development of the draft protocols. These draft protocols must still be reviewed and approved by the AISA Board, and then submitted to FERC for approval as part of an AISA Tariff filing.

Q. MR. DELANEY MAINTAINS THAT THE AISA WILL NOT QUALIFY AS AN RTO.[8] DO YOU AGREE?

A. Yes. But the AISA was never intended to assume the scope of responsibilities of an RTO. The AISA is strictly an interim organization, intended to provide the necessary assurance that transmission access is allocated and managed fairly for the implementation of retail competition. Accordingly, it provides an alternative dispute resolution process and protocols governing transmission allocation, scheduling, must-run generation, ancillary services, energy imbalances, and emergency operations, among others. But the AISA does not take control over the operation of the grid. That responsibility will be the role of Desert STAR.

Q. IN HIS TESTIMONY, MR. DELANEY EXPRESSES CONCERNS ABOUT MARKET POWER IN THE PHOENIX AREA.[9] DO YOU WISH TO COMMENT ON THIS ISSUE?

A. There is no question that during times of heavy demand, APS will have considerable horizontal market power in the Phoenix area due to the limited transmission import capability into Phoenix. At such times, load must be met by generation that is located in the Phoenix area, all of which is currently owned or controlled by APS or SRP. Under a traditional monopoly model, there is no concern with this circumstance. However, in a competitive market, a mitigation strategy must be employed to address

[8] Direct testimony of Tom Delaney (Enron), p. 10, line 22 to p. 11, line 5.

[9] Direct testimony of Tom Delaney (Enron), p. 4, line 20 to p. 5, line 5.

such extensive market power. This situation is the well-known "must-run generation" condition.

Q. HOW IS MUST-RUN GENERATION ADDRESSED IN THE SETTLEMENT AGREEMENT?

A. As I stated above, the Settlement Agreement requires APS to comply with the AISA protocols, one of which addresses must-run generation. According to the draft protocol, market participants will be told in advance how much local generation will be necessary to meet customer needs in Phoenix. Through their scheduling coordinators, ESPs will be able to meet their local generation requirement a number of ways, including: (1) acquiring additional transmission into Phoenix from another market participant, (2) contracting with a local generation provider (such as SRP or a merchant plant), (3) reducing demand through load reduction programs, and (4) purchasing "must-offer energy" from APS. "Must-offer energy" refers to energy that APS is obligated under the protocol to make available to scheduling coordinators at APS' cost-of-service. The must-offer obligation arises due to APS' market power during must-run conditions. This approach was developed by stakeholders in the AISA Operating Committee, and I believe it is a very reasonable way to address the Phoenix must-run situation for the near future, at least until there is a more diverse ownership of local generation facilities, or until Desert STAR implements a must-run protocol of its own.

Q. MR. DELANEY ALSO EXPRESSES CONCERN ABOUT THE CREATION OF THE APS GENERATING AFFILIATE.[10] DO YOU WISH TO COMMENT ON THIS ISSUE?

A. Yes. Mr. Delaney is concerned that the creation of the APS generating affiliate will lead to market power abuses, and he sees this as a problem with the Settlement Agreement. However, the requirement to separate competitive assets from the regulated portion of the company is a requirement of the Electric Competition Rules. Therefore, the need for vigilance against market power abuse arises first in the application of the Rules. The issue at hand is the need for a code of conduct with respect to affiliate transactions. As I stated in my direct testimony, the establishment of effective rules governing affiliate relationships is an integral part of successfully implementing retail competition. In the proposed Electric Competition Rules, this function had been fulfilled, in part, by the "Affiliate Transactions" section. Unfortunately, however, that section was deleted from the proposed Rules and replaced with a requirement for Affected Utilities to file a code of conduct within ninety days of the adoption of the Rules.

The Settlement Agreement contemplates that APS' code of conduct filing will proceed in accordance with the Commission's proposed Rules as modified. The parties to the Settlement Agreement are free to participate in any such code of conduct proceeding and to advocate their own positions at such time. In the meantime, APS will adhere to a voluntary, interim code of conduct, that will be served on the parties within thirty days of Commission approval of the Settlement Agreement.

[10] Direct testimony of Tom Delaney, p. 4, lines 5-18.

Given that the "Affiliate Transactions" section of the proposed Rules has been deleted, the approach taken in the Settlement Agreement is the most reasonable way to address code of conduct issues without adding further delay to the start of competition.

Q. DOES THE SETTLEMENT AGREEMENT PERMIT APS TO ENGAGE IN PRICING BEHAVIOR THAT ABUSES GENERATION MARKET POWER?

A. No. The APS generating affiliate will be under the jurisdiction of FERC, which should be expected to evaluate the market power conditions prevailing when the affiliate's wholesale pricing requirements are determined.

Q. DR. ROSENBERG'S TESTIMONY PROVIDES AN EXAMPLE OF HOW A CHANGED CAPITAL STRUCTURE CAN CAUSE HIGHER CAPITAL COSTS FOR A UTILITY'S REGULATED SUBSIDIARY.[11] DOES THE SETTLEMENT AGREEMENT ALLOW APS TO UNILATERALLY RESTRUCTURE ITS CAPITAL STRUCTURE FOR ITS REGULATED SUBSIDIARY TO THE DETRIMENT OF RATEPAYERS?

A. No, because the capital structure of the regulated subsidiary will remain under the scrutiny of the Commission. I agree with Dr. Rosenberg that it is important that the regulated affiliate not be allowed to end up with a more costly capital structure as a result of the corporate restructuring. Clearly, the final say in this matter rests with the Commission, which will be determining APS' allowed rate-of-return in the rate case scheduled to be completed by 2004. I believe it would be foolish for APS to present the Commission with a disadvantageous capital structure for its regulated affiliate, because it

[11] Direct testimony of Alan Rosenberg, p. 5, line 15 to p. 8, line 7.

would be doing so at its own risk. Certainly, in approving the Settlement Agreement, the Commission may see fit to serve notice that it will be paying careful attention to the capital structure of the regulated affiliate that results from the corporate restructuring.

Q. IN HIS TESTIMONY, MR. KINGERSKI MAINTAINS THAT APS WILL BE ALLOWED TO DEFER RECOVERY OF STANDARD OFFER COSTS UNTIL AFTER JULY 1, 2004 AND CITES THIS AS AN EXAMPLE OF PREDATORY PRICING IN THE SETTLEMENT AGREEMENT.[12] DO YOU WISH TO COMMENT ON THIS POINT?

A. Under the Settlement Agreement, APS is allowed such a deferral only in the limited case of customers who return to Standard Offer service after having left for the competitive market and by returning cause APS to incur commodity costs that are not otherwise recoverable under standard offer rates. In general, however, there is no deferral of costs associated with Standard Offer service. Prior to July 1, 2004, APS is completely at risk for recovery of costs associated with this service.

<u>CONCLUSION</u>

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. The membership of AECC has participated diligently in the electric competition process conducted by the Commission through numerous rounds of hearings and workshops. The Settlement Agreement represents a good faith effort by AECC, other customer interests, and APS to resolve the many impediments that have heretofore stymied the implementation of retail access. Even with approval of the agreement by the

[12] Direct testimony of Harry J. Kingerski (Enron), p. 10, line 10 to page 11, line 10.

Commission, it would not be the final word on the subject, but just a first – albeit significant -- step. Still ahead lies final adoption of the AISA protocols (which should continue to evolve over time), the establishment of a Code of Conduct to be approved by the Commission, the development of Desert STAR, and continued regulatory oversight pertaining to market power issues. I recommend that the Commission approve the Settlement Agreement and allow retail access to proceed, bearing in mind that the implementation of retail access is not yet complete.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Incremental Competitive Margin for a Commercial-sized APS Customer

<u>Customer Assumptions</u>

Competitive supply available	Sep-99
Annual kWh consumption	2,190,000
Load Factor	50%
KW	500
Line loss factor Transmission	2.50%
Line loss factor Distribution	4.30%
Forward Price Inflator (beyond 18 months)	2.00%
NYMEX PV Prices adjusted for weekend and off-peak periods, as of	07/07/99

Date	Standard Offer	Distribution	Transmission	Unbundled Cost System Benefits	CTC	Ancillary	Market Price	Market Price adjusted for Line Losses	Total Competitive Cost	Incremental Competitive Margin	Incremental Competitive Margin
	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	%
Sep-99	$0.07610	$0.02970	$0.00368	$0.00115	$0.00675	$0.00092	$0.04202	$0.04488	$0.08707	-$0.01098	-14%
Oct-99	$0.07522	$0.02932	$0.00356	$0.00115	$0.00653	$0.00089	$0.02715	$0.02900	$0.07045	$0.00477	6%
Nov-99	$0.06836	$0.02683	$0.00368	$0.00115	$0.00675	$0.00092	$0.02364	$0.02525	$0.06438	$0.00398	6%
Dec-99	$0.06750	$0.02629	$0.00356	$0.00115	$0.00653	$0.00089	$0.02608	$0.02785	$0.06628	$0.00123	2%
Jan-00	$0.06750	$0.02518	$0.00356	$0.00115	$0.00591	$0.00089	$0.02317	$0.02475	$0.06144	$0.00606	9%
Feb-00	$0.07025	$0.02622	$0.00395	$0.00115	$0.00655	$0.00098	$0.02109	$0.02252	$0.06137	$0.00888	13%
Mar-00	$0.06750	$0.02518	$0.00356	$0.00115	$0.00591	$0.00089	$0.02155	$0.02302	$0.05971	$0.00779	12%
Apr-00	$0.06836	$0.02550	$0.00368	$0.00115	$0.00611	$0.00092	$0.02225	$0.02376	$0.06113	$0.00723	11%
May-00	$0.07515	$0.02809	$0.00356	$0.00115	$0.00591	$0.00089	$0.02089	$0.02231	$0.06192	$0.01324	18%
Jun-00	$0.07610	$0.02845	$0.00368	$0.00115	$0.00611	$0.00092	$0.02412	$0.02576	$0.06607	$0.01003	13%
Jul-00	$0.07403	$0.02809	$0.00356	$0.00115	$0.00591	$0.00089	$0.03695	$0.03946	$0.07907	-$0.00504	-7%
Aug-00	$0.07403	$0.02809	$0.00356	$0.00115	$0.00591	$0.00089	$0.04936	$0.05272	$0.09232	-$0.01829	-25%
Sep-00	$0.07496	$0.02845	$0.00368	$0.00115	$0.00611	$0.00092	$0.04241	$0.04529	$0.08560	-$0.01065	-14%
Oct-00	$0.07409	$0.02809	$0.00356	$0.00115	$0.00591	$0.00089	$0.02737	$0.02923	$0.06884	$0.00526	7%
Nov-00	$0.06733	$0.02550	$0.00368	$0.00115	$0.00611	$0.00092	$0.02451	$0.02618	$0.06354	$0.00379	6%
Dec-00	$0.06649	$0.02518	$0.00356	$0.00115	$0.00591	$0.00089	$0.02703	$0.02887	$0.06556	$0.00093	1%
Jan-01	$0.06649	$0.02417	$0.00356	$0.00115	$0.00446	$0.00089	$0.02363	$0.02524	$0.05947	$0.00702	11%
Feb-01	$0.06920	$0.02517	$0.00395	$0.00115	$0.00494	$0.00098	$0.02151	$0.02297	$0.05916	$0.01003	14%
Mar-01	$0.06649	$0.02417	$0.00356	$0.00115	$0.00446	$0.00089	$0.02198	$0.02348	$0.05771	$0.00878	13%
Apr-01	$0.06733	$0.02448	$0.00368	$0.00115	$0.00461	$0.00092	$0.02270	$0.02424	$0.05908	$0.00825	12%
May-01	$0.07403	$0.02696	$0.00356	$0.00115	$0.00446	$0.00089	$0.02131	$0.02276	$0.05978	$0.01425	19%
Jun-01	$0.07496	$0.02730	$0.00368	$0.00115	$0.00461	$0.00092	$0.02460	$0.02628	$0.06394	$0.01102	15%
Jul-01	$0.07292	$0.02696	$0.00356	$0.00115	$0.00446	$0.00089	$0.03769	$0.04025	$0.07728	-$0.00436	-6%
Aug-01	$0.07292	$0.02696	$0.00356	$0.00115	$0.00446	$0.00089	$0.05035	$0.05377	$0.09079	-$0.01788	-25%
Sep-01	$0.07383	$0.02730	$0.00368	$0.00115	$0.00461	$0.00092	$0.04326	$0.04620	$0.08386	-$0.01003	-14%
Oct-01	$0.07298	$0.02696	$0.00356	$0.00115	$0.00446	$0.00089	$0.02792	$0.02982	$0.06684	$0.00614	8%
Nov-01	$0.06632	$0.02448	$0.00368	$0.00115	$0.00461	$0.00092	$0.02500	$0.02670	$0.06154	$0.00478	7%
Dec-01	$0.06549	$0.02417	$0.00356	$0.00115	$0.00446	$0.00089	$0.02757	$0.02945	$0.06368	$0.00182	3%

Annual Summary

2000 Average	$0.07132	$0.02683	$0.00363	$0.00115	$0.00603	$0.00091	$0.02839	$0.03032	$0.06888	$0.00244	4%
2001 Average	$0.07025	$0.02576	$0.00363	$0.00115	$0.00455	$0.00091	$0.02896	$0.03093	$0.06693	$0.00332	5%

Incremental Competitive Margin for a Commercial-sized APS Customer

Customer Assumptions	
Competitive supply available	Sep-99
Annual kWh consumption	876,000
Load Factor	50%
KW	200
Line loss factor Transmission	2.50%
Line loss factor Distribution	4.30%
Forward Price Inflator (beyond 18 months)	2.00%
NYMEX PV Prices adjusted for weekend and off-peak periods, as of	07/07/99

Date	Standard Offer	Distribution	Transmission	Unbundled Cost System Benefits	CTC	Ancillary	Market Price	Market Price adjusted for Line Losses	Total Competitive Cost	Incremental Competitive Margin	Incremental Competitive Margin
	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	%
Sep-99	$0.08668	$0.03389	$0.00368	$0.00115	$0.00675	$0.00092	$0.04202	$0.04488	$0.09127	-$0.00458	-5%
Oct-99	$0.08556	$0.03338	$0.00356	$0.00115	$0.00653	$0.00089	$0.02715	$0.02900	$0.07451	$0.01105	13%
Nov-99	$0.07794	$0.03042	$0.00368	$0.00115	$0.00675	$0.00092	$0.02364	$0.02525	$0.06817	$0.00977	13%
Dec-99	$0.07677	$0.02996	$0.00356	$0.00115	$0.00653	$0.00089	$0.02608	$0.02785	$0.06995	$0.00683	9%
Jan-00	$0.07677	$0.02869	$0.00356	$0.00115	$0.00591	$0.00089	$0.02317	$0.02475	$0.06496	$0.01182	15%
Feb-00	$0.08051	$0.03011	$0.00395	$0.00115	$0.00655	$0.00098	$0.02109	$0.02252	$0.06526	$0.01525	19%
Mar-00	$0.07677	$0.02869	$0.00356	$0.00115	$0.00591	$0.00089	$0.02155	$0.02302	$0.06323	$0.01355	18%
Apr-00	$0.07794	$0.02913	$0.00368	$0.00115	$0.00611	$0.00092	$0.02225	$0.02376	$0.06476	$0.01318	17%
May-00	$0.08540	$0.03197	$0.00356	$0.00115	$0.00591	$0.00089	$0.02089	$0.02231	$0.06580	$0.01960	23%
Jun-00	$0.08668	$0.03246	$0.00368	$0.00115	$0.00611	$0.00092	$0.02412	$0.02576	$0.07008	$0.01660	19%
Jul-00	$0.08412	$0.03197	$0.00356	$0.00115	$0.00591	$0.00089	$0.03695	$0.03946	$0.08295	$0.00116	1%
Aug-00	$0.08412	$0.03197	$0.00356	$0.00115	$0.00591	$0.00089	$0.04936	$0.05272	$0.09621	-$0.01209	-14%
Sep-00	$0.08538	$0.03246	$0.00368	$0.00115	$0.00611	$0.00092	$0.04241	$0.04529	$0.08962	-$0.00423	-5%
Oct-00	$0.08428	$0.03197	$0.00356	$0.00115	$0.00591	$0.00089	$0.02737	$0.02923	$0.07272	$0.01156	14%
Nov-00	$0.07677	$0.02913	$0.00368	$0.00115	$0.00611	$0.00092	$0.02451	$0.02618	$0.06717	$0.00959	12%
Dec-00	$0.07562	$0.02869	$0.00356	$0.00115	$0.00591	$0.00089	$0.02703	$0.02887	$0.06908	$0.00654	9%
Jan-01	$0.07562	$0.02754	$0.00356	$0.00115	$0.00446	$0.00089	$0.02363	$0.02524	$0.06285	$0.01278	17%
Feb-01	$0.07930	$0.02890	$0.00395	$0.00115	$0.00494	$0.00098	$0.02151	$0.02297	$0.06290	$0.01641	21%
Mar-01	$0.07562	$0.02754	$0.00356	$0.00115	$0.00446	$0.00089	$0.02198	$0.02348	$0.06108	$0.01454	19%
Apr-01	$0.07677	$0.02797	$0.00368	$0.00115	$0.00461	$0.00092	$0.02270	$0.02424	$0.06257	$0.01420	19%
May-01	$0.08412	$0.03069	$0.00356	$0.00115	$0.00446	$0.00089	$0.02131	$0.02276	$0.06351	$0.02061	24%
Jun-01	$0.08538	$0.03116	$0.00368	$0.00115	$0.00461	$0.00092	$0.02460	$0.02628	$0.06779	$0.01759	21%
Jul-01	$0.08285	$0.03069	$0.00356	$0.00115	$0.00446	$0.00089	$0.03769	$0.04025	$0.08101	$0.00185	2%
Aug-01	$0.08285	$0.03069	$0.00356	$0.00115	$0.00446	$0.00089	$0.05035	$0.05377	$0.09452	-$0.01167	-14%
Sep-01	$0.08410	$0.03116	$0.00368	$0.00115	$0.00461	$0.00092	$0.04326	$0.04620	$0.08772	-$0.00362	-4%
Oct-01	$0.08302	$0.03069	$0.00356	$0.00115	$0.00446	$0.00089	$0.02792	$0.02982	$0.07057	$0.01245	15%
Nov-01	$0.07562	$0.02797	$0.00368	$0.00115	$0.00461	$0.00092	$0.02500	$0.02670	$0.06503	$0.01059	14%
Dec-01	$0.07449	$0.02754	$0.00356	$0.00115	$0.00446	$0.00089	$0.02757	$0.02945	$0.06705	$0.00744	10%

Annual Summary

2000 Average	$0.08120	$0.03061	$0.00363	$0.00115	$0.00603	$0.00091	$0.02839	$0.03032	$0.07265	$0.00854	11%
2001 Average	$0.07998	$0.02928	$0.00363	$0.00115	$0.00455	$0.00091	$0.02896	$0.03093	$0.07055	$0.00943	12%