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Jana Van Ness
Manager
State Regulation

Tel 602/250-2310
Fax 602/250-3399
e-mail:Jana.VanNess@aps.com
http://www.apsc.com

Mail Station 9905
P.O. Box 53999
Phoenix, AZ 85072-3999

May 29, 2002

E-00000A-02-0051
E-01345A-01-0822
E-00000A-01-0630
E-01933A-02-0069
E-01933A-98-0471

Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, Arizona 85007

RE: ARIZONA PUBLIC SERVICE COMPANY'S DIRECT TESTIMONY ON "TRACK A" ISSUES UNDER THE GENERIC DOCKET
DOCKET NUMBERS: E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630, E-01933A-02-0069, E-01933A-98-0471

Dear Sir or Madam:

Pursuant to the Procedural Order dated May 2, 2002, for the above referenced Docket Numbers, Arizona Public Service Company "(APS") is hereby filing the direct testimony of Mr. Jack E. Davis and Dr. William Hieronymus.

If you or your staff have any questions, please feel free to call me.

Sincerely,

Jana Van Ness

Jana Van Ness
Manager
State Regulation

Attachment

JVN/srm

Cc: Original (plus 18 copies)
Service List

Arizona Corporation Commission
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TESTIMONY OF JACK E. DAVIS

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

May 29, 2002

Table of Contents

TESTIMONY OF JACK E. DAVIS ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (Docket No. E-00000A-02-0051)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Jack E. Davis. My business address is 400 North Fifth Street, Phoenix, Arizona 85072. I am President of Energy Delivery and Sales for Arizona Public Service Company ("APS" or "Company"). I am also President of Pinnacle West Capital Corporation ("PWCC").

Q. DID YOU PREVIOUSLY SUBMIT WRITTEN TESTIMONY IN THIS CONSOLIDATED DOCKET?

A. Yes. I filed both direct and rebuttal testimony in Docket No. E-01345A-01-0822. However, since that testimony was never actually heard by the Arizona Corporation Commission ("Commission"), I have provided a Statement of Qualifications as an attachment to this testimony. *See* Appendix A.

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

A. In response to the Commission's Procedural Order dated May 2, 2002 ("Procedural Order"), I will discuss the reasons behind the transfer of most of the Company's generating assets to Pinnacle West Energy Corporation ("PWEC"). As also requested in the Procedural Order, I will address (from a layman's point of view) the issues of affiliate transactions, codes of conduct and the division of jurisdictional authority over pricing as between this Commission and the Federal Energy Regulatory Commission ("FERC").

Q. WILL APS PRESENT OTHER WITNESSES?

A. Yes. Dr. William Hieronymus will address the questions raised by Staff concerning the potential for PWEC to exercise meaningful market power post-divestiture. Market power was explicitly identified as a "Track A" issue in the Procedural Order. Dr. Hieronymus also discusses the reasons why divestiture of APS generation assets to PWEC remains in the public interest.

Q. WILL ANY OF THE COMPANY WITNESSES DIRECTLY DISCUSS COMPETITIVE BIDDING PROCEDURES AND OBJECTIVES IN THEIR TESTIMONY?

A. No. The Procedural Order has designated these as "Track B" issues. The Company has proposed a separate but parallel process of addressing and resolving "Track B" issues.

II. SUMMARY

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. The Commission's Electric Competition Rules (A.A.C. R14-2-1601, *et seq.*) specifically mandated divestiture of all APS generation assets by December 31, 2000. At the Company's request, this divestiture was both expressly authorized by the Commission and postponed by up to two years as a result of the 1999 APS Settlement Agreement, which settlement was approved and adopted by the Commission in Decision No. 61973 (October 6, 1999). *See* Schedule JED-1GD, attached. An earlier settlement agreement negotiated with Commission Staff in 1998 but eventually withdrawn, also provided for divestiture of APS generation to an affiliated entity. The reasons prompting these various actions by the Commission and/or Staff are as valid today as they were in 1998 and 1999. They also explain why the divestiture of generation by electric utilities to subsidiaries or other affiliated entities has been a common part of industry restructuring in other jurisdictions. The Commission has had in place comprehensive Affiliate Rules (A.A.C. R14-2-801, *et seq.*) since 1990. Affiliate transactions are also reviewed in individual proceedings, both rate and otherwise. Similarly, the Commission and FERC have approved Codes of Conduct. In addition, APS has in place implementing Policies & Procedures (Commission) for its Commission-approved Code of Conduct and Standards of Conduct (FERC) that govern the interaction between affiliated merchant energy functions (e.g., PWM&T) and the wire (transmission) functions of APS. These existing regulatory policies and powers have proven effective as to those utilities covered by such provisions.

Finally, I am aware that sales to APS of power from the wholesale electric market are regulated by FERC. This has been true since long before I came to the Company, and I am not aware of any proposals to change this jurisdictional fact of life. That does not mean, however, that the Commission is powerless to either effectively participate in FERC proceedings affecting Arizona consumers or that it has surrendered its ability to review discretionary decisions by APS management to determine whether they were prudent given the facts and circumstances known to APS at the time such decisions were made.

III. <u>TRANSFER OF APS GENERATION TO PWEC</u>

Q. DO THE ELECTRIC COMPETITION RULES DISCUSS THE ISSUE OF DIVESTITURE OF GENERATION ASSETS TO AN AFFILIATE?

A. Yes. In Decision No. 61969 (September 29, 1999) the Commission reaffirmed the already existing provisions of the Electric Competition Rules requiring divestiture of competitive generation and other competitive assets. Specifically, A.A.C. R14-2-1615 (A) states:

> All competitive generation assets and competitive services shall be separated from an Affected Utility prior to January 1, 2001.

But this story goes back over a year prior to Decision No. 61969. In Decision No. 61071 (August 10, 1998), the Commission, at Staff's urging, added a mandatory divestiture provision to the Electric Competition Rules. Although originally proposed as a California-style divestiture to out-of-state merchant plant developers, APS and Tucson Electric Power successfully argued for a third option — divestiture to an Arizona affiliate. *See* A.A.C. R14-2-1615. That provision was later reaffirmed in Decision No. 61272 (December 11, 1998) and, of course, in Decision No. 61969.

Q. WERE THE PROS AND CONS OF DIVESTITURE DEBATED DURING THE VARIOUS RULEMAKING PROCEEDINGS THAT EVENTUALLY RESULTED IN THE PRESENT ELECTRIC COMPETITION RULES?

A. Yes. It had been a topic of considerable debate and analysis since the original consideration of the Electric Competition Rules in 1996. Unlike the 50% competitive bidding requirement, divestiture was fully subject to the review and comment process of Arizona rulemaking — not once but on at least four separate occasions. In conclusion, the Commission found that:

> only through the divestiture of competitive services or the transfer of competitive services to an affiliate would the subsidization and crossovers between monopoly and competition be prohibited.

Decision No. 61272 at Appendix C, p. 33.

Nearly a year after that Decision, the Commission again considered the issue of generation divestiture to an affiliate or affiliates of an Affected Utility and again concluded after yet another full-blown rulemaking proceeding that:

> [the] separation of monopoly and competitive services by the incumbent Affected Utilities <u>must</u> take place in order to foster development of a competitive market in Arizona

. . .

> the requirement that competitive generation assets and Competitive Services be separated to an unaffiliated party or to a separate corporate affiliate or affiliates, will provide greater protection against cross-subsidization than would separation to a subsidiary.

Decision No. 61969 at 60-61 (emphasis supplied).

Q. DO THE ELECTRIC COMPETITION RULES IMPOSE ANY DUTIES OR RESTRICTIONS ON THE TRANSFEREE(S) OF DIVESTED ELECTRIC GENERATION?

A. No.

Q. WHAT DID THE 1999 APS SETTLEMENT AGREEMENT AND THE COMMISSION DECISION APPROVING AND ADOPTING SUCH SETTLEMENT AGREEMENT HAVE TO SAY ABOUT THE DIVESTITURE OF APS GENERATION ASSETS TO AN AFFILIATE?

A. Decision No. 61973 reaffirmed for the fourth time that divestiture of the Company's generation to an affiliate was "in the public interest" and thus granted:

> all requisite Commission approvals for . . . the creation by APS or its parent of new corporate affiliates . . . and the transfer thereto of APS' generation assets ...

See 1999 APS Settlement Agreement at §§ 4.2 and 4.4.

In its adoption of the 1999 APS Settlement, the Commission went on to state:

> [T]he Commission supports and authorizes the transfer by APS to an affiliate or affiliates of all its generation and [other] competitive electric service assets as set forth in the Agreement Agreement no later than December 31, 2002."

Decision No. 61973 at 10.

The Commission further adopted the following language as set forth in the Agreement:

> The Commission has determined that allowing the Generation

> Assets to become "eligible facilities," within the meaning of Section 32 of the Public Utility Holding Company Act ("PUHCA"), and owned by an APS EWG ["Exempt Wholesale Generator"] affiliate (1) will benefit consumers, (2) is in the public interest, and (3) does not violate Arizona law.

Id. at Attachment 1, p.7.

Unlike most settlements before the Commission, the 1999 APS Settlement Agreement provided for the Commission itself to become a party to the settlement by virtue of its approval of that settlement in Decision No. 61973. The legality of the 1999 APS Settlement Agreement, including the Commission's inclusion as a party to the settlement, and Decision No. 61973 survived unscathed through two separate judicial appeals, the last of which was finally decided in December of 2001. In upholding the 1999 APS Settlement Agreement, the Arizona Court of Appeals stated:

> The agreement <u>requires</u> APS to divest its generation assets by December 31, 2002, and <u>requires</u> the Commission approve the formation of an APS affiliate to acquire those assets at book value. [Opinion at ¶ 8.]
>
> . . .
>
> Section 6.1 [of the Settlement] makes the Commission <u>a party to the agreement</u>, and section 6.2 <u>precludes the Commission from taking or proposing any action inconsistent with the agreement</u> and <u>requires the Commission to actively defend it</u>. [Opinion at ¶ 33.]
>
> . . .
>
> The general rule, however, is that a <u>contract</u> that extends beyond the terms of the members of a public board is valid if made in good faith and if its does not involve the performance of personal or professional services for the board. [Citation omitted.] The [Arizona Consumers] Council has not alleged that the [settlement] <u>contract</u> was not entered into in good faith, and the <u>contract</u> does not involve personal services for Commission members. <u>The [settlement] contract can therefore bind future commissions</u>. [Citation omitted.] [Emphases supplied.] [Opinion at ¶ 38.]

Q. WAS DIVESTITURE A KEY ELEMENT OF THE SETTLEMENT?

A. Yes. Divestiture of APS generation was at the very heart of the 1999 APS Settlement Agreement from the time of its original submission to the Commission in May 1999. It was an express part of the Company's bargained-for consideration in the agreement. APS would have never entered into any settlement that did not guarantee its ability to divest its generation to an affiliate or affiliates, that did not require the Commission to make the findings of fact necessary for that affiliate or affiliates to be an "Exempt Wholesale Generator," or that did not allow the recovery of transition costs.

Q. ASIDE FROM THE 1999 APS SETTLEMENT AGREEMENT ITSELF, HAVE APS AND ITS PARENT CORPORATION, PWCC, TAKEN SPECIFIC STEPS IN REGARD TO DIVESTITURE OF APS GENERATING ASSETS TO PWEC?

A. Yes. These include:

1) forming PWEC and subsequently obtaining a financial credit rating (contingent upon transfer of the APS generating assets) for PWEC from major credit rating agencies;

2) reorganization and reassignment of APS personnel to PWM&T and PWEC and the retention by PWEC of new personnel to both operate APS generation and to engage in the construction of new generation;

3) PWEC's initiation of over $1 billion dollars in new generation construction to serve APS retail customers, which decision was wholly dependent upon the ability to acquire existing APS generation under the provisions of the Electric Competition Rules and the 1999 APS Settlement Agreement;

4) provision of interim financing by PWCC for PWEC's construction of new generation to serve APS load, which financing has placed an extreme burden on PWCC without the ability to collateralize the APS generating assets;

5) development of a comprehensive "buy-back" purchase power agreement ("PPA") whereby APS generating assets could remain dedicated to APS retail customers at cost-based prices;

6) notice to or consents from some 3500 co-participants, fuel suppliers, government entities, creditors, etc., for transfer of the APS generation and related contracts, permits, rights-of-way, letters of credit, etc.;

7) preparation of requests for and the securing of several private letter rulings from the IRS addressing the transfer of APS generation to PWEC and the continued tax-advantaged status of the Palo Verde Nuclear Generating Station ("PVNGS") decommissioning trust;

8) preparation of legal documents of transfer (deeds, bills of sale, assignments, etc.);

9) preparation of the data required by Decision No. 61973 to be included in the 30-day notice of transfer, presently to be filed on August 1, 2002; and

10) submission of an application to the Nuclear Regulatory Commission ("NRC") for the transfer of the Company's operating license at PVNGS.

The last two critical path events prior to the actual transfer are: 1) securing NRC approval of a license transfer for the operation of the PVNGS; and 2) securing approval from the owners of or (more likely) a buyout of the secured lease obligation bonds ("SLBs") associated with the previously authorized sale/leaseback of PVNGS Unit 2. APS submitted its application for operating license transfer to the NRC last month. Approval is expected within no more than six months from the date of filing. Also, the Company will initiate buyout of the SLBs in the next couple of months. This buyout will be an extremely expensive proposition and will significantly increase the divestiture-related expenditures incurred by APS to date.

Q. DID ANYONE OPPOSE THE DIVESTITURE PROVISIONS OF THE 1999 APS SETTLEMENT AGREEMENT?

A. No. Obviously none of the signatories were in disagreement over the necessity of such a restructuring of the Company's lines of business into competitive and non-competitive entities. And no non-signatory participant in the proceeding resulting in approval and adoption of the 1999 APS Settlement Agreement, including Staff, was opposed to divestiture.

Q. YOU PREVIOUSLY MENTIONED A 1998 SETTLEMENT WITH COMMISSION STAFF. DID THAT SETTLEMENT ALSO INCLUDE A DIVESTITURE REQUIREMENT?

A. Yes. Staff, APS and Tucson Electric Power Company ("TEP") negotiated a three-way agreement wherein APS would acquire some of TEP's generation and TEP would acquire the Company's EHV transmission assets. APS would then be required to divest the combined APS/TEP generation to an affiliate.

Q. DID EITHER SETTLEMENT AGREEMENT IMPOSE ANY CONDITIONS ON THE AFFILIATE RECEIVING APS GENERATION ASSETS?

A. No. In fact, neither Staff nor the Commission, or for that matter, any of the signatories to either agreement, ever suggested that any conditions be imposed.

Q. ARE DIVESTITURE AND COMPETITIVE BIDDING UNDER RULE 1606(B) LINKED?

A. Absolutely, both in the historical context of the Electric Competition Rules and in the practical sense. I say historical context because the two provisions [Rule 1606(B) and Rule 1615] arose at the same time and have always been synchronized in their starting date. Even during the approval process of the

1999 APS Settlement Agreement, the variance granted to Rule 1606(B) was referred to as a "corresponding delay," that is, "corresponding" to the delay in implementation of Rule 1615. Moreover, the competitive bidding and other power procurement provisions of Rule 1606(B) refer only to "Utility Distribution Companies," which in the parlance of the Electric Competitions Rules is used only to describe Affected Utilities such as APS in their post-divestiture state of restructuring. Practically speaking, it would make little sense for a still vertically-integrated utility to bid for resources it already owns, a concession that even merchant generators such as Sempra have acknowledged in response to the Company's data requests.

IV. AFFILIATE RULES AND CODE OF CONDUCT

Q. HOW LONG HAS THE COMMISSION HAD COMPREHENSIVE AFFILIATE TRANSACTION REGULATIONS IN EFFECT?

A. The Affiliate Rules were, in their present form, enacted in 1990. They address both specific types of affiliate transactions and more generic issues such as cost allocation, diversification, etc. The Affiliate Rules are organized as follows:

Rule 801 – Definitions

Rule 802 – Applicability (Class A utilities and affiliates)

Rule 803 – Regulates organizations and reorganizations at the holding company level; this includes any acquisition of or divestiture of an affiliate of the Arizona utility and even the acquisition or divestiture of a financial interest in such affiliate

Rule 804 – Requires prior approval of specific transactions between the utility and any affiliate; requires affiliates to make books and records available to the Commission

Rule 805 – Requires annual report on affiliates and affiliated transactions as well as future business plans of the holding company and affiliates

Rule 806 – Allows waivers of Affiliate Rules if "in the public interest"

Q. DID THE COMMISSION ALSO ADDRESS AFFILIATE TRANSACTIONS IN INDIVIDUAL ORDERS PRIOR TO THE ENACTMENT OF COMPREHENSIVE AFFILIATE RULES?

A. Yes. In Decision Nos. 56548 (July 12, 1989) and 55196 (September 18, 1986), the Commission imposed both substantive and procedural provisions governing affiliate transaction specific to APS and its affiliates. These orders were subsequently rescinded or modified by the Commission, but they evidence that the Commission is far from powerless to address concerns about the potential for affiliate abuse. Moreover, the Commission still retains the power to disallow affiliate charges in rate proceedings if it finds them imprudent.

Q. DO SOME OR ALL THE MERCHANT PLANT INTERVENORS HAVE REGULATED ELECTRIC UTILITY AFFILIATES?

A. Yes, although most of them claimed that information was either confidential or claimed not to know what the word "affiliate" meant. Sempra, Reliant, Duke, Panda/TECO, PG&E, AES and PPL all have traditional electric utility affiliates.

Q. WILL ANY OF THEM BE SUBJECT TO THE AFFILIATE RULES?

A. Not unless the Commission chooses to make them so. At present, only entities affiliated with an Arizona electric utility having at least $5 million in annual retail sales are subject to affiliate restrictions, and according to Commission records, no such Arizona retail utility affiliates of the merchant plant intervenors exist.

Q. DOES APS PRESENTLY HAVE IN EFFECT A CODE OF CONDUCT GOVERNING ITS RELATIONS WITH VARIOUS AFFILIATES?

A. It has both a Commission-approved Code of Conduct and a FERC-approved Code of Conduct. Below is a brief description of the origin and purpose of each of these Codes of Conduct:

The Commission-approved Code of Conduct is in accordance with Rule 1616 of the Electric Competition Rules and represented a Staff-APS joint proposal. Subsequent to the Code of Conduct's approval in Decision No. 62416 (April 3, 2000), the Company submitted Policies & Procedures ("P&P") to implement the Code of Conduct, which were in turn reviewed by Commission Staff for conformity with the requirements of Decision No. 62416.

The FERC Code of Conduct is intended to protect captive customers from subsidizing unregulated or competitive activities. The Standards of Conduct prevent discriminatory access to both physical facilities and network information. *See Re Pinnacle West Capital Corp.*, 95 FERC ¶61,300 at 62,026 (2001).

Q. DO YOU BELIEVE THE COMMISSION'S AFFILIATE RULES AND THE COMMISSION AND FERC-APPROVED CODES OF CONDUCT ARE SUFFICIENT TO PREVENT AND REMEDY AFFILIATE ABUSE?

A. Yes. They are more than sufficient, at least for utilities that are covered by them such as APS. As noted above, the Commission can also issue individual orders both in and outside the context of rate proceedings on this issue and can disallow the recovery of specific costs from Arizona consumers. Neither of these is true, of course, with regard to those power suppliers in Arizona that are exempt from the Affiliate Rules and the requirements of Rule 1616, and which are not otherwise "public service corporations." I will concede that most, but not all these entities, have FERC Codes of Conduct and are subject to FERC's Standards of Conduct. Whether that standing alone is sufficient to address any Commission concerns is an issue for the Commission to determine in this or some later proceeding.

V. THE JURISDICTIONAL ISSUE

Q. WOULD DIVESTITURE OF APS' GENERATION TO PWEC RESULT IN THE FERC HAVING JURISDICTION OVER APS PURCHASES OF ELECTRICITY?

A. FERC has had that jurisdiction since the 1930s. The transfer of APS generation to PWEC or, for that matter, to anyone else, would not change that fact. Without significant owned-generation, however, APS will obviously have to purchase most of its Standard Offer service requirements from wholesale suppliers. This too has always been understood since the first additions of Rule 1606 and Rule 1615 to the Electric Competition Rules back in 1998. However, by submitting its proposed PPA to the Commission for its review and approval even prior to filing the agreement with FERC, the Company offered the Commission an opportunity quite possibly not available to it should it be required to purchase power from non-affiliates.

Q. EVEN THOUGH DIVESTITURE DOES NOT CHANGE THE HISTORIC JURISDICTIONAL SEPARATION BETWEEN STATE AND FEDERAL REGULATORS, SHOULDN'T THE COMMISSION BE CONCERNED THAT FERC WILL PERMIT HIGHER RATES THAN WOULD HAVE BEEN THE CASE UNDER THIS COMMISSION'S TRADITIONAL RATEMAKING SYSTEM?

A. No. Such FERC-authorized rates might be either higher or lower than cost-of-service, unless the wholesale transaction itself is cost-based in the same manner as the proposed PPA. But to the extent APS must obtain power from non-affiliated sources, it is a risk the Commission has already decided to accept under the competitive-bidding or other market-based power acquisition strategies contemplated by Rule 1606(B). In the Staff Report dated March 22, 2002, the need for Commission monitoring of and participation in FERC market proceedings is addressed in some detail. Letters in this Docket from two of the Commissioners specifically address such a Commission role. APS supports these efforts and believes the Commission can be an effective voice in support of Arizona consumers.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. Divestiture of APS generation to PWEC has been a requirement of the Electric Competition Rules for years. It was an integral part of two settlements, the second of which was adopted by the Commission and upheld as binding by the Courts. Over the past 20 months, APS has undertaken numerous steps and spent millions of dollars to be in a position to effectuate that divestiture as agreed to in 1999. Divestiture is also the basis for the competitive bidding provision of Rule 1606, which makes absolutely no sense in its absence.

The Commission and FERC have adequate provisions in place to prevent, detect and correct affiliate abuse and discriminatory treatment of any nature. These include comprehensive Affiliate Rules and Codes of Conduct (and the P&P and FERC Standards of Conduct), individual orders, and after-the-fact rate reviews.

APS purchases from the competitive wholesale market are and have been regulated by FERC. The Commission has full power and authority to monitor and participate in FERC proceedings and can review the prudence of discretionary APS procurement decisions after-the-fact in individual rate cases. Under terms of the proposed PPA, Commission involvement would also have been extended to encompass before-the-fact review and approval.

Q. DOES THAT CONCLUDE YOUR INITIAL WRITTEN TESTIMONY IN THIS GENERIC PROCEEDING?

A. Yes, it does.

APPENDIX A

STATEMENT OF WITNESS QUALIFICATIONS

Jack E. Davis is President for Pinnacle West Capital Corporation (PWCC) and President of Energy Delivery and Sales for Arizona Public Service Company (APS). As President of PWCC, Mr. Davis has responsibility for Bulk Power Marketing & Trading. As APS President for Energy Delivery and Sales, Mr. Davis has responsibility for Transmission Planning and Operations, Customer Service, Economic Development, and Pricing and Regulation. Mr. Davis is also on the Boards of PWCC and APS, as well as the Boards of APS Energy Services and Pinnacle West Energy Corporation.

Mr. Davis graduated from New Mexico State University in 1969 with a Bachelor of Science Degree in Medical Technology and in 1973 with a Bachelor of Science in Electrical Engineering. He joined APS in 1973 and has held various supervisory and managerial positions in both the APS System Planning and Power Contracts and APS System Operations Departments. In 1990, Mr. Davis was named APS Director of System Development and Power Operation and thereafter promoted to APS Vice-President of Generation and Transmission in 1993. In October 1996, he was named APS Executive Vice-President of Commercial Operations and in 1998 he was promoted to the position of APS President, Energy Delivery and Sales. In March of 2000, he became the Chief Operating Officer for PWCC and in February 2001, was promoted to President of PWCC.

Mr. Davis has served as the past-Chairman of the Western Systems Coordinating Council (WSCC) and is a member of its Board of Trustees. He is also past-Chairman on the Western Systems Power Pool as well as past-President of Western Energy and Supply Transmission (WEST) Associates. Mr. Davis is presently a member of the National Electric Reliability Council Board of Trustees, and he is a registered professional Engineer in the State of Arizona.

SCHEDULE JED-1GD

BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED

OCT 06 1999

DOCKETED BY	ad

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 DECISION NO. 61973 **OPINION AND ORDER**

DATES OF HEARING:	July 12, 1999 (pre-hearing conference), July 14, 15, 16, 19, 20, and 21, 1999
PLACE OF HEARING:	Phoenix, Arizona
PRESIDING OFFICER:	Jerry L. Rudibaugh
IN ATTENDANCE:	Carl J. Kunasek, Chairman Jim Irvin, Commissioner
APPEARANCES:	Mr. Steven M. Wheeler, Mr. Thomas Mumaw and Mr. Jeffrey B. Guldner, SNELL & WILMER, LLP, on behalf of Arizona Public Service Company;
	Mr. C. Webb Crockett and Mr. Jay Shapiro, FENNEMORE CRAIG, on behalf of Cyprus Climax Metals, Co., ASARCO, Inc., and Arizonans for Electric Choice & Competition;
	Mr. Scott S. Wakefield, Chief Counsel, and Ms. Karen Nally on behalf of the Residential Utility Consumer Office;
	Ms. Betty Pruitt on behalf of the Arizona Community Action Association;
	Mr. Timothy Hogan on behalf of the Arizona Consumers Council;

Mr. Robert S. Lynch on behalf of the Arizona Transmission Dependent Utility Group;

Mr. Walter W. Meek on behalf of the Arizona Utility Investors Association;

Mr. Douglas C. Nelson, DOUGLAS C. NELSON, P.C., on behalf of Commonwealth Energy Corporation;

Mr. Lawrence V. Robertson, Jr., MUNGER & CHADWICK, and Ms. Leslie Lawner, Director Government Affairs on behalf of Enron Corporation, and Mr. Robertson on behalf of PG&E Energy Services;

Mr. Lex J. Smith, BROWN & BAIN, P.A., on behalf of Illinova Energy Partners and Sempra Energy Trading;

Mr. Randall H. Werner, ROSHKA, HEYMAN & DeWULF, P.L.C., on behalf of NEV Southwest;

Mr. Norman Furuta on behalf of the Department of the Navy;

Mr. Bradley S. Carroll on behalf of Tucson Electric Power Company; and

Mr. Christopher C. Kempley, Assistant Chief Counsel and Ms. Janet F. Wagner, Staff Attorney, Legal Division on behalf of the Utilities Division of the Arizona Corporation Commission.

BY THE COMMISSION:

On December 26, 1996, the Arizona Corporation Commission ("Commission") in Decision No. 59943 enacted A.A.C. R14-2-1601 through R14-2-1616 ("Rules" or "Electric Competition Rules").

On June 22, 1998, the Commission issued Decision No. 60977, the Stranded Cost Order which required each Affected Utility to file a plan for stranded cost recovery.

On August 10, 1998, the Commission issued Decision No. 61071 which made modifications to the Rules on an emergency basis.

On August 21, 1998, Arizona Public Service Company ("APS") filed its Stranded Costs plan.

On November 5, 1998, APS filed a Settlement Proposal that had been entered into with the Commission's Utilities Division Staff ("Staff Settlement Proposal"). Our November 24, 1998 Procedural Order set the matter for hearing. On November 25, 1998, the Commission issued

Decision No. 61259 which established an expedited procedural schedule for evidentiary hearings on the Staff Settlement Proposal.

On November 30, 1998, the Arizona Attorney General's Office, in association with numerous other parties, filed a Verified Petition for Special Action and Writ of Mandamus with the Arizona Supreme Court ("Court") regarding the Commission's November 25, 1998 Procedural Order, Decision No. 61259. The Attorney General sought a Stay of the Commission's consideration of the Staff Settlement Proposal with APS and Tucson Electric Power Company ("TEP").

On December 1, 1998, Vice Chief Justice Charles J. Jones granted a Motion for Immediate Stay of the Procedural Order. On December 9, 1998, the Commission Staff filed a notice with the Supreme Court that the Staff Settlement Proposal had been withdrawn from Commission consideration.

On April 27, 1999, the Commission issued Decision No. 61677, which modified Decision No. 60977. On May 17, 1999, APS filed with the Commission a Notice of Filing, Application for Approval of Settlement Agreement ("Settlement" or "Agreement") [1] and Request for Procedural Order.

Our May 25, 1999 Procedural Order set the matter for hearing commencing on July 14, 1999.

This matter came before a duly authorized Hearing Officer of the Commission at its offices in Phoenix, Arizona. APS, Cyprus Climax Metals, Co., ASARCO, Inc., Arizonans for Electric Choice & Competition ("AECC"), Residential Utility Consumer Office ("RUCO"), the Arizona Community Action Association ("ACAA"), the Arizona Consumers Council, the Arizona Transmission Dependent Utility Group, the Arizona Utility Investors Association, Enron Corporation, PG&E Energy Services, Illinova Energy Partners, Sempra Energy Trading, NEV Southwest, the Department of the Navy, Tucson Electric Power Company, Commonwealth Energy Corporation

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[1] The Parties to the Proposed Settlement are as follows: the Residential Utility Consumer Office, Arizona Public Service Company, Arizona Community Action Association and the Arizonans for Electric Choice and Competition which is a coalition of companies and associations in support of competition that 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 Multi-housing 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.

("Commonwealth") and Staff of the Commission appeared through counsel. Evidence was presented concerning the Settlement Agreement, and after a full public hearing, this matter was adjourned pending submission of a Recommended Opinion and Order by the Presiding Officer to the Commission. In addition, a post-hearing briefing schedule was established with simultaneous briefs filed on August 5, 1999.

DISCUSSION

Introduction

The Settlement provides for rate reductions for residential and business customers; sets the amount, method, and recovery period of stranded costs that APS can collect in customer charges; establishes unbundled rates; and provides that APS will separate its generating facilities, which will operate in the competitive market, from its distribution system, which will continue to be regulated.

According to APS, the Settlement was the product of months of hard negotiations with various customer groups. APS opined that the Settlement provides many clear benefits to customers, potential competitors, as well as to APS. Some of those benefits as listed by APS are as follows:

- Allowing competition to commence in APS' service territory months before otherwise possible and expanding the initial eligible load by 140 MW;
- Establishing both Standard Offer and Direct Access rates, and providing for annual rate reductions with a cumulative total of as much as $475 million by 2004;
- Ensuring stability and certainty for both bundled and unbundled rates;
- Resolving the issue of APS' stranded costs and regulatory asset recovery in a fair and equitable manner;
- Providing for the divestiture of generation and competitive services by APS in a cost-effective manner;
- Removing the specter of years of litigation and appeals involving APS and Commission over competition-related issues;
- Continuing support for a regional ISO and the AISA;
- Continuing support for low income programs; and
- Requiring APS to file an interim code of conduct to address affiliate relationships.

The Settlement was entered into by RUCO and the ACAA reflecting Agreement by residential customers of APS to the Settlement's terms and conditions. In addition, the Settlement was executed by the AECC, a coalition of commercial and industrial customers and trade associations. AECC opined that since residential and non-residential customers have agreed to the Settlement, the "public interest" has been served. AECC indicated the Settlement was not perfect but was the result of "give and take" by each of the parties. Accordingly, AECC urged the Commission to protect the "public interest" by approving the Settlement and not allow Energy Service Providers ("ESPs") to delay the benefits that competition has to offer.

Legal Issues:

The Arizona Consumers Council ("Consumers Council") opined that the Agreement was not legal because: (1) there was no full rate proceeding[2]; (2) Section 2.8 of the Agreement violates A.R.S. Section 40-246, regarding Commission initiated rate reductions; and (3) the Agreement illegally binds future Commissions. According to the Consumers Council, the Commission does not have evidence to support a finding that the rates proposed in the Agreement are just and reasonable; that the rate base proposed is proper; and asserted the proposed adjustment clause can not be established outside a general rate case.

Staff argued that the Commission in Decision No. 59601, dated April 26, 1996, has previously determined just and reasonable rates for APS which must be charged until changed in a rate proceeding. According to Staff, this case is not about changing existing rates, but instead involves the introduction of a new service - direct access. The direct access rates have been designed to replicate the revenue flow from existing rates. Staff opined that the Commission has routinely, and lawfully, approved rates for new services outside of a rate case. Further, Staff asserted that the rates proposed in the Settlement are directly related to a complete financial review. Staff indicated that the Consumers Council has provided no contrary information and should not be allowed to collaterally attack Decision No. 59601.

APS argued that no determination of fair value rate base ("FVRB"), fair value rate of return

[2] Although the Consumers Council indicated they did not believe a full rate proceeding was necessary, it is unclear as to the type of proceeding the Consumers Council believed was necessary.

("FVROR"), or other financial analysis is legally necessary to justify current APS rate levels, allow the introduction of a new service, or to evaluate a series of voluntary rate decreases. In spite of that, APS did provide information to support a FVRB of $5,195,675,000 and FVROR of 6.63 percent. No other party presented evidence in support of a FVRB or FVROR. Staff supported APS.

We concur with Staff and APS. The Consumers Council has provided no legal authority that a full rate proceeding is necessary in order to adopt a rate reduction or rates for new services. Further, pursuant to the Arizona Constitution, the Commission has jurisdiction over ratemaking matters. We also find that notice of the application and hearing was provided and that APS has provided sufficient financial information to support a finding of FVRB and FVROR. Lastly, this Commission can clearly bind future Commissions as a result of its Decision. However, as later discussed, we agree there are limitations to such legal authority.

<u>Shopping Credit</u>

One of the most contentious issues in the hearing was the level of the "shopping credit." The "shopping credit" is the difference between the customer's Standard Offer Rate and the Direct Access Rate available to customers who take service from ESPs. The ESPs generally argued that the Settlement's "shopping credits" were not sufficient to allow a new entrant to make a profit. AECC opined that such an argument was nothing more than a request to increase ESP's profits.

Staff opined that the "shopping credit" was too low and recommended it be increased without impacting the stranded cost recovery amount of $350 million. Under Staff's proposal, the increased "shopping credit" would be offset by reducing the competitive transition charge ("CTCs"). Further, Staff recommended that any stranded costs not collected could simply be deferred and collected after 2004.

The AECC expert testified that the "shopping credit" under the Agreement was superior to the "Shopping Credit" in the Staff Settlement Proposal as well as the one offered to SRP's customers. APS argued that artificially high shopping credits will likely increase ESP profits without lowering customer rates and will encourage inefficient firms to enter the market. Based on the analysis of the

40kW to 200 kW customer group[3], APS showed an average margin on the "shopping credit" of over 8 mils per kWh or a 23 percent markup over cost. APS asserted that the test for a reasonable "shopping credit" "should not be whether all ESPs can profit on all APS customers all of the time".

Based on the evidence presented, the "shopping credits" appear to be reasonable to allow ESPs to compete in an efficient manner. Further, we do not find customer rates should be increased simply to have higher "shopping credits".

Metering and Billing Credits

The metering and billing credits resulting from the Agreement are based on decremental costs. Several of the ESPs and Staff argued that these credits should be based upon embedded costs and not decremental costs. APS responded that such a result could cause them to lose revenues since its costs would only go down by the decremental amounts. Staff testified that the Company would not lose significant income if it used embedded costs since it would free up resources to service new customers.

We concur. The proposed credits for metering, meter reading and billing[4] will result in a direct access customer paying a portion of APS costs as well as a portion of the ESP's costs. We believe this would stymie the competitive market for these services. As a result, we find the approval of the Settlement should be conditioned upon the use of Staff's proposed credits for metering, meter reading, and billing.

Proposed One-Year Advance Notice Requirement:

Section 2.3 provides that

> "Customers greater than 3MW who chose a direct access supplier must give APS one year's advance notice before being eligible to return to Standard Offer service." [emphasis added]

Several parties expressed concerns that the one-year notice requirement to return to Standard Offer service would create a deterrent to load switching by large industrial, institutional and commercial customers. PG&E proposed that any increased cost could be charged directly to the

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[3] Represents over 80 percent of the general service customers for competitive access in phase one.

[4] For example, the monthly credits for a direct access residential customers are $1.30, $0.30, and $0.30 for metering, meter reading and billing, respectively.

customer as a condition to its return.

We agree that APS needs to have some protection from customers leaving the system when market prices are low and jumping back on Standard Offer rates when market prices go up. The suggestion by PG&E that the customer be allowed to go back to the Standard Offer if the customer pays for additional costs it has caused is a reasonable resolution. Accordingly, we will order APS to submit substitute language on this issue.

Section 2.8

Several of the parties expressed concern that Section 2.8 of the Agreement allows APS to seek rate increases under specified conditions. Additionally, as previously discussed, the Consumers Council opined that Section 2.8 violated A.R.S. Section 40-246. Staff recommended the Commission condition approval of the Agreement on Section 2.8 being amended to include language that the Commission or Staff may commence rate change proceedings under conditions paralleling those provided to the utility, including response to petitions submitted under A.R.S. § 40-246.

We agree that Section 2.8 is too restrictive on the Commission's future action. Accordingly, we will condition approval of the Agreement on inclusion of the following language in Section 2.8:

> Neither the Commission nor APS shall be prevented from seeking or authorizing a change in unbundled or Standard Offer rates prior to July 1, 2004, in the event of (a) conditions or circumstances which constitute an emergency, such as an inability to finance on reasonable terms, or (b) material changes in APS' cost of service for Commission-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders. Except for the changes otherwise specifically contemplated by this Agreement, unbundled and Standard Offer rates shall remain unchanged until at least July 1, 2004.

Section 7.1

The Consumers Council opined that there was language in the Agreement which would illegally bind future Commissions. While Staff disagreed with the legal opinion of the Consumers Council, Staff was concerned with some of the binding language in the Agreement and in particular with the following language in Section 7.1:

> 7.1. To the extent any provision of this Agreement is inconsistent with any existing or future Commission order, rule or regulation or is inconsistent with the Electric

> Competition Rules as now existing or as may be amended in the future, the provisions of this Agreement shall control and the approval of the Agreement by the Commission shall be deemed to constitute a Commission-approved variation or exemption to any conflicting provision of the Electric Competition Rules.

Staff recommended the Commission not approve Section 7.1.

We share Staff's concerns. We also recognize that the parties want to preserve their benefits to their Agreement. We agree with the parties that to the extent any provision of the Agreement is inconsistent with the Electric Competition Rules as finalized by the Commission in September 1999, the provisions of the Agreement shall control. We want to make it clear that the Commission does not intend to revisit the stranded cost portion of the Agreement. It is also not the Commission's intent to undermine the benefits that parties have bargained for. With that said, the Commission must be able to make rule changes/other future modifications that become necessary over time. As a result, we will direct the parties and Staff to file within 10 days, a revised Section 7.1 consistent with the Commission's discussions herein and subsequently approved by this Commission.

<u>Generation Affiliate</u>

Section 4.1 of the Agreement provides the following:

> 4.1 The Commission will approve the formation of an affiliate or affiliates of APS to acquire at book value the competitive services assets as currently required by the Electric Competition Rules. In order to facilitate the separation of such assets efficiently and at the lowest possible cost, the Commission shall grant APS a two-year extension of time until December 31, 2002, to accomplish such separation. A similar two-year extension shall be authorized for compliance with A.A.C. R14-2-1606(B).

Related to Section 4.1 is Section 2.6(3) which allows APS to defer costs of forming the generation affiliate, to be collected beginning July 1, 2004.

According to NEV Southwest, APS indicated that it intends to establish a generation affiliate under Pinnacle West, not under APS. Further, that APS intends to procure generation for standard offer customers from the wholesale generation market as provided for in the Electric Competition Rules. Additionally, it was NEV Southwest's understanding that the affiliate generation company could bid for the APS standard offer load under an affiliate FERC tariff, but there would be no automatic privilege outside of the market bid. NEV Southwest supports the aforementioned concepts and recommended they be explicitly stated in the Agreement.

We concur with NEV Southwest. We shall order APS to include language as requested by

NEV Southwest. Power for Standard Offer Service will be acquired in a manner consistent with the Commission's Electric Competition Rules. We generally support the request of APS to defer those costs related to formation of a new generation affiliate pursuant to the Electric Competition Rules. We also recognize the Company is making a business decision to transfer the generation assets to an affiliate instead of an unrelated third party. As a result, we find the Company's proposed mitigation of stranded costs[5] in the Settlement should also apply to the costs of forming the new generation affiliate. Accordingly, Section 2.6(3) should be modified to reflect that only 67 percent of those costs to transfer generation assets to an affiliate shall be allowed to be deferred for future collection.

Some parties were concerned that Sections 4.1 and 4.2 provide in effect that the Commission will have approved in advance any proposed financing arrangements associated with future transfers of "competitive services" assets to an affiliate. As a result, there was a recommendation that the Commission retain the right to review and approve or reject any proposed financing arrangements. In addition, some parties expressed concern that APS has not definitively described the assets it will retain and which it will transfer to an affiliate.

We share the concerns that the non-competitive portion of APS not subsidize the spun-off competitive assets through an unfair financial arrangement. We want to make it clear that the Commission will closely scrutinize the capital structure of APS at its 2004 rate case and make any necessary adjustments. The Commission supports and authorizes the transfer by APS to an affiliate or affiliates of all its generation and competitive electric service assets as set forth in the Agreement no later than December 31, 2002. However, we will require the Company to provide the Commission with a specific list of any assets to be so transferred, along with their net book values at the time of transfer, at least thirty days prior to the actual transfer. The Commission reserves the right to verify whether such specific assets are for the provision of generation and other competitive electric services or whether there are additional APS assets that should be so transferred.

Unbundled Rates

Several parties expressed concern that the Agreement's unbundled rates fail to provide the

[5] Agreement to not recover $183 million out of a claimed $533 million.

necessary information to determine whether a competitor's price is lower than the Standard Offer rate. Further, some of the parties asserted that APS has not performed a functional cost-of-service study and as a result the Settlement's "shopping credit" is an artificial division of costs. In response, APS indicated the Standard Offer rates can not be unbundled on a strict cost-of-service basis unless the Standard Offer rates are redesigned to equal cost-of-service. APS opined that such a process would result in significant rate increases for many customers.

AECC asserted that a full rate case would result in additional months/years of delay with continued drain of resources by all interested entities.

The ESPs asserted that the bill format proposed by APS is misleading and too complex. In general, the ESPs desired a bill format that would allow customers to easily compare Standard Offer and Direct Access charges in order to make an informed decision. As a result, APS was directed to circulate an Informational Unbundled Standard Offer Bill ("Bill") to the parties for comments. Subsequent to the hearing, a Bill was circulated to the parties for comments to determine what consensus could be reached on its format. In general, there was little dispute with the format of the Bill. However, PG&E and Commonwealth disagreed with the underlying cost allocation methodologies. Enron was concerned that the Bill portrayed the Standard Offer to be more simplistic than the Direct Access portion of the Bill. Enron proposed a bill format that would clearly identify those services which are available from an ESP. Based on comments from RUCO and Staff, APS made general revisions to the proposed Bill.

We find the APS Attachment AP-1R, second revised dated 8/16/99 provides sufficient information in a concise manner to enable customers to make an informed choice. (See Attachment No. 2 herein). However, we find the Enron breakdown into a Part 1 versus Parts 2 and 3 will further help educate customers as to choice. We will direct APS to further revise its Bill to have a Part 1 as set forth by the Enron breakdown. We believe Parts 2 and 3 can be combined for simplicity.

We concur with APS that it is not necessary to file a revised cost-of-service study at this time. The proposed Standard Offer rates contained in the Settlement are based on existing tariffs approved by this Commission. Further, we concur with AECC that a full rate case with a revised cost-of-service study would result in months/years of additional delay. Lastly, the Standard Offer rates as proposed in the Settlement are consistent with the Commission's requirement that no customer shall receive a rate increase. The following was extracted from Decision No. 61677:

> "No customer or customer class shall receive a rate increase as a result of stranded cost recovery by an Affected Utility under any of these options."

Code of Conduct

There were concerns expressed that APS would be writing its own Code of Conduct. Subsequently, APS did provide a copy of its proposed Code of Conduct to the parties for comment. Several parties also expressed concern that any Code of Conduct would not cover the actions of a single company during the two-year delay for transferring generation assets.

Based on the above, we will direct APS to file with the Commission no later than 30 days of the date of this Decision, its interim Code of Conduct. We will direct APS to file its revised Code of Conduct within 30 days of the date of this Decision. Such Code of Conduct should also include provisions to govern the supply of generation during the two-year period of delay for the transfer of generation assets so that APS doesn't give itself an undue advantage over the ESPs. All parties shall have 60 days from the date of this Decision to provide their comments to APS regarding the revised Code of Conduct. APS shall file its final proposed Code of Conduct within 90 days of the date of this Decision. Subsequently, within 10 days of filing the Code of Conduct, the Hearing Division shall establish a procedural schedule to hear the matter.

Section 2.6(1)

Pursuant to the Agreement, the Commission shall approve an adjustment clause or clauses which among other things would provide for a purchased power adjustor ("PPA") for service after July 1, 2004 for Standard Offer obligations. Part of the justification for the PPA was the fact that these costs would be outside of the Company's control.

We concur that a PPA would result in less risk to the Company resulting in lower costs for the Standard Offer customers. As a result, we will approve the concept of the PPA as set forth in Section 2.6(1) with the understanding that the Commission can eliminate the PPA once the Commission has provided reasonable notice to the Company.

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Requested Waivers

Section 4.3 of the Agreement would automatically act to exempt APS and its affiliates from the application of a wide range of provisions under A.R.S. Title 40. In addition, under Section 4.5 of the Agreement, Commission approval without modification will act to grant certain waivers to APS and its affiliates of a variety of the provisions of the Commission's affiliate interest rules (A.A.C. R14-2-801, *et seq.*), and the rescission of all or portions of certain prior Commission decisions.

Staff recommended that the Commission reserve its approval of the requested statute waivers until such time as their applicability can be evaluated on an industry-wide basis, rather than providing a blanket exemption for APS and its affiliates. Additionally, Staff recommended that the Commission not waive the applicability of A.A.C. R14-2-804(A), in order to preserve the regulatory authority needed by the Commission to justify approving Exempt Wholesale Generator ("EWG") status for APS' generation affiliate.

We concur with Staff. Accordingly, the requested statutory waivers shall not be granted by this Decision. Those waivers will be considered in an industry-wide proceeding to be scheduled at the Commission's earliest convenience. The requested waivers of affiliate interest rules and rescission of prior Commission decisions shall be granted, except that the provisions of A.A.C. R14-2-804(A) shall not be waived.

ANALYSIS/SUMMARY

Consistent with our determination in Decision No. 60977, the following primary objectives need to be taken into consideration in deciding the overall stranded cost issue:

A. Provide the Affected Utilities a reasonable opportunity to collect 100 percent of their unmitigated stranded costs;

B. Provide incentives for the Affected Utilities to maximize their mitigation effort;

C. Accelerate the collection of stranded costs into as short of a transition period as possible consistent with other objectives;

D. Minimize the stranded cost impact on customers remaining on the standard offer;

E. Don't confuse customers as to the bottom line; and

F. Have full generation competition as soon as possible.

The Commission also recognized in Decision No. 60977 that the aforementioned objectives were in conflict. Part of that conflict is reflected in the following language extracted from Decision No. 60977:

> One of the main concerns expressed over and over by various consumer groups was that the small consumers would end up with higher costs during the transition phase and all the benefits would flow to the larger users. At the time of the hearing, there had been minimal participation in California by residential customers in the competitive electric market place. It is not the Commission's intent to have small consumers pay higher short-term costs in order to provide lower costs for the larger consumers. Accordingly, we will place limitations on stranded cost recovery that will minimize the impact on the standard offer.

Decision No. 61677 modified Decision No. 60977 and allowed each Affected Utility to chose from five options.

With the modifications contained herein, we find the overall Settlement satisfies the objectives set forth in Decision Nos. 60977 and 61677. We believe the Settlement will result in an orderly process that will have real rate reductions[6] during the transition period to a competitive generation market. The Settlement allows <u>every APS customer</u> to have the immediate opportunity to benefit from the change in market structure while maintaining reliability and certainty of delivery. Further, the Settlement in conjunction with the Electric Rules will provide every APS customer with a choice in a reasonable timeframe and in an orderly manner. If anything, the Proposed Settlement favors customers over competitors in the short run since APS has agreed to reductions in rates totaling 7.5 percent[7]. This Commission supports competition in the generation market because of increased benefits to customers, including lower rates and greater choice. While some of the potential competitors have argued that higher "shopping credits" will result in greater choice, we find that a higher shopping credit would also mean less of a rate reduction for APS customers. We find that the Settlement strikes the proper balance between competing objectives by allowing immediate

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[6] There have been instances in other states where customers were told they would receive rate decreases which were then offset by a stranded cost add-on.

[7] Pursuant to Decision No. 59601, dated April 24, 1996, 0.68 percent of that decrease would have occurred on July 1, 1999.

rate reductions while maintaining a relatively short transition period for collection of stranded costs, followed shortly thereafter with a full rate case. At that point in time the collection of stranded costs will be completed and unbundled rates can be modified based upon an updated cost study.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. APS is certificated to provide electric service as a public service corporation in the State of Arizona.

2. Decision No. 59943 enacted R14-2-1601 through –1616, the Retail Electric Competition Rules.

3. Following a hearing on generic issues related to stranded costs, the Commission issued Decision No. 60977, dated June 22, 1998.

4. Decision No. 61071 adopted the Emergency Rules on a permanent basis.

5. On August 21, 1998, APS filed its Stranded Costs plan.

6. On November 5, 1998, APS filed the Staff Settlement Proposal.

7. Our November 24, 1998 Procedural Order set the matter for hearing.

8. Decision No. 61259 established an expedited procedural schedule for evidentiary hearings on the Staff Settlement Proposal.

9. The Court issued a Stay of the Commission's consideration of the Staff Settlement Proposal.

10. Staff withdrew the Staff Settlement Proposal from Commission consideration.

11. On May 17, 1999, APS filed its Settlement requesting Commission approval.

12. Our May 25, 1999 Procedural Order set the Settlement for hearing commencing on July 14, 1999.

13. Decision No. 61311 (January 11, 1999) stayed the effectiveness of the Emergency Rules and related Decisions, and ordered the Hearing Division to conduct further proceedings in this Docket.

14. In Decision No. 61634 (April 23, 1999), the Commission adopted modifications to R14-2-201 through-207, -210 and 212 and R14-2-1601 through –1617.

15. Pursuant to Decision No. 61677, dated April 27, 1999, the Commission modified Decision No. 60977 whereby each Affected Utility could choose one of the following options: (a) Net Revenues Lost Methodology; (b) Divestiture/Auction Methodology; (c) Financial Integrity Methodology; (d) Settlement Methodology; and (e) the Alternative Methodology.

16. APS and other Affected Utilities filed with the Arizona Superior Court various appeals of Commission Orders adopting the Competition Rules and related Stranded Cost Decisions (the "Outstanding Litigation").

17. Pursuant to Decision No. 61677, APS, RUCO, AECC, and ACAA entered into the Settlement to resolve numerous issues, including stranded costs and unbundled tariffs.

18. The difference between market based prices and the cost of regulated power has been generally referred to as stranded costs.

19. Any stranded cost recovery methodology must balance the interests of the Affected Utilities, ratepayers, and the move toward competition.

20. All current and future customers of the Affected Utilities should pay their fair share of stranded costs.

21. Pursuant to the terms of the Settlement Agreement, APS has agreed to the modification of its CC&N in order to implement competitive retail access in its Service Territory.

22. The Settlement Agreement provides for competitive retail access in APS' Service Territory, establishes rate reductions for all APS customers, sets a mechanism for stranded cost recovery, resolves contentious litigation, and therefore, is in the public interest and should be approved.

23. The information and formula for rate reductions contained in Exhibit AP-3 Appended to APS Exhibit No. 2 provides current financial support for the proposed rates.

24. RUCO, ACAA, and AECC collectively, represent residential and non-residential customers.

25. According to AECC, the Agreement results in higher shopping credits than in the Staff

Settlement Proposal as well as those offered by SRP.

26. The decremental approach for metering and billing will not provide sufficient credits for competitors to compete.

27. Pursuant to the Settlement, customers will receive substantial rate reductions without the necessity of a full rate case.

28. An APS rate case would take a minimum of one year to complete.

29. ESPs that have been certificated have shown more of an interest in serving larger business customers than residential customers.

30. It is not in the public or customers' interests to forego guaranteed Standard Offer rate reductions in order to have a higher shopping credit.

31. The Settlement will permit competition in a timely and efficient manner and insure all customers benefit during the transition period.

32. Based on the evidence presented, the FVRB and FVROR of APS is determined to be $5,195,675,000 and 6.63 percent, respectively.

33. The terms and conditions of the Settlement Agreement as modified herein are just and reasonable and in the public interest.

CONCLUSIONS OF LAW

1. The Affected Utilities are public service corporations within the meaning of the Arizona Constitution, Article XV, under A.R.S. §§ 40-202, -203, -250, -321, -322, -331, -336, -361, -365, -367, and under the Arizona Revised Statutes, Title 40, generally.

2. The Commission has jurisdiction over the Affected Utilities and of the subject matter contained herein.

3. Notice of the proceeding has been given in the manner prescribed by law.

4. The Settlement Agreement as modified herein is just and reasonable and in the public interest and should be approved.

5. APS should be authorized to implement its Stranded Cost Recovery Plan as set forth in the Settlement Agreement.

6. APS' CC&N should be modified in order to permit competitive retail access in APS'

CC&N service territory.

7. The requested statutory waivers should not be granted at this time. A proceeding should be commenced to consider statutory waivers on an industry-wide basis. The other waivers requested by APS in the Settlement should be granted as modified herein, except that the provisions of A.A.C. R14-2-804(A) shall not be waived.

ORDER

IT IS THEREFORE ORDERED that the Settlement Agreement as modified herein is hereby approved and all Commission findings, approvals and authorizations requested therein are hereby granted.

IT IS FURTHER ORDERED that Arizona Public Service Company's CC&N is hereby modified to permit competitive retail access consistent with this Decision and the Competition Rules.

IT IS FURTHER ORDERED that within 30 days of the date of this Decision, Arizona Public Service Company shall file a proposed Code of Conduct for Commission approval.

IT IS FURTHER ORDERED that Arizona Public Service Company shall file a revised Settlement Agreement consistent with the modifications herein.

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IT IS FURTHER ORDERED that within ten days of the date the proposed Code of Conduct is filed, the Hearing Division shall issue a Procedural Order setting a procedural schedule for consideration of the Code of Conduct.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 6th day of October, 1999.

BRIAN C. McNEIL
EXECUTIVE SECRETARY

DISSENT ______________
JLR:dap

SERVICE LIST FOR: ARIZONA PUBLIC SERVICE COMPANY

DOCKET NOS.: E-01345A-98-0473, E-01345A-97-0773 and RE-00000C-94-0165

Service List for RE-00000C-94-0165

Paul A. Bullis, Chief Counsel
LEGAL DIVISION
1200 W. Washington Street
Phoenix, Arizona 85007

Utilities Division Director
ARIZONA CORPORATION COMMISSION
1200 W. Washington Street
Phoenix, Arizona 85007

ATTACHMENT 1

SETTLEMENT AGREEMENT

May 14, 1999

This settlement agreement ("Agreement") is entered into as of May 14, 1999, by Arizona Public Service Company ("APS" or the "Company") and the various signatories to this Agreement (collectively, the "Parties") for the purpose of establishing terms and conditions for the introduction of competition in generation and other competitive services that are just, reasonable and in the public interest.

INTRODUCTION

In Decision No. 59943, dated December 26, 1996, the Arizona Corporation Commission ("ACC" or the "Commission") established a "framework" for introduction of competitive electric services throughout the territories of public service corporations in Arizona in the rules adopted in A.A.C. R14-2-1601 *et seq.* (collectively, "Electric Competition Rules" as they may be amended from time to time). The Electric Competition Rules established by that order contemplated future changes to such rules and the possibility of waivers or amendments for particular companies under appropriate circumstances. Since their initial issuance, the Electric Competition Rules have been amended several times and are currently stayed pursuant to Decision No. 61311, dated January 5, 1999. During this time, APS, Commission Staff and other interested parties have participated in a number of proceedings, workshops, public comment sessions and individual negotiations in order to further refine and develop a restructured utility industry in Arizona that will provide meaningful customer choice in a manner that is just, reasonable and in the public interest.

This Agreement establishes the agreed upon transition for APS to a restructured entity and will provide customers with competitive choices for generation and certain other retail services. The Parties believe this Agreement will produce benefits for all customers through implementing customer choice and providing rate reductions so that the APS service territory may benefit from economic growth. The Parties also believe this Agreement will fairly treat APS and its shareholders by providing a reasonable opportunity to recover prudently incurred investments and costs, including stranded costs and regulatory assets.

Specifically, the Parties believe the Agreement is in the public interest for the following reasons. First, customers will receive substantial rate reductions. Second, competition will be promoted through the introduction of retail access faster than would have been possible without this Agreement and by the functional separation of APS' power production and delivery functions. Third, economic development and the environment will benefit through guaranteed rate reductions and the continuation of renewable and energy efficiency programs. Fourth, universal service coverage will be maintained through APS' low income assistance programs and establishment of "provider of last resort" obligations on APS for customers who do not wish to participate in retail access. Fifth, APS will be able to recover its regulatory assets and stranded costs as provided for in this Agreement without the necessity of a general rate proceeding. Sixth, substantial litigation and associated costs will be avoided by amicably resolving a number of important and contentious issues that have already been raised in the courts and before the Commission. Absent approval by the Commission of the settlement reflected by this Agreement, APS would seek full stranded cost recovery and pursue other rate and competitive restructuring provisions different than provided for herein. The other Parties would challenge at least portions of APS' requested relief, including the recovery of all stranded costs. The resulting regulatory hearings and related court appeals would delay the start of competition and drain the resources of all Parties.

NOW, THEREFORE, APS and the Parties agree to the following provisions which they believe to be just, reasonable and in the public interest:

TERMS OF AGREEMENT

ARTICLE I
IMPLEMENTATION OF RETAIL ACCESS

1.1. The APS distribution system shall be open for retail access on July 1, 1999; provided, however, that such retail access to electric generation and other competitive electric services suppliers will be phased in for customers in APS' service territory in accordance with the proposed Electric Competition Rules, as and when such rules become effective, with an additional 140 MW being made available to eligible non-residential customers. The Parties shall urge the Commission to approve Electric Competition Rules, at least on an emergency basis, so that meaningful retail access can begin by July 1, 1999. Unless subject to judicial or regulatory restraint, APS shall open its distribution system to retail access for all customers on January 1, 2001.

1.2. APS will make retail access available to residential customers pursuant to its December 21, 1998, filing with the Commission.

1.3. The Parties acknowledge that APS' ability to offer retail access is contingent upon numerous conditions and circumstances, a number of which are not within the direct control of the Parties. Accordingly, the Parties agree that it may become necessary to modify the terms of retail access to account for such factors, and they further agree to address such matters in good faith and to cooperate in an effort to propose joint resolutions of any such matters.

1.4. APS agrees to the amendment and modification of its Certificate(s) of Convenience and Necessity to permit retail access consistent with the terms of this Agreement. The Commission order adopting this Agreement shall constitute the necessary Commission Order amending and modifying APS' CC&Ns to permit retail access consistent with the terms of this Agreement.

ARTICLE II
RATE MATTERS

2.1. The Company's unbundled rates and charges attached hereto as Exhibit A will be effective as of July 1, 1999. The Company's presently authorized rates and charges shall be deemed its standard offer ("Standard Offer") rates for purposes of this Agreement and the Electric Competition Rules. Bills for Standard Offer service shall indicate individual unbundled service components to the extent required by the Electric Competition Rules.

2.2. Future reductions of standard offer tariff rates of 1.5% for customers having loads of less than 3 MW shall be effective as of July 1, 1999, July 1, 2000, July 1, 2001, July 1, 2002, and July 1, 2003, upon the filing and Commission acceptance of revised tariff sheets reflecting such decreases. For customers having loads greater than 3 MW served on Rate Schedules E-34 and E-35, Standard Offer tariff rates will be reduced: 1.5%, effective July 1, 1999; 1.5% effective July 1, 2000; 1.25% effective July 1, 2001; and .75% effective July 1, 2002. The 1.5% Standard Offer rate reduction to be effective July 1, 1999, includes the rate reduction otherwise required by Decision No. 59601. Such decreases shall become effective by the filing with and acceptance by the Commission of revised tariff sheets reflecting each decrease.

2.3. Customers greater than 3 MW who choose a direct access supplier must give APS one year's advance notice before being eligible to return to Standard Offer service.

2.4. Unbundled rates shall be reduced in the amounts and at the dates set forth in Exhibit A attached hereto upon the filing and Commission acceptance of revised tariff sheets reflecting such decreases.

2.5. This Agreement shall not preclude APS from requesting, or the Commission from approving, changes to specific rate schedules or terms and conditions of service, or the approval of new rates or terms and conditions of service, that do not significantly affect the overall earnings of the Company or materially modify the tariffs or increase the rates approved in this Agreement. Nothing contained in this Agreement shall preclude APS from filing changes to its tariffs or terms and conditions of service which are not inconsistent with its obligations under this Agreement.

2.6. Notwithstanding the rate reduction provisions stated above, the Commission shall, prior to December 31, 2002, approve an adjustment clause or clauses which will provide full and timely recovery beginning July 1, 2004, of the reasonable and prudent costs of the following:

(1) APS' "provider of last resort" and Standard Offer obligations for service after July 1, 2004, which costs shall be recovered only from Standard Offer and "provider of last resort" customers;

(2) Standard Offer service to customers who have left Standard Offer service or a special contract rate for a competitive generation supplier but who desire to return to Standard Offer service, which costs shall be recovered only from Standard Offer and "provider of last resort" customers;

(3) compliance with the Electric Competition Rules or Commission-ordered programs or directives related to the implementation of the Electric Competition Rules, as they may be amended from time to time, which costs shall be recovered from all customers receiving services from APS; and

(4) Commission-approved system benefit programs or levels not included in Standard Offer rates as of June 30, 1999, which costs shall be recovered from all customers receiving services from APS.

By June 1, 2002, APS shall file an application for an adjustment clause or clauses, together with a proposed plan of administration, and supporting testimony. The Commission shall thereafter issue a procedural order setting such adjustment clause application for hearing and including reasonable provisions for participation by other parties. The Commission order approving the adjustment clauses shall also establish reasonable procedures pursuant to which the Commission, Commission Staff and interested parties may review the costs to be recovered. By June 30, 2003, APS will file its request for the specific adjustment clause factors which shall, after hearing and Commission approval, become effective July 1, 2004. APS shall be allowed to defer costs covered by this Section 2.6 when incurred for later full recovery pursuant to such adjustment clause or clauses, including a reasonable return.

2.7. By June 30, 2003, APS shall file a general rate case with prefiled testimony and supporting schedules and exhibits; provided, however, that any rate changes resulting therefrom shall not become effective prior to July 1, 2004.

2.8. APS shall not be prevented from seeking a change in unbundled or Standard Offer rates prior to July 1, 2004, in the event of (a) conditions or circumstances which constitute an emergency, such as the inability to finance on reasonable terms, or (b) material changes in APS' cost of service for Commission regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decision, actions or orders. Except for the changes otherwise specifically contemplated by this Agreement, unbundled and Standard Offer rates shall remain unchanged until at least July 1, 2004.

ARTICLE III
REGULATORY ASSETS AND STRANDED COSTS

3.1. APS currently recovers regulatory assets through July 1, 2004, pursuant to Commission Decision No. 59601 in accordance with the provisions of this Agreement.

3.2. APS has demonstrated that its allowable stranded costs after mitigation (which result from the impact of retail access), exclusive of regulatory assets, are at least $533 million net present value.

3.3. The Parties agree that APS should not be allowed to recover $183 million net present value of the amounts included above. APS shall have a reasonable opportunity to recover $350 million net present value through a competitive transition charge ("CTC") set forth in Exhibit A attached hereto. Such CTC shall remain in effect until December 31, 2004, at which time it will terminate. If by that date APS has recovered more or less than $350 million net present value, as calculated in accordance with Exhibit B attached hereto, then the nominal dollars associated with any excess recovery/under recovery shall be credited/debited against the costs subject to recovery under the adjustment clause set forth in Section 2.6(3).

3.4. The regulatory assets to be recovered under this Agreement, after giving effect to the adjustments set forth in Section 3.3, shall be amortized in accordance with Schedule C of Exhibit A attached hereto.

3.5. Neither the Parties nor the Commission shall take any action that would diminish the recovery of APS' stranded costs or regulatory assets provided for herein. The Company's willingness to enter into this Agreement is based upon the Commission's irrevocable promise to permit recovery of the Company's regulatory assets and stranded costs as provided herein. Such promise by the Commission shall survive the expiration of the Agreement and shall be specifically enforceable against this and any future Commission.

ARTICLE IV
CORPORATE STRUCTURE

4.1. The Commission will approve the formation of an affiliate or affiliates of APS to acquire at book value the competitive services assets as currently required by the Electric Competition Rules. In order to facilitate the separation of such assets efficiently and at the lowest possible cost, the Commission shall grant APS a two-year extension of time until

December 31, 2002, to accomplish such separation. A similar two-year extension shall be authorized for compliance with A.A.C. R14-2-1606(B).

4.2. Approval of this Agreement by the Commission shall be deemed to constitute all requisite Commission approvals for (1) the creation by APS or its parent of new corporate affiliates to provide competitive services including, but not limited to, generation sales and power marketing, and the transfer thereto of APS' generation assets and competitive services, and (2) the full and timely recovery through the adjustment clause referred to in Section 2.6 above for all of the reasonable and prudent costs so incurred in separating competitive generation assets and competitive services as required by proposed A.A.C. R14-2-1615, exclusive of the costs of transferring the APS power marketing function to an affiliate. The assets and services to be transferred shall include the items set forth on Exhibit C attached hereto. Such transfers may require various regulatory and third party approvals, consents or waivers from entities not subject to APS' control, including the FERC and the NRC. No Party to this Agreement (including the Commission) will oppose, or support opposition to, APS requests to obtain such approvals, consents or waivers.

4.3. Pursuant to A.R.S. § 40-202(L), the Commission's approval of this Agreement shall exempt any competitive service provided by APS or its affiliates from the application of various provisions of A.R.S. Title 40, including A.R.S. §§ 40-203, 40-204(A), 40-204(B), 40-248, 40-250, 40-251, 40-285, 40-301, 40-302, 40-303, 40-321, 40-322, 40-331, 40-332, 40-334, 40-365, 40-366, 40-367 and 40-401.

4.4. APS' subsidiaries and affiliates (including APS' parent) may take advantage of competitive business opportunities in both energy and non-energy related businesses by establishing such unregulated affiliates as they deem appropriate, which will be free to operate in such places as they may determine. The APS affiliate or affiliates acquiring APS' generating assets may be a participant in the energy supply market within and outside of Arizona. Approval of this Agreement by the Commission shall be deemed to include the following specific determinations required under Sections 32(c) and (k)(2) of the Public Utility Holding Company Act of 1935:

> APS or an affiliate is authorized to establish a subsidiary company, which will seek exempt wholesale generator ("EWG") status from the Federal Energy Regulatory Commission, for the purposes of acquiring and owning Generation Assets.
>
> The Commission has determined that allowing the Generation Assets to become "eligible facilities," within the meaning of Section 32 of the Public Utility Holding Company Act ("PUHCA"), and owned by an APS EWG affiliate (1) will benefit consumers, (2) is in the public interest, and (3) does not violate Arizona law.

The Commission has sufficient regulatory authority, resources and access to the books and records of APS and any relevant associate, affiliate, or subsidiary company to exercise its duties under Section 32(k) of PUHCA.

APS will purchase any electric energy from its EWG affiliate at market based rates. This Commission has determined that (1) the proposed transaction will benefit consumers and does not violate Arizona law; (2) the proposed transaction will not provide APS' EWG affiliate an unfair competitive advantage by virtue of its affiliation with APS; (3) the proposed transaction is in the public interest.

The APS affiliate or affiliates acquiring APS' generating assets will be subject to regulation by the Commission, to the extent otherwise permitted by law, to no greater manner or extent than that manner and extent of Commission regulation imposed upon other owners or operators of generating facilities.

4.5. The Commission's approval of this Agreement will constitute certain waivers to APS and its affiliates (including its parent) of the Commission's existing affiliate interest rules (A.A.C. R14-2-801, *et seq.*), and the rescission of all or portions of certain prior Commission decisions, all as set forth on Exhibit D attached hereto.

4.6. The Parties reserve their rights under Sections 205 and 206 of the Federal Power Act with respect to the rates of any APS affiliate formed under the provisions of this Article IV.

ARTICLE V
WITHDRAWAL OF LITIGATION

5.1. Upon receipt of a final order of the Commission approving this Agreement that is no longer subject to judicial review, APS and the Parties shall withdraw with prejudice all of their various court appeals of the Commission's competition orders.

ARTICLE VI
APPROVAL BY THE COMMISSION

6.1. This Agreement shall not become effective until the issuance of a final Commission order approving this Agreement without modification on or before August 1, 1999. In the event that the Commission fails to approve this Agreement without modification according to its terms on or before August 1, 1999, any Party to this Agreement may withdraw from this Agreement and shall thereafter not be bound by its provisions; provided, however, that if APS withdraws from this Agreement, the Agreement shall be null and void and of no further force and effect. In any event, the rate reduction provisions of this Agreement shall not take effect until this Agreement is approved. Parties so withdrawing shall be free to pursue their respective positions without prejudice. Approval of this Agreement by the Commission shall make the Commission a Party to this Agreement and fully bound by its provisions.

6.2. The Parties agree that they shall make all reasonable and good faith efforts necessary to (1) obtain final approval of this Agreement by the Commission, and (2) ensure full implementation and enforcement of all the terms and conditions set forth in this Agreement. Neither the Parties nor the Commission shall take or propose any action which would be inconsistent with the provisions of this Agreement. All Parties shall actively defend this Agreement in the event of any challenge to its validity or implementation.

ARTICLE VII
MISCELLANEOUS MATTERS

7.1. To the extent any provision of this Agreement is inconsistent with any existing or future Commission order, rule or regulation or is inconsistent with the Electric Competition Rules as now existing or as may be amended in the future, the provisions of this Agreement shall control and the approval of this Agreement by the Commission shall be deemed to constitute a Commission-approved variation or exemption to any conflicting provision of the Electric Competition Rules.

7.2. The provisions of this Agreement shall be implemented and enforceable notwithstanding the pendency of a legal challenge to the Commission's approval of this Agreement, unless such implementation and enforcement is stayed or enjoined by a court having jurisdiction over the matter. If any portion of the Commission order approving this Agreement or any provision of this Agreement is declared by a court to be invalid or unlawful in any respect, then (1) APS shall have no further obligations or liability under this Agreement, including, but not limited to, any obligation to implement any future rate reductions under Article II not then in effect, and (2) the modifications to APS' certificates of convenience and necessity referred to in Section 1.4 shall be automatically revoked, in which event APS shall use its best efforts to continue to provide noncompetitive services (as defined in the proposed Electric Competition Rules) at then current rates with respect to customer contracts then in effect for competitive generation (for the remainder of their term) to the extent not prohibited by law and subject to applicable regulatory requirements.

7.3. The terms and provisions of this Agreement apply solely to and are binding only in the context of the purposes and results of this Agreement and none of the positions taken herein by any Party may be referred to, cited or relied upon by any other Party in any fashion as precedent or otherwise in any other proceeding before this Commission or any other regulatory agency or before any court of law for any purpose except in furtherance of the purposes and results of this Agreement.

7.4. This Agreement represents an attempt to compromise and settle disputed claims regarding the prospective just and reasonable rate levels, and the terms and conditions of competitive retail access, for APS in a manner consistent with the public interest and applicable legal requirements. Nothing contained in this Agreement is an admission by APS that its current rate levels or rate design are unjust or unreasonable.

7.5. As part of this Agreement, APS commits that it will continue the APS Community Action Partnership (which includes weatherization, facility repair and replacement, bill assistance, health and safety programs and energy education) in an annual amount of at least $500,000 through July 1, 2004. Additionally, the Company will, subject to Commission approval, continue low income rates E-3 and E-4 under their current terms and conditions.

7.6. APS shall actively support the Arizona Independent Scheduling Administrator ("AISA") and the formation of the Desert Star Independent System Operator. APS agrees to modify its OATT to be consistent with any FERC approved AISA protocols. The Parties reserve their rights with respect to any AISA protocols, including the right to challenge or seek modifications to, or waivers from, such protocols. APS shall file changes to its existing OATT consistent with this section within ten (10) days of Commission approval of this Agreement pursuant to Section 6.1.

7.7. Within thirty (30) days of Commission approval of this Agreement pursuant to Section 6.1, APS shall serve on the Parties an Interim Code of Conduct to address inter-affiliate relationships involving APS as a utility distribution company. APS shall voluntarily comply with this Interim Code of Conduct until the Commission approves a code of conduct for APS in accordance with the Electric Competition Rules that is concurrently effective with codes of conduct for all other Affected Utilities (as defined in the Electric Competition Rules). APS shall meet and confer with the Parties prior to serving its Interim Code of Conduct.

7.8. In the event of any disagreement over the interpretation of this Agreement or the implementation of any of the provisions of this Agreement, the Parties shall promptly convene a conference and in good faith shall attempt to resolve such disagreement.

7.9. The obligations under this Agreement that apply for a specific term set forth herein shall expire automatically in accordance with the term specified and shall require no further action for their expiration.

7.10. The Parties agree and recommend that the Commission schedule public meetings and hearings for consideration of this Agreement. The filing of this Agreement with the Commission shall be deemed to be the filing of a formal request for the expeditious issuance of a procedural schedule that establishes such formal hearings and public meetings as may be necessary for the Commission to approve this Agreement in accordance with

Exhibit A
5/10/99
DA-R1

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-R1
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company and where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable only to electric delivery required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10.)

TYPE OF SERVICE

Service shall be single phase, 60 Hertz, at one standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's premise). Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is required for motors of an individual rated capacity of 7-1/2 HP or more.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

May – October Billing Cycles (Summer):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.04158	$0.00115	$0.00930

November – April Billing Cycles (Winter):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.03518	$0.00115	$0.00930

B. MINIMUM $ 10.00 per month

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$1.30 per month
Meter Reading	$0.30 per month
Billing	$0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to the Company's Terms and Conditions for Standard Offer and Direct Access Services (Schedule #1) and Schedule #10. These schedules have provisions that may affect customer's monthly bill.

Exhibit A
5/10/99
DA-GS1

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-GS1
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable to all electric service required when such service is supplied at one point of delivery and measured through one meter. For those customers whose electricity is delivered through more than one meter, service for each meter shall be computed separately under this rate unless conditions in accordance with the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service) are met. For those service locations where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

This rate schedule is not applicable to residential service, resale service or direct access service which qualifies for Rate Schedule DA-GS10.

TYPE OF SERVICE

Service shall be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's premise. Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceed 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in the Company's Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

June – October Billing Cycles (Summer):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$ month	$12.50			
Per kW over 5		$0.721		
Per kWh for the first 2,500 kWh		$0.04255		
Per kWh for the next 100 kWh per kW over 5		$0.04255		
Per kWh for the next 42,000 kWh		$0.02901		
Per kWh for all additional kWh		$0.01811		
Per all kWh			$0.00115	
Per all kW				$2.43

A. RATE (continued)

November – May Billing Cycles (Winter):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$12.50			
Per kW over 5		$0.652		
Per kWh for the first 2,500 kWh		$0.03827		
Per kWh for the next 100 kWh per kW over 5		$0.03827		
Per kWh for the next 42,000 kWh		$0.02600		
Per kWh for all additional kWh		$0.01614		
Per all kWh			$0.00115	
Per all kW				$2.43

PRIMARY AND TRANSMISSION LEVEL SERVICE:

1. For customers served at primary voltage (12.5kV to below 69kV), the Distribution charge will be discounted by 11.6%.
2. For customers served at transmission voltage (69kV or higher), the Distribution charge will be discounted 52.6%.
3. Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the average kW supplied during the 15-minute period of maximum use during the month, as determined from readings of the delivery meter.

B. MINIMUM

$12.50 plus $1.74 for each kW in excess of five of either the highest kW established during the 12 months ending with the current month or the minimum kW specified in the agreement for service, whichever is the greater.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$4.00 per month
Meter Reading	$0.30 per month
Billing	$0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP or under the Company's Open Access Transmission Tariff. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

(CONTINUED ON PAGE 3)

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

CONTRACT PERIOD

0 – 1,999 kW:	As provided in Company's standard agreement for service.
2,000 kW and above:	Three (3) years, or longer, at Company's option for initial period when construction is required. One (1) year, or longer, at Company's option when construction is not required.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These Schedules have provisions that may affect customer's monthly bill.

Section 6.1 and that afford interested parties adequate opportunity to comment and be heard on the terms of this Agreement consistent with applicable legal requirements.

DATED at Phoenix, Arizona, as of this 14th day of May, 1999.

RESIDENTIAL UTILITY CONSUMER OFFICE

By Greg Patterson

Title Director

ARIZONA PUBLIC SERVICE COMPANY

By Jack Davis

Title President Delivery & Sales

ARIZONA COMMUNITY ACTION ASSOCIATION

By [illegible]

Title Executive Director

(Party) ______

By ______

Title ______

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION,* a coalition of companies and associations in support of competition that includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, [redacted], Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, [redacted], Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multi-housing Association, Arizona Rock Products Association, Arizona Restaurant Association, [redacted], and Arizona Retailers Association. **

By Peter A. Wong

Title CHAIRMAN

(Party) ______

By ______

Title ______

(Party) ______

By ______

Title ______

* Enron is NOT a signatory to This Agreement

Also [illegible]

DECISION NO. 61973

Exhibit A
5/10/99
DA-GS10

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-GS10
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
EXTRA LARGE GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable only to customers whose monthly maximum demand is 3,000 kW or more for three (3) consecutive months in any continuous twelve (12) month period ending with the current month. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by individual customer contract. For those customers whose electricity is delivered through more than one meter, service for each meter shall be computed separately under this rate unless conditions in accordance with the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service) are met.

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at Company's standard voltages that are available within the vicinity of customer's premise.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$3.53		$2.82
per kWh		$0.00999	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE:

1. For customers served at primary voltage (12.5kV to below 69kV), the Distribution charge will be discounted by 4.8%.
2. For customers served at transmission voltage (69kV or higher), the Distribution charge will be discounted 36.7%.
3. Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$55.00 per month
Meter Reading	$ 0.30 per month
Billing	$ 0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP. T he Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

CONTRACT PERIOD

For service locations in:

a) Isolated Areas: Ten (10) years, or longer, at Company's option, with standard seven (7) year termination period.
b) Other Areas: Three (3) years, or longer, at Company's option.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

Exhibit A
5/13/99
DA-GS11

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-GS11
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
RALSTON PURINA

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to Ralston Purina (Site #863970289) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 12.5 kV.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$2.58		$1.86
per kWh		$0.00732	$0.00115	

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$55.00 per month
Meter Reading	$ 0.30 per month
Billing	$ 0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

Exhibit A
5/13/99
DA-GS12

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-GS12
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
BHP COPPER

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to BHP Copper (Site #774932285) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 12.5 kV or higher.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution at Primary Voltage	Distribution at Transmission Voltage	System Benefits	Competitive Transition Charge
$/month	$2,430.00				
per kW		$2.35	$1.22		$1.54
per kWh		$0.00665	$0.00346	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE:

Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 30-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$55.00 per month
Meter Reading	$ 0.30 per month
Billing	$ 0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

Exhibit A
5/13/99
DA-GS13

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-GS13
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
CYPRUS BAGDAD

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to Cyprus Bagdad (Site #120932284) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 115 kV or higher.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$1.05		$1.34
per kWh		$0.00298	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE:

Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 30-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month, until June 30, 2004 when this minimum will no longer be applicable.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$55.00 per month
Meter Reading	$ 0.30 per month
Billing	$ 0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

5/10/99
Schedule A

ARIZONA PUBLIC SERVICE COMPANY

Competitive Transition Charges
By Direct Access Rate Classes

Line #	Direct Access Rate Class	Competition Transition Charges Effective January 1 of 1999	2000	2001	2002	2003	2004
1	Residential, DA-R1 (per kWh)	$ 0.0093	$ 0.0084	$ 0.0063	$ 0.0056	$ 0.0050	$ 0.0036
2	Under 3 mW, DA-GS1, (per kW/mo.)	$ 2.43	$ 2.20	$ 1.66	$ 1.46	$ 1.30	$ 0.94
3	3 mW and Above, DA-GS10 (per kW/mo.)	$ 2.82	$ 2.55	$ 1.89	$ 1.72	$ 1.51	$ 1.09
4	BHP Copper (per kW/mo.)	$ 1.54	$ 1.53	$ 1.06	$ 0.95	$ 0.83	$ 0.61
5	Cyprus Copper (per kW/mo.)	$ 1.34	$ 1.46	$ 1.05	$ 0.94	$ 0.82	$ 0.61
6	Ralston Purina (per kW/mo.)	$ 1.86	$ 1.98	$ 1.50	$ 1.34	$ 1.18	$ 0.87
7	Average Retail (per kWh)	$ 0.0067	$ 0.0061	$ 0.0054	$ 0.0048	$ 0.0043	$ 0.0031

Charges are based upon recovery of $350 million NPV derived from APS' Compliance Filing of 8/21/98 as adjusted to synchronize Direct Access and Standard Offer revenue decreases.

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ARIZONA PUBLIC SERVICE ANY

Exhibit
5/13/9>
Schedule B

Distribution Charges
By Direct Access Rate Classes

Line #	Direct Access Rate Class	Distribution Charges Effective January 1 of 1999	2000	2001	2002	2003	2004✓
	Residential, DA-R1						
1	Summer per kWh	$ 0.04158	$ 0.04041	$ 0.03934	$ 0.03837	$ 0.03748	$ 0.03689
2	Winter per kWh	$ 0.03518	$ 0.03419	$ 0.03329	$ 0.03247	$ 0.03172	$ 0.03122
	DA-GS1 (Under 3 mW)						
	Summer Rates						
3	per kW for all kW over 5	$ 0.721	$ 0.691	$ 0.663	$ 0.638	$ 0.615	$ 0.600
4	per kWh for the first 2,500 kWh	$ 0.04255	$ 0.04075	$ 0.03912	$ 0.03763	$ 0.03627	$ 0.03537
5	per kWh for the next 100 kWh per kW over 5	$ 0.04255	$ 0.04075	$ 0.03912	$ 0.03763	$ 0.03627	$ 0.03537
6	per kWh for the next 42,000 kWh	$ 0.02901	$ 0.02779	$ 0.02667	$ 0.02565	$ 0.02473	$ 0.02411
7	per kWh for all additional kWh	$ 0.01811	$ 0.01735	$ 0.01665	$ 0.01602	$ 0.01544	$ 0.01506
	Winter Rates						
8	per kW for all kW over 5	$ 0.652	$ 0.624	$ 0.599	$ 0.576	$ 0.555	$ 0.541
9	per kWh for the first 2,500 kWh	$ 0.03827	$ 0.03666	$ 0.03519	$ 0.03385	$ 0.03263	$ 0.03182
10	per kWh for the next 100 kWh per kW over 5	$ 0.03827	$ 0.03666	$ 0.03519	$ 0.03385	$ 0.03263	$ 0.03182
11	per kWh for the next 42,000 kWh	$ 0.02600	$ 0.02490	$ 0.02390	$ 0.02299	$ 0.02216	$ 0.02161
12	per kWh for all additional kWh	$ 0.01614	$ 0.01546	$ 0.01484	$ 0.01427	$ 0.01376	$ 0.01342
	Voltage Discounts						
13	Primary Voltage	11.6%	12.1%	12.6%	13.1%	13.6%	13.9%
14	Transmission Voltage	52.6%	54.9%	57.2%	59.5%	61.7%	63.3%
	DA-GS10 (3 mW and Above)						
15	per kW	$ 3.53	$ 3.33	$ 3.15	$ 2.98	$ 2.83	$ 2.73
16	per kWh	$ 0.00999	$ 0.00943	$ 0.00892	$ 0.00845	$ 0.00802	$ 0.00774
	Voltage Discounts						
17	Primary Voltage Discount	4.8%	5.1%	5.3%	5.6%	5.9%	6.2%
18	Transmission Voltage Discount	36.7%	38.9%	41.1%	43.4%	45.8%	47.4%
	DA-GS11 (Ralston Purina)						
19	per kW	$ 2.58	$ 2.71	$ 2.57	$ 2.44	$ 2.32	$ 2.25
20	per kWh	$ 0.00732	$ 0.00767	$ 0.00727	$ 0.00691	$ 0.00657	$ 0.00635
	DA-GS12 (BHP Copper)						
21	Primary Voltage Delivery - per kW	$ 2.35	$ 2.30	$ 2.16	$ 2.07	$ 1.99	$ 1.93
22	per kWh	$ 0.00665	$ 0.00651	$ 0.00611	$ 0.00585	$ 0.00561	$ 0.00546
23	Transmission Voltage Delivery - per kW	$ 1.22	$ 1.17	$ 1.03	$ 0.94	$ 0.85	$ 0.80
24	per kWh	$ 0.00346	$ 0.00332	$ 0.00292	$ 0.00266	$ 0.00242	$ 0.00227
	DA-GS13 (Cyprus Bagdad)						
25	per kW	$ 1.05	$ 1.21	$ 1.03	$ 0.94	$ 0.85	$ 0.80
26	per kWh	$ 0.00297	$ 0.00343	$ 0.00292	$ 0.00266	$ 0.00242	$ 0.00227

✓ Transmission voltage customers will not pay Distribution Charges after June 30, 2004

DOCKET NO. E-01345A-98-0473 ET AL.

DECISION NO. 61973

Exhibit A
5/14/99
Schedule C

ARIZONA PUBLIC SERVICE COMPANY

Regulatory Asset Amortization Schedule
(Millions of Dollars)

1999	2000	2001	2002	2003	1/1 - 6/30 2004 [1]	Total [2]
164	158	145	115	86	18	686

[1] Amortization ends 6/30/2004
[2] Includes the disallowance from Section 3.3

5/7/99

EXHIBIT C

Generation assets include, but are not limited to, APS' interest in the following generating stations:

Palo Verde
Four Corners
Navajo
Cholla
Saguaro
Ocotillo
West Phoenix
Yucca
Douglas
Childs
Irving

including allocated common and general plant, support assets, associated land, fuel supplies and contracts, etc. Generation assets will not include facilities included in APS' FERC transmission rates.

Exhibit B

Annual ACC Jurisdictional Sales of Delivered kWh or kW[1]		x % then Eligible for Access	x Applicable CTC (¢/kWh or $/kW[2]) = Annual Recovery[3]
1999	Residential	20	.93
	General Service less than 3MW	20	2.43
	General Service greater than 3MW	20	2.82
	BHP Copper	20	1.54
	Cyprus Copper	20	1.34
	Ralston Purina	20	1.86
2000	Residential	20	.84
	General Service less than 3MW	20	2.20
	General Service greater than 3MW	20	2.55
	BHP Copper	20	1.53
	Cyprus Copper	20	1.46
	Ralston Purina	20	1.98
2001	Residential	100	.63
	General Service less than 3MW	100	1.66
	General Service greater than 3MW	100	1.89
	BHP Copper	100	1.06
	Cyprus Copper	100	1.05
	Ralston Purina	100	1.50
2002	Residential	100	.56
	General Service less than 3MW	100	1.46
	General Service greater than 3MW	100	1.72
	BHP Copper	100	.95
	Cyprus Copper	100	.94
	Ralston Purina	100	1.34
2003	Residential	100	.50
	General Service less than 3MW	100	1.30
	General Service greater than 3MW	100	1.51
	BHP Copper	100	.83
	Cyprus Copper	100	.82
	Ralston Purina	100	1.18
2004	Residential	100	.36
	General Service less than 3MW	100	.94
	General Service greater than 3MW	100	1.09
	BHP Copper	100	.61
	Cyprus Copper	100	.61
	Ralston Purina	100	.87

[1] This formula assumes no change in APS' distribution service territory. In the event of any material change (e.g. by purchase, sale, expansion, condemnation, etc.) the formula will be adjusted such that APS receives the same opportunity to recover the agreed upon level of costs.
[2] General Service unmetered loads will have a demand calculated for CTC purposes based on contract energy.
[3] At the end of 2004 the net present value will be calculated to compare to the $350 million.

h:\rda\settlement 99\Exhibit B (RA-CTC scenario).doc

EXHIBIT D

Affiliate Rules Waivers

R14-2-801(5) and R14-2-803, such that the term "reorganization" does not include. and no Commission approval is required for, corporate restructuring that does not directly involve the utility distribution company ("UDC") in the holding company. For example, the holding company may reorganize. form, buy or sell non-UDC affiliates, acquire or divest interests in non-UDC affiliates, etc., without Commission approval.

R14-2-804(A)

R14-2-805(A) shall apply only to the UDC

R14-2-805(A)(2)

R14-2-805(A)(6)

R14-2-805(A)(9), (10), and (11)

Recision of Prior Commission Orders

Section X.C of the "Cogeneration and Small Power Production Policy" attached to Decision No. 52345 (July 27, 1981) regarding reporting requirements for cogeneration information.

Decision No. 55118 (July 24, 1986) - Page 15, Lines 5-1/2 through 13-1/2; Finding of Fact No. 24 relating to reporting requirements under the abolished PPFAC.

Decision No. 55818 (December 14, 1987) in its entirety. This decision related to APS Schedule 9 (Industrial Development Rate) which was terminated by the Commission in Decision No. 59329 (October 11, 1995).

9th and 10th Ordering Paragraphs of Decision No. 56450 (April 13, 1989) regarding reporting requirements under the abolished PPFAC.

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ATTACHMENT 2

ARIZONA PUBLIC SERVICE COMPANY

Informational Unbundling for Standard Offer

Proposed Standard Offer Bill

Sample Summer Bill on Rate E-12 at the Proposed 7/1/99 Rate Level
1.5% Overall Residential Class Decrease (1.68% decrease in energy charges from 9/1/98 Rate Level)

The following information is proposed to be shown on the customer's monthly bill:

Page 1, Standard Offer Bill Calculation:

Your total energy usage this month is: 991 kWh

Basic Service Charge	$ 7.50
Charge for kWh used	100.09
Regulatory Assessment	0.20
Sales Tax	7.06
TOTAL	$ 114.85

Page 2, Informational Unbundling:

Your total energy usage for this month is: 991 kWh
You Standard Offer Bill is (see page 1): $ 114.85

If you choose to receive competitive services from an Electric Service Provider, your APS bill on Rate DA-R1 for delivery service would include:

Metering Service:	$ 1.30	
Meter Reading Service:	0.30	
Billing Service:	0.30	
Distribution Service:	49.30	
System Benefits:	1.14	
Competitive Transition Charge:	9.22	
Regulatory Assessment:	0.12	
Sales Tax:	4.04	
Total Charges for APS Delivery Service Only:		$ 65.72
Transmission and Ancillary Services billed to your Electric Service Provider:		$ 5.09
Generation Services:		$ 44.04
Shopping Credit to purchase competitively supplied Generation and Transmission Service, including any applicable taxes and regulatory assessments		$ 49.13 or, 4.96 ¢/kWh

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Jana Van Ness
Manager
Regulatory Affairs

Tel 602/250-2310
Fax 602/250-3399
e-mail: jvanness@apsc.com
http://www.apsc.com

Mail Station 9909
P.O. Box 53999
Phoenix, AZ 85072-3999

December 1, 1999

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

RE: APS Settlement Proceeding
ACC Docket Nos. E-01345A-98-0473, E-01345A-97-0773, RE-00000C-94-0165

Dear Sir or Madam:

Pursuant to the Opinion and Order, Decision No. 61973 in the above referenced Dockets, Arizona Public Service is filing an Addendum to the Settlement Agreement incorporating the modifications required by that Decision. This Addendum has been reviewed and executed by all signatories to the original APS Settlement Agreement.

If you have any questions regarding this filing, please contact me at (602)250-2310.

Sincerely,

Jana Van Ness

Jana Van Ness
Manager
State Regulations

Attachment

Cc: Docket Control (18 copies plus original)
Parties of Record

Addendum to Settlement Agreement

This Addendum is to the Settlement Agreement dated May 14, 1999 (hereafter "Agreement") between Arizona Public Service Company ("APS" or "Company") and the various signatories to the Agreement (collectively with APS, the "Parties"). By signing this Addendum to Settlement Agreement ("Addendum"), the Parties intend to revise certain provisions of the Agreement as directed by the Arizona Corporation Commission ("Commission") in Decision No. 61973 (October 6, 1999) ("Decision"). The Decision adopted and approved the Agreement subject to certain modifications.

I.
Introduction and Recitals

1. On May 14, 1999, the Parties entered into the Agreement;

2. On May 17, 1999, APS filed with the Commission a Notice of Filing Application for Approval of Settlement Agreement and Request for Procedural Order.

3. Commencing on July 14, 1999, and pursuant to a Procedural Order issued by the Hearing Division of the Commission, a full public evidentiary hearing on the Agreement was conducted.

4. On October 6, 1999, the Commission issued its Decision No. 61973 adopting and approving the Agreement as modified in the Decision.

5. The Parties now wish to enter into this Addendum to revise the Agreement as directed in the Decision.

II.
Addendum Agreement

1. Metering, Meter Reading, and Billing Credits

A. The Company's revised unbundled rates and charges reflecting the metering, meter reading, and billing credits required by the Decision are attached hereto as Revised Exhibit A.

B. The revised unbundled rates and charges in Revised Exhibit A to this Addendum are substituted for the corresponding tariffs in Exhibit A to the Agreement.

C. Schedules A through C of Exhibit A to the Agreement are not affected by this Addendum and were adopted and approved by the Commission in the Decision as originally proposed in the Agreement.

2. Advanced Notice for Large Customers. Section 2.3 of the Agreement is replaced with and superceded by the following provision:

> 2.3. Customers greater than 3 MW who choose a direct access supplier must either (a) give APS one year's advance notice before being eligible to return to Standard Offer service, or (b) pay APS for all additional costs incurred as a result of the customer returning to Standard Offer service without providing APS at least one year's advance notice.

3. Deferral of Transfer Costs. Section 2.6(3) of the Agreement is replaced with and superceded by the following provision:

> (3) compliance with the Electric Competition Rules or Commission-ordered programs or directives related to the implementation of the Electric Competition Rules, as they may be amended from time to time, which costs shall be recovered from all customers receiving services from APS, provided however, that no more than sixty-seven percent (67%) of the costs to transfer generation assets to an affiliate or affiliates shall be allowed to be deferred for future collection under this provision; and

4. Rate Matters. Section 2.8 of the Agreement is replaced with and superceded by the following provision:

> 2.8. Neither the Commission nor APS shall be prevented from seeking or authorizing a change in unbundled or Standard Offer rates prior to July 1, 2004, in the event of (a) conditions or circumstances which constitute an emergency, such as an inability to finance on reasonable terms, or (b) material changes in APS' cost of service for Commission-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders. Except for the changes otherwise specifically contemplated by this Agreement, unbundled and Standard Offer rates shall remain unchanged until at least July 1, 2004.

5. Generation Affiliate. Section 4.1 of the Agreement is replaced with and superceded by the following provisions:

4.1. Affiliates.

(1) The Commission will approve the formation of an affiliate or affiliates of APS to acquire at book value the competitive services and assets as currently required by the Electric Competition Rules. In order to facilitate the separation of such assets efficiently and at the lowest possible cost, the Commission shall grant APS a two-year extension of time until December 31, 2002, to accomplish such separation. A similar two-year extension shall be authorized for compliance with A.A.C. R14-2-1606(B).

(2) The affiliate or affiliates formed under this Section 4.1 shall be direct subsidiaries of Pinnacle West Capital Corporation, and not APS.

(3) After the extensions granted in this Section 4.1 have expired, APS shall procure generation for Standard Offer customers from the competitive market as provided for in the Electric Competition Rules. An affiliated generation company formed pursuant to this Section 4.1 may competitively bid for APS' Standard Offer load, but enjoys no automatic privilege outside of the market bid on account of its affiliation with APS.

6. Statutory Waivers. Section 4.3 of the Agreement is deleted in its entirety.

7. Waivers of Affiliate Interest Rules. The Revised Exhibit D to this Addendum setting forth the Affiliate Rules Waivers is substituted for the corresponding Exhibit D to the Agreement so that the proposed waiver of R14-2-804(A) in the Agreement is deleted.

8. Conflicts with Electric Competition Rules. In reliance upon the Commission's directive in Decision No. 61973 (page 9) that "We want to make it clear that the Commission does not intend to revisit the stranded cost portion of the Agreement. It is also not the Commission's intent to undermine the benefits that parties have bargained for," Section 7.1 is replaced with and superseded by the following provision:

> 7.1. Approval of this Agreement by the Commission shall constitute a waiver of any existing Commission order, rule or regulation to the extent necessary to permit performance of the Agreement, as approved by the Commission. Any future Commission order, rule or regulation shall be construed and administered, insofar as possible, in a manner so as not to conflict with the specific provisions of this Agreement, as approved by the Commission. In the event any of the Parties deems a future Commission order, rule or regulation to be inconsistent with the specific provisions of this Agreement, a waiver of the new Commission order, rule or regulation shall be sought.
>
> Nothing in this Agreement is intended to otherwise interfere with the Commission's ability to exercise its regulatory authority by the issuance of orders, rules or regulations. The requirements of this Agreement shall be performed in accordance with the Commission's Electric Competition Rules including any specific waivers granted by the Commission's order approving this Agreement, except where a specific provision of this Agreement would excuse compliance.

9. Interim Code of Conduct. Section 7.7 of the Agreement is replaced with and superceded by the following provision:

> 7.7. Within thirty (30) days of the date of the Commission decision approving this Agreement pursuant to Section 6.1, APS shall file an initial proposed Code of Conduct to address inter-affiliate relationships involving APS as a utility distribution company as required by the Electric Competition Rules and which includes provisions to govern the supply of generation during the two-year extension provided for by Section 4.1 of this Agreement. Interested parties may provide APS with comments on the initial proposed Code of Conduct within sixty (60) days of the date of the Commission decision approving this Agreement. APS will file a final proposed Code of Conduct for Commission approval within ninety (90) days of the date of the Commission decision approving this Agreement. Until the Commission approves a Code of Conduct for APS, APS will voluntarily comply with the initial proposed Code of Conduct or, once filed, the final proposed Code of Conduct.

10. Effect of Addendum. Other than as specifically modified by this Addendum, all provisions of the Agreement remain in full force and effect.

AGREED TO AS OF November 21, **1999:**

RESIDENTIAL UTILITY CONSUMER OFFICE

By Barbara Wytaske

Title Acting Director

ARIZONA PUBLIC SERVICE COMPANY

By Jack Davis

Title President [illegible]

ARIZONA COMMUNITY ACTION ASSOCIATION

By Betty K Pruitt

Title Acting Executive Director

(Party)

By ______________________

Title ______________________

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION, a coalition of companies and associations in support of competition that includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Hughes, 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 Multi-housing 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.

By [illegible]

Title President

Stan Barnes

(Party)

By ______________________

Title ______________________

(Party)

By ______________________

Title ______________________

Revised
EXHIBIT D
Affiliate Rules Waivers

R14-2-801(5) and R14-2-803, such that the term "reorganization" does not include, and no Commission approval is required for, corporate restructuring that does not directly involve the utility distribution company ("UDC") in the holding company. For example, the holding company may reorganize, form, buy or sell non-UDC affiliates, acquire or divest interests in non-UDC affiliates, etc., without Commission approval.

R14-2-805(A) shall apply only to the UDC

R14-2-805(A)(2)

R14-2-805(A)(6)

R14-2-805(A)(9), (10), and (11)

Recision of Prior Commission Orders

Section X.C of the "Cogeneration and Small Power Production Policy" attached to Decision No. 52345 (July 27, 1981) regarding reporting requirements for cogeneration information.

Decision No. 55118 (July 24, 1986) - Page 15, Lines 5-1/2 through 13-1/2; Finding of Fact No. 24 relating to reporting requirements under the abolished PPFAC.

Decision No. 55818 (December 14, 1987) in its entirety. This decision related to APS Schedule 9 (Industrial Development Rate) which was terminated by the Commission in Decision No. 59329 (October 11, 1995).

9th and 10th Ordering Paragraphs of Decision No. 56450 (April 13, 1989) regarding reporting requirements under the abolished PPFAC.

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5351
Tariff or Schedule No. DA-GS1
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable to all electric service required when such service is supplied at one point of delivery and measured through one meter. For those customers whose electricity is delivered through more than one meter, service for each meter shall be computed separately under this rate unless conditions in accordance with the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service) are met. For those service locations where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

This rate schedule is not applicable to residential service, resale service or direct access service which qualifies for Rate Schedule DA-GS10.

TYPE OF SERVICE

Service shall be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's premise. Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceed 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in the Company's Schedule #10

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

June – October Billing Cycles (Summer)

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$12.50			
Per kW over 5		$0.721		
Per kWh for the first 2,500 kWh		$0.04255		
Per kWh for the next 100 kWh per kW over 5		$0.04255		
Per kWh for the next 42,000 kWh		$0.02901		
Per kWh for all additional kWh		$0.01811		
Per all kWh			$0.00115	
Per all kW				$2.43

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

A. RATE (continued)

November – May Billing Cycles (Winter):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$12.50			
Per kW over 5		$0.652		
Per kWh for the first 2,500 kWh		$0.03827		
Per kWh for the next 100 kWh per kW over 5		$0.03827		
Per kWh for the next 42,000 kWh		$0.02600		
Per kWh for all additional kWh		$0.01614		
Per all kWh			$0.00115	
Per all kW				$2.43

PRIMARY AND TRANSMISSION LEVEL SERVICE:

1. For customers served at primary voltage (12.5kV to below 69kV), the Distribution charge will be discounted by 11.6%.
2. For customers served at transmission voltage (69kV or higher), the Distribution charge will be discounted 52.6%.
3. Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the average kW supplied during the 15-minute period of maximum use during the month, as determined from readings of the delivery meter.

B. MINIMUM

$12.50 plus $1.74 for each kW in excess of five of either the highest kW established during the 12 months ending with the current month or the minimum kW specified in the agreement for service, whichever is the greater.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$7.62 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP or under the Company's Open Access Transmission Tariff. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

(CONTINUED ON PAGE 3)

APPROVED FOR FILING
DECISION # 61973

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

CONTRACT PERIOD

0 - 1,999 kW:	As provided in Company's standard agreement for service.
2,000 kW and above:	Three (3) years, or longer, at Company's option for initial period when construction is required. One (1) year, or longer, at Company's option when construction is not required.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These Schedules have provisions that may affect customer's monthly bill.

APPROVED FOR FILING

DECISION #: 61973

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5350
Tariff or Schedule No. DA-R1
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company and where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable only to electric delivery required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10.)

TYPE OF SERVICE

Service shall be single phase, 60 Hertz, at one standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's premise). Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is required for motors of an individual rated capacity of 7-1/2 HP or more.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

May – October Billing Cycles (Summer):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.04158	$0.00115	$0.00930

November – April Billing Cycles (Winter):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.03518	$0.00115	$0.00930

B. MINIMUM $ 10.00 per month

APPROVED FOR FILING
DECISION #: 61973

(CONTINUED ON REVERSE SIDE)

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$4.00 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to the Company's Terms and Conditions for Standard Offer and Direct Access Services (Schedule #1) and Schedule #10. These schedules have provisions that may affect customer's monthly bill.

APPROVED FOR FILING
DECISION #: 61973

Exhibit A
DA-GS10

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5352
Tariff or Schedule No. DA-GS10
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
EXTRA LARGE GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable only to customers whose monthly maximum demand is 3,000 kW or more for three (3) consecutive months in any continuous twelve (12) month period ending with the current month. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by individual customer contract. For those customers whose electricity is delivered through more than one meter, service for each meter shall be computed separately under this rate unless conditions in accordance with the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service) are met.

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at Company's standard voltages that are available within the vicinity of customer's premise.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$3.53		$2.82
per kWh		$0.00999	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE

1. For customers served at primary voltage (12.5kV to below 69kV), the Distribution charge will be discounted by 4.8%.
2. For customers served at transmission voltage (69kV or higher), the Distribution charge will be discounted 36.7%.
3. Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$154.15 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

CONTRACT PERIOD

For service locations in:

a) Isolated Areas: Ten (10) years, or longer, at Company's option, with standard seven (7) year termination period.
b) Other Areas: Three (3) years, or longer, at Company's option.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

DECISION # 61973

Exhibit A

DA-GS11

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5395
Tariff or Schedule No. DA-GS11
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
RALSTON PURINA

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to Ralston Purina (Site #863970289) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 12.5 kV.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$2.58		$1.86
per kWh		$0.00732	$0.00115	

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$154.15 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING

DECISION #: 61973

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. T he Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

APPROVED FOR FILING
DECISION #: 61973

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5396
Tariff or Schedule No. DA-GS12
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
BHP COPPER

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to BHP Copper (Site #774932285) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 12.5 kV or higher.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution at Primary Voltage	Distribution at Transmission Voltage	System Benefits	Competitive Transition Charge
$/month	$2,430.00				
per kW		$2.35	$1.22		$1.54
per kWh		$0.00665	$0.00346	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE

Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 30-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.
2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$154.15 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

APPROVED FOR FILING
DECISION #: 61973

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5397
Tariff or Schedule No. DA-GS13
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
CYPRUS BAGDAD

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to Cyprus Bagdad (Site #120932284) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 115 kV or higher.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$1.05		$1.34
per kWh		$0.00298	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE:

Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 30-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month, until June 30, 2004 when this minimum will no longer be applicable.

APPROVED FOR FILING
DECISION #: 61973

(CONTINUED ON REVERSE SIDE)

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$154.15 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

APPROVED FOR FILING

DECISION #: 61973

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Schedule A

ARIZONA PUBLIC ⌞ ⸝ICE COMPANY

Competitive Transition Charges
By Direct Access Rate Classes

Line #	Direct Access Rate Class	Competition Transition Charges Effective January 1 of 1999	2000	2001	2002	2003	2004
1	Residential, DA-R1 (per kWh)	$ 0.0093	$ 0.0084	$ 0.0063	$ 0.0056	$ 0.0050	$ 0.0036
2	Under 3 mW, DA-GS1, (per kW/mo.)	$ 2.43	$ 2.20	$ 1.66	$ 1.46	$ 1.30	$ 0.94
3	3 mW and Above, DA-GS10 (per kW/mo.)	$ 2.82	$ 2.55	$ 1.89	$ 1.72	$ 1.51	$ 1.09
4	BHP Copper (per kW/mo.)	$ 1.54	$ 1.53	$ 1.06	$ 0.95	$ 0.83	$ 0.61
5	Cyprus Copper (per kW/mo.)	$ 1.34	$ 1.46	$ 1.05	$ 0.94	$ 0.82	$ 0.61
6	Ralston Purina (per kW/mo.)	$ 1.86	$ 1.98	$ 1.50	$ 1.34	$ 1.18	$ 0.87
7	Average Retail (per kWh)	$ 0.0067	$ 0.0061	$ 0.0054	$ 0.0048	$ 0.0043	$ 0.0031

Charges are based upon recovery of $350 million NPV derived from APS' Compliance Filing of 8/21/98 as adjusted to synchronize Direct Access and Standard Offer revenue decreases.

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Schedule B

ARIZONA PUBLIC S... ...CE COMPANY

Distribution Charges
By Direct Access Rate Classes

Line #	Direct Access Rate Class	1999	2000	2001	2002	2003	2004 ✓
		Distribution Charges Effective January 1 of					
	Residential, DA-R1						
1	Summer per kWh	$ 0.04158	$ 0.04041	$ 0.03934	$ 0.03837	$ 0.03748	$ 0.03689
2	Winter per kWh	$ 0.03518	$ 0.03419	$ 0.03329	$ 0.03247	$ 0.03172	$ 0.03122
	DA-GS1 (Under 3 mW)						
	Summer Rates						
3	per kW for all kW over 5	$ 0.721	$ 0.691	$ 0.663	$ 0.638	$ 0.615	$ 0.600
4	per kWh for the first 2,500 kWh	$ 0.04255	$ 0.04075	$ 0.03912	$ 0.03763	$ 0.03627	$ 0.03537
5	per kWh for the next 100 kWh per kW over 5	$ 0.04255	$ 0.04075	$ 0.03912	$ 0.03763	$ 0.03627	$ 0.03537
6	per kWh for the next 42,000 kWh	$ 0.02901	$ 0.02779	$ 0.02667	$ 0.02565	$ 0.02473	$ 0.02411
7	per kWh for all additional kWh	$ 0.01811	$ 0.01735	$ 0.01665	$ 0.01602	$ 0.01544	$ 0.01506
	Winter Rates						
8	per kW for all kW over 5	$ 0.652	$ 0.624	$ 0.599	$ 0.576	$ 0.555	$ 0.541
9	per kWh for the first 2,500 kWh	$ 0.03827	$ 0.03666	$ 0.03519	$ 0.03385	$ 0.03263	$ 0.03182
10	per kWh for the next 100 kWh per kW over 5	$ 0.03827	$ 0.03666	$ 0.03519	$ 0.03385	$ 0.03263	$ 0.03182
11	per kWh for the next 42,000 kWh	$ 0.02600	$ 0.02490	$ 0.02390	$ 0.02299	$ 0.02216	$ 0.02161
12	per kWh for all additional kWh	$ 0.01614	$ 0.01546	$ 0.01484	$ 0.01427	$ 0.01376	$ 0.01342
	Voltage Discounts						
13	Primary Voltage	11.6%	12.1%	12.6%	13.1%	13.6%	13.9%
14	Transmission Voltage	52.6%	54.9%	57.2%	59.5%	61.7%	63.3%
	DA-GS10 (3 mW and Above)						
15	per kW	$ 3.53	$ 3.33	$ 3.15	$ 2.98	$ 2.83	$ 2.73
16	per kWh	$ 0.00999	$ 0.00943	$ 0.00892	$ 0.00845	$ 0.00802	$ 0.00774
	Voltage Discounts						
17	Primary Voltage Discount	4.8%	5.1%	5.3%	5.6%	5.9%	6.2%
18	Transmission Voltage Discount	36.7%	38.9%	41.1%	43.4%	45.8%	47.4%
	DA-GS11 (Ralston Purina)						
19	per kW	$ 2.58	$ 2.71	$ 2.57	$ 2.44	$ 2.32	$ 2.25
20	per kWh	$ 0.00732	$ 0.00767	$ 0.00727	$ 0.00691	$ 0.00657	$ 0.00635
	DA-GS12 (BHP Copper)						
21	Primary Voltage Delivery - per kW	$ 2.35	$ 2.30	$ 2.16	$ 2.07	$ 1.99	$ 1.93
22	per kWh	$ 0.00665	$ 0.00651	$ 0.00611	$ 0.00585	$ 0.00561	$ 0.00546
23	Transmission Voltage Delivery - per kW	$ 1.22	$ 1.17	$ 1.03	$ 0.94	$ 0.85	$ 0.80
24	per kWh	$ 0.00346	$ 0.00332	$ 0.00292	$ 0.00266	$ 0.00242	$ 0.00227
	DA-GS13 (Cyprus Bagdad)						
25	per kW	$ 1.05	$ 1.21	$ 1.03	$ 0.94	$ 0.85	$ 0.80
26	per kWh	$ 0.00297	$ 0.00343	$ 0.00292	$ 0.00266	$ 0.00242	$ 0.00227

✓ Transmission voltage customers will not pay Distribution Charges after June 30, 2004

ARIZONA PUBLIC SERVICE COMPANY

Regulatory Asset Amortization Schedule
(Millions of Dollars)

1999	2000	2001	2002	2003	1/1 - 6/30 2004 [1/]	Total [2/]
164	158	145	115	86	18	686

[1/] Amortization ends 6/30/2004

[2/] Includes the disallowance from Section 3.3

Commissioner Jim Irvin
Arizona Corporation Commission
Dissenting Opinion
Decision No. 61973
October 19, 1999

Have you ever been promised a present, given a different one, and then asked to pay for it yourself? Well, that's what has happened to Arizona residential consumers and small businesses with the Commission's approval of the Arizona Public Service ("APS") settlement agreement/contract. In sum, Arizona consumers were promised robust competition, given a modest rate cut (actually, 6.83%), and then asked to pay for that rate cut to the tune of an additional *minimum* of $350 million dollars in stranded cost recovery for APS (plus an undetermined amount for "transition" costs associated with creating affiliates to handle competitive ventures). The parties to this settlement agreement are APS, AECC (a representative of industrial and commercial interests), the Residential Utility Consumer Office[1] (RUCO – a state utility "watchdog") and Arizona Community Action Association. Excluded from participating in the negotiations was the Arizona Corporation Commission, the Arizona Consumers Council and potential competitors of APS, like PG& E Energy Services, Commonwealth Energy and others. Such exclusions – as well as a lack of adequate representation for residential consumers – testify to the fact that this settlement agreement does not encompass the wide spectrum of interests it holds itself out to represent.

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[1] In the recent Auditor General's performance audit of RUCO, it states, "According to the act establishing RUCO, the agency is intended to represent the interests of residential consumers, critically analyze proposals made by public service corporations to the Commission, and formulate and present recommendations to the Commission." According to Greg Patterson – then Director – RUCO did not perform any type of critical analysis to determine whether the benefits to residential consumers are fair and

Consumers Promised Competition

When the Commission embarked on deregulation over five years ago, the primary purpose was to restructure the electric industry by introducing the generation portion of utility service to the wonders of the free marketplace – where robust competition would spark innovative technologies, and consumer choice would improve quality of service and drive rates downward. Incumbent monopolies such as APS fought hard and challenged the Commission's authority to change the regulatory paradigm, but so far these legal challenges have been unsuccessful.

On September 21, 1999 – as I promised voters in 1996 to help bring about competition in Arizona – I voted for a second time in favor of the Electric Competition Rules ("Rules") for the purpose of beginning the deregulation process; one that had been stalled earlier this year. While the Rules are not perfect, and while future Commissions will need to make adjustments to the Rules to assure a 'fair' competitive market, I believe they provide a framework where consumer and free-market interests enjoy some safeguards. However, only *two days* after these Rules were adopted, the Commission has now approved a settlement which, among other things, gives many "exemptions" and "waivers" from provisions in the Rules which conflict with the APS settlement contract.

When potential competitor after competitor testifies that the APS settlement agreement will not provide an appropriate atmosphere for competition within APS' service territory, it is our role as regulators to at least consider their arguments. Unfortunately, at least one Commissioner indicated he was unwilling to consider any amendment unless it was proposed by a party to the agreement. However, many

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reasonable in light of APS' stranded cost recovery figure, or whether the figures supplied by APS and AECC are accurate.

potential competitors – which are not parties to the settlement -- argue that the shopping credits provided for in the settlement are too low, a view supported by Commission Staff.

Staff opined that it had, "demonstrated that the proposed shopping credits were inadequate when considered in reference to each entire class of customers. The fact that one particular customer may experience an adequate shopping credit does not justify the Commission's approval when the referenced customer's usage characteristics are different than those of the class as a whole."[2] In fact, Staff argued that making a modification to the shopping credit would make it more likely that a competitive market can develop without increasing rate levels, and still allow the company to collect all its stranded costs. Not surprisingly, APS counsel stated during Open Meeting that any increase in the shopping credits would be a "dealbreaker." My proposed amendment was then subsequently voted down, as was the opportunity to develop a more competitive market in Arizona.

<u>Consumers Given Modest Rate Cuts</u>

One provision of the APS settlement agreement hailed by consumer groups such as RUCO is the modest 6.83% rate cut to residential Standard Offer customers. How RUCO came to this conclusion is unclear; its Director admitted during testimony that no critical financial analysis of *any portion* of the agreement was conducted by its staff. Timothy Hogan, who represents the Arizona Consumers Council (which is opposed to the settlement) asked the appropriate question; "Is it enough?" APS has not been through a full rate case since 1988, and this Commission has not undertaken the

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[2] Staff's Exceptions to Recommended Order

process to determine if the company has been – or is currently – overearning profits. The population in the Phoenix metropolitan area has exploded since 1988, and one can ascertain that customer growth has mirrored that number as well. If the goal of this Commission was to get rate cuts for all consumers, a rate case certainly would have been less onerous and less expensive to all parties than the monumental effort to deregulate the generation portion of the electric industry.

More disturbing is the fact that these "guaranteed" rate cuts are not guaranteed at all. Of the 7.5% rate cut APS proposed, about one-tenth of that number was already ordered by this Commission in 1996. In addition, the company reserves the right to come back and seek changes to its rates prior to July 1, 2004 (the year the "guarantee" expires) in the event of an unforeseen event or an emergency. APS claims that these rate cuts will save all consumers close to $475 million dollars in savings during this transition period. However, Commission staff estimates that the savings are closer to $329 million dollars, with about $173 million going to residential consumers. Unfortunately, RUCO and ACAA conducted no analysis at all.

Customers Pay through Stranded Costs

"Stranded Cost Recovery" is a term artfully used by incumbent utilities to explain why consumers should have to pay them to change the system. Under the original Stranded Cost Order, incumbent utilities such as APS would have had to divest themselves of generation assets – a process which would give a clear indication to all parties of their value. However, the Rules were changed in April, 1999 to allow incumbent utilities to utilize *any* method outside divestiture to recover its stranded costs. In an article appearing in Forbes earlier this year entitled "Poor me," Christopher Palmeri writes, "Not every state legislature or utility commission has the political will to force divestiture, however." After explaining how incumbent utilities often litigate the matter of stranded cost recovery as a tactic of delay, he writes, "For this reason, legislators and regulators sometimes feel like they need to cut some deal, any deal, just to get a competitive market moving forward." It is a tactic that has worked brilliantly for APS.

The argument advanced by APS is that in changing the regulatory paradigm from one of a monopoly system to a competitive marketplace, certain investments (such as generation plants) lose value. If anything, the market has shown throughout many states (CA, MA, NY, CN) that generation assets can be sold at nearly twice the book value of the plant.[3] Although APS contends that its generation assets are at least $533 million dollars over market value, how can the market value be determined when nothing has been offered for sale in Arizona?

The Commission has had a long standing practice (and one which I support) of allowing utilities' shareholders to keep fifty percent (50%) of any net profit of assets divested. The other fifty percent (50%) is returned to ratepayers who paid for those assets. So how does a utility get around this concept of "stranded benefit"? Instead of divesting themselves of the asset through the open market, they transfer it to an affiliate at "book value," thus bypassing any need to account for a net profit. Meanwhile, the asset still retains it higher "market value" and, if then sold by the generation affiliate, may fetch a hefty price. Only with divestiture can the open market determine whether a utility is left with "stranded costs" or "stranded benefits."

[3] Palmeri writes, "According to data collected by Cambridge Energy Research Associates, the average nonnuclear power plant put up for sale last year sold for nearly twice its book value." Forbes

Another justification APS advances for the recovery of stranded costs is that "lost revenues" will result by losing current customers to new market entrants. If this is true, why did Pinnacle West Energy Corporation (an APS energy affiliate) announce plans to build and upgrade new generating facilities to meet the demands set by customer growth?[4] In its recent application to the Commission, Pinnacle West Energy Corporation writes:

> "The growth rate in electricity use has exceeded six percent a year for Arizona Public Service Company (APS) customers in Arizona. Growth in the metro-Phoenix area is expected to increase peak customer demand for power from 7,000 MW in 1999 to over 9,000 MW in 2005. In order to meet that need, new generating plants and transmission lines will be needed to import more power into the Valley."

And I thought consumers in Arizona were being asked to pay for "stranded costs" because of lower valued plants, in addition to APS' estimates on how many customers it stands to lose to new market entrants. APS Energy Services (an APS marketing affiliate) already markets power in other states such as California. So, while Arizona consumers are being asked to foot the bill for APS' stranded cost recovery, California consumers are being marketed "competitive" cost power by its affiliate.

<u>Conclusions</u>

1. The APS settlement contract does not promote competition. Rather, it protects the status quo, making Standard Offer Service more attractive to the average consumer and tougher for competitors to effectively compete within APS' service territory. Also, the shopping credits provided for in the agreement are too low.

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[4] In 1988, APS' customer based was 582,003. In 1996, it was 717,614. In 1998, it had grown to 798,697. These figures are based on APS filed annual reports.

2. The aggregate 6.83% rate cut over the next four years is a modest figure considering that APS has not been through a rate case since 1988. Is it enough, given APS' rapid growth in its customer base since that time? And what about the so-called "guarantee," even though APS reserves the right to change its rates in the case of an emergency?

3. Parties to the agreement like RUCO did not perform a critical financial analysis of the proposal, either with regards to the consumer rate cuts or the stranded cost recovery for APS. Furthermore, they accepted the information provided by APS and AECC without analyzing its veracity.

4. APS has not proved it is entitled to its stranded cost recovery figure. Commission staff estimates that under the APS methodology, stranded cost recovery should be approximately $110 million dollars, far below the estimated figure of $533 million calculated by APS. Additionally, Arizona's Court of Appeals has ruled that utilities do not have a "regulatory compact" with the Commission, a concept advance by utilities to justify their reasons for stranded cost recovery.

5. The agreement provides for exemptions to APS to the recently passed Competition Rules; rules which attempt to bring about a level playing field to foster a competitive market in Arizona. Such exemptions render the protections for fair competition in the Rules meaningless.

6. Attempting to bind future Commissions to the "benefits" bargained for by the parties has been challenged as unconstitutional, and -- contrary to APS' assertions made in the settlement agreement – its adoption by this Commission will create *more* litigation rather than less litigation.

In my opinion, the APS agreement/contract passed today represents an affirmation of the status quo, does not promote competition through a leveled playing field, and contains rate cuts which could likely have been more if obtained through a rate case. Because the provisions contained therein are not in the public interest, I cannot vote in favor of the agreement, and must therefore dissent.

Jim Irvin, Commissioner
Arizona Corporation Commission

TESTIMONY OF WILLIAM H. HIERONYMUS

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

May 29, 2002

TESTIMONY OF WILLIAM H. HIERONYMUS

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TESTIMONY OF WILLIAM H. HIERONYMUS

INTRODUCTION

Q. Please state your name, occupation and business address.

A. My name is William H. Hieronymus. I am a Vice President of the consulting firm Charles River Associates, Inc. Charles River Associates is an economic and management consulting firm with offices in Boston; Washington D.C.; Philadelphia; College Station and Houston, Texas; Salt Lake City and several West Coast cities as well as international offices in Europe and the Pacific. My business address is 200 Clarendon Street T-33, Boston, MA 02116.

Q. What is your occupational background?

A. I have assisted clients on the economic and management issues involving utilities since approximately 1975. Since that time, I have performed numerous engagements for utilities, independent power producers, government agencies and other parties with interests in the industry. Since approximately 1988, I have focused on the restructuring of the electric power industry, initially in Europe and the Far East and, from 1993, in North America. In that context, I have performed engagements concerning utility privatization legislation; the treatment and quantification of stranded cost; the creation of regulatory and market rules; asset valuation and market forecasting; and market power monitoring and mitigation. I have testified well over 100 times before state commissions, the Federal Energy Regulatory Commission (FERC), legislative bodies and federal courts. I also have appeared before the Arizona Corporation Commission (Commission) on numerous occasions. Most recently I submitted prepared written testimony on behalf of the Arizona Public Service Company (APS) in Docket No. E-01345-01-0822. My resume is attached as Exhibit WHH-1.

Q. What is the purpose of your testimony in this proceeding?

A. I have been asked by APS to comment on two issues. The first is whether the separation of generation from APS, consistent with the Commission's existing competition rules and the APS Settlement, is in the public interest. The second is whether Pinnacle West Energy Corporation (PWEC), as the future owner of the APS generation, will have market power.

SUMMARY OF CONCLUSIONS

Q. Please summarize your conclusions.

A. Regarding the first question, the separation of APS's generation is in the public interest because the public interest is best served by the creation of a liquid and vibrant competitive wholesale market. Severing the vertical connections between generation and transmission materially facilitates the creation of a competitive wholesale market by reducing concerns about the exercise of vertical market power. Eliminating unitary ratemaking over the various portions of the utility enterprise, especially the full separation of the generation entity from the distribution and customer service entity, eliminates cross-subsidization concerns.

The benefits of a competitive wholesale market flow primarily from three causes. First, the progressive movement from cost of service to market pricing produces powerful efficiency incentives that did not exist previously. Related to this is the improvement in management decision making for competitive services as more profit-oriented managements replace utility monopoly managements and their regulators as decision makers concerning what to build, how to contract for fuels, and how to operate generating facilities. Second, a competitive wholesale market allows customers to benefit as competition among efficient generators drives down prices relative to what they would have been under continued monopoly regulation. Third, a competitive wholesale market is an essential underpinning of retail competition and, with it, the product and pricing innovations that retail competition can produce.

Within the context of the WSCC market area, there can be a competitive market even if APS remains an "old fashioned" utility, vertically integrating load and generation. However, APS's customers will not be allowed to benefit from either the wholesale or retail competitive alternatives if this occurs.

The experience with gas deregulation taught the lesson that separation of the control of the transmission network from the control of bulk energy supply is an essential element of creating a competitive wholesale market. Beginning with Order No. 888 and continuing on through the current campaign to cause all electric transmission to be controlled by RTOs that are independent of generation-owning entities, this separation of generation from transmission has been the main theme of FERC policies to promote competitive wholesale markets.

Because the bulk of existing generation is, or was, owned by vertically integrated utilities, the creation of a vibrant wholesale market also is facilitated by reducing the connection between a utility's existing generation and its load. Separation of competitive generation from remaining regulated monopoly entities is necessary to eliminate potential cross-subsidies that could interfere with both wholesale and retail competition

I am aware that recent events in areas near Arizona have tarnished the image of market restructuring. I believe that, allegations of misbehavior notwithstanding, the specific events of 2000-2001 in the WSCC arose from a very unusual combination of events that are unlikely to recur simultaneously and must be understood in that context. It is notable that many other policy decision makers have not been fazed by the California experience. The movement away from the regulated monopoly model to the competitive market model has only marginally slackened its pace. In most of the U.S., in Europe, Asia, South America and parts of Africa, indeed even in a number of formerly communist countries, the belief that competitive wholesale and retail energy markets are superior to regulated monopoly remains unshaken.

Turning to the second topic of my testimony, potential market power in a competitive market and the potential market power that a post-divestiture PWEC might be alleged to have, this issue is difficult to summarize easily. As a general matter, PWEC, even if it had full authority to sell power from the entire fleet of its assets (including those to be transferred) would lack market power in relevant regional power markets, since its share of such markets is small and those markets are structurally competitive, and will remain so after divestiture. Moreover, the Pinnacle West companies are not in fact free to sell their power at market rates.

Currently, the Pinnacle West companies only have power to sell during off-peak periods. Completion of Red Hawk Units 1 and 2, and West Phoenix Unit 5 will somewhat improve its balance between load and resources. However, load growth in Arizona is so rapid that these units will be absorbed before they are on line, with the result that Pinnacle West still will have insufficient resources owned or under current contract to serve 2003 loads reliably while making sales during most near-peak periods. In off-peak periods, they will have power to sell, but so will many other sellers. Hence, these shoulder and off-peak markets will be vigorously competitive.

If APS is granted its requested variance from the Commission's Rule 1606(B) and enters into a long term contract with PWCC to serve its standard offer load, its net short position will be maintained. Under the proposed agreement with APS, PWEC would contract away its generation on a long-term basis. Since its ability to sell energy at market prices would be small, it would lack market power. As is the case today, its ability to sell power to the market would be primarily during off-peak periods when competition is especially vigorous.

To the extent that the Commission's final resolution of the issues in this and related dockets frees up PWEC capacity or, more generally allows such capacity to be sold into short term markets at market rates, PWEC's share of such markets will increase. Even in this event, PWEC still will lack market power in regional power markets (e.g. the market consisting at a minimum of the Desert Southwest and Southern California). In most respects, it is this larger market that is appropriately considered in evaluating PWEC's potential market power, since power pricing reflects relatively unconstrained competition across it during most periods.

The potential market power adhering to assets located within load pockets such as Phoenix and Yuma is prospectively constrained by existing APS tariff provisions for "must run" power[1] and will continue to be constrained by RTO tariff conditions once an RTO becomes operational.

Whenever there is a transition from traditional regulation to competitive markets, the issue arises as to whether the generation portion of the previously vertically integrated utility will have locational market power over the customers in the related control area. Pinnacle West has passed FERC's test (the "hub and spoke" test) to determine whether it should be authorized to sell power at market rates, including the right to sell at market rates within the APS control area. Since this authority was granted, FERC has supplanted the test that Pinnacle West passed with a new and more stringent test (the "Supply Margin Assessment"). I have performed this test and find that a post-divestiture PWEC still would qualify for market rates in all areas, including the APS control area.

If the Commission has any remaining concern that PWEC could have locational market power in the APS control area, that concern can be addressed readily. APS's customers are potentially subject to PWEC exercising market power only if their loads are not covered by bilateral contracts. If those loads are substantially covered by bilateral contracts – whether with PWEC (through PWCC) or some other seller – PWEC will not have market power with respect to them. Since any well-designed resolution of the issues in this docket will assure that the APS Standard Offer Service will be backed to a large degree by bilateral agreements, PWEC will not have locational market power in the APS control area.

THE BENEFITS OF A COMPETITIVE MARKET AND NEED TO TRANSFER FACILILITIES

Q. What is the current status of market deregulation in the U.S.?

A. A pictorial summary created by the U.S. Department of Energy is attached as Exhibit No. WHH-2. The primary focus of the DOE analysis is on retail access. However, underlying retail access in most or all instances is wholesale market restructuring. According to DOE, 24 states plus the District of Columbia have enacted retail access by law or by regulation. These states include most of the Northeast and Mid-Atlantic, and much of the Midwest and Southwest and West Coast areas. The areas without approved retail access include the prairie and mountain states, much of the Southeast and some hydro-based states in the Northwest. Arizona is classified as having approved retail access, as is correct. The states with approved retail access include one, California, where access has

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[1] My understanding is that FERC has accepted the form of the must run protocol as part of APS's tariff but requires that the specific (i.e. price) terms of the tariff be filed before the must run portion of the tariff becomes active.

been suspended and seven where it has been delayed since the events of 2000-2001.

Q. What common activities have the states with retail access undergone?

A. The activities relevant to this proceeding include separation of generation, transmission and distribution (and in some case retailing or customer service); specifically the corporate separation of generation either into a separate subsidiary or by divestiture to third parties or a combination of the two; creating regulatory structures for retail competition, including provider of last resort regulations; and the creation of transitional arrangements to ensure price stability and guard against the exercise of market power.

Q. You noted that a common activity in states with retail access is the separation of competitive generation from the regulated monopoly activities. Has this been done in all such states?

A. Yes, with the exception of Virginia. Notably, Virginia retail access is off to a very slow start.

Q. Why is the separation of the generating assets from the regulated utility a nearly universal element of the move to retail access?

A. There are several reasons. First, the creation of a market-driven, competitive market is seen as beneficial in its own right. Indeed, many industry experts believe that wholesale competition, not retail competition, is the primary benefit from utility restructuring. Second, both retail access initiatives and the federal move to pull transmission planning and control out of the vertically integrated utility undermine the basis for maintaining a regulated monopoly source of generation. Third, both retail and wholesale competition require a deep and liquid wholesale market. This is made more difficult if the load-serving utility retains its generation.

Q. **Please expand on the desirability of a competitive wholesale market.**

A. There are two main "fathers" of the movement to deregulate electricity market. The first was the analogy to other markets that previously were tightly regulated and then deregulated. These include rail and motor freight, telecommunications, airlines and natural gas. These earlier industry deregulations were seen as a success. The causes for the perceived success – reducing the scope for vertical market power and cross-subsidization, more profit driven and innovative managements, and removing politics and regulatory policies to a substantial degree from micro-decision making -- were seen as applying also to the electric utility sector.

The second was the then-recent history of the electricity industry itself. Both regulators and utilities had been badly bruised by the experience of over-building expensive baseload generation in the 1970s and early 1980s. As reserve margins narrowed, utilities were reluctant to build, and regulators to approve, new power plants. In some states, regulator or legislatively driven excessive costs for QF power were a cause of high rates. Indeed, the first part of the CPUC's "Blue Book" that kicked off its deregulation initiative reads like a plea for someone to "stop me before I make bad regulatory decisions about new generation again."

On the more positive side, the experience with QF power beginning in the mid-1980s and with Exempt Wholesale Generators in the early 1990s created confidence that non-utility resources could be absorbed into the generating mix without impairing reliability. Confidence in a competitive wholesale market also was enhanced by development of a new and better technology for gas-fired generating equipment that could be built quickly and without a need for high front-loaded revenues. Further, increasing trading volumes among utilities, particularly within the existing "tight pools" in the Northeast, created confidence that a wholesale market that depended on both bilateral contracts and spot trading transactions could be operated reliably and economically.

This then-recent history, both negative and positive, along with introduction of competitive electricity markets in the U.K., continental Europe and elsewhere created the confidence that competitive markets for electricity could work and provide efficiency benefits to the economy and cost benefits to consumers. Moreover, a competitive wholesale electric market could underpin retail competition and with it the innovations that had been seen with the deregulation of other industries. This fit well with the general presumption that pervades the U.S. political system and economy that free competitive markets are preferable to government supervision of markets and companies.

Q. Do regulators and public officials in the states that have deregulated remain committed to deregulation, including the separation of generation from regulation?

A. Yes. I asked my staff to do a state-by-state online search for remarks made recently by such officials. These officials remain confident that their markets will work well and provide benefits to consumers. I will cite a representative sample:

- Deregulation in Texas took effect on January 1, 2002. Since then, According to Texas Governor Rick Perry, consumer costs have plummeted $1 billion due to residential rate savings.[2] "Texas' success can be attributed to the deregulated market's design, competitor strategy, and the good fortune of low wholesale prices."[3] Texas Public Utility Commissioner Rebecca Klein says that electricity market in Texas is "healthy" and customers that have switched electric suppliers are "already seeing savings of up to 12 percent."[4] Tom Noel, CEO of the Electric Reliability Council of Texas (ERCOT), said that "electric deregulation thus far has been successful," and that, "new electricity suppliers have been chosen by approximately 270,000 of the 5.5 million Texas residents who have gained the right to pick new providers on January 1."[5] For the last three years, the Center for the Advancement of Energy Markets (CAEM) has published the "Red Index" (Retail Electric Deregulation Index) which is, in their words, "a scorecard for measuring progress on energy restructuring."[6] CAEM uses 22 objective

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2 *Hopefuls clash over electricity; Sanchez, Perry cite higher, lower rates*, San Antonio Express-News, Metro/South Texas section; pg. 5B, May 16, 2002

3 Xenergy Vice President Bruce Humphrey (http://www.eren.doe.gov/electricity_restructuring/weekly/apr05_02.html)

4 *Texas Officials and Suppliers Proclaim Electric Deregulation A Success Thus Far,* PR Newswire, Financial Section, February 28, 2002

5 *Texas Deregulation Picking Up Speed,* Energy Daily, Volume 30, Number 28, February 12, 2002

6 Retail Energy Deregulation Index 2002 (Abstract), Center for the Advancement of Energy Markets

restructuring criteria to arrive at a state's score based on 100 points. The CAEM criteria are broken up into a competitive framework cluster, a generation cluster, a consumer cluster, a distribution cluster, and a commission cluster. Texas took the top U.S. spot, in the 2002 Index, with 69 points. Ken Malloy, CEO of CAEM, said, "I am confident that Texas customers will enjoy the benefits of electric competition much sooner than customers in other states."[7]

- On March 27, 2002, Pennsylvania's Public Utility Commission Chairman Glen R. Thomas and Mark Schwiker, the Governor of Pennsylvania, announced, "the first Pennsylvania customers will see the Competitive Transition Charge eliminated from their bill. Duquesne Light customers will see their rates drop between 16 and 20 percent."[8] Pennsylvania's Electric Choice program has, over the last 5 years, saved customers more than $4 billion in electricity costs.[9] Pennsylvania ranks second among states in the 2002 RED Index, having recently been overtaken by Texas.[10] On February 7, 2001, in his annual budget address to the General Assembly, then Pennsylvania Governor Tom Ridge said, "We have delivered approximately $3 billion in savings, due to guaranteed rate cuts, savings from shopping, and avoided fuel costs." Then-Pennsylvania Public Utility Commission Chairman John M. Quain added, "Before electricity choice,

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7 *Texas Electric Competition Ranked #1 in U.S.,* (web site)

8 *PUC Chairman Thomas Marks Milestone for Electric Competition: First PA Customers See Lower Rates Thanks to 'Stranded Cost' Coming Off Bills,* March 27, 2002 (http://puc.paonline.com)

9 *PUC Chairman Thomas Marks Milestone for Electric Competition: First PA Customers See Lower Rates Thanks to 'Stranded Cost' Coming Off Bills,* March 27, 2002 (http://puc.paonline.com)

10 Retail Energy Deregulation Index 2002 (Abstract), Center for the Advancement of Energy Markets

Pennsylvania electric rates were 15 percent above the national average, and now our rates are 4.4 percent below the national average."[11]

- "About 46 percent of the total amount of electricity used every day in Maine is purchased from competitive power suppliers", said Maine Public Utilities Commission spokesman Phil Lindley.[12] "For large and midsize commercial customers, Maine has more competition in energy supply than perhaps any state. In Central Maine Power's territory, for instance, 88 percent of all manufacturers and other large power users have signed contracts with energy providers. For medium users such as supermarkets, the figure is 42 percent."[13] Maine has seen success that most states haven't in converting customers to competitive suppliers because they use a system where "the standard offer tracks the wholesale market up or down on a year-to-year basis, with the cost of competitive supplies staying in the same range. In most states, the multi-year standard offers rate remains well below wholesale market rates this year and the number of users choosing alternative suppliers has declined."[14]

- On February 1, 2002, the Michigan Public Service Commission (PSC) released its "Status of Electric Competition in Michigan" report. According to the PSC's findings, competition in Michigan's retail electric choice program grew 30 percent

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[11] *Pennsylvania Again Ranked No. 1 in Nation for Electric Deregulation,* Commonwealth of Pennsylvania Office of the Governor: Commonwealth News Bureau, February 7, 2001

[12] *Power rates to change today; For many customers, prices will decrease,* Bangor Daily News, March 1, 2002

[13] *Restructuring quietly meeting most goals,* Maine Sunday Telegram, BUSINESS; Pg. 1F, January 6, 2002

during 2001.[15] To date, the Commission has licensed 15 alternative electric suppliers to serve its State's customers. "Commissioner Robert Nelson has said that he believes the state would experience a dramatic increase in commercial load going to competition, particularly in Detroit Edison's territory."[16] The commission remains confident of the success of retail access despite a slow start, citing transitional problems including "infrastructure limitations, economic difficulties nationally and statewide and the simple need for participants to learn how to compete effectively."[17]

- Ohio's electric restructuring is in the second year of a five-year market development period. Alan R. Schriber, Chairman of the Public Utilities Commission of Ohio (PUCO), reports that 40 governmental aggregators received certification from the PUCO and subsequently their programs have accounted for 85 percent of the residential switching customers, 50 percent of the commercial switching customers and 25 percent of the industrial switching customers.[18]

These comments focus primarily on retail access, since delivering choice to customers is a primary motive for utility restructuring. However, these policy-

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14 *Marketers serving more load in Maine as standard offer rate hikes take effect*, Retail Services Report, COMPETITION; Pg. 5, September 28, 2001

15 *Status of Electric Competition in Michigan,* Michigan Public Service Commission: Department of Consumer & Industry Services, February 1, 2002

16 *Electric Restructuring Weekly Update,* The United States Department of Energy, February 8, 2002 (http://www.eren.doe.gov/electricity_restructuring/weekly/feb08_02.html#mich)

17 *Status of Electric Competition in Michigan,* Michigan Public Service Commission: Department of Consumer & Industry Services, February 1, 2002

18 *The Ohio Retail Electric Choice Programs Report of Market Activity for the Year 2001,* Public Utility Commission of Ohio, April 2002

makers would not remain bullish on the success of retail access unless they also were confident that underlying wholesale markets also were competitive.

Q. **Your summary indicated that a number of states had not embarked on deregulation and that some had backtracked from scheduled deregulation after the California experience. Why have some states shown lesser interest in restructuring their electricity industries?**

A. The reasons vary. Many of the states that have not undertaken restructuring are states with low rates and low variable production costs. Low rates give rise to "if it ain't broke, don't fix it." Low variable costs cause concerns that restructuring would cause power to be shipped to higher cost markets or, more generally, for low in-state prices to be arbitraged against higher prices in nearby areas. Some states are primarily public power and for both tax-related reasons and cultural ones are reluctant to participate in markets. Some states may simply be conservative, not in the political-economic sense of being pro-market and pro-capitalism, but in the sense of reluctant to change. Finally, in some states a short legislative calendar has contributed to failure to take up the issue in preference to other concerns seen as more pressing.

What is signal about the motives for not moving to restructure is the relative absence of a defense of the status quo except in the public power states. States that have eschewed restructuring due to low generation costs do so for the pragmatic reason that the current system allows them to circumvent what otherwise would be constitutional barriers to measures that keep in-state power from being sold in multi-state markets. Only Florida might be considered to be affirmatively status quo, relying on vertically integrated utilities for make or buy decisions and prohibiting purely merchant generators.

Q. You alluded earlier to what was going on internationally. Can you summarize briefly?

A. Yes. Utility deregulation first started in Chile in the 1980s. In 1988, the U.K. embarked on privatizing its state-owned electricity industry. Privatization was completed in 1990, with separation of generation, transmission and distribution, a partial breakup of generation (into three entities) and limited retail access, since expanded to full retail access, with a retail access program ranked as the most successful in the world. In 1993, the European Union adopted a retail electric competition program with phased access that now stands at about 40 percent. National initiatives in some member states resulted in 100 percent access. Both the EU and its member states have taken steps to create competitive underlying wholesale markets. Restructuring is complete in Australia and New Zealand, well underway in Korea, Singapore and Hong Kong, and beginning in China. Various South American countries have restructured their markets to accommodate new entry and the sale of companies to new owners. Some of the larger former Soviet republics and satellite nations in Eastern Europe have completed or are well on their way to restructuring.

Q. In your summary at the beginning of this section, you indicated that the legal and operational separation of utility functions generally was one reason for the legal separation of generation. What did you mean?

A. The alternative to the creation of a competitive wholesale market is the Integrated Resource Planning (IRP) process. IRP recognizes that generation and transmission are built to serve load economically and reliably and are, in a sense, interchangable. Under IRP, demand-side measures, transmission planning and generation planning all must be done interdependently.

Retail access means that no entity can plan its generation for a stable and predictable customer base for the simple reason that the load that it will serve cannot be predicted with the same accuracy as previously. Whereas previously load uncertainty related to the economy and weather of a predetermined region, generation planning can no longer be based on "native load" but must reflect the market opportunities of selling generation not only to a (relatively unknown) base of retail customers but also to the market.

Related to this is a concern with cross-subsidy and preferential self-dealing that can undermine the effectiveness of retail competition. These appear to have been the principal reasons for this Commission's approval of asset transfers on a number of previous occasions, as discussed in Mr. Jack Davis's testimony.

Another break in the vertical chain that underpinned IRP is the separation of transmission planning and operation from both generation and from retail operations. FERC Order 888 required strong codes of conduct restricting communication between transmission providing portions of a utility and those portions with market functions, including expressly those that buy and sell power. It since has broadened the application of those codes. More fundamentally, FERC's RTO initiative, together with its insistence that all essential transmission planning and operation functions occur at the RTO level, have broken the nexus between transmission and generation planning. Whereas previously a utility could trade off between generation siting decisions and transmission investments, that process cannot be integrated, at least not directly, in an RTO world wherein the RTO plans transmission and merchant generators site generation.

Q. The third summary reason why utility generating assets need to be separated is the need for a deep and liquid wholesale market. Why is this needed?

A. All markets benefit from many buyers and sellers and from transparency. By transparency, I mean that there exists a market price (rather than several prices for the same product and area) and that this price is visible and knowable to all actors in the market. This inherently requires deep and liquid markets. If all existing utility-owned or controlled generation remained with the utility, then most of the power used by customers (all of it, initially) would be outside of the market and the market correspondingly thinner.

Q. Doesn't this imply that APS's proposed PPA will have a negative effect on competitive markets since it will reduce the amount of energy traded in the market for its duration?

A. No, not materially. If your question had been, would long term PPAs covering <u>all of the load in the WSCC and all of the existing generation</u> injure competitive markets, my answer would have been yes. However, this is not the case. The large-scale divestitures in California and the substantial amount of new merchant generation being built in the region are sufficient to create a deep and liquid market under foreseeable circumstances. This gives APS and the Commission the luxury of deciding whether it wants the PPA on other grounds, such as price, reliability, fuel diversity and so forth without needing to be concerned about whether wholesale power markets will be deep and liquid.

Q. Your comment about California divestiture prompts me to ask what your basis is for the statement that the California experience has not deterred other states and was due to causes unlikely to recur. Why is it?

A. What happened in California can be traced to four causes, each of which is unlikely to affect Arizona in the future. Briefly, these are: 1) a supply shortage, amplified by a temporary gas shortage; 2) the absence of long-term contracts; 3) market design flaws; 4) the absence of regulatory safeguards and slowness in regulatory response. The first, a shortage of supply, is the principal cause of the crisis. The remaining three are reasons why the tight supply conditions had such a great effect on customers, the California utilities and markets throughout the WSCC.

The reasons for the supply shortage are well known. For years, California said "no" to new power plants. Indeed, I was SCE and PG&E's economics witness in the last CPUC proceeding in which they sought, unsuccessfully, to gain CPUC permission to build a major new power plant. That proceeding took place in 1980! In the late 1990s, California was rapidly sucking up all of the available surpluses in surrounding states. This amplified the effects of demand growth on making supplies available to California disappear. Then, the record shortage of hydro, combined with hot weather, created a need to run essentially all available generation. This created inherently higher marginal costs and a seller's market that was conducive to the exercise of market power or, at a minimum, shortage pricing. Partly as a result of the high demand for gas-fired generation and partly for other reasons, some of which were not specific to California or the West, gas prices surged and availability fell, resulting in the extension of high prices into and through the winter of 2000-2001.

While another low rainfall year doubtless will occur in the future, such abnormal hydro conditions will not be the norm. Importantly, even if such conditions recur, the conjunction of low rainfall with regionally inadequate supply and wholly price insensitive demand are conditions that are quite unlikely.

The absence of bilateral contracts with terms that would have reflected more normal market expectations meant that the California utilities, and other buyers without sufficient contracts to meet their sales obligations, faced the high market prices for much of their power. If the California utilities and other utilities in the western U.S. had had, for example, 95 percent contract cover, I doubt that we would be talking about California today. The absence of contracts sufficient to cover load obligations had two causes: the decision to not sign transitional PPAs for divested generation and a more general prohibition on the IOUs buying power outside of the PX spot market. That provision, designed to assure market liquidity, was patterned after the U.K. market rules that required that all power be sold through a central spot market. However, while all power flowed through the pool in the U.K., bilateral contracts were still the norm, covering some 90-odd percent of distribution company purchases. A contract form called "contracts for differences" insulated pricing from the volatile pool price despite that the power was bought and sold through the pool.

The absence of bilateral contracts may have had another effect as well. As I will discuss more thoroughly in connection with market power, a seller's incentive to seek to drive up prices is reduced to the extent that it has pre-sold power. If all of a seller's output is being sold in short term markets, it can profitably withhold a large amount of power in order to raise prices for the remainder. While I am not aware of a definitive demonstration that such withholding occurred in California, the incentive to do so clearly was magnified by the lack of bilateral sales.

Market participants and regulators have learned these lessons. California load is now fully covered, perhaps over-covered, by forward contracts. The California ISO is planning market changes, particularly an installed capacity obligation, to insure that adequate reserves exist, generally covered by forward contracts. Other load serving entities in the region also has taken steps to increase contract cover.

Poor market rules bear some of the blame for the California experience. The "gaming" recently revealed in internal Enron memoranda existed primarily to take advantage of flaws in the rules. Other rules, or the toothlessness of existing rules, contributed to high costs of power in the ISO's market. Rules changes, including market power mitigation procedures since have been made to cure at least some of these problems.

The last cause that I cited was a slow regulatory response. The adversely affected California parties and public officials were tardy in making use of available opportunities to seek redress at FERC and initiate a refund-effective date under Section 206 of the Federal Power Act. FERC was, at that time, led by a Chairman who was ideologically indisposed to intervention in markets. Perhaps most fatally, California officials left retail prices unchanged despite the high costs in the wholesale market, with the result that the demand response that would have brought supply and demand better into balance did not occur. Doubtless, these officials were motivated in part by an unconditional rate freeze that was part of the California restructuring legislation that allowed the illusion that the high costs would be absorbed by utility investors. Again, this is a lesson that, having been learned, should not be repeated.

Indeed, the change in federal and state vigilance about the exercise of market power, both horizontal and vertical, has been very marked. In particular, FERC's insistence on RTO formation has taken on a new urgency since RTO market power monitoring and mitigation is seen as the principal "front line" defense against both the exercise of market power and gaming of inadequate or inefficient market rules. Notwithstanding this role of the RTOs, the FERC itself has stepped up its market power policing with proposed new rules to eliminate the time gap in which prices are not subject to refund, new market power tests, and a new 100 person investigation and enforcement unit.

Q. What conclusion do you draw about the California experience?

A. Simply that the Commission should not retreat from its previously expressed belief in a competitive market merely because of the California experience. At FERC and among the market participants and policy makers in WSCC markets, lessons have been learned, perhaps even over-learned, to prevent a recurrence.

This does not mean, however, that the Commission should ignore the experience in California and in other markets that prices can be volatile. Electricity is a commodity and, like all commodities, will be prone to "boom-bust" cycles. Moreover, as the market price of electricity comes increasingly to be dependent on the price of gas, the natural volatility of prices will increase. The reduction in volatility and in dependence on a single fuel source that is forecasted to increase in price more rapidly than competing fuels is a substantial benefit of entering into a long term purchase of energy from a generation fleet utilizing a mixture of fuels and technologies.

MARKET POWER

Q. What is the purpose of this section of your testimony?

A. Among the "Track A" issues set for hearing by the Commission is "the transfer of assets and associated market power issues". The purpose of this testimony is address market power in a post-transfer world.

Q. Please begin by defining market power.

A. Market power is the ability, profitably, to sustain an increase in price above a competitive level. Each element of this statement matters. Manifestly, in order to increase prices, the firm or firms in question must have the ability to do so. In any market with an upward-sloping supply curve,[19] all firms have some such ability, albeit perhaps only to a minimal extent. Hence the next word: the action taken must be profitable. If a market participant withholds capacity, price will increase. However, its own sales will fall. The profitability calculus depends on whether the increase in profits from higher prices outweighs, or not, the decrease in profit resulting from lost sales. Next, the increase must be sustainable. If prices are increased, rivals will react, for example by shifting output to the affected market. Entry also may occur. The Federal antitrust authorities, i.e., the Antitrust Division of the U.S. Department of Justice (DOJ) and the Federal Trade Commission (FTC), and FERC tend to regard entry that can occur within a one to two year period as available to discipline prices. Lastly, price increases are measured relative to a competitive price; in the vague words of the DOJ/FTC Merger Guidelines, the increase of concern can be "small but significant".

Q. How is market power exercised?

A. Exercising market power requires that capacity be withheld from the market. It is basic economics that the price in a market is determined at the intersection of the supply and demand curves. By withholding capacity, a supplier will reduce aggregate market supply, causing price to rise. Generally, the steeper the supply curve, the greater is the increase. Hence, if there are other suppliers with

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[19] An upward-sloping supply curve means nothing more than that the price at which an additional amount of output will be provided increases as the amount demanded increases. For example, low loads can be met with coal and nuclear generation, moderate loads with relatively efficient gas-fired generation and high loads will require use of inefficient gas-fired or oil units. With relatively rare exceptions, most supply curves are upward sloping, especially in the short run.

significant capacity only slightly more expensive than the firm's competitive bid price (termed an elastic supply condition), the attempt by the firm to raise price significantly will be mostly unsuccessful and almost certainly unprofitable. Generally, the competitive price for electricity supply is flat over broad regions, then jumps between fuel types and technology, and becomes steeply increasing only in the region at the end of the supply curve, where inefficient units with low but diverse efficiency are the only remaining units. This is important in the current context because the substantial amount of combined cycle capacity being built in or near Arizona has quite similar cost characteristics and similar opportunity costs, so that this region of the supply curve is flat. This means that only in very high load period (when all such units are already running) or perhaps very low periods (when prices are below the variable costs of such units), will feasible withholding strategies in spot markets be potentially profitable.

Electricity also is believed to have a quite inelastic demand. That is, load does not change materially if wholesale prices rise. This partly is a consequence of the essential nature of some electric services and the fact that it does not consume a large amount of household income or represent a large proportion of most business costs. The other reason, of some policy significance, is tariff design. If the prices charged to consumers do not change as wholesale prices change, there will be no demand response. I discussed this in the context of the California experience. Many experts also believe that real time price signaling, allowing customers to avoid price spikes by reducing consumption (or even paying them to do so) would discipline market power.

Market power can be exercised by a single, dominant firm or by the joint action of multiple firms. Overtly collusive behavior (price fixing or bid rigging) among erstwhile competitors is illegal and subject to severe sanction. Tacitly collusive behavior is not illegal, and its prevention is a major focus of merger and acquisition policy.

Market power generally is conceived of as involving two types of activities.[20] Horizontal market power is what most people think of as monopoly or oligopoly power. It flows from a dominant share of supply by a single firm or from cooperative behavior among a small group of sellers collectively possessing a dominant share of the supply of a product. While this condition is not itself illegal, abuse of it or some types of efforts to create it are. A second type of market power is called vertical market power. The relevant example would be for an owner of a transmission system, itself a legal monopoly in its area, to use that monopoly over an "essential facility" to exclude or disadvantage competitors in related activities such as generation or serving retail customers.

In this discussion, I focus on horizontal market power. That is not because vertical market power is less important. Indeed, in electricity, vertical market power has far greater potential to destroy competitive markets. Rather, it is because the actions of this Commission in approving generation divestiture and of the FERC in its orders and its RTO policy already have focused so strongly on preventing the exercise of vertical market power.

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[20] A third type of market power, monopsony, or power exercised by buyers over sellers, is not relevant to this discussion.

Q. How do FERC and the antitrust authorities analyze horizontal market power?

A. It is necessary to distinguish between enforcement – the detection and punishment of illegal behavior – and prevention. Since the market power issue in this proceeding is whether the divestiture of APS generation to PWEC will give it market power prospectively, I will focus on prevention.

For the past several decades, the main focus of the antitrust authorities has been on market structure. Is a single firm so dominant that it clearly can exercise market power? Is the structure of an industry so concentrated that tacitly collusive behavior is likely? If so, they will guard against measures firms might take to increase concentration or preserve a concentrated structure or a firm's dominant position.

About 20 years ago, the antitrust authorities adopted a particular measure of market concentration, called a Herfindahl-Hirshmann Index (HHI). This test measures market concentration by summing the squares of individual firm's market shares. For example, a market in which there are 5 equal sized firms (i.e. each has a 20 percent share) would have an index value of 2000 (20 percent squared is 400; 5 times 400 equals 2000). A market with a concentration of 1800 is considered to be highly concentrated and subject to anticompetitive behavior, though the standard is not a 'bright line" but rather a test to determine whether further investigation is warranted. Similarly, a single firm possessing a 35 percent share is considered potentially dominant.

FERC, in 1996, adopted this methodology for looking at mergers. The FERC methodology focuses on a "delivered price test" that fundamentally counts as "in the market" all capacity that can reach such market using the physical transmission system (i.e. imports are limited by transmission constraints) with costs below or just above the market price. In testimony before this Commission in 1999, in Case No. E-01345A-98-0473 et al., I applied this test to the APS market. I concluded that the APS market area had an HHI of about 1200 and that APS's share was about 23 percent. These are well below the trigger values for FERC and the antitrust authorities. I also noted that a focus on the APS market area likely was not warranted since Arizona participates in a wider market consisting of at least Southern California and the Desert Southwest. Since that time, PWEC has added or nearly completed additional capacity. However, substantially more capacity has been, or is being, added by other firms and transmission is being expanded. Hence, if I were to redo this analysis for Pinnacle West today, the results would show a still smaller market share for PWEC.

Q. **In this earlier testimony, didn't you concede that some APS units are must run and could exercise market power?**

A. Under some circumstances, generally the highest load conditions in the summer, APS and SRP capacity located in the Valley is must run. Capacity in Yuma also is must run at some times. By definition, this means that, absent mitigating conditions, the owners of the capacity could name their own price, with the alternative of rolling blackouts. This condition is not unique to the APS control area. There are many other must run units in the U.S., usually but not always located in or near major cities. There are well-established means of mitigating the potential market power of such units. APS already has created protocols for such mitigation in its FERC-approved tariffs. This, or equally robust mitigation will be carried forward when WestConnect becomes operational.

Q. You stated that your 1999 testimony discussed market definition and indicated that an area larger than the APS control area was appropriate. Why is this?

A. By way of introduction, an analysis of market power always begins with the definition of relevant product and geographic markets. Here, the product market of greatest interest is electric energy. FERC simply assumes as a starting point that a control area is a relevant geographic market, though it invites evidence of larger or smaller markets and routinely uses geographic market definitions that are larger than control areas. It was simply because it is FERC's default assumption that I used the APS control area as the relevant geographic market.

In fact, the power markets of the WSCC are highly interdependent. Unless transmission constraints prevent it, an increase in prices in one area draws power from other areas, raising prices in those areas also. This connection of prices across broad regions is, to one degree or another, common to all interconnected power markets. APS is interconnected with other Desert Southwest utilities and more importantly is strongly interconnected with Southern California. The transmission capacity from Arizona to California is rarely if ever fully utilized. The transmission capacity from California to Arizona is so slack that the WSCC doesn't even quantify its limit. Likewise, there is substantial capacity linking Southern to Northern California and California to the Northwest via the DC interconnection into Southern California and the California-Oregon interconnect into Northern California

California is, and is likely to remain, capacity short and shorter still in terms of economic energy. Typical year energy imports into California are about 50 billion kWh. As an important power sink, it interconnects prices in the WSCC. I recall a study submitted by the California Attorney General's market power expert in the state proceeding that approved the merger of Southern California Gas and Enova into Sempra that found that the degree of price convergence in western power markets was very high.

In the market power analysis that I explain later in this testimony, I have assumed that APS is a relevant geographic market. In fact, in this larger interconnected market in which prices are determined, PWEC's share is quite small and it clearly lacks market power.

Q. Assuming that the asset transfer takes place and that the PPA does not exist, would PWEC have market power in these larger markets?

A. No. PWEC's share of either a Desert Southwest-Southern California or WSCC market would be small, a single digit share, even if it were free to sell all of its output at market rates in short to intermediate term markets.

Q. You noted that FERC had adopted the antitrust authorities' method of assessing prospective market power in 1996. In what context did that adoption take place?

A. It was adopted in the Merger Policy Statement that indicated how FERC would assess the market power implications of mergers and acquisitions.

Q. Are there other contexts in which FERC assesses prospective market power using other analysis methods?

A. Yes. Under Section 205 of the Federal Power Act, FERC regulates the pricing of wholesale transactions. Within its Section 205 authority, FERC has devised tests to determine whether sellers will be authorized to sell power at market prices, as opposed, for example, to cost of service prices.

Until recently, FERC relied on a simple "hub and spoke" test. On two separate occasions, in 1999 and 2000, FERC granted Pinnacle West affiliates market rate authority based at least in part on Pinnacle West passing the hub and spoke test.

The hub and spoke test was criticized by some FERC Commissioners and by others, primarily on the grounds that it ignored transmission constraints. Last autumn, FERC adopted a new method, dubbed the "supply margin assessment" as its standard for testing whether market rate authority was appropriate. As discussed below, Pinnacle West will also pass this new test to demonstrate that it qualifies to sell power at market rates.

Subsequently, FERC has noted that the supply margin assessment test, or SMA, will be applied to market-based rate applications on an interim basis until new analytical methods for analyzing market power are reviewed and adopted. The SMA test was further refined by FERC in *AEP Power Marketing, Inc., et al.*, Docket No. ER96-2495-015, *et al.* 97 FERC ¶ 61,219 (2001) ("AEP Order").

Q. Would PWEC continue to meet FERC's Requirements for market-based rate authority under the SMA test?

A. Yes. I have conducted the SMA test for PWEC using a summer 2003 snapshot and find that the test is easily passed. The results of the SMA test are summarized in Exhibit No. WHH-3.

Q. How is the SMA test conducted?

A. The SMA test measures whether a market's peak demand could be met without the applicant's generation. Each utility control area is deemed to be a separate market. For each market where applicants own or control generating resources, applicants are instructed to compare the applicant's generation capacity in the market to the difference between "Available Supply" and peak demand in the market (termed the "Supply Margin"). Available Supply includes all of the generating capacity located in the market, plus imports, quantified as the uncommitted capacity that can reach the market using available inbound transmission capacity, as measured by the Total Transfer Capability (TTC) value for all transmission lines that enter the control area, irrespective of current use or ownership. If the Supply Margin is greater than applicant's generation, then peak load can be met without the applicant's generation, and the seller is not considered pivotal in the market. Reserves are not taken into account in the test, either for purposes of determining what capacity is uncommitted or for determining load levels.

Q. Is the SMA test regarded as a stricter test than the test previously used by FERC in determining whether an applicant should have the authority to sell at market rates?

A. Yes, very much so. First, the ability to rely on imports is constrained by physical capacity. This was not true previously, so that the amount of supply in the market is much reduced. Second, while the previous test either compared applicants' total capacity to the total capacity in the market or its uncommitted capacity to the total uncommitted capacity in the market, this test combines applicants total capacity with only the uncommitted capacity that can be imported. When the SMA was first announced, it was widely believed to be a regulatory sledgehammer to force utilities into RTOs, since most utilities would fail the test in their home market, while utilities in RTOs were exempt from the test for sales in the RTO (including in their own market).

Q. What market did you analyze for purposes of conducting the SMA test?

A. FERC's application of the SMA test continues to rely on control areas as the relevant market areas, and I have analyzed APS' control area as the relevant market. While the SMA is not formally applied only to the applicant's own control area, it is most unlikely that an applicant would fail the test in some other market area at present.

Q. How did you calculate Available Supply inside the APS control area?

A. I included all of the generation physically located inside of APS' control area, which includes about 6,571 MW owned by (or under contract at time of summer peak to) PWEC or its affiliates and about 5,783 MW owned by other entities, including new merchant capacity and capacity at jointly-owned units located in APS' control area. PWEC's total includes the new and planned upgrades at Red Hawk and West Phoenix and APS' purchases from PacifiCorp and SRP.[21] The SMA test does not require that capacity within the control area owned by others whose loads are outside the control area be eliminated from the supply margin. Presumably, this is because such owners (e.g. El Paso Electric or Public Service Company of New Mexico) can use substitute generation located outside the control area being analyzed to meet load, and presumably would do so if prices within the control area were to rise to above competitive levels. Thus, the total Available Supply from inside the APS control area is 12,354 MW (6,571 MW owned or controlled by PWEC and 5,783 MW owned by other entities).

Q. How did you calculate the amount of imports to include as part of Available Supply in the SMA test?

A. The TTC into the APS control area is expected to be 11,089 MW by summer 2003. This total includes the planned transmission upgrades at Palo Verde – Rudd. I have reduced this capacity by 2,146 MW to account for PWEC's share of Palo Verde and for Red Hawk, since importing their power from the SRP

[21] Note that the SMA test is wholly insensitive to the amount of the applicant's capacity since the central issue is whether other sellers could meet the load, not whether the applicant could meet it.

switchyard to which they are connected uses up this amount of capacity. Thus, the TTC that I use is 8,943 MW.

Next, I determined whether there were sufficient uncommitted generating resources available to potentially serve the APS control area. I conservatively considered only newly constructed units or those planned to come on-line by the summer of 2003, as listed in the California Energy Commission's WSCC Proposed Generating Database (available on its website) as being potentially available to serve the market. The total new capacity in control areas directly interconnected to APS is 23,814 MW by the summer of 2003. Since this greatly exceeds the TTC that I am using, the SMA rules limit imports to the 8,943 MW of TTC as capacity available to the APS market.

Q. **Please Describe the results of your analysis.**

A. A summary of the results of the SMA test is provided in Exhibit No. WHH-3. As detailed above, the total Available Supply to the APS control area is 21,297 MW. This total includes about 12,354 MW inside the control area and 8,943 MW from outside of the control area. Total load in the APS control area by summer 2003 is expected to be 6,127 MW, based on APS' forecast in its FERC Form 714 filings.

The Supply Margin is the difference between Available Supply and load and is 15,170 MW (21,297 MW less 6,127 MW). PWEC's capacity in the market is 6,571 MW. Since the Supply Margin is greater than the capacity of PWEC and its affiliates, the SMA test is passed. That is, PWEC is not a pivotal supplier under the SMA test. Indeed, capacity controlled by others is more than twice the control area load.

Q. **Are there any other potential areas outside of APS' control area where PWEC is a pivotal supplier?**

A. No. PWEC and its affiliates own capacity at Palo Verde interconnected to switchyards in the SRP control area, however PWEC is not a pivotal supplier in the SRP control area which has experienced a significant amount of new and planned capacity additions, especially around Palo Verde.

Q. **Please summarize your review of the results of FERC-mandated market power tests.**

A. Over the past few years, FERC has mandated three market power tests: the hub and spoke test, the merger-related delivered price test, and the new SMA used for determination of market rate authority. Pinnacle West, APS and its affiliates have qualified for market rate authority under each of these tests, based on the demonstration that they lack market power, individually or collectively.

Q. **Assuming, notwithstanding your analyses and the results of the FERC-mandated market power tests, that the Commission has remaining concerns that a post-divestiture PWCC might be able to exercise market power with respect to entities serving its jurisdictional customers, can you provide guidance concerning how those concerns could be addressed?**

A. The most obvious means of dealing with potential market power is to require that the supplier dedicate a portion of its capacity to a long-term contract.

Alternatively (or additionally) the Commission could assure that the entities serving those customers (or at least the Standard Offer supplier) are substantially covered by bilateral contracts.

Q. Why does a long-term contract mitigate potential market power?

A. Recall that in my general discussion of market power I relayed that the exercise of market power requires both the ability and incentive to do so. If a supplier controls sufficient capacity that the "ability" issue is a question, then reducing the incentive is a cure. To the extent that PWEC has sold its energy under a long-term contract, the pricing of which does not float with the market, it has no incentive to raise prices.

This can be shown in the following example. Suppose that PWEC controls 6,000 MW of capacity. Assume further that withholding 1,000 MW from the market increases the price by $3 per MWh. Also assume that the withheld capacity would have earned $8 per MWh in contribution to profit and fixed costs. The withholding is profitable; profits increase by 5,000*$3 for the remaining capacity and fall by 1,000* $8 for the withheld capacity, so the net profit is $15,000 minus $8,000. Now assume that, say, 4,000 MW of capacity has been sold in a bilateral contract. The impact of withholding on the market price is unaffected: withholding 1,000 MW still increases the market price by $3 per MWh. However, there now are only 1,000 MW of PWEC capacity receiving the elevated price, since the price received for the 4,000 MW of bilateral sales is not increased. The profit calculus now is 1,000*$3 minus 1,000*$8, so the formerly profitably strategy to raise prices is no longer profitable.

Q. Are PWCC and its affiliates currently subject to this type of market power control?

A. Yes. Currently, as a result of the rate plan adopted in the APS Settlement, APS has pre-determined retail rates through at least the first half of 2004. APS, and indeed the Pinnacle West family of companies, do not have enough capacity to supply that load. During high load conditions, when prices are most susceptible to manipulation, the company is a net buyer in the market and hence has a disincentive to increase prices. Even during hours when it has something to sell, the amount of its capacity that it must dedicate to meet APS and wholesale requirements loads leaves it with little to sell into (or withhold from) the market.

APS's proposed long term purchased power agreement with PWCC effectively continues the current style of mitigation far into the future. Since APS would have the right to PWEC's total capacity, and would exercise that right with respect to most of it most of the time, PWEC would have little available to sell at market rates and hence no incentive to increase prices.

Q. Is it necessary that all of PWEC's capacity be dedicated to APS and requirements load in order to constrain its potential market power?

A. No. As I have shown, PWEC would meet FERC's test for market rate authority even if none of its capacity were dedicated to contracts. If the Commission accords less than full faith to the efficacy of that test, and disbelieves the result that APS would price competitively even if all of its capacity were available to sell at market prices, it still would follow that a less-than-100 percent dedication would mitigate potential market power to satisfactory levels. Moreover, any capacity that is dedicated to APS, even if less than 100 percent, thereby reduces the incentive to exercise market power. Any PWEC capacity that wins in any competitive bid auction and thereby gains an intermediate to long-term contract similarly reduces the risk of it exercising market power. As a practical matter, I cannot conceive of an implementation of Commission Rule 1606(B) that would not cover APS's Standard Offer load with bilateral contracts, put the majority of PWEC capacity under bilateral contracts, or both.

It is important to ask the question, over whom is PWEC allegedly exercising market power? If the Commission's policy coming out of these proceedings results in APS's customers being covered by intermediate to long term contracts with PWEC and other parties, as I assume it will, then APS Standard Offer customers have little or no exposure to the competitive wholesale short-term market. SRP and TEP are or will be by then essentially self-reliant and not dependent on power from PWEC. APS's wholesale customers are covered by FERC-regulated contracts. Since Arizona loads will be substantially covered, the energy that PWEC would have available to sell would have to compete in a broad regional wholesale market in which its share is small. In that market, there can be no serious concern that PWEC could exercise market power.

CONCLUSIONS

Q. Would you please summarize your conclusions?

A. Yes. The Commission has determined that Arizona customers are best served by the creation of competitive wholesale and retail markets. Events subsequent to that policy determination have not undercut, and to a substantial extent have confirmed, the soundness of that decision. I recommend that the Commission continue with its policies to restructure the Arizona electricity industry that it regulates.

In furtherance of creating a competitive market, the Commission determined that the jurisdictional utilities should separate their generating assets from transmission, distribution and customer service functions. This remains sound policy.

PWEC will not have market power. In the larger regional market in which it competes, it is a small player. Within Arizona, and in particular within the APS control area, PWEC passes all of the FERC-mandated tests for market power. The potential market power inherent in its must run units will be mitigated by APS's Open Access Tariff provisions and by a future RTO's market power mitigation measures. Any remaining concerns that the Commission might have can be mooted by an intermediate to long-term PPA between PWEC or PWCC and APS and/or by intermediate to long-term bilateral contracts with other suppliers.

Q. Does this complete your written direct testimony in this proceeding?

A. Yes, it does.

WILLIAM H. HIERONYMUS — Vice President

Ph.D. Economics, University of Michigan
M.A. Economics, University of Michigan
B.A. Social Science, University of Iowa

William Hieronymus has consulted extensively to managements of electricity and gas companies, their counsel, regulators, and policymakers. His principal areas of concentration are the structure and regulation of network utilities and associated management, policy, and regulatory issues. Dr. Hieronymus has spent the last thirteen years working on the restructuring and privatization of utility systems in the U.S. and internationally. In this context he has assisted the managements of energy companies on corporate and regulatory strategy, particularly relating to asset acquisition and divestiture. He has testified extensively on regulatory policy issues and on market power issues related to mergers and acquisitions. In his twenty-plus years of consulting to this sector, he also has performed a number of more specific functional tasks, including selecting investments; determining procedures for contracting with independent power producers; and assisting in contract negotiation, tariff formation, demand forecasting, and fuels market forecasting. Dr. Hieronymus has testified frequently on behalf of energy sector clients before regulatory bodies, federal courts, and legislative bodies in the United States and United Kingdom. He has contributed to numerous projects, including the following:

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U.S. Market Restructuring Assignments

- Dr. Hieronymus advised on the formation of a Transco in response to FERC's Order 2000. His primary role was to advise on the concepts and details of market design.

- Dr. Hieronymus serves as an advisor to the senior executives of an electric utility on restructuring and related regulatory issues, and he has worked with senior management in developing strategies for shaping and adapting to the emerging competitive market in electricity. As a part of this general assignment, he has testified regarding regulatory filings with state agencies, evaluation of potential acquisitions, and aspects of internal restructuring.

- For several utilities seeking merger approval, Dr. Hieronymus has prepared and testified to market power analyses at FERC and before state commissions. He also has assisted in discussions with the Antitrust Division of the Department of Justice and in responding to information requests. The mergers on which Dr. Hieronymus has testified include both electricity mergers and combination mergers involving electricity and gas companies. Among the major mergers where he has testified are Sempra, Xcel, Exelon, AEP-CSW, Dynergy-Illinois Power, Con Edison-Orange and Rockland, Dominion-CNG, Nisource-Consolidated Natural , Eon-LG&E and Nyseg_RG&E.

- For utilities seeking to sell or purchase generating assets, Dr. Hieronymus has provided analyses concerning market power in support of submissions under sections 203 and 205 of the Federal Power Act and analyses required by state regulatory commissions.

- For utilities and power pools engaged in restructuring activities, he has assisted in examining various facets of proposed reforms. Such analysis has included features of the proposals affecting market efficiency and those that have potential consequences for market power. Where relevant, the analysis also has examined the effects of alternative reforms on the client's financial performance and achievement of other objectives.

- For the New England Power Pool (NEPOOL), Dr. Hieronymus examined the issue of market power in connection with NEPOOL's movement to market-based pricing for energy, capacity, and ancillary services. He also assisted the New England utilities in preparing their market power mitigation proposal. The main results of his analysis were incorporated in NEPOOL's market power filing before FERC.

- For a coalition of independent generators, he provided affidavits advising FERC on changes to the rules under which the northeastern U.S. power pools operate.

- As part of a large planning and analysis team, Dr. Hieronymus assisted a Midwest utility in developing an innovative proposal for electricity industry restructuring. This work formed the basis for that utility's proposals in its state's restructuring proceeding.

- Dr. Hieronymus has contributed substantially to projects dealing with the restructuring of the California electricity industry. In this context he also is a witness in California and FERC proceedings on the subject of market power and mitigation.

Valuation of Utility Assets in North America

- Dr. Hieronymus has testified in state securitization and stranded cost quantification proceedings, primarily in forecasting the level of market prices that should be used in assessing the future revenues and the operating contribution earned by the owner of utility assets in energy and capacity markets. The market price analyses are tailored to the specific features of the market in which a utility will operate and reflect transmission-constrained trading over a wide geographic area. He also has testified in rebuttal to other parties' testimony concerning stranded costs, and has assisted companies in internal stranded cost and asset valuation studies.

- He was the primary valuation witness on behalf of a western utility in an arbitration proceeding concerning the value of a combined cycle plant coming off lease that the utility wished to purchase.

- He assisted a bidder in determining the commercial terms of plant purchase offers as well as assisting clients in assessing the regulatory feasibility of potential acquisitions and mergers.

Other U.S. Utility Engagements

- Dr. Hieronymus has contributed to the development of several benchmarking analyses for U.S. utilities. These have been used in work with clients to develop regulatory proposals, set cost reduction targets, restructure internal operations, and assess merger savings.

- Dr. Hieronymus was a co-developer of a market simulation package tailored to region-specific applications. He and other senior personnel have conducted numerous multi-day training sessions using the package to help utility clients in educating management regarding the consequences of wholesale and retail deregulation and in developing the skills necessary to succeed in this environment.

- He has made numerous presentations to U.S. utility managements regarding the U.K. electricity system and, for senior U.S. utility managements, has arranged meetings with executives and regulators in the U.K.

- For an East Coast electricity holding company, Dr. Hieronymus prepared and testified to an analysis of the logic and implementation issues concerning utility-sponsored conservation and demand-management programs as alternatives to new plant construction.

- In connection with nuclear generating plants nearing completion, he has testified in Pennsylvania, Louisiana, Arizona, Illinois, Missouri, New York, Texas, Arkansas, New Mexico, and before the Federal Energy Regulatory Commission regarding plant-in-service rate cases on the issues of equitable and economically efficient treatment of plant costs for tariff-setting purposes, regulatory treatment of new plants in other jurisdictions, the prudence of past system planning decisions and assumptions, performance incentives, and the life-cycle costs and benefits of the units. In these and other utility regulatory proceedings, Dr. Hieronymus and his colleagues have provided extensive support to counsel, including preparation of interrogatories, cross-examination support, and assistance in writing briefs.

- On behalf of utilities in the states of Michigan, Massachusetts, New York, Maine, Indiana, Pennsylvania, New Hampshire, and Illinois, he has submitted testimony in regulatory proceedings on the economics of completing nuclear generating plants that are currently under construction. His testimony has covered the likely cost of plant completion; forecasts of operating performance; and extensive analyses of the impacts of completion, deferral, and cancellation upon ratepayers and shareholders.

- For utilities engaged in nuclear plant construction, Dr. Hieronymus has performed a number of highly confidential assignments to support strategic decisions concerning the continuance of construction. Areas of inquiry included plant cost, financial feasibility, power marketing opportunities, the impact of potential regulatory treatments of plant cost on shareholders and customers, and evaluation of offers to purchase partially completed facilities.

- For an eastern Pennsylvania utility that suffered a nuclear plant shutdown due to NRC sanctions relating to plant management, he filed testimony regarding the extent to which replacement power cost exceeded the costs that would have occurred but for the shutdown.

- For a major Midwestern utility, Dr. Hieronymus headed a team that assisted senior management in devising its strategic plans, including examination of such issues as plant refurbishment/life extension strategies, impacts of increased competition, and available diversification opportunities.
- On behalf of two West Coast utilities, Dr. Hieronymus testified in a needs certification hearing for a major coal-fired generation complex concerning the economics of the facility relative to competing sources of power, particularly unconventional sources and demand reductions.
- For a large western combination utility, he participated in a major 18-month effort to provide the client with an integrated planning and rate case management system. His specific responsibilities included assisting in the design and integration of electric and gas energy demand forecasts, peak load and load shape forecasts, and forecasts of the impacts of conservation and load management programs.
- For two Midwestern utilities, Dr. Hieronymus prepared an analysis of intervenor-proposed modifications to the utilities' resource plans. He then testified on their behalf before a legislative committee.
- For a major combination electric and gas utility, he directed the adaptation of a financial simulation model for use in resource planning and evaluation of conservation programs.

U.K. Assignments

- Following promulgation of the white paper that established the general framework for privatization of the electricity industry in the United Kingdom, Dr. Hieronymus participated extensively in the task forces charged with developing the new market system and regulatory regime. His work on behalf of the Electricity Council and the twelve regional councils focused on the proposed regulatory regime, including the price cap and regulatory formulas, and distribution and transmission use of system tariffs. He was an active participant in industry-government task forces charged with creating the legislation, regulatory framework, initial contracts, and rules of the pooling and settlements system. He also assisted the regional companies in the valuation of initial contract offers from the generators, including supporting their successful refusal to contract for the proposed nuclear power plants that subsequently were canceled as being non-commercial.
- During the preparation for privatization, Dr. Hieronymus assisted several individual U.K. electricity companies in understanding the evolving system, in developing use of system tariffs, and in enhancing technical capabilities in power purchasing and contracting. He continued to advise a number of clients, including regional companies, power developers, large industrial customers, and financial institutions on the U.K. power system for a number of years after privatization.

- Dr. Hieronymus assisted four of the regional electricity companies in negotiating equity ownership positions and developing the power purchase contracts for a 1,825 megawatt combined cycle gas station. He also assisted clients in evaluating other potential generating investments including cogeneration and non-conventional resources.

- Dr. Hieronymus also has consulted on the separate reorganization and privatization of the Scottish electricity sector. Part of his role in that privatization included advising the larger of the two Scottish companies and, through it, the Secretary of State on all phases of the restructuring and privatization, including the drafting of regulations, asset valuation, and company strategy.

- He assisted one of the Regional Electricity Companies in England and Wales in the 1993 through 1995 regulatory proceedings that reset the price caps for its retailing and distribution businesses. Included in this assignment was consideration of such policy issues as incentives for the economic purchasing of power, the scope of price control, and the use of comparisons among companies as a basis for price regulation. Dr. Hieronymus's model for determining network refurbishment needs was used by the regulator in determining revenue allowances for capital investments.

- He assisted this same utility in its defense against a hostile takeover, including preparation of its submission to the Cabinet Minister who had the responsibility for determining whether the merger should be referred to the competition authority.

Assignments Outside the U.S. and U.K.

- Dr. Hieronymus assisted a large state-owned European electricity company in evaluating the impacts of the 1997 EU directive on electricity that *inter alia* requires retail access and competitive markets for generation. The assignment included advice on the organizational solution to elements of the directive requiring a separate transmission system operator and the business need to create a competitive marketing function.

- For the European Bank for Reconstruction and Development, he performed analyses of least-cost power options and evaluated the return on a major investment that the Bank was considering for a partially completed nuclear plant in Slovakia. Part of this assignment involved developing a forecast of electricity prices, both in Eastern Europe and for potential exports to the West.

- For the OECD he performed a study of energy subsidies worldwide and the impact of subsidy elimination on the environment, particularly on greenhouse gases.

- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, Dr. Hieronymus developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command-and-control system to a decentralized, corporatized system.

- For Iberdrola, the largest investor-owned Spanish electricity company, he assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution companies, its regulation, and the phasing out of subsidies. He also has assisted the company in evaluating generation expansion options and in valuing offers for imported power.

- Dr. Hieronymus contributed extensively to a project for the Ukrainian Electricity Ministry, the goal of which was to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. The proposed reorganization is based on regional electric power companies, linked by a unified central market, with market-based prices for electricity.

- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior managers for the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, Dr. Hieronymus continued to advise both the Russian energy and power ministry and the government-owned generation and transmission company on restructuring and market development issues.

- On behalf of a large continental electricity company, Dr. Hieronymus analyzed the proposed directives from the European Commission on gas and electricity transit (open access regimes) and on the internal market for electricity. The purpose of this assignment was to forecast likely developments in the structure and regulation of the electricity sector in the common market and to assist the client in understanding their implications.

- For the electric utility company of the Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.

- For a task force representing the Treasury, electricity generating, and electricity distribution industries in New Zealand, Dr. Hieronymus undertook an analysis of industry structure and regulatory alternatives for achieving the economically efficient generation of electricity. The analysis explored how the industry likely would operate under alternative regimes and their implications for asset valuation, electricity pricing, competition, and regulatory requirements.

TARIFF DESIGN METHODOLOGIES AND POLICY ISSUES

- Dr. Hieronymus participated in a series of studies for the National Grid Company of the United Kingdom and for ScottishPower on appropriate pricing methodologies for transmission, including incentives for efficient investment and location decisions.

- For a U.S. utility client, he directed an analysis of time-differentiated costs based on accounting concepts. The study required selection of rating periods and allocation of costs to time periods and within time periods to rate classes.

- For EPRI, Dr. Hieronymus directed a study that examined the effects of time-of-day rates on the level and pattern of residential electricity consumption.

- For the EPRI-NARUC Rate Design Study, he developed a methodology for designing optimum cost-tracking block rate structures.

- On behalf of a group of cogenerators, Dr. Hieronymus filed testimony before the Energy Select Committee of the UK Parliament on the effects of prices on cogeneration development.

- For the Edison Electric Institute (EEI), he prepared a statement of the industry's position on proposed federal guidelines regarding fuel adjustment clauses. He also assisted EEI in responding to the U.S. Department of Energy (DOE) guidelines on cost-of-service standards.

- For private utility clients, Dr. Hieronymus assisted in the preparation both of their comments on draft FERC regulations and of their compliance plans for PURPA Section 133.

- For the EEI Utility Regulatory Analysis Program, he co-authored an analysis of the DOE position on the purposes of the Public Utilities Regulatory Policies Act (PURPA) of 1978. The report focused on the relationship between those purposes and cost-of-service and ratemaking positions under consideration in the generic hearings required by PURPA.

- For a state utilities commission, Dr. Hieronymus assessed its utilities' existing automatic adjustment clauses to determine their compliance with PURPA and recommended modifications.

- For DOE, he developed an analysis of automatic adjustment clauses currently employed by electric utilities. The focus of this analysis was on efficiency incentive effects.

- For the commissioners of a public utility commission, Dr. Hieronymus assisted in preparation of briefing papers, lines of questioning, and proposed findings of fact in a generic rate design proceeding.

SALES FORECASTING METHODOLOGIES FOR GAS AND ELECTRIC UTILITIES

- For the White House Sub-Cabinet Task Force on the future of the electric utility industry, Dr. Hieronymus co-directed a major analysis of "least-cost planning studies" and "low-growth energy futures." That analysis was the sole demand-side study commissioned by the task force, and it formed an important basis for the task force's conclusions concerning the need for new facilities and the relative roles of new construction and customer side-of-the-meter programs in utility planning.

- For a large eastern utility, Dr. Hieronymus developed a load forecasting model designed to interface with the utility's revenue forecasting system-planning functions. The model forecasts detailed monthly sales and seasonal peaks for a 10-year period.

- For DOE, he directed development of an independent needs assessment model for use by state public utility commissions. This major study developed the capabilities required for independent forecasting by state commissions and provided a forecasting model for their interim use.

- For several state regulatory commissions, Dr. Hieronymus has consulted in the development of service area-level forecasting models of electric utility companies.

- For EPRI, he authored a study of electricity demand and load forecasting models. The study surveyed state-of-the-art models of electricity demand and subjected the most promising models to empirical testing to determine their potential for use in long-term forecasting.

- For a Midwestern electric utility, he provided consulting assistance in improving the client's load forecast, and testified in defense of the revised forecasting models.

- For an East Coast gas utility, Dr. Hieronymus testified with respect to sales forecasts and provided consulting assistance in improving the models used to forecast residential and commercial sales.

OTHER STUDIES PERTAINING TO REGULATED AND ENERGY COMPANIES

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These cases have included Sherman Act Section 1 and 2 allegations, contract negotiations, generic rate hearings, ITC hearings, and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. For a major electrical equipment vendor, Dr. Hieronymus testified on damages with respect to alleged defects and associated fraud and warranty claims. In connection with mergers for which he is the market power expert, Dr. Hieronymus is assisting clients in responding to the Hart-Scott-Rodino requests issued by the Antitrust Division of the U.S. Department of Justice. In an arbitration case, he testified as to changed circumstances affecting the equitable nature of a contract. In a municipalization case, he testified concerning the reasonable expectation period for the supplier of power and transmission services to a municipality.

- For a private client, Dr. Hieronymus headed a project that examined the feasibility and value of a major synthetic natural gas project. The study analyzed both the future supply costs of alternative natural gas sources and the effects of potential changes in FPC rate regulations on project viability. The analysis was used in preparing contract negotiation strategies.

- For an industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, Dr. Hieronymus developed an estimate of the potential market for the system by geographic area.
- For the U.S. Environmental Protection Agency (EPA), he was the principal investigator in a series of studies that forecasted future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

Dr. Hieronymus has addressed a number of conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervenor strategies in utility regulatory proceedings, utility deregulation, and utility-related opportunities for investment bankers. Prior to rejoining CRA in June 2001, Dr. Hieronymus was a Member of the Management Group at PA Consulting, which acquired Hagler Bailly, Inc. in October 2000. He was a Senior Vice President of Hagler Bailly. In 1998, Hagler Bailly acquired Dr. Hieronymus's former employer, Putnam, Hayes & Bartlett, Inc. He was a Managing Director at PHB. He joined PHB in 1978. From 1973 to 1978 he was a Senior Research Associate at CRA. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving as a Captain in the U.S. Army

WILLIAM H. HIERONYMUS — Vice President

Ph.D.	Economics, University of Michigan
M.A.	Economics, University of Michigan
B.A.	Social Science, University of Iowa

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- Dr. Hieronymus advised on the formation of a Transco in response to FERC's Order 2000. His primary role was to advise on the concepts and details of market design.
- Dr. Hieronymus serves as an advisor to the senior executives of an electric utility on restructuring and related regulatory issues, and he has worked with senior management in developing strategies for shaping and adapting to the emerging competitive market in electricity. As a part of this general assignment, he has testified regarding regulatory filings with state agencies, evaluation of potential acquisitions, and aspects of internal restructuring.
- For several utilities seeking merger approval, Dr. Hieronymus has prepared and testified to market power analyses at FERC and before state commissions. He also has assisted in discussions with the Antitrust Division of the Department of Justice and in responding to information requests. The mergers on which Dr. Hieronymus has testified include both electricity mergers and combination mergers involving electricity and gas companies. Among the major mergers where he has testified are Sempra, Xcel, Exelon, AEP-CSW, Dynergy-Illinois Power, Con Edison-Orange and Rockland, Dominion-CNG, Nisource-Consolidated Natural , Eon-LG&E and Nyseg_RG&E.
- For utilities seeking to sell or purchase generating assets, Dr. Hieronymus has provided analyses concerning market power in support of submissions under sections 203 and 205 of the Federal Power Act and analyses required by state regulatory commissions.
- For utilities and power pools engaged in restructuring activities, he has assisted in examining various facets of proposed reforms. Such analysis has included features of the proposals affecting market efficiency and those that have potential consequences for market power. Where relevant, the analysis also has examined the effects of alternative reforms on the client's financial performance and achievement of other objectives.
- For the New England Power Pool (NEPOOL), Dr. Hieronymus examined the issue of market power in connection with NEPOOL's movement to market-based pricing for energy, capacity, and ancillary services. He also assisted the New England utilities in preparing their market power mitigation proposal. The main results of his analysis were incorporated in NEPOOL's market power filing before FERC.
- For a coalition of independent generators, he provided affidavits advising FERC on changes to the rules under which the northeastern U.S. power pools operate.
- As part of a large planning and analysis team, Dr. Hieronymus assisted a Midwest utility in developing an innovative proposal for electricity industry restructuring. This work formed the basis for that utility's proposals in its state's restructuring proceeding.

- Dr. Hieronymus has contributed substantially to projects dealing with the restructuring of the California electricity industry. In this context he also is a witness in California and FERC proceedings on the subject of market power and mitigation.

Valuation of Utility Assets in North America

- Dr. Hieronymus has testified in state securitization and stranded cost quantification proceedings, primarily in forecasting the level of market prices that should be used in assessing the future revenues and the operating contribution earned by the owner of utility assets in energy and capacity markets. The market price analyses are tailored to the specific features of the market in which a utility will operate and reflect transmission-constrained trading over a wide geographic area. He also has testified in rebuttal to other parties' testimony concerning stranded costs, and has assisted companies in internal stranded cost and asset valuation studies.

- He was the primary valuation witness on behalf of a western utility in an arbitration proceeding concerning the value of a combined cycle plant coming off lease that the utility wished to purchase.

- He assisted a bidder in determining the commercial terms of plant purchase offers as well as assisting clients in assessing the regulatory feasibility of potential acquisitions and mergers.

Other U.S. Utility Engagements

- Dr. Hieronymus has contributed to the development of several benchmarking analyses for U.S. utilities. These have been used in work with clients to develop regulatory proposals, set cost reduction targets, restructure internal operations, and assess merger savings.

- Dr. Hieronymus was a co-developer of a market simulation package tailored to region-specific applications. He and other senior personnel have conducted numerous multi-day training sessions using the package to help utility clients in educating management regarding the consequences of wholesale and retail deregulation and in developing the skills necessary to succeed in this environment.

- He has made numerous presentations to U.S. utility managements regarding the U.K. electricity system and, for senior U.S. utility managements, has arranged meetings with executives and regulators in the U.K.

- For an East Coast electricity holding company, Dr. Hieronymus prepared and testified to an analysis of the logic and implementation issues concerning utility-sponsored conservation and demand-management programs as alternatives to new plant construction.

- In connection with nuclear generating plants nearing completion, he has testified in Pennsylvania, Louisiana, Arizona, Illinois, Missouri, New York, Texas, Arkansas, New Mexico, and before the Federal Energy Regulatory Commission regarding plant-in-service rate cases on the issues of equitable and economically efficient treatment of plant costs for tariff-setting purposes, regulatory treatment of new plants in other jurisdictions, the prudence of past system planning decisions and assumptions, performance incentives, and the life-cycle costs and benefits of the units. In these and other utility regulatory proceedings, Dr. Hieronymus and his colleagues have provided extensive support to counsel, including preparation of interrogatories, cross-examination support, and assistance in writing briefs.

- On behalf of utilities in the states of Michigan, Massachusetts, New York, Maine, Indiana, Pennsylvania, New Hampshire, and Illinois, he has submitted testimony in regulatory proceedings on the economics of completing nuclear generating plants that are currently under construction. His testimony has covered the likely cost of plant completion; forecasts of operating performance; and extensive analyses of the impacts of completion, deferral, and cancellation upon ratepayers and shareholders.

- For utilities engaged in nuclear plant construction, Dr. Hieronymus has performed a number of highly confidential assignments to support strategic decisions concerning the continuance of construction. Areas of inquiry included plant cost, financial feasibility, power marketing opportunities, the impact of potential regulatory treatments of plant cost on shareholders and customers, and evaluation of offers to purchase partially completed facilities.

- For an eastern Pennsylvania utility that suffered a nuclear plant shutdown due to NRC sanctions relating to plant management, he filed testimony regarding the extent to which replacement power cost exceeded the costs that would have occurred but for the shutdown.

- For a major Midwestern utility, Dr. Hieronymus headed a team that assisted senior management in devising its strategic plans, including examination of such issues as plant refurbishment/life extension strategies, impacts of increased competition, and available diversification opportunities.

- On behalf of two West Coast utilities, Dr. Hieronymus testified in a needs certification hearing for a major coal-fired generation complex concerning the economics of the facility relative to competing sources of power, particularly unconventional sources and demand reductions.

- For a large western combination utility, he participated in a major 18-month effort to provide the client with an integrated planning and rate case management system. His specific responsibilities included assisting in the design and integration of electric and gas energy demand forecasts, peak load and load shape forecasts, and forecasts of the impacts of conservation and load management programs.

- For two Midwestern utilities, Dr. Hieronymus prepared an analysis of intervenor-proposed modifications to the utilities' resource plans. He then testified on their behalf before a legislative committee.

- For a major combination electric and gas utility, he directed the adaptation of a financial simulation model for use in resource planning and evaluation of conservation programs.

U.K. Assignments

- Following promulgation of the white paper that established the general framework for privatization of the electricity industry in the United Kingdom, Dr. Hieronymus participated extensively in the task forces charged with developing the new market system and regulatory regime. His work on behalf of the Electricity Council and the twelve regional councils focused on the proposed regulatory regime, including the price cap and regulatory formulas, and distribution and transmission use of system tariffs. He was an active participant in industry-government task forces charged with creating the legislation, regulatory framework, initial contracts, and rules of the pooling and settlements system. He also assisted the regional companies in the valuation of initial contract offers from the generators, including supporting their successful refusal to contract for the proposed nuclear power plants that subsequently were canceled as being non-commercial.

- During the preparation for privatization, Dr. Hieronymus assisted several individual U.K. electricity companies in understanding the evolving system, in developing use of system tariffs, and in enhancing technical capabilities in power purchasing and contracting. He continued to advise a number of clients, including regional companies, power developers, large industrial customers, and financial institutions on the U.K. power system for a number of years after privatization.

- Dr. Hieronymus assisted four of the regional electricity companies in negotiating equity ownership positions and developing the power purchase contracts for a 1,825 megawatt combined cycle gas station. He also assisted clients in evaluating other potential generating investments including cogeneration and non-conventional resources.

- Dr. Hieronymus also has consulted on the separate reorganization and privatization of the Scottish electricity sector. Part of his role in that privatization included advising the larger of the two Scottish companies and, through it, the Secretary of State on all phases of the restructuring and privatization, including the drafting of regulations, asset valuation, and company strategy.

- He assisted one of the Regional Electricity Companies in England and Wales in the 1993 through 1995 regulatory proceedings that reset the price caps for its retailing and distribution businesses. Included in this assignment was consideration of such policy issues as incentives for the economic purchasing of power, the scope of price control, and the use of comparisons among companies as a basis for price regulation. Dr. Hieronymus's model for determining network refurbishment needs was used by the regulator in determining revenue allowances for capital investments.

- He assisted this same utility in its defense against a hostile takeover, including preparation of its submission to the Cabinet Minister who had the responsibility for determining whether the merger should be referred to the competition authority.

Assignments Outside the U.S. and U.K.

- Dr. Hieronymus assisted a large state-owned European electricity company in evaluating the impacts of the 1997 EU directive on electricity that *inter alia* requires retail access and competitive markets for generation. The assignment included advice on the organizational solution to elements of the directive requiring a separate transmission system operator and the business need to create a competitive marketing function.

- For the European Bank for Reconstruction and Development, he performed analyses of least-cost power options and evaluated the return on a major investment that the Bank was considering for a partially completed nuclear plant in Slovakia. Part of this assignment involved developing a forecast of electricity prices, both in Eastern Europe and for potential exports to the West.

- For the OECD he performed a study of energy subsidies worldwide and the impact of subsidy elimination on the environment, particularly on greenhouse gases.

- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, Dr. Hieronymus developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command-and-control system to a decentralized, corporatized system.

- For Iberdrola, the largest investor-owned Spanish electricity company, he assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution companies, its regulation, and the phasing out of subsidies. He also has assisted the company in evaluating generation expansion options and in valuing offers for imported power.

- Dr. Hieronymus contributed extensively to a project for the Ukrainian Electricity Ministry, the goal of which was to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. The proposed reorganization is based on regional electric power companies, linked by a unified central market, with market-based prices for electricity.

- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior managers for the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, Dr. Hieronymus continued to advise both the Russian energy and power ministry and the government-owned generation and transmission company on restructuring and market development issues.

- On behalf of a large continental electricity company, Dr. Hieronymus analyzed the proposed directives from the European Commission on gas and electricity transit (open access regimes) and on the internal market for electricity. The purpose of this assignment was to forecast likely developments in the structure and regulation of the electricity sector in the common market and to assist the client in understanding their implications.

- For the electric utility company of the Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.

- For a task force representing the Treasury, electricity generating, and electricity distribution industries in New Zealand, Dr. Hieronymus undertook an analysis of industry structure and regulatory alternatives for achieving the economically efficient generation of electricity. The analysis explored how the industry likely would operate under alternative regimes and their implications for asset valuation, electricity pricing, competition, and regulatory requirements.

TARIFF DESIGN METHODOLOGIES AND POLICY ISSUES

- Dr. Hieronymus participated in a series of studies for the National Grid Company of the United Kingdom and for ScottishPower on appropriate pricing methodologies for transmission, including incentives for efficient investment and location decisions.

- For a U.S. utility client, he directed an analysis of time-differentiated costs based on accounting concepts. The study required selection of rating periods and allocation of costs to time periods and within time periods to rate classes.

- For EPRI, Dr. Hieronymus directed a study that examined the effects of time-of-day rates on the level and pattern of residential electricity consumption.

- For the EPRI-NARUC Rate Design Study, he developed a methodology for designing optimum cost-tracking block rate structures.

- On behalf of a group of cogenerators, Dr. Hieronymus filed testimony before the Energy Select Committee of the UK Parliament on the effects of prices on cogeneration development.

- For the Edison Electric Institute (EEI), he prepared a statement of the industry's position on proposed federal guidelines regarding fuel adjustment clauses. He also assisted EEI in responding to the U.S. Department of Energy (DOE) guidelines on cost-of-service standards.

- For private utility clients, Dr. Hieronymus assisted in the preparation both of their comments on draft FERC regulations and of their compliance plans for PURPA Section 133.

- For the EEI Utility Regulatory Analysis Program, he co-authored an analysis of the DOE position on the purposes of the Public Utilities Regulatory Policies Act (PURPA) of 1978. The report focused on the relationship between those purposes and cost-of-service and ratemaking positions under consideration in the generic hearings required by PURPA.

- For a state utilities commission, Dr. Hieronymus assessed its utilities' existing automatic adjustment clauses to determine their compliance with PURPA and recommended modifications.

- For DOE, he developed an analysis of automatic adjustment clauses currently employed by electric utilities. The focus of this analysis was on efficiency incentive effects.

- For the commissioners of a public utility commission, Dr. Hieronymus assisted in preparation of briefing papers, lines of questioning, and proposed findings of fact in a generic rate design proceeding.

SALES FORECASTING METHODOLOGIES FOR GAS AND ELECTRIC UTILITIES

- For the White House Sub-Cabinet Task Force on the future of the electric utility industry, Dr. Hieronymus co-directed a major analysis of "least-cost planning studies" and "low-growth energy futures." That analysis was the sole demand-side study commissioned by the task force, and it formed an important basis for the task force's conclusions concerning the need for new facilities and the relative roles of new construction and customer side-of-the-meter programs in utility planning.

- For a large eastern utility, Dr. Hieronymus developed a load forecasting model designed to interface with the utility's revenue forecasting system-planning functions. The model forecasts detailed monthly sales and seasonal peaks for a 10-year period.

- For DOE, he directed development of an independent needs assessment model for use by state public utility commissions. This major study developed the capabilities required for independent forecasting by state commissions and provided a forecasting model for their interim use.

- For several state regulatory commissions, Dr. Hieronymus has consulted in the development of service area-level forecasting models of electric utility companies.

- For EPRI, he authored a study of electricity demand and load forecasting models. The study surveyed state-of-the-art models of electricity demand and subjected the most promising models to empirical testing to determine their potential for use in long-term forecasting.

- For a Midwestern electric utility, he provided consulting assistance in improving the client's load forecast, and testified in defense of the revised forecasting models.

- For an East Coast gas utility, Dr. Hieronymus testified with respect to sales forecasts and provided consulting assistance in improving the models used to forecast residential and commercial sales.

OTHER STUDIES PERTAINING TO REGULATED AND ENERGY COMPANIES

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These cases have included Sherman Act Section 1 and 2 allegations, contract negotiations, generic rate hearings, ITC hearings, and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. For a major electrical equipment vendor, Dr. Hieronymus testified on damages with respect to alleged defects and associated fraud and warranty claims. In connection with mergers for which he is the market power expert, Dr. Hieronymus is assisting clients in responding to the Hart-Scott-Rodino requests issued by the Antitrust Division of the U.S. Department of Justice. In an arbitration case, he testified as to changed circumstances affecting the equitable nature of a contract. In a municipalization case, he testified concerning the reasonable expectation period for the supplier of power and transmission services to a municipality.

- For a private client, Dr. Hieronymus headed a project that examined the feasibility and value of a major synthetic natural gas project. The study analyzed both the future supply costs of alternative natural gas sources and the effects of potential changes in FPC rate regulations on project viability. The analysis was used in preparing contract negotiation strategies.

- For an industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, Dr. Hieronymus developed an estimate of the potential market for the system by geographic area.
- For the U.S. Environmental Protection Agency (EPA), he was the principal investigator in a series of studies that forecasted future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

Dr. Hieronymus has addressed a number of conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervenor strategies in utility regulatory proceedings, utility deregulation, and utility-related opportunities for investment bankers.
Prior to rejoining CRA in June 2001, Dr. Hieronymus was a Member of the Management Group at PA Consulting, which acquired Hagler Bailly, Inc. in October 2000. He was a Senior Vice President of Hagler Bailly. In 1998, Hagler Bailly acquired Dr. Hieronymus's former employer, Putnam, Hayes & Bartlett, Inc. He was a Managing Director at PHB. He joined PHB in 1978. From 1973 to 1978 he was a Senior Research Associate at CRA. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving as a Captain in the U.S. Army

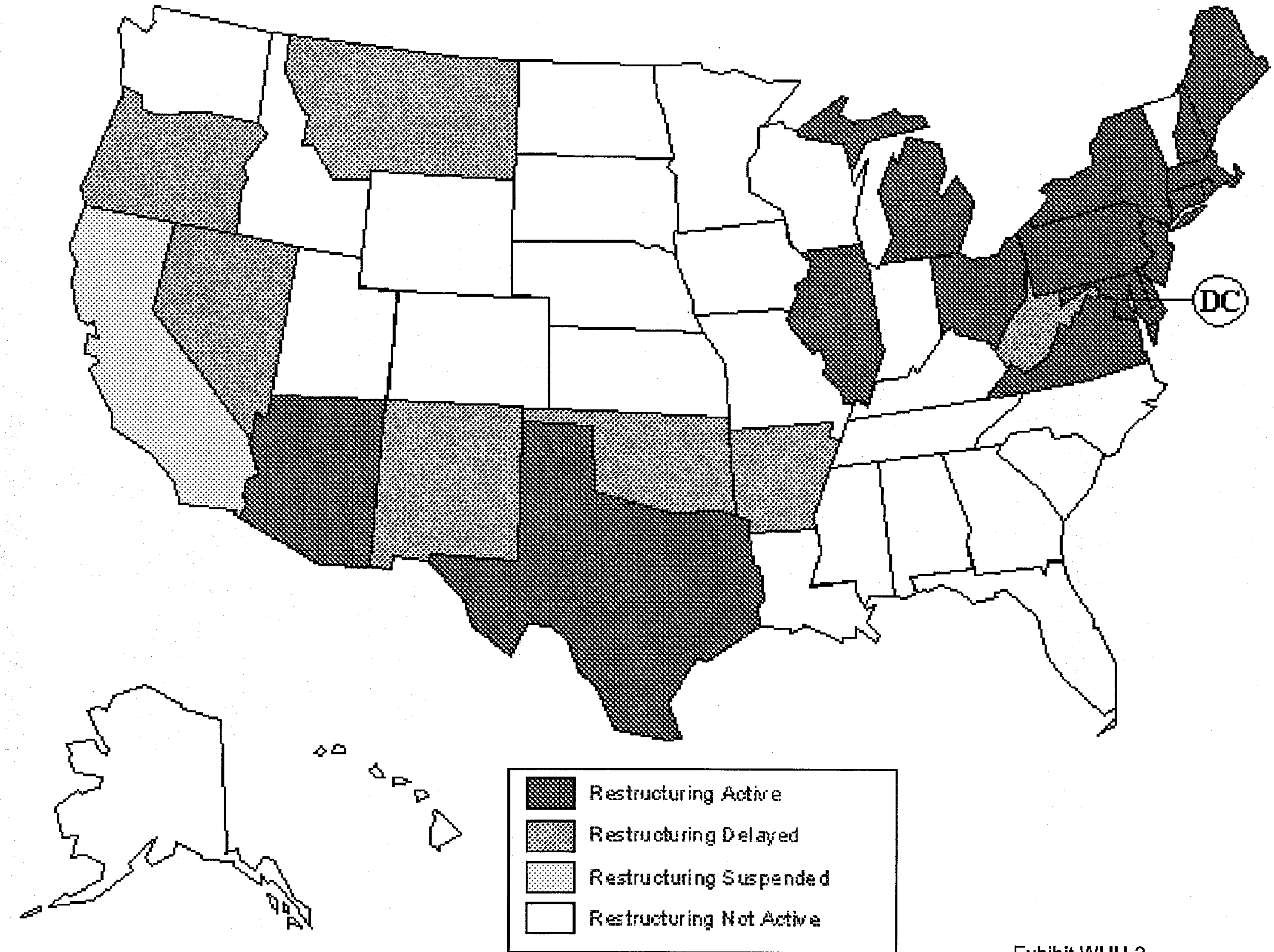


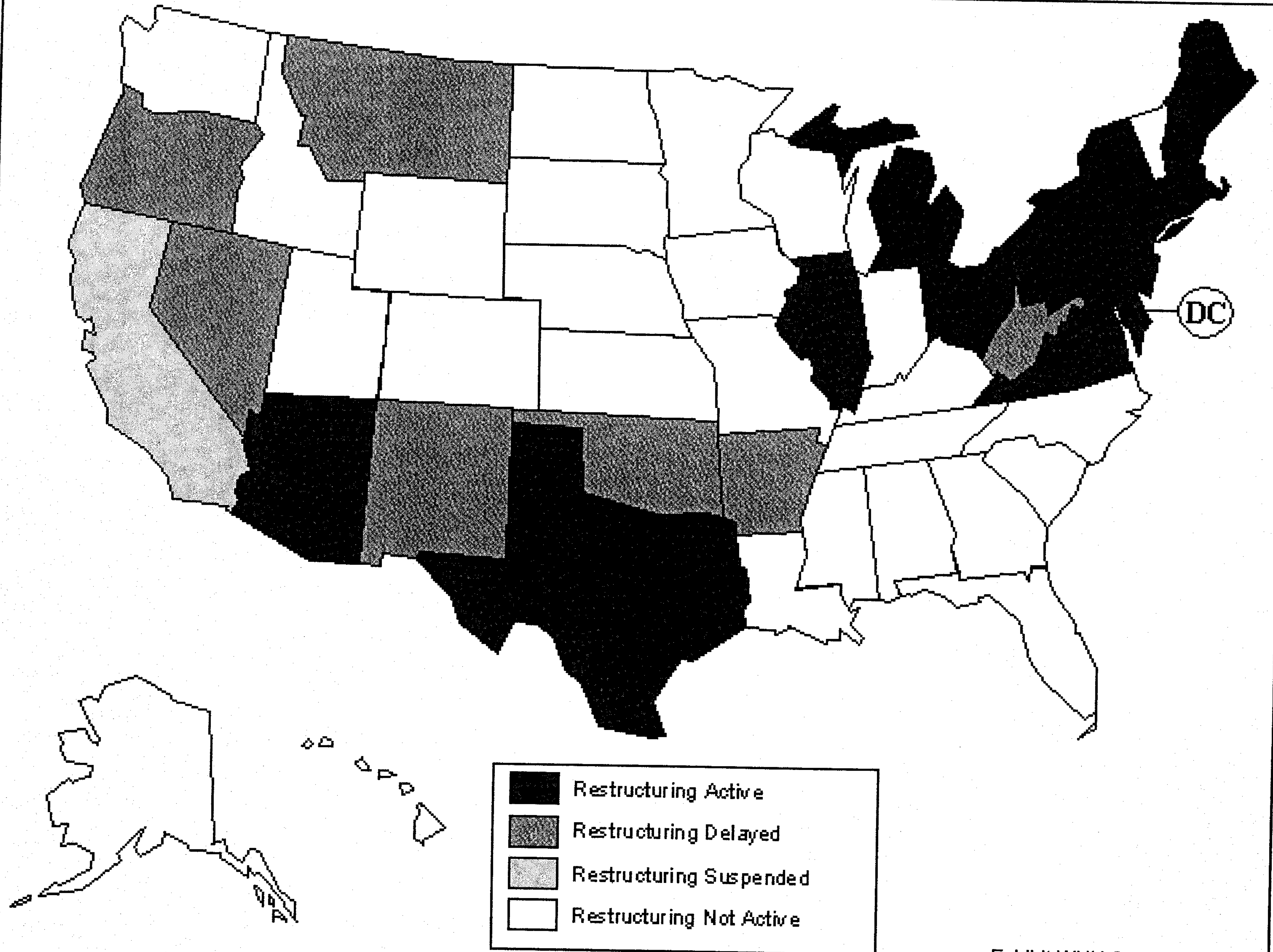
Exhibit WHH-2

Exhibit No. WHH-3
SMA Screen for APS Control Area
Summer 2003

Inside Generation	**MW**	*Key*
PWEC and Affiliated Generation		
PWEC (owned) [1/]	5,751	
PWEC (contracts) [2/]	820	
Subtotal: PWCC	6,571	*[A]*
Merchant Capacity (owner)		
Gila River 1-4 (Panda/TECO)	2,080	
Desert Basin (Reliant)	510	
Subtotal: Merchant Capacity	2,590	
Existing Capacity (excludes PWEC afffiliated capacity)		
Four Corners	1,258	
Navajo	1,935	
Subtotal: Existing Capacity at Jointly-Owned Units	3,193	
Subtotal: Non-PWEC Internal Generation	5,783	*[B]*
Total Local Generation:	12,354	*[C] = [A] + [B]*
Imports [3/]	8,943	*[D]*
Available Supply	21,297	*[E] = [C] + [D]*
Peak Control Area (APS) Load	6,127	*[F]*
Supply Margin	**15,170**	*[G] = [E] - [F]*
Can Load be Met without PWEC Capacity?	**Yes**	*Is [A] < [G] ?*
Non-PWEC Affiliated Generation in Excess of Load	**8,599**	*[E] -[A] - [F]* *(or, [G] - [A])*

Potential Imports	**TTC** [5/]	**New Capacity** [6/]	**Minimum (TTC or New Capacity)**
TTC into APS	8,943		
Arizona		5,110	
California		15,483	
Colorado		2,059	
New Mexico		1,162	
Total:	8,943	23,814	8,943

Notes:
[1/] Includes PWEC affiliated capacity at Palo Verde and Redhawk.
[2/] Includes 480 MW PacifiCorp purchase and 340 MW purchase from SRP.
[3/] Import TTC into APS system was reduced by APS' share of Palo Verde and Redhawk.
[4/] APS peak load forecasts is for 2003 (from 2000 FERC Form 714 filings).
[5/] TTC value consists of 11,089 MW of TTC, less 2,146 MW to account for APS' share of Palo Verde and Redhawk.
[6/] New Capacity estimates from WSCC Proposed Generation Database (http://www.energy.ca.gov/electricity/wscc_proposed_generation.html.) and http://www.cc.state.az.us/utility/electric/Gen020051/jds1606.pdf
Only units categorized as Operational, Under construction, or Regulatory approval received and with on-line dates prior to summer 2003 are included in totals from WSCC Database.



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