Barbara A. Klemstine
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June 4, 1999

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

RE: Docket No. E-01345A-98-0473
Docket No. E-01345A-0773
Docket No. RE-00000C-94-0165

Dear Sir or Madam:

Pursuant to the Hearing Officer's Procedural Order, dated May 25, 1999, Arizona Public Service Company was to file testimony and supporting documents on or before June 4, 1999. Enclosed is the direct testimony of Jack E. Davis, John H. Landon and Alan Propper supporting the Proposed Settlement.

We request that all cooerespondence, documents, testimony and discovery produced by parties in this docket be sent to both of the following parties:

Barbara Klemstine
Arizona Public Service Company
PO Box 53999
Mail Station 9909
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APS
Arizona Public Service Company

COMPANY CORRESPONDENCE

Additionally, in order to facilitate a quick response time to discovery requests it would be appreciated, if you have the e-mail capability, if you would e-mail the request to SMADDEN@APSC.COM in addition to faxing the request to the above parties.

If you have any questions, please contact me at (602)250-2031.

Sincerely,

Barbara A. Klemstine
Manager
Regulatory Affairs

Cc: Docket (Original, plus 10 copies)

BEFORE THE

ARIZONA CORPORATION COMMISSION

TESTIMONY OF JACK E. DAVIS

On Behalf of

Arizona Public Service Company

Docket No. E-01345A-98-0473
Docket No. E-01345A-97-0773
Docket No. RE-00000C-94-0165

June 4, 1999

TABLE OF CONTENTS

DIRECT TESTIMONY
OF
JACK E. DAVIS

(Docket Nos. E-01345A-98-0473, et al.)

I. <u>INTRODUCTION</u>

1.Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

1.A. My name is Jack E. Davis, and my business address is 400 North Fifth Street, Phoenix, Arizona 85004

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

2.A. I am President of Energy Delivery and Sales for Arizona Public Service Company ("APS" or "Company"). My educational and professional qualifications and experience are set forth in Schedule JED-1, which is attached to my testimony.

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

3.A. In response to the Arizona Corporation Commission's ("Commission") Procedural Order of May 25, 1999, I will provide some background to the Settlement Agreement dated May 17, 1999 between APS and a broad group of consumer interests ("APS

Settlement Agreement" or "Agreement"). This Agreement, along with its attachments, can be found as Attachment JED –2 to my testimony. It is important for the Commission and other interested parties to understand and appreciate the difficulty involved in reaching agreement with these diverse groups on so many complicated and important issues. I then discuss and explain each of the various individual sections and provisions of the APS Settlement Agreement and outline why the Commission's timely approval of this Agreement is in the public interest.

II. BACKGROUND TO THE APS SETTLEMENT AGREEMENT

4.Q. COULD YOU DESCRIBE THE GENERAL SCOPE OF THE APS SETTLEMENT AGREEMENT?

4.A. Yes. The APS Settlement Agreement addresses a multitude of competition-related issues, including the phase-in of retail electric competition, Standard Offer rates, recovery and mitigation of stranded costs, regulatory asset recovery, unbundled rates for customers choosing competitive electric service providers, divestiture, dismissal of pending litigation between APS and the Commission, market structure, transmission access and pricing, etc. It is a global settlement of numerous critical issues that would have greatly complicated and likely prevented the implementation of retail electric competition in the Company's service area anytime this year.

5.Q. WOULD YOU SUMMARIZE THE AGREEMENT'S PRIMARY BENEFITS?

5.A. The most obvious benefits are the five rate reductions for most Standard Offer customers and the accelerated introduction of competition in the APS service area. The five rate reductions provided for in the Agreement represent a cumulative reduction in rates to such customers of as much as $ 475 million by 2004.

But this Agreement does much more than simply opening up the APS service territory and reducing APS rates. It:

(1) establishes both bundled and unbundled rates;

(2) provides that such rates (except for the aforementioned rate decreases) will remain in place through the middle of 2004 – providing needed price stability in the early years of retail competition;

(3) resolves the stranded cost issue;

(4) ends APS' litigation with the Commission over competition-related issues;

(5) addresses important transmission and market structure issues, including divestiture of APS generation to a Pinnacle West affiliate; and,

(6) requires implementation by APS of an interim code of conduct.

In summary, the Agreement will remove concerns that have hung over the Arizona market since 1996 and promote entry of new competitors into the APS service area.

6.Q. WHY DID APS AND THE OTHER PARTIES ENTER INTO SUCH A GLOBAL SETTLEMENT AGREEMENT?

6.A. The motivation on both sides for these negotiations, which were widely known to be underway, was at least three fold.

One mutual goal was to avoid or minimize the seemingly endless contested hearings that would have resulted had each of the matters contained in the APS Settlement Agreement not been resolved through negotiation. For example, the previous "generic" stranded cost proceeding in 1998 took over six months from beginning to end, and even then the final order has gone through one subsequent major revision and has generated several judicial appeals. That effort would have to be multiplied many fold to deal with the specifics of stranded costs, unbundled rates, etc. Although the Commission has scheduled hearings on some of the matters addressed by the Agreement, I feel that this schedule is very ambitious, and I believe it unlikely that the Commission could have completed all these hearings and issued orders allowing competition to begin anytime significantly before the end of this year.

Second, the parties wished to maximize the overall benefits to them of any settlement. No amount of evidentiary hearings could have resulted in many of the additional benefits realized by the Commission and consumers under the Agreement. Most notable of these are the annual rate reductions, which can only be achieved by voluntary agreement of the Company, and the acceleration of competition in the APS service area.

Third, APS hoped to eliminate some of the uncertainty currently hanging over the implementation of retail electric competition. This included:

(1) withdrawing the various lawsuits by APS against the Commission challenging A.A.C. R14-2-1601, *et seq.* ("the Electric Competition Rules") and its various generic stranded cost decisions;

(2) allowing Standard Offer customers to see tangible benefits from the introduction of competition in the form of five annual rate decreases; and,

(3) establishing a fixed stranded cost figure, with a pre-set phasing out of the transition charges as stranded costs and regulatory assets are recovered per the Agreement. This effectively provides a series of annual rate reductions for those customers choosing competitive electric service providers ("ESPs").

III. PROVISIONS OF THE APS SETTLEMENT AGREEMENT

7.Q. WERE YOU PERSONALLY INVOLVED IN THE NEGOTIATIONS THAT LED TO THE APS SETTLEMENT AGREEMENT?

7.A. Yes. I was personally involved in all of these negotiations. I have also consulted extensively with the Company's attorneys and other Company personnel who both took part in this process and were involved in the drafting of the Agreement itself.

8.Q. WOULD YOU PLEASE DESCRIBE THE VARIOUS PROVISIONS OF THE APS SETLEMENT AGREEMENT?

8.A. Yes. The easiest way is to just go through the Agreement, Article by Article.

Article I:

Article I addresses the actual implementation of retail access in the APS service area. It calls for competition to be phased in as proposed in the Electric Competition Rules pending before the Commission with the exception that APS would increase the non-residential load eligible for access in the first phase by some 140 MW. This additional allowance restored to non-residential customers the allocated demand lost by the December 11, 1998 amendments to the original 1996 Electric Competition Rules. Residential customers would receive access in accordance with the Company's December 21, 1998, filing, which also allowed for more potential residential access than would be required under the Commission's proposed electric competition rules. That residential phase-in plan is shown in Attachment JED-4.

The initial competitive phase described above is also contingent upon the Commission's approval of the Electric Competition Rules. However, APS has agreed to implement 100% retail access by January 1, 2001. To remove any remaining doubt as to the legality of the retail electric competition contemplated under the proposed electric competition rules and the Agreement, APS agrees to a modification of its certificates of convenience and necessity consistent with the terms of the Agreement. Finally, the parties to the Agreement urged the Commission to adopt the proposed Electric Competition Rules on an emergency basis by as early as July 1, 1999.

Article II:

Article II provides for a series of rate decreases both for Standard Offer customers and customers of unbundled distribution service. Standard Offer customers under 3 MW receive five 1.5% rate decreases. This group includes all of our residential customers and roughly 99% of the non-residential customers. Large Standard Offer customers (3 MW or larger) would get four decreases totaling 5%. Unbundled rates would decline from year to year in accordance with Exhibit A, Schedule A to the Agreement. The large Standard Offer customers received lesser rate decreases than residential and other commercial customers because it was believed that such large customers would have greater opportunities to benefit in the competitive market.

Article II also requires that customers over 3 MW give APS one year's notice before returning to Standard Offer. Under both H.B. 2663 and the Commission's proposed Electric Competition Rules, the Company would not be required to offer these large customers Standard Offer service under any conditions. The provision finally agreed upon represents a compromise position. It allows large customers to return to the protection of Standard Offer rates, but requires one year's notice. The notice will allow APS (which by the end of 2002 would have no Company-owned generation) to secure the additional supplies of purchased power necessary to serve the returning customer without overly burdening existing Standard Offer customers.

Article II requires the Commission to approve an adjustment mechanism by the end of 2002 (coincident with the divestiture of APS generation) that would recover certain specified costs not encompassed within the Standard Offer and unbundled distribution rates approved by the Agreement. These costs would include the prudent costs of purchasing electricity to meet the Company's Standard Offer and Provider of Last Resort obligations under the Electric Competition Rules, as well as future increases in Systems Benefits costs authorized by the Commission. APS is obliged to make a specific proposal for this mechanism no later than June 1, 2002. This filing by APS would be followed by an evidentiary hearing to consider the appropriate structure and implementation protocols for such a rate mechanism. Moreover, before any deferred costs could actually be recovered, both the signatories to the Agreement and other affected parties could contest the prudence of the costs proposed by APS for recovery through the mechanism as well as the eligibility of such costs for recovery under the terms of Article II.

Article II directs that the Company file a general rate case no later than June 30, 2003 – with new rates implemented no sooner than July 1, 2004. This latter date is coincident to the final amortization of regulatory assets and would allow the Commission to readjust the Company's rates both to reflect the end of this expense item and any other changes in rate base or expense during the moratorium period. It would also be at this time that the rate adjustment mechanism approved by the Commission in 2002 would first begin to collect the previously deferred costs subject to recovery by such mechanism.

Lastly, Article II contains provisions allowing emergency rate relief under specified circumstances and also tariff filings not significantly affecting Company earnings. Both of these provisions are standard and have been included in every previous APS rate settlement.

Article III:

Article III begins by acknowledging that APS is presently recovering regulatory assets over an eight-year period ending July 1, 2004. It then goes on to state that APS has demonstrated stranded costs (excluding regulatory assets) in an amount of at least $533 million (present value). The Company is required to permanently forgo recovery of some $183 million (present value - $234 in nominal costs) of these amounts. There is also a true-up mechanism that limits the Company's recovery under the CTC to $350 million. This true up is handled through the previously discussed rate adjustment mechanism as either a deferred debit (sums owned APS) or a deferred credit (amounts owed by APS to customers). Finally, Article III contains some technical provisions intended to make the approved Agreement more binding in its legal effect and which are necessary to satisfy certain accounting requirements.

Article IV:

The proposed Electric Competition Rules require the divestiture of the Company's competitive lines of business – either to an affiliate or to an unrelated third party. This Article helps to implement that requirement by:

(1) granting certain otherwise necessary Commission approvals;

(2) providing for the deferral and later recovery of the prudent costs of the required corporate restructuring; and,

(3) assuring that the Commission and the signatory parties support (or at least not oppose) the Company's efforts to obtain any required approvals from other government agencies and/or third parties (e.g., FERC, NRC, shareholders, etc.). These parties retain their rights under Sections 205 and 206 of the Federal Power Act to object to the rates filed with FERC by such an affiliate of the Company.

Article IV also waives compliance with certain statutory requirements not particularly relevant to competitive service providers. This waiver is specifically authorized by H.B. 2663.

The remainder of Article IV deals first with the required Commission findings under federal law that will enable the competitive APS generating affiliate to become an exempt wholesale generator ("EWG"), and then with some Commission-created regulatory burdens. Designation as a EWG would free the newly formed competitive affiliate of the Company from federal holding company regulations that unnecessarily burden what is supposed to be a competitive service provider. Similarly, certain of the Commission's general affiliate transaction rules (A.A.C. R14-2-801, *et seq.*) are waived, and all or portions of some old Commission decisions are rescinded. The former are substantially the same portions of the affiliate rules that Commission Staff agreed to waive in the previous (October 1998) APS rate settlement agreement. The Commission decisions referenced in Exhibit D to the Agreement are old orders dealing with PURPA reporting requirements for "qualified facility"

("QF") purchases, Schedule 9 (economic development), and the Company's now defunct fuel adjustment clause. The Company has no QF purchases under PURPA, and Schedule 9 has long since been cancelled. APS lost its fuel adjustment clause in 1989. Yet these regulatory relics from the past continued to mandate that APS file periodic reports with the Commission even though there is nothing of relevance left to report.

Article V:

This Article addresses the voluntary withdrawal by APS of the Company's various legal suits against the Commission over the Electric Competition Rules and the generic stranded cost orders. Such withdrawal will be "with prejudice" – meaning the Company would not be able to re-file any of these actions later, even if the Agreement were subsequently challenged in court. Consequently, the lawsuits will not be finally dismissed until the Commission approves the Agreement and any appeals of that approval are resolved.

Article VI:

Article VI talks about Commission approval of the Agreement. It allows parties to withdraw from the Agreement if it is not approved by August 1, 1999, but it does not result in the automatic termination of the Agreement unless APS is the party withdrawing. The balance of the Article is aimed at assuring that once the Agreement is approved, without modification, it will actually be binding on the various signatories and that the parties, including the Commission, will actively support the APS Settlement Agreement against any legal challenge.

Article VII:

Most of this Article contains technical legal provisions. However, there are also substantive provisions. These include the continuation of programs benefiting low-income residential customers, an interim code of conduct and APS support for AISA and Desert Star.

This last provision of Article VII also requires the Company to file a FERC open access transmission tariff ("OATT") within 10 days of the Commission's approval of the Agreement. APS must revise its current OATT to reflect certain provisions needed to facilitate implementation of Retail Network Integration Transmission Service. This service is similar to Network Integration Transmission Service contained in FERC's pro forma tariff (upon which the APS OATT is modeled). However, a number of changes were necessary to accommodate retail access under the Commission's Electric Competition Rules, namely incorporation of certain operational and pricing protocols that are being developed by the AISA Operating Committee.

IV. BENEFITS OF THE APS SETTLEMENT AGREEMENT

9.Q. WHAT ARE PRIMARY BENEFITS OF THE APS SETTLEMENT AGREEMENT?

9.A. There are at least nine that come to mind. These include:

(1) The accelerated introduction of retail electric competition in the APS service area;

(2) annual rate reductions;

(3) rate stability and certainty for both bundled and unbundled rates;

(4) resolution of the stranded cost and regulatory assets issues in a fair and equitable manner;

(5) continued support for a regional ISO and the AISA;

(6) assurance of divestiture of generation and other competitive services by APS in a cost-effective manner;

(7) dismissal of all APS litigation against the Commission;

(8) continued support for existing low-income programs; and,

(9) an interim code of conduct for affiliate relationships.

10.Q. WOULD YOU ELABORATE ON EACH OF THESE BENEFITS?

10.A. Yes, although I have alluded to many of them already.

1. <u>Accelerated Introduction of Competition</u>:

With the approval of this Agreement and the interim implementation of the Electric Competition Rules as urged by the parties, the APS service area will be open to certificated competitors months sooner than would otherwise be the case. And a larger share of APS load will be eligible for retail access in the first step of the phase-in.

2. Annual Rate Reductions:

Without the necessity of a full-blown rate proceeding (taking a year or more for each anticipated rate reduction), APS has voluntarily agreed to annual rate decreases for each of the next five years for the overwhelming majority of its customers – both Standard Offer and competitive access. As discussed earlier, this provides a cumulative benefit of some $ 475 million to APS customers. This follows on the heels of four prior APS rate reductions. Unlike the anticipated but as of yet unproven benefits of competition, these are assured benefits for all customers, whether or not they participate in the competitive electric market.

3. Unbundled and Bundled Rates:

Obviously, there could be no meaningful and informed customer choice without knowing both the unbundled and bundled rates for electricity. Moreover, it is also helpful to both consumers and competitors if there is some assurance that these rates will not be changing for some period of time, or at least that the only changes will be rate reductions. The Agreement achieves this rate stability during the first five years of electric competition.

4. Regulatory Assets and Stranded Cost:

Resolution of these issues in a manner acceptable to the Company is why APS is dismissing its litigation against the Commission, why APS agreed to guarantee rate reductions, and why APS made all the other concessions embodied in the Agreement. As it is, APS will get no stranded cost or regulatory asset recovery after 2004. Moreover, APS will have to write-off $234 million in nominal dollars ($183 million present value) of the above amounts. The Agreement's treatment of stranded costs, albeit less favorable to APS, is still consistent with the vast majority of other jurisdictions that have addressed this issue and not inconsistent with either the Electric Competition Rules or the Stranded Cost Order:

> ... we find the Affected Utilities should have a reasonable opportunity to collect 100% of their stranded costs.
>
> . . .
>
> Because of the difficulty of mitigating regulatory assets, as well as possible financial implications, we believe they [regulatory assets] should also be given an assured recovery.

Stranded Cost Order at 10-11.

The $533 million dollar stranded cost figure referenced in the Agreement comes from the Company's August 21, 1998 filing with the Commission. A copy of Schedule 2 to that filing is contained in Attachment JED-3. This calculation assumes that very significant stranded cost mitigation can and will take place in the next five years. Finally, the $533 million dollar stranded cost figure does not give APS any credit for its prior mitigation efforts as reflected in the rate reductions given in 1994, 1996, 1997 and 1998. These reductions will have provided cumulative ratepayer benefits of $460 million through mid-1999.

5. <u>Support for AISA and Desert Star</u>:

APS continues to believe the development of these entities is essential for competition by guaranteeing access to utility transmission systems on a comparable and non-discriminatory basis. The AISA has identified 10 operational/pricing protocols that are needed to facilitate retail access within Arizona in a fair and equitable manner. The AISA Operating Committee is developing these protocols, and to date, six of the protocols have been completed, and the remaining four are very close to completion.

6. <u>Divestiture</u>:

APS will divest its generation and competitive electric marketing functions to separate affiliates subject to the provisions of A.A.C. R14-2-1616. Given the realities of Palo Verde, this is as far towards complete disintegration of APS as a vertical monopoly as is reasonably obtainable or desirable.

7. <u>Litigation</u>:

No matter how confident the Commission may be about its legal position in this litigation (despite the recent invalidation by the courts of many of the Commission's telephone competition rules), its removal is clearly a benefit for both it and those supporting the Commission's Electric Competition Rules. Moreover, the conservation of legal and managerial resources now used by both sides to this litigation allows them to concentrate on the already difficult task of implementing electric competition in the days ahead.

8. Support for Low-Income Programs:

APS has pledged to maintain continued funding of existing low-income residential programs. If new low-income programs are developed to replace existing ones, APS will support them at these existing funding levels.

9. Code of Conduct:

In addition to the code of conduct required by the proposed electric competition rules, APS will have in place an interim code of conduct that should provide all parties with additional assurance that there will be no improper or anti-competitive contacts between APS and its competitive affiliates.

V. CONCLUSION

11.Q. IN CONCLUSION, WOULD YOU SUMMARIZE YOUR MAJOR POINTS?

11.A. The APS Settlement Agreement provides benefits not achievable in any other way. It is a balanced Agreement that "clears the decks" for the beginning of retail electric competition in 1999. Such a global settlement was the result of months of painful give-and-take negotiations. I urge the Commission to evaluate the APS Settlement Agreement as a holistic document rather than listen to those who would "nit pick" the Agreement to pieces.

Just as important, the Commission should reject the cries of those who demand, after 80 years of regulated monopoly, overnight implementation of a utopian model of competition, or which urge endless additional analyses of these issues in search of 100% certainty. This will only delay any competition.

The alternative to the Agreement is to schedule or reschedule hearings on all the contested issues resolved by the Agreement. This will delay for months the implementation of competition and likely could result in even more litigation. Even this dreary scenario of delay, expense and uncertainty would not reflect the loss of those negotiated benefits from the Agreement that could not be realized regardless of how much the parties litigated.

APS urges the Commission to approve this Agreement as presented. It is fair, comprehensive, has broad-based support, and is most certainly in the public interest.

12.Q. DOES THIS CONCLUDE YOUR DIRECT WRITTEN TESTIMONY?

12.A. Yes.

Schedule JED-1

STATEMENT OF WITNESS QUALIFICATIONS

Jack E. Davis is President of Energy Delivery and Sales for Arizona Public Service Company and a member of its Board of Directors. As President of Energy Delivery and Sales, Mr. Davis has responsibility for Bulk Power Trading, Transmission Planning and Operations, Customer Service, Economic Development, and Pricing and Regulation.

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 Arizona Public Service Company that same year and has held various supervisory and managerial positions in both the System Planning and Power Contracts and Systems Operations Departments. In 1990, Mr. Davis was named Director of System Development and Power Operation and thereafter promoted to Vice-President of Generation and Transmission in 1993. In October 1996, he was named Executive Vice President of Commercial Operations and 1998 he was named to his present position.

Mr. Davis is the Past President of the Western Energy Supply and Transmission, Chairman of the Western Systems Coordinating Council (WSCC), a member of the WSCC Board of Trustees, and (past chairman of the WSCC Regional Planning Policy Committee), a member of the National Electric Reliability Council Board of Trustees, past President of the Western Systems Power Pool and a member of the Southwest Regional Transmission Association Board of Trustees. Additionally, he is a registered professional electrical engineer in the State of Arizona.

SCHEDULE JED-2

APS SETTLEMENT AGREEMENT

BEFORE THE ARIZONA CORPORATION COMMISSION

JIM IRVIN
Commissioner-Chairman
TONY WEST
Commissioner
CARL J. KUNASEK
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

NOTICE OF FILING, APPLICATION FOR APPROVAL OF SETTLEMENT AGREEMENT, AND REQUEST FOR PROCEDURAL ORDER

Arizona Public Service Company ("APS") hereby files the attached Settlement Agreement ("Settlement Agreement") dated as of May 17, 1999, between APS and the other signatories to this Agreement (collectively, the "Parties"). The Parties, which includes a broad coalition of large and small consumer interests, entered into the Settlement Agreement for the purpose of agreeing upon terms and conditions for the introduction of competition in generation and other competitive services that they believe to be just, reasonable and in the public interest.

Pursuant to 7.10 of the Settlement Agreement, APS, on behalf of the Parties, respectfully requests that the Commission approve the Settlement Agreement as soon as practicable in accordance with a procedural schedule that establishes such formal hearings and/or public meetings as are required by applicable legal requirements and that afford interested parties adequate opportunity to comment and be heard on the terms of the Settlement Agreement.

APS also requests that the procedural schedule set forth in the April 21, 1999, Procedural Order regarding consideration of APS' stranded costs and unbundled rates (issues which are resolved in the Settlement Agreement) be suspended pending Commission consideration of this Settlement Agreement. Because the Settlement Agreement contemplates Commission approval no later than August 1, 1999, the Parties have attached hereto as Exhibit A a suggested procedural schedule for Commission consideration.

RESPECTFULLY SUBMITTED this 17th day of May, 1999.

SNELL & WILMER L.L.P.

Steven M. Wheeler

Steven M. Wheeler
Thomas L. Mumaw
Jeffrey B. Guldner

Attorneys for Arizona Public Service Company

661820.01

EXHIBIT A

APS Settlement Procedural Schedule

Filing of Settlement Agreement . . . . *May 17*

Procedural Order Issued . . . . *May 28*

Filing Date for Testimony from Parties
to the Settlement Agreement . . . . *June 4*

Filing Date for Testimony from Staff and Intervenors . . . . . *June 25*

Filing Date for Rebuttal Testimony from
Parties to the Settlement Agreement . . . . *July 9*

Hearing Begins . . . . *July 13*

662233.01

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

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

Title President Delivery & Sales

ARIZONA COMMUNITY ACTION ASSOCIATION

By

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

Title CHAIRMAN

(Party)

By

Title

(Party)

By

Title

*nron is not a signatory to this Agreement

**Also included: Boeing, Az School Board Association, National Federation of Independent Business (NFIB), Az Hospital Association, Lockheed Martin, Abbot LABS, Raytheon

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

(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	$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.

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

(CONTINUED ON REVERSE SIDE)

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.

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.

(CONTINUED ON REVERSE SIDE)

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. 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.

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.

(CONTINUED ON REVERSE SIDE)

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.

(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	$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.

(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	$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.

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.

Exhibit A
5/13/99
Schedule B

ARIZONA PUBLIC SERVICE COMPANY

Distribution Charges
By Direct Access Rate Classes

Line #	Direct Access Rate Class	Distribution Charges Effective January 1 of 1999	2000	2001	2002	2003	2004[a]
	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

[a] Transmission voltage customers will not pay Distribution Charges after June 30, 2004

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

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.

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 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.

SCHEDULE JED-3

APS STRANDED COST CALCULATION

FILED 8/21/98

Exhibit 2

Arizona Public Service Company
Stranded Cost Estimate
(Millions of Dollars)

Year	Energy Production (GWH)	Generation Costs: Capital	Fuel	O&M	A&G	Total	¢/kWh	Market Revenue: $Millions	¢/kWh	Stranded Cost $Millions
1999	23,152	363	270	154	67	854	3.69	(608)	2.63	49
2000	23,652	364	284	151	70	870	3.68	(609)	2.57	52
2001	24,571	360	295	147	65	867	3.53	(663)	2.70	204
2002	23,374	346	295	143	63	847	3.63	(661)	2.83	186
2003	23,374	351	311	155	64	881	3.77	(710)	3.04	171
2004	23,647	347	320	155	68	890	3.76	(761)	3.22	129
Stranded Cost (Net Present Value @ 8.8%)										570
ACC Jurisdictional @ 93.5%										533

SCHEDULE JED-4

APS RESIDENTIAL PHASE-IN PLAN

FILED 12/21/98

APS
Commitment. Innovation. Energy.

RECEIVED
AZ CORP COMMISSION

DEC 21 10 33 AM '98

DOCUMENT CONTROL

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December 21, 1998

Mr. Ray Williamson
Acting Director, Utilities Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

ARIZONA CORPORATION COMMISSION
RECEIVED
DEC
Director of Utilities

Re: Docket RE-00000 C-94-0165
Residential Phase-In Program

Dear Mr. Williamson:

On September 15, 1998, pursuant to Decision No. 61071, Arizona Public Service Company submitted a Residential Phase-In Program proposal. On October 19, 1998, Staff approved APS's proposal as written. Pursuant to Decision No. 61272, APS is submitting a revised copy of our Approved Residential Phase-In Program reflecting the change in the "Rules" increasing the number of residential customers eligible for direct access.

A copy of this document and the attached letter is being filed in Docket Control for interested parties.

If you have any questions, please contact me at 250-2031.

Sincerely,

Barbara A. Klemstine

Barbara A. Klemstine
Manager
Regulatory Affairs

BAK/srm

Enclosure

ARIZONA PUBLIC SERVICE COMPANY

DIRECT ACCESS RESIDENTIAL PHASE-IN PROGRAM IMPLEMENTATION PLAN

I. GENERAL DESCRIPTION

The residential phase-in program has been developed to provide a means by which Arizona Public Service Company ("APS" or "the Company") will provide current and new residential customers with the opportunity to procure competitive services from a source other than APS. This plan describes notification procedures, selection, and tracking mechanisms necessary to meet the Arizona Corporation Commission's ("ACC" or "the Commission") requirements as set forth in A.A.C.R14-2-1604 (Rule 1604.)

II. ELIGIBILITY

<u>General</u>
The Arizona Corporation Commission requires that a minimum of 1¼% of residential customers have access to competitive electric services. The number of eligible residential customers will increase by an additional 1¼% every quarter until January 1, 2001. In accordance with these rules, approximately 1¼ of APS' 685,672 residential customers (as of July 1998) or 8,750 residential customers; (the actual number of 8,570 was rounded upward) will be eligible for competitive electric service beginning January 1, 1999. Each subsequent quarter, an additional 8,750 residential customers will be eligible for direct access.

<u>Solar</u>
All residential customers who produce or purchase at least 10% of their annual electricity consumption from photovoltaic or solar thermal energy resources that were installed in Arizona after January 1, 1997 shall be eligible for participation in a competitive market. Customers who provide evidence of such solar or photovoltaic consumption to APS (i.e. an equipment purchase receipt or Energy Service Provider resource statement) will be declared eligible. This will be in addition to the above-mentioned residential eligibility (8,750 eligible residential customers per quarter) and will not be considered as part of the 20% of 1995 system peak demand otherwise eligible for direct access. Solar or photovoltaic customers must also identify themselves as such through their ESP for immediate processing of a service request. APS reserves the right to implement policies to verify and track eligibility of photovoltaic and solar energy resources.

<u>Low-Income Residential Customers</u>
To ensure that low-income residential customers (customers on Rate Schedules E-3 and E-4) have an opportunity to participate in direct access, ½ of 1% of the low-income residential customers (there are approximately 26,000 customers on E-3 and E-4) will be

eligible for direct access and not counted towards the 20% of system peak demand. This results in 150 per quarter or 1,200 in total.

III. Calculation of Reserved Residential Load

Each affected utility is required to make available at least 20% of its 1995 system retail peak demand for competitive generation on a first-come first-serve basis. Twenty percent of APS' 1995 system retail peak demand of 3,725 mW is 745 mW (demands measured at the meter). To calculate the proportion of the 745 mW that must be "reserved" for residential direct access, a system peak coincident demand of 3.30 kW (as estimated from APS' ongoing load survey program) was used for each eligible residential customer. The following calculation was then used to estimate the residential "reserved" portion of the APS load available for competitive generation:

Reserved Load = Total # Residential Customers Eligible x 3.3 kW

or

Reserved Load = (8,750 x 8) x 3.3 = 231 mW

Where:	8,750	=	The number of residential customers eligible per quarter
	8	=	The number of quarters between January 1, 1999 and January 1, 2001
	3.3	=	Average residential system peak coincident demand

The amount of load available for competitive generation for non-residential customers is then 514 mW (745 mW less 231 mW).

IV. PROCESS FOR CUSTOMER NOTIFICATION OF RESIDENTIAL PHASE-IN PROGRAM

APS will implement a notification process to inform all APS residential customers concerning the residential phase-in program. This notification process is designed to inform APS' residential customers concerning the applicable provisions and eligibility requirements set forth in A.A.C.R14-2-1604(B). Based on consumer response, APS will evaluate the appropriate means of ongoing notification during the phase-in period.

Bill inserts will be sent to all residential customers upon Commission review of the Company's Implementation Plan. This bill insert will, at a minimum, contain the following information:

A. The qualification requirements for residential customers set forth in A.A.C.R14-2-1604(B).

B. Residential phase-in program direct access eligibility dates.

C. A reply card to request additional information.

D. A phone number for customers to call and ask questions or request additional information.

New residential customers (those connecting service after October 31, 1998) will be notified about direct access through the existing customer kit process used to welcome new customers.

V. CUSTOMER EDUCATION AND INFORMATION SERVICES TO BE OFFERED

Coincident with the bill insert, APS will offer customer education and information services such as online services, media relations, bi-monthly publications, public presentations/forums, direct mailings/bill communications and Spanish translations where appropriate to all APS residential customers concerning competition (including the residential phase-in program).

The information provided on the bill insert and reply form will be available on the APS Internet web site so customers can access and review the notification literature. The web site will identify locations where reply cards are available or customers can provide their name and address on-line and have an information packet sent to them.

Upon receipt of a customer reply card or customer request, a direct access customer information packet will be provided.

A separate direct access phone line in Phoenix has been established to answer questions and handle information requests. The APS Customer Solutions Center 800 number will also be provided to customers as a communication link to answer direct access questions and handle information requests. These phone numbers will be included in bill inserts, advertising, and customer information packages.

VI. SELECTION AND TRACKING MECHANISM FOR RESIDENTIAL CUSTOMERS BASED ON A FIRST-COME FIRST SERVE BASIS

Residential customers will be eligible for access on a first-come first-serve basis. Customers must actually choose an alternative energy supplier and have that supplier submit a request to switch which will be counted. The time that the request to switch is received by APS will be used to establish priority for direct access. The first 8,750 requests that are accepted will have access in the first quarter and any requests in excess will be put on a waiting list for the next quarters prioritized by time received. This selection method has several advantages: 1) it will ensure that access slots do not go unused (only customers committed to choosing an alternate supplier will have access), 2) there will not be an eligibility list that has to remain confidential, and 3) ESPs will be able to market to the class as a whole rather than only a small segment.

As a result of the ACC workshop process, APS has developed a Direct Access Service Request ("DASR") process to facilitate direct access. This process enables APS to track customer switching to and between Electric Service Providers ("ESPs"), verify customer eligibility during the direct access phase-in period, and provide a timing mechanism to place requests in a sequential order based on the time they were submitted to APS. The DASR will be the mechanism used to track customers on first-come first-serve basis.

To educate ESPs and ensure the process moves smoothly as possible the Company will have an ESP Open House in October. Additionally, an Internet site has been established were ESPs can access information.

<u>DASR Process</u>
Customers wishing to select direct access will contact their preferred ESP. The ESP will then prepare DASRs and submit them to APS. DASRs will be time and date stamped upon receipt by APS to track the order of receipt. APS will respond back to the ESP, on valid DASRs, a DASR status of "accepted" until the remaining slots are filled.

APS will begin accepting DASRs for the first quarter on December 1, 1998. APS will monitor both the number of customers that have effectively switched to direct access and are receiving competitive services as well as the number of DASRs that are accepted and assigned a switch date within the quarter. The quarter will be closed once APS has accepted DASRs for the total number of customers eligible in that quarter.

As the DASRs are accepted, APS will respond to the ESP confirming the change date. Once the quarterly requirements have been filled, all subsequent DASRs will be held in a pending status, establishing a waiting list, until the first business day one month prior to the proceeding quarter. On that day, APS will begin processing the pending DASRs from the waiting list in the order they were received for the next quarter. APS will respond back to the ESP, for valid DASRs, an accepted status as well as assign the next scheduled read date for the switch date.

APS will maintain a waiting list of up to 61,250 DASRs. If the waiting list is full, no further DASRs will be accepted. APS will update the newly created APS ESP Internet site with eligibility and waiting list status. If a DASR is submitted for a first time Direct Access customer and is rescinded before the effective switch date, the customer will not be given preferential treatment over other first time Direct Access customers. An ESP cannot submit changes to a DASR that is on the waiting list. The only action that can be taken by the ESP is a cancellation. Once the DASR is processed and the ESP has received an accepted status, the ESP may then initiate any appropriate changes.

Customers may elect to change ESPs during the phase-in period. The ESP acquiring the customer is responsible for submitting a DASR change. Eligibility follows the residential customer and not the site location (that is, service address.) However, if an eligible customer returns to a standard offer rate, then they must reapply for competitive eligibility through the DASR process.

VII. LOAD PROFILING

Under FERC Order 888 (Open Access Transmission), APS as a control area operator, requires hourly loads from each Scheduling Coordinator (either the ESP itself or a mutually agreed upon third party) for energy imbalance and settlement. Pursuant to R14-2-1613(J.7) residential customers with loads of 20kW (or 100,000 kWh annually) will be permitted to use load profiling to satisfy the requirements for hourly consumption data. APS will make a revised OAT filing with FERC to accommodate retail direct access. The load profiling methodology will be part of that filing and must be approved by FERC. Each scheduling coordinator's hourly-profiled and hourly-metered loads will be summed for each hour to determine its hourly responsibilities for settlement.

The load profiling process takes the retail customers cumulative kilowatt-hour (kWh) for the billing cycle and allocates it to each hour in the cycle based on a load curve developed from a statically valid sample set that is representative of the retail customer's load.

The allocation process involves:

1. Determining the representative sample set's ratio for each hour, by dividing each of its hourly loads by its total usage for the billing cycle. The billing cycle starts the hour and date that the retail customer's meter was last read and stops the hour and date of the current read.
2. The ratio for each hour is then multiplied by the retail customer's total kWh usage for the billing cycle to obtain each hourly load for that customer.

During the phase-in, APS plans to use two segment sets. These are high country residential and low country residential. Customers will be assigned one of these two profiles based upon the geographic area in which they reside.

Initially these profiles will be static. That is profiled loads will be developed based on the static profile then adjusted to reflect the profiled days system load pattern. The adjustment is needed to reflect changes in the system due to weather and other system conditions. The adjustment will be determined for each hour using the following formula:

$$\text{Adjustment} = \frac{\text{APS current system profile ratio for hour}}{\text{APS historic system profile ratio for hour}}$$

Static profiles will be provided when they are available. APS estimates that by 2001, dynamic profiles will be utilized.

BEFORE THE

ARIZONA CORPORATION COMMISSION

TESTIMONY OF JOHN H. LANDON

On Behalf of

Arizona Public Service Company

Docket No. E-01345A-98-0473
Docket No. E-01345A-97-0773
Docket No. RE-00000C-94-0165

June 4, 1999

TABLE OF CONTENTS

I. QUALIFICATIONS

Q. Please state your name and business address.

A. My name is John H. Landon, and my business address is Two Embarcadero Center, Suite 1160, San Francisco, California, 94111.

Q. What is your current position?

A. I am a principal and director of the energy and telecommunications practice of Analysis Group/Economics, an economic consulting firm. I have included my CV as Exhibit 1 in this testimony.

Q. Please outline your educational background.

A. I received a B.A. degree with highest honors from Michigan State University with a major in economics in 1964. I subsequently attended graduate school at Cornell University, where I was awarded an M.A. in economics in 1967 and a Ph.D. in the same field in 1969.

Q. Where were you employed after leaving Cornell University?

A. I served on the faculty of Case Western Reserve University from 1968 to 1973, rising from the rank of assistant professor to associate professor, and on the faculty of the University of Delaware from 1973 to June 1977 as an associate professor.

Q. Which subjects did you teach during this period?

A. I taught microeconomics, industrial organization, antitrust economics, regulatory economics and economic forecasting.

Q. Where were you employed after leaving the University of Delaware?

A. I was employed by National Economic Research Associates from 1977 to 1997 as a Senior Consultant, Vice President, and Senior Vice President and member of the Board of Directors.

Q. What was the nature of your assignments at NERA?

A. Much of my work at NERA was on issues relating to the application of economic principles to the electric utility industry. I participated in numerous projects addressing economic and related antitrust issues before the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), the Securities and Exchange Commission (SEC), state regulatory commissions, and federal and state district courts.

Q. When did you join Analysis Group/Economics?

A. I joined in March of 1997.

Q. Are your assignments at Analysis Group/Economics similar in nature to those you performed while with NERA?

A. Yes. In addition, I serve as director of the energy and telecommunications practice at Analysis Group/Economics.

Q. Have you previously testified?

A. Yes. I have testified on many occasions before state and federal courts and regulatory agencies on a variety of matters.

Q. Have you testified before the Arizona Corporation before?

A. Yes. I have submitted testimony before this Commission on a variety of rate and regulatory matters, including incentive pricing, stranded cost recovery, and other electric industry restructuring issues.

Q. Have you participated in retail access or electric restructuring in jurisdictions other than Arizona?

A. Yes. I have been involved extensively with retail access or restructuring issues in Arizona, California, Delaware, Florida, Illinois, Iowa, Louisiana, Maryland, Michigan, Nevada, New York, Ohio, Oregon, Pennsylvania, Texas, and in the Province of Alberta. Outside North America, I have participated in teams working on these issues in the U.K., Chile and Colombia. I have testified in Arizona, California, Delaware, Florida, Illinois, Iowa, Maryland, Michigan, Nevada, Pennsylvania, and Texas on these issues.

Q. Have you testified on the subject of stranded investment?

A. Yes. I have testified on stranded investment issues in Arizona, Delaware, Iowa, Michigan, Pennsylvania, Texas, and before the Federal Energy Regulatory Commission. I have also assisted utilities in negotiating with large customers on issues relating to stranded investment recovery.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I have been asked by Arizona Public Service Company (APS or Company) to evaluate its recent application for approval from the Arizona Corporate Commission (ACC or Commission) of a settlement agreement (Agreement) between APS and a broad coalition of consumer interests.

III. EXECUTIVE SUMMARY AND ORGANIZATION OF TESTIMONY

Q. Please summarize your testimony.

A. In general, I find the Settlement Agreement to be consistent with sound economic principles and believe that the Commission approval would serve the public interest. More specific, I believe that the Agreement

- would facilitate a rapid transition to competition in retail electricity, which in turn will benefit consumers through greater choice and lower prices for electric services;
- provides benefits to both consumers and shareholders;
- fairly allows shareholders an opportunity to recover regulatory assets and stranded costs, although I believe the Agreement will cause APS to significantly under-recover these costs;
- places a significant amount of risk for stranded cost and regulatory asset recovery on APS shareholders;

- provides APS with several powerful mitigation incentives;
- has a strong consensus of support from consumer and business groups in Arizona.

Q. How is your testimony organized?

A. I divide my testimony into seven ensuing sections. Section IV highlights the major provisions of the Agreement. Section V explains how the Agreement should help usher in competitive electricity markets in Arizona. Section VI discusses the rate cuts explicitly outlined in the Agreement. Section VII addresses market power issues and concerns. Section VIII discusses APS's regulatory asset and stranded cost figures in the Agreement and provides arguments that APS is likely to significantly under-collect on these costs. Section IX discusses the savings in time and resources that the approval of the Agreement produces and notes that the Agreement has the endorsement of consumer groups in Arizona. Section X provides my final conclusions.

IV. OVERVIEW OF THE AGREEMENT

Q. Please summarize the major provisions of the Agreement.

A. The major provisions of the Agreement are as follows:

1. Retail access begins immediately upon both Commission approval of the Agreement and enactment of the Electric Competition Rules, which could come as early as August 1, 1999. Retail access will be phased in at different times for different customer groups, with full

open access assured by January 1, 2001. This is a rapid transition to competition.

2. APS will enact annual rate cuts during the 1999-2004 transition period, with the size of the reductions differing by customer class.
3. APS will continue to recover its regulatory assets and will be allowed to recover $350 million (in net present value terms) of its regulatory assets and stranded costs through a monthly competitive transition charge (CTC) until July 1, 2004. Market participants and consumers should benefit from a relatively short and well-defined recovery period.
4. APS will transfer its competitive service assets at book value to a separate, unregulated subsidiary by December 31, 2002.
5. APS and all signatories to the Agreement will withdraw their appeals of the Commission's competition orders and regulations.

I will discuss these provisions in more detail later in my testimony.

V. ESTABLISHMENT OF RETAIL COMPETITION

Q. What are the main benefits of open retail access and a competitive energy market?

A. In economic theory and practice, competitive markets maximize consumer welfare. In competitive markets, firms use fewer resources in the production of goods and services (technical efficiency), price goods and services to allocate society's resources to their highest-valued uses (allocative efficiency), and introduce new products and innovative methods of production to gain competitive advantage (dynamic efficiency). Firms that enjoy legitimate competitive advantages such as economies of scale and scope, brand name recognition, and goodwill pass these advantages on to customers in the form of lower prices. The net result is that customers are made better off, goods and services and production methods continually evolve to better meet customers' needs at lower costs, and only the most efficient firms survive.

Under open competition, firms have the strongest incentive and pressure to improve products, services, and production processes relative to rivals and to innovate in order to capture the financial gains from market superiority. Successful firms earn higher profits and prosper. Unsuccessful firms, with higher costs and poorer quality products and service, lose sales. Buyers are left with the most skillful entrepreneurs and best products and services, all offered at the most attractive prices. Technological gains in products and production processes are stimulated by market incentives. Competitive pressures require firms to adopt the most efficient means of production, distribution, marketing, and organization. Because competitive prices reflect marginal costs, society's scarce resources are allocated in the most efficient manner.

Q. Does the Agreement further the attainment of these benefits?

A. Yes, it does. The Agreement has numerous pro-competitive aspects. It ushers in consumer choice very rapidly by beginning open access immediately upon approval and upon enactment of the Electric Competition Rules and by allowing for full open access within two years. It addresses concerns about market power, which I discuss in more detail below, by outlining a transfer of APS's competitive assets to an affiliate, calling for new affiliate relation rules, and pledging support for independent control of transmission assets. Further, it benefits consumers by implementing significant rate cuts. Finally, it handles the recovery of regulatory assets and stranded costs in a manner that will not distort customer choice or the formation of a competitive market.

Q. What are the relevant dates for the implementation of open access, according to the Agreement?

A. Retail access may begin as early as August 1, 1999, provided that the Commission approves the Settlement Agreement and the Electric Competition Rules are enacted. Retail access will be fully phased in by January 1, 2001. The Electric Competition Rules will govern when customers will have open access to choose an electricity provider. In addition to beginning open access almost immediately, the Agreement provides for a very rapid transition from regulation to competitive electricity markets, which should hasten the benefits available to consumers. It is virtually impossible that competition could be implemented this quickly without this negotiated settlement.

VI. RATE REDUCTIONS

Q. Please describe the rate reductions specified in the Agreement.

A. APS will enact rate cuts annually during the 1999-2004 transition period, with the size of the reductions depending on customer size:

- Residential and business customers (less than 3MW), representing over 99 percent of the Company's customers, will receive a 1.5 percent rate reduction annually every July 1 from 1999 to 2004.
- Larger customers (3MW and above) will receive the following rate reductions: 1.5 percent on July 1 1999 and 2000, 1.25 percent in 2001, and 0.75 percent in 2002.

These explicit cuts will start to benefit all electricity consumers directly while competitive generation markets are developing. They also, conversely, increase the risk to APS shareholders.

Q. Has APS made other rate cuts in recent years?

A. Yes. APS has been reducing electricity rates for all customers since 1994. These rate reductions amounted to 2.7 percent in 1994, 3.4 percent in 1996, 1.2 percent in 1997, and 1.1 percent in 1998. These previous rate reductions represent an annual reduction in revenues for APS of $112 million. In the context of past reductions, the additional rate reductions in the Agreement are even more impressive.

Q. How do these rate reductions compare with experience in other states?

A. While almost all states have implemented rate freezes during their transition periods, many, including Maine, Maryland, Michigan, Montana, Nevada, New Hampshire, Oklahoma, Pennsylvania, and Rhode Island, have declined to impose any explicit rate reductions during their transition periods.

VII. MARKET POWER ISSUES

Q. Does the Agreement provide safeguards against anti-competitive behavior?

A. Yes. Following approval of the Agreement, APS (or its parent, Pinnacle West Capital Corporation) will establish a separate affiliate or affiliates that will acquire all generation assets. The consumer groups that are signatories to the Agreement have agreed not to oppose the transfer of competitive assets from APS to this affiliate. These competitive affiliates will be subject to state and federal oversight to the same degree as all other competitive firms.

Q. In your opinion, are the provisions for the transfer of the Company's generation assets fair?

A. Yes. The Agreement provides for the transfer of the Company's generation assets at book value. Based on my assessment of market electric prices, I believe that the book value of APS's generation portfolio will be greater than the market value of the assets. In fact, this disparity between market and book values is implicit in the $533 stranded cost figure contained in the Agreement, which I will discuss this later in my testimony. The transition period will allow the Company an opportunity to recover some, but not all, of the difference between the book value and the market value of its generation assets. Therefore, the Company's generation assets are likely to be transferred at a value greater than or equal to market value.

Q. Does the Agreement address the issue of affiliate relations?

A. Yes. Under the Agreement, APS will develop an interim code of conduct within 30 days of this Commission's approval of the Agreement. This code of conduct will remain in effect until the Commission approves a permanent code of conduct in accordance with the proposed Electric Competition Rules.

Q. Are there any characteristics of the Arizona market that are relevant to the issue of market power?

A. Yes. There are a large number of high-voltage transmission lines connecting Arizona with the rest of the WSCC. Therefore access to Arizona is relatively unconstrained at most times. With relatively unconstrained access, the energy market in Arizona should have a large number of firms competing to provide generation services, and market power is not likely to become an issue. Even in areas having partially constrained transmission access, the operations of the Arizona Independent Scheduling Administrator (AISA) and Desert Star, as approved by FERC, are likely to alleviate any anti-competitive concerns.

Q. Has the Agreement addressed the issues of market power and access to transmission facilities?

A. Yes. Market power and non-discriminatory access to the transmission network are very important issues in the establishment of competitive energy markets. The Settlement Agreement states that APS will actively support the AISA, and agrees to modify its Open Access Transmission Tariff to be consistent with any FERC-approved AISA protocols. AISA will ensure non-discriminatory access to the transmission grid and resolve any significant market power issues. The Agreement also states that APS will actively support the formation of the Desert Star Independent System Operator. Both the AISA and Desert Star will be subject to FERC oversight. If AISA and Desert Star develop as expected, there will be no valid concern about anti-competitive behavior or market power. This Commission and the FERC have the authority to ensure that the AISA and Desert Star resolve these issues. Moreover, the implementation of the Settlement Agreement would not in itself contribute to anti-competitive behavior or market power even in the absence of AISA or Desert Star.

VIII. REGULATORY ASSETS AND STRANDED COSTS

A. Specifics of the Agreement

Q. Will the Agreement allow APS to recover fully its regulatory assets and stranded costs?

A. No. APS has agreed to a disallowance of $183 million.

Q. How much will APS collect through the CTC?

A. The Company will recover $350 million through the monthly CTC. The charge will remain in effect until December 31, 2004.

Q. Do you believe that the mechanism for settlement cost recovery outlined in the Agreement conforms to sound economics?

A. Yes, for two main reasons. First, recovery is accomplished through a non-bypassable CTC. This will allow the Company to collect stranded and regulatory asset-related costs in a competitively neutral manner. Second, the recovery period is short, ending in December 2004.

Q. Why do you say that the CTC is "competitively neutral"?

A. The CTC, as laid out in the Agreement, is non-bypassable: customers will not be able to escape paying a CTC by leaving the incumbent provider, nor will they pay extra if they choose a competing firm. In other words, each customer's transition charge will not depend on his choice of provider, and customers will not benefit or pay a penalty for choosing the incumbent or any other firm as its supplier of competitive services. Therefore, the CTC will not distort the competitive market or delay the onset of competition, and it will neither favor nor hinder the incumbent or any entrant into the Arizona market. Firms in the market will compete solely on price and service quality, independent of the CTC.

A simple hypothetical example can illustrate how the CTC is competitively neutral. Suppose a customer of the incumbent currently pays $25 per month for electricity. Once the CTC commences, suppose the customer pays a disaggregated bill consisting of a $3 monthly CTC fee plus $12 per month for distribution and other non-competitive services plus $10 for generation, for a total bill of $25. Suppose now that a competing firm can offer her the same quantity of electricity usage for $8. Since the customer will pay the $3 monthly CTC regardless of whether she stays with the incumbent or leaving for a competitor, she will pay $23 per month by choosing the competing firm or $25 if she remains with the incumbent. While the CTC has affected the total amount of her electricity bill, price competition among suppliers depends on the price of service alone and not on the amount of the CTC.

Q. Why should the recovery period be as short as possible?

A. While settlement cost recovery will not delay the formation of competitive markets, a quick recovery period will settle up costs incurred during cost-of-service regulation and will "close the book" on the regulatory era in generation, as well as reduce regulatory costs. In much the same way that paying off a loan early allows a consumer to feel unburdened by past debts, a shorter recovery period will hasten a new period of consumer choice and benefits.

Q. Have other state regulatory commissions allowed full recovery of stranded costs?

A. Yes. Regulators or legislators have endorsed full recovery, or the opportunity for full recovery, of prudently incurred stranded costs in California, Connecticut, Illinois, Maine, Massachusetts, Michigan, Montana, New Jersey, New York, Rhode Island, and Vermont. The methods of calculation and recovery differ in each jurisdiction, and many commissions have imposed rate caps or other mechanisms that tend to limit the pace of stranded cost recovery, but all state commissions have recognized the fairness of allowing utilities to recover stranded costs.

Additionally, other states have allowed longer stranded cost recovery periods than is stipulated in the Agreement. Of the states to resolve stranded cost recovery issues to date, Connecticut, Illinois, Maine, Massachusetts, Michigan, New Hampshire, New Jersey, Pennsylvania, and Rhode Island have all authorized longer stranded cost collection periods than the Agreement would establish.

Q. Are consumers protected from over-recovery by the proposed settlement?

A. Yes. In addition to the explicit reduction in rates I discussed earlier in my testimony, the proposed settlement contains provisions to prevent over-recovery of the settlement amount. Specifically, the Agreement states that, at the end of the CTC collection period on December 31, 2004, any under- or over-recovery of the $350 million will be debited or credited in an adjustment clause in the Electric Competition Rules.

B. APS Estimates

Q. Have you reviewed the stranded cost calculations presented by APS in Docket E-01345A-98-0473?

A. Yes, I have.

Q. What is your general conclusion regarding APS's analysis?

A. It is my conclusion that APS has significantly underestimated the potential for stranded costs associated with its generation assets, to the gain of customers and at substantial risk to the shareholders.

Q. Have you examined how APS made its estimate of stranded costs in this matter?

A. Yes.

Q. Do you believe that the Company used conservative assumptions in the estimation of stranded costs?

A. Yes. In calculating its stranded costs, APS has made three assumptions that tend to increase the value of the generation assets, thereby reducing total stranded costs. Specifically, the APS analysis:

- uses a six-year stranded period instead of using a life-cycle analysis;
- uses very aggressive capacity factors for the coal and nuclear power plants; and
- uses a relatively low level of competitive new entry into the generation market, and thus higher projected market prices.

Q. Please describe how the six-year stranded period underestimates stranded costs.

A. A six-year stranded period underestimates stranded costs compared to the life-cycle method simply because it includes only six years of lost revenues instead of the total lost revenues over the remaining life span of the asset.

Q. Please describe how you have reached the conclusion that APS used aggressive capacity factors in the estimation of stranded costs.

A. The capacity factors assumed for the APS coal plants are all high relative to recent experience. Table 1 presents the actual capacity factors for APS coal and nuclear plants over the period 1993-1997. Table 2 presents the capacity factors used in the stranded cost calculations. The case of the Palo Verde nuclear unit is slightly different from the coal case. Its performance in 1996 and 1997 was excellent. However, between 1993 and 1997 the capacity factor for Palo Verde varied considerably between 67 percent and 91 percent. The average for this period was 79 percent. The average capacity factor used in the stranded cost calculation is 88 percent.

Table 1: Historic capacity factors for APS plants

	Cholla	Four Corners	Navajo	Palo Verde
1993	80.55	83.14	85.65	68.97
1994	78.24	83.05	84.38	66.89
1995	58.35	81.69	80.85	77.25
1996	57.44	73.98	70.48	91.25
1997	72.03	77.36	68.94	88.51
Average	69.32	79.84	78.06	78.57

Table 2: Capacity factors used in stranded cost calculations

	Cholla	Four Corners 1-3	Four Corners 4-5	Four Corners (average)	Navajo	Palo Verde
1999	90.1	88.7	91.1	89.9	69.5	88.9
2000	92.2	88.9	85.4	87.2	74.0	89.2
2001	92.1	89.9	93.0	91.5	84.4	88.0
2002	92.2	89.1	85.5	87.3	89.0	88.0
2003	96.2	89.6	91.2	90.4	85.6	84.4
2004	91.8	90.4	93.3	91.9	88.0	88.1
Average	92.4	89.4	89.9	89.7	81.8	87.8

Q. **How do the Company's capacity factor assumptions underestimate stranded costs?**

A. If generation output is lower than assumed by the capacity factors, stranded costs will be greater than the Company has estimated.

Q. Please describe how the low level of competitive entry assumed by APS underestimates stranded costs.

A. Information from many sources indicates that competitive new entry will be significant, especially in the California market and other markets adjacent to Arizona. As new units enter the market, older and less efficient units get 'pushed' further up the dispatch stack. One consequence is that market clearing energy prices will drop. Therefore, underestimating competitive entry, as APS appears to have done, will lead to higher electricity prices and higher revenues for APS's power plants. Assuming higher energy revenues lowers stranded cost responsibilities, to the benefit of customers.

C. Mitigation of Stranded Costs

Q. Should utilities have the obligation to mitigate stranded costs in a reasonable way?

A. Yes. Stranded costs stem from the difference between assets acquired under a regulatory regime and the value of those assets in a competitive market. However, the utility may be able to take actions that reduce this difference in valuation. Such actions are frequently referred to as mitigation efforts. Reducing, or mitigating, total stranded costs lowers the total impact of the transition from regulation to competition by lowering costs or increasing the value of the utility's assets in a competitive marketplace. To increase the value of its assets, thereby lowering stranded costs, the incumbent utility will try to operate more efficiently.

Q. Does APS's proposal include mitigation efforts?

A. Yes. As I discussed in Section VI, the Company has a history of agreeing to rate cuts and is further extending this policy by agreeing to this settlement. In addition, the Company's calculation of stranded costs itself assumes significant mitigation. In particular, the assumption regarding capacity factors is very aggressive. In estimating its stranded costs, APS has assumed that it will be able to operate its generation assets at very high usage rates in the future. The Company assumes all of the risk that asset performance will be below the assumptions in the stranded cost calculations. The effort to improve the operating efficiency of these units, and the assumption of the downside risk in the event that these goals are not achieved, represents a significant mitigation effort on the part of the Company. Furthermore, a very conservative estimate of new generation also produces a lower estimate of stranded costs, thereby increasing the risk to shareholders. Finally, the establishment of a settlement amount lower than the very conservative estimate of stranded costs alone provides still more mitigation. In my view, APS has agreed to much more mitigation than I believe is attainable.

IX. ADDITIONAL ITEMS

Q. Who has endorsed the Settlement Agreement?

A. The Settlement Agreement has the support of several major consumer groups in Arizona, including the Residential Utility Consumer Office, the Arizona Community Action Association, and Arizonans for

Electric Choice and Competition. The last group includes numerous companies (such as Honeywell and Allied Signal) as well as many industry associations. Customer endorsement is strong evidence that the Agreement will serve the public interest.

Q. What would be the impact of the Commission's not approving the Agreement?

A. Commission approval will prevent delays to open access, the development of competitive markets, and the consumer benefits that will ensue from these. Without this Agreement, continued negotiations and possible litigation would unnecessarily divert APS management and Arizona regulatory resources and attention away from the important goal of restructuring Arizona's electricity markets and creating customer choice. Upon approval of the Agreement, APS and all signatories agree to drop all appeals of Commission's competition orders. The parties would thereby save the state the cost and uncertainty of litigating recovery of stranded costs.

X. CONCLUSIONS

Q. Please summarize your conclusions.

A. My conclusions are as follows:

- The Settlement Agreement is consistent with sound economic principles and should hasten competitive markets in Arizona, which in turn will yield consumer benefits of efficiency, choice, and lower prices.

- The Settlement Agreement is in the public interest and should be approved.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit 1

Curriculum Vitae of JOHN H. LANDON

Dr. Landon has served as an economic consultant to the electric utility, coal, and uranium industries for over 20 years. His consulting experience has been wide-ranging and includes analysis of deregulation, strategic planning, competition, ratemaking, transmission governance, performance-based regulation, statistical benchmarking, demand-side management, cost allocation, and pricing. Dr. Landon has testified more than 100 times before federal district courts, state courts, the Securities and Exchange Commission, the Federal Energy Regulatory Commission, and various state commissions, and has prepared numerous expert reports and affidavits. He has authored or co- authored more than 20 articles published in academic and trade journals, two book chapters, and several monographs.

His litigation work has involved damages assessments, forecasting, merger analysis, market definition and market power, valuation, antitrust liability, cost allocation, and pricing.

Prior to joining Analysis Group/Economics, Dr. Landon was Senior Vice President at NERA, Inc. Previously, he held positions as Associate Professor of Economics at the University of Delaware and Case Western Reserve University. Dr. Landon holds a Ph.D. in Economics from Cornell University.

PROFESSIONAL ACTIVITIES

Member of the Governor of Delaware's Economic Advisory Committee

Director of the Center for Policy Studies at the University of Delaware

A Director of the Delaware Econometric Model Group

Senior Research Associate in the Research Program in Industrial Economics at Case Western Reserve University

Member of the American Economic Association

Associate Member of the American Bar Association

TESTIMONY PROVIDED FOR THE FOLLOWING CLIENTS:

Commonwealth Edison Company
Before the Illinois Commerce Commission, Docket Nos. 98-0147 and 98-0148, October, 1998 (Direct and Rebuttal Testimonies)

Nevada Power Company
Before the Public Utilities Commission of Nevada, Docket No. 97-5034, September 1998.

Arizona Public Service Corporation
Before the Arizona Corporation Commission, Docket No. RE-00000C-94-165, August 1998

Arizona Public Service Corporation
Before the Arizona Corporation Commission, Docket No. E-01345A-98-0245, *July 1998.*

The Detroit Edison Company
Before the Michigan Public Service Commission, July 1998.

Delmarva Power & Light Company
Before the Maryland Public Service Commission, Case No. 8738, July 1, 1998.

Nevada Power Company
Before the Public Utilities Commission of Nevada, Docket No. 97-5034, July 1998.

Nevada Power Company
Before the Public Utilities Commission of Nevada, Docket No. 97-8001, June 1998.

Delmarva Power & Light Company
Before the Delaware Public Service Commission, PSC Docket No. 97-394F, May 1998.

The McGraw-Hill Companies, Inc.
Before the District Court, City and County of Denver, State of Colorado, Case No. 96-CV-6977, May 1998.

Southern California Edison Company
Before the Public Utilities Commission of the State of California, Application Nos. 97-11-004, 97-11-011, 97-12-012, May 1998.

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BEFORE THE

ARIZONA CORPORATION COMMISSION

TESTIMONY OF ALAN PROPPER

On Behalf of

Arizona Public Service Company

Docket No. E-01345A-98-0473
Docket No. E-01345A-97-0773
Docket No. RE-00000C-94-0165

June 4, 1999

Q. What is your name and business address?

A. My name is Alan Propper. My business address is 400 N. 5th Street, Phoenix Arizona, 85004.

Q. By whom are you employed and what is your position?

A. I am employed by Arizona Public Service Company (APS) as Director of Pricing and Regulation. In this position, I am responsible for establishing and administrating APS's tariffs and contracts that are under the jurisdictions of the Arizona Corporation Commission (ACC) and the Federal Energy Regulatory Commission (FERC).

Q. Would you discuss your educational background and business experience?

A. My background and experience are set forth in Appendix-A to this testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present APS's proposed rates for Direct Access Service, as specified in the Settlement Agreement dated May 17, 1999. In addition, I will discuss the philosophies and methodologies used in the development of the proposed rates, as well as related issues concerning cost allocation, Stranded Cost recovery, and certain terms and conditions pertaining to Direct Access Service.

Q. Are you sponsoring any Schedules?

A. Yes. I am sponsoring Schedule AP-1, which contains the embedded cost-of-service study; Schedule AP-2, which summarizes the pro-forma adjustments to the 1996 test year; Schedule AP-3, the 1996 Settlement Rate Reduction filed in May, 1999; Schedule AP-4, which summarizes the calculation of fair value rate base and fair value rate of return; Schedule AP-5, which summarizes System Benefits costs; Schedule AP-6, which contains the calculation and summary of the Competitive Transition Charges (CTC); Schedule AP-7, which contains the Direct Access Service rate design computations; Schedule AP-8, which is the proposed Direct Access Service rate schedules set forth in the Settlement Agreement; and Schedule AP-9, which summarizes the rate credits applicable to Direct Access Service customers not receiving Metering, Meter Reading, or Billing services from APS.

Q. Was this testimony and were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. Would you define what is meant by Standard Offer Service?

A. Standard Offer Service customers are those retail customers who choose to continue to have their electric service bundled and provided by APS. In other words, these customers opt for keeping the status quo when it comes to competition and customer choice, and will continue to have APS provide bundled electric service comprised of Generation, Transmission, Ancillary Services, Distribution, Metering, Meter Reading, and Billing.

Q. Have you developed new Standard Offer Service rates in conjunction with the Settlement Agreement?

A. No. The initial Standard Offer Service rates will be those currently effective in APS's retail tariff and contracts. However, these rates will receive periodic reductions, as specified in Section 2.2 of the Settlement Agreement.

Q. Would you discuss what is meant by Direct Access Service?

A. Direct Access Service customers are retail customers who choose to have their electric service unbundled and purchase their Generation, Transmission, Ancillary, and generally Metering, Meter Reading, and Billing Services through an Electric Service Provider(s) (ESP) and Scheduling Coordinator rather than APS. These customers will still receive certain services from APS, but they will only be charged for Basic Delivery Service, Distribution Service (which includes recovery of Regulatory Assets), System Benefits, and Stranded Costs.

Q. Was an embedded class cost-of-service study used in the development of the Direct Access Service rates?

A. Yes. A cost allocation study was specifically prepared and utilized to identify and apportion bundled rates into the Direct Access delivery charges as proposed by APS for retail Direct Access Service. This study appears as Schedule AP-1.

Q. Would you discuss the development of the embedded cost allocation study?

A. This study was prepared using industry accepted principles and practices. In general, the numerous expense and rate base items that comprise APS's costs were grouped into major categories, such as Plant in Service or Operating & Maintenance Expense. Each of these categories was first broken down into Production, Transmission, or Distribution related functions, then classified as Demand, Energy, or Customer related. Allocation factors based on kilowatts, kilowatthours, and number of customers were then developed so that allocations of the functionalized and classified costs could be made to the federal and state jurisdictions and to the three newly established customer classes.

Q. What was the next step in the process after the allocations were performed?

A. Once allocations of this nature are completed, the rate designer would normally accumulate the expense and rate base costs so that revenue requirements could be established for each customer class or each function. However, for the purposes of this filing, the apportionment factors shown in Schedule AP-7 were developed instead of revenue requirements so that existing bundled rates could be transformed into proposed unbundled Direct Access Service rates at existing revenue levels.

Q. Why did you choose to use an apportionment process rather than designing unbundled rates directly from a functional revenue requirement analysis?

A. There were two primary reasons: (1) revenue stability; and (2) rate continuity. It is APS's intent that the process of rate unbundling produce neither large revenue erosion due to rate migration nor customer dislocation due to reallocation of revenue requirements. By apportioning current bundled rates into functional charges that total to the bundled rate, appropriate revenue recovery is assured. This is particularly helpful for APS at this time when the current bundled rates will have been decreased three times under the 1996 Settlement mechanism prior to the start of competition. Apportioning the current bundled rates assures us that the unbundled rates are synchronized with current bundled rate levels.

Q. In addition to an assurance of comparable total revenue recovery, does apportionment provide an advantage when dealing with the rates of the individual classes of business?

A. Yes. Apportioning the current rate structures for the General Service customers preserves, to the extent possible, the blend between the bundled rates and the ACC regulated unbundled rates. APS's Rate E-32, for customers with peak demand less than 3MW, has a relatively complex rate structure, with its effective demand charge varying by load factor and energy usage through the use of a kWh/kW block expander. The apportionment of the E-32 rate structure preserves this structure, including the seasonal price differentials, for the corresponding unbundled Distribution rate, thus reducing the rate dislocations that would result from the transition to competitive service.

Q. Was the use of a 1996 test year suitable for this cost-of-service study?

A. Yes. The 1996 test year was used for consistency with APS's previous filings and settlement negotiations on the subject of Direct Access Service and Stranded Costs. Since pro-forma adjustments were made to the 1996 data, and since the study results were used for cost apportionment as opposed to establishing revenue requirements, I did not feel a more recent test year would produce an improved estimate of functionalized costs. Although complete 1998 data was not available at the time the study was performed, enough 1998 information was available to develop suitable pro-forma adjustments. The pro-forma adjustments used for the 1996 test year are presented in Schedule AP-2.

Q. Why is it appropriate to adjust the 1996 test year level to 1998 levels?

A. The final rate reduction under the 1996 Settlement mechanism is based upon 1998 unit costs and unit prices. Therefore, the 1996 costs adjusted to 1998 is appropriate. Attached as Schedule AP-3 is the .68% rate reduction APS filed with the ACC on May 21, 1999.

Q. Have you calculated the fair value rate base and fair value rate of return based upon the adjusted test year and the revenue level pursuant to the 1996 Settlement mechanism?

A. Yes, based on 1998 and as shown in Schedule AP-4, APS has a fair value rate base of $5,195,675,000 and a fair value rate of return of 6.63%.

Q. Have any new or special procedures been used in preparing this cost allocation study?

A. Yes. Due to the nature and anticipated use of the cost allocation study somewhat unique procedures were used to establish the allocated retail class costs associated with Transmission Service, Ancillary Services, and Must Run, as well as the costs associated with System Benefits and Regulatory Assets.

Q. How were retail Transmission costs determined?

A. In compliance with FERC Order No. 888, APS filed an Open Access Transmission Tariff (OATT). The outcome of that case resulted in an Annual Transmission Revenue Requirement for APS of $86.5 million. To develop the retail classes' cost responsibility for Transmission Service, the retail jurisdiction's four summer months' contributions to the system peak, or 4CP methodology, was utilized. This is consistent with FERC precedent regarding the APS Transmission system.

Q. How were the retail costs associated with Ancillary Services determined?

A. Three Ancillary Services were identified for cost analysis purposes, and to accommodate Direct Access. These are Regulation, Spinning Reserve, and Supplemental Reserve. In addition, Scheduling was identified as a required Ancillary Service, but its associated costs and charges were included with Transmission. Similar to Transmission Service, APS' FERC OATT established Ancillary Service rates at levels that would recover the revenue requirement for each of the Ancillary Services. The cost responsibility for each retail class was determined based on each class's allocated portion of the revenue requirement associated with each of the Ancillary Services.

Q. Would you explain what you mean by Must Run?

A. Must Run resources are existing generation units utilized to supply power and energy to load areas (or zones) within a utility's system that are limited on the amount of remote generation that could otherwise be imported into the area because of thermal limitations on transmission paths, as well as voltage and stability considerations within the constrained area. If the load within the congested area exceeds the transmission import capability into the area, local generation resources located within these zones must be dispatched in order to meet the total load requirements in the constrained area. APS's resources dispatched out of economic sequence for this purpose are deemed to be Must Run resources.

Q. Would you briefly describe the unbundling methodology used to determine the costs associated with Must Run?

A. In order to unbundle the costs associated with providing Must Run, it was necessary to identify which of APS's generating units were utilized to perform this service, the percentage of each unit's availability that is used to perform Must Run, and the appropriate costs associated with each of the units. The proportionate share of the fixed and variable costs of the units related to Must Run were then calculated. For cost responsibility purposes, these Must Run costs were refunctionalized as Distribution.

Q. Would you explain what is meant by System Benefits?

A. System Benefits refer to the costs associated with low income programs, renewable resources, demand side management, nuclear plant decommissioning, nuclear fuel disposal, customer education, and other items that are included in rates by approval of the ACC. For the purposes of this cost allocation study, System Benefits costs have been separately accumulated and unbundled. The System Benefits items that have been included in the proposed rates and their associated costs appear in Schedule AP-5.

Q. Would you explain what is meant by Regulatory Assets?

A. Regulatory Assets are expenses already incurred by APS on projects, equipment, and financial obligations that have not as yet been charged to customers. Pursuant to ACC Decision No. 59601, the ACC authorized the collection of these expenses from customers through electric rates over an extended period of time, thereby avoiding significant increases to customer bills. Examples of Regulatory Assets are deferred income tax payments, coal mine reclamation costs, and financing costs for generation units. For the purposes of this cost allocation study, Regulatory Assets have been separately accumulated and assigned to Distribution.

Q. Would you discuss the development of the apportionment factors used in designing the rates for Direct Access Service?

A. Once the costs associated with the specific sub-functions, such as System Benefits and Regulatory Assets, were segregated, the Production, Transmission, and Distribution costs were allocated to each proposed Direct Access Service class. Percentages were then calculated for each of the functions for each of the three classes, as shown in Schedule 4 of Schedule AP-7. These percentages served as the apportionment factors that were applied to each of the three bundled rates to yield the Direct Access charges as shown in Schedules 1, 2, and 3 of Schedule AP-7.

Q. Why is there a need for CTCs, and how were they developed?

A. CTCs are charges that are included in rates to recover a defined level of Stranded Costs. Using projections of generation costs, market prices, and sales, annual revenue requirements to recover a total of $350 million through 2004 were determined. These costs were then allocated to each of the three retail Direct Access Service classes, using each of the class's contribution to the system peak load as an allocating factor. Unit Costs per kWh for each class for each year were then developed by dividing the costs by the anticipated sales.

Q. What adjustments were made to the unit Stranded Costs to convert them to CTCs?

A. The unit Stranded Costs were adjusted so that Direct Access Service and Standard Offer Service rate decreases provided for in the Settlement Agreement would be better synchronized with each other and to reflect the implicit stranded cost levels in special contracts APS has with BHP Copper, Cyprus Bagdad Copper, and Ralston Purina.

Q. Were any additional changes made to the unit Stranded Costs to produce the final CTCs?

A. For the General Service classes, the energy related CTC charges were converted to demand charges using class average load factors. This conversion to demand charges better reflects cost incidence and better blends the Direct Access rates with the corresponding Standard Offer rates. The CTCs, as well as the proof of revenue used to confirm the $350 million recovery level are shown on Schedule AP-6.

Q. How will the CTCs be used in tracking the recovery of $350 in Stranded Costs?

A. At the end of each calendar year of the Stranded Cost recovery period ending December 31, 2004, the annual ACC jurisdictional sales to both Standard Offer and Direct Access customers will be multiplied by the percentage of APS load eligible for Direct Access Service during that year. This sales amount, calculated by class, will then be multiplied by the CTC in effect for that class for that year. This will result in an annual dollar amount of Stranded Cost recovery. This formula is shown in Exhibit B to the Settlement Agreement. After the annual recovery amount for the year 2004 is calculated, the recovery amounts for all years for all classes will be summed. The NPV of this total stranded cost recovery will be calculated, and the resultant dollar amount will then be compared to the $350 million recovery allowed by the Settlement Agreement.

Q. Will these recovery amounts then be reconciled?

A. Yes. Any amount of stranded cost over- or under-recovered of the $350 million will be incorporated into the adjustment clause as provided for in Section 2.6(3) and Section 3.3 of the Settlement Agreement.

Q. How were the Direct Access Service rates developed?

A. Basically, the rate design involved a five step process. First, rates for three basic classes were determined. Second, after adjusting for the recovery of specific costs, the apportionment factors were applied to each of these rates, which resulted in unbundled functionalized prices for each rate. Third, final Direct Access Service rates were established that were comprised of charges for Basic Delivery Service, Distribution and Regulatory Assets, System Benefits, and a CTC, as well as provisions for Transmission and Primary service level discounts. Fourth, Direct Access Service rates for special contracts with BHP Copper, Cyprus Bagdad Copper, and Ralston Purina were established. Fifth, monthly credits were developed for those Direct Access Service customers using an ESP for their Metering, Meter Reading, and Billing requirements. The final proposed rate schedules for Direct Access Service appear in Schedule AP-8.

Q. Schedule B of Exhibit A of the Settlement Agreement contains the Distribution Charges to be effective January 1 of each year from 1999 to 2004. How were the changes in these charges calculated?

A. The Distribution Charges are comprised of revenue requirements for both Distribution and Regulatory Assets. To comply with the provisions of the Settlement Agreement concerning Regulatory Asset Amortization, it was necessary to reduce the Regulatory Assets components by 8.9% in the years 2000 through 2003 and 6.5% in 2004, as can be seen in Schedules 1 through 3 of Schedule AP-7. Additional computations were made to reflect the lower, implicit Regulatory Assets costs in special contracts APS has with BHP Copper, Cyprus Bagdad Copper, and Ralston Purina.

Q. Why have only three class rates plus three contract rates been chosen under which Direct Access Service will be offered?

A. Traditionally, APS's tariff has contained a large number of individual rates for each general class of business in order to reflect cost-to-serve differences that are primarily related to generation cost differences, and to allow for intraclass and interclass subsidization and rate of return differentials. Generation cost differences should play no part in the design of non-generation related Direct Access Service charges, and intraclass rate of return differentials should not be a complicating and anti-competitive factor in an era of multiple potential service providers that are competing to supply various components of Direct Access Service. As a step towards implementing this concept, only three general class rates--Residential (DA-R1), General Service under 3MW (DA-GS1), and General Service 3MW and greater (DA-GS10)--have been developed to serve customers desiring Direct Access Service.

Q. Have any aspects of intraclass, generation related rate of return differentials in the rate designs been preserved?

A. Yes, for the time being. In order to avoid drastic customer dislocations, the proposed three rate designs retain several of the generation related features inherent in the current bundled full service rates. These include such features as load factor blocks and seasonality.

Q. Have interclass return differentials been preserved?

A. To a certain extent, yes. But, once again the intention is only for the time being, and to ease into cost based rates through a transition period. The rate levels, and therefore cost recovery relationships, among the Residential, General Service under 3MW, and General Service 3MW and greater classes in the proposed Direct Access Service rates are the same as those for the similar services provided under APS's current tariff. In addition, and as stated in a previous answer, the rate designs for the three Direct Access Service rates parallel those of the dominant rate for similar services under APS's current tariff. In fact, the proposed Direct Access Service rate for General Service under 3MW is the apportionment of the current Rate E-32, and the proposed rate for General Service 3MW and greater is the apportionment of the current Rate E-34. This methodology was used for the express purpose of limiting the magnitude of pricing dislocations to individual customers.

Q. You indicated that interclass return differentials would be maintained "for the time being." Why have you adopted this approach, and in what time frame would you anticipate that it would end?

A. This approach is consistent with the ACC's stated objective that the transition to competition should not result in rate increases. Immediately eliminating class return differentials would have significant dislocation impacts. The remaining rate of return differentials should be eliminated when Direct Access

Service and competition in general is fully operational. Whether this actually occurs in the market place at the end of the phase-in period or when the Stranded Cost recovery and the CTCs expire cannot be definitively stated at this time. However, the elimination of class rate of return differentials should be a major objective of a future rate case.

Q. How were the rate credits developed for a Direct Access Customer using an ESP for the required Metering, Meter Reading, and Billing services?

A. The "avoided costs" associated with each of these particular services were identified and quantified. Avoided costs were defined as the estimated cost reductions that would be experienced by APS by providing a specific service to one less or the decremental customer. Avoided costs were used in these calculations since most embedded costs do not disappear for APS when a customer chooses an alternative supplier for Metering, Meter Reading, or Billing services. If full embedded costs had been used as the measure of these credits, a revenue shortfall would occur that would increase the unitized revenue requirements of all remaining customers. A summary of these credits appears in Schedule AP-9.

Q. Could you further explain avoided costs as they pertain to Metering?

A. Retail rates presently include charges for the capital expenditures APS has made over time to acquire and install meters, and for the costs of the meter shop and related equipment. These charges are composed of depreciation expenses and a return on the net book value of the meters. The only avoided cost, at least for the transition period, would be the cost of the actual meter on the customer premise, assuming its sale or re-use, adjusted to reflect the cost of retrieval and testing.

Q. Could you further explain avoided costs as they pertain to Meter Reading?

A. If a customer chooses a service provider other than APS to read his meter, the only cost reductions that would initially be experienced by APS would be the cost associated with reading this particular meter. This cost is no more than the time it takes for the meter reader to go from the curb to the meter, read or probe that meter, and return to the curb. The meter reader would still be required to walk past the premise to continue his route. There could actually be an increase in cost if certain meters are not read, since the meter reader must continually adjust his routine to accommodate a continually changing route. In addition, costs could increase as a result of the customer information system being regularly updated to reflect Direct Access Service related meter changes.

Q. Could you further explain avoided costs as they pertain to Billing?

A. The only cost reductions that would initially be experienced by APS would be related to the production and mailing of the physical bill. APS would still be required to retain its current level of personnel, a billing system, and customer inquiry support. In fact, with Direct Access Service, APS anticipates an increase in calls from customers asking billing related questions which could easily exceed any Billing related cost savings.

Q. Could customers choosing Direct Access Service still have APS provide some of their non-Distribution related services?

A. It is possible that relatively low use customers choosing Direct Access Service will not all have their ESP provide or arrange for all their requirements for Generation, Transmission, Ancillary Services, Metering, Meter Reading, and Billing. However, the exceptions would probably only apply to Metering, Meter Reading, and possibly Billing.

Q. Aside from the development of the three Direct Access Service rates, are there any other portions of the APS retail tariff that need modification to accommodate this service?

A. Yes. Certain provisions in APS's Terms and Conditions of Service should be modified to accommodate the transition to Direct Access Service. However, these selected updates to APS's Schedules will be filed separately at a later date.

Q. Would you discuss Generation, Transmission, and Ancillary Services as they apply to Direct Access Service customers?

A. The Direct Access Service customer could contract for Generation from any certified ESP he chooses, assuming that all required Transmission and Ancillary Services could be obtained. That portion of the Transmission and Ancillary Services required from APS would be provided indirectly to the retail customer through a Scheduling Coordinator selected by the customer or the customer's ESP. APS would bill the Scheduling Coordinator for these services under the rates and terms and conditions to be specified in APS's

OATT as authorized by FERC. It cannot be assumed that the Scheduling Coordinator will simply pass these costs along to the customer's ESP, who in turn could pass them on to the customer since, as unregulated entities, the Scheduling Coordinator and the ESP would each be free to define their own rate levels and designs. They may choose to rebundle charges to the customer or charge a premium above the Transmission and Ancillary Services prices charged to the Scheduling Coordinator by APS.

Q. Will a Direct Access Service customer need to have direct involvement with the Arizona Independent Scheduling Administrator (AISA) or the planned Desert STAR Independent System Operator (ISO)?

A. No, although customers or their representatives are welcome to join and/or participate in these organizations. The purpose of the AISA and the ISO are to establish the operating and later pricing protocols to assure a non-discriminatory and reliable operation of Arizona's and the Southwest's transmission systems. APS is a member of both organizations, intends to participate in the development of the operational and pricing protocols to be implemented by these organizations, and will file a revised OATT with FERC that will reflect how Transmission and Ancillary Services would be provided to Scheduling Coordinators in a Direct Access Service environment.

Q. Why is it necessary to develop new protocols, instead of using the provisions in the Company's current OATT as accepted by FERC?

A. FERC's pro-forma Transmission tariff, upon which APS' OATT is based, is geared to Transmission Service for wholesale customers. It is not readily amenable for service to retail Direct Access Service customers. AISA's Operating Committee participants have identified those aspects of service to retail customers taking network Transmission Service that were not adequately addressed in FERC's pro-forma Transmission tariff. They are in the process of developing suitable operating and pricing protocols that would facilitate Transmission Service to retail customers.

Q. Will AISA's protocols be finalized in time for APS to implement them for retail access in accordance with the Settlement Agreement?

A. Most of the protocols have already been developed or are in the final stages of development. It is hoped that they will all be finalized by the time APS must revise and file its OATT with FERC to accommodate retail access. In the event that some of the protocols are not completed by the time APS must file its revised OATT with the FERC, APS plans to submit the completed protocols along with interim versions of those protocols remaining to be completed. At such time as the AISA files its own OATT with the FERC containing the completed protocols, APS would again revise its OATT to include the AISA's protocol manual.

Q. Is any action by the ACC necessary in order for APS to implement the proposed revisions to its OATT as contemplated by the Settlement Agreement in a timely manner?

A. Yes. The ACC's support of APS's proposed changes is very important for FERC's acceptance. Therefore, APS requests that the ACC either a) intervene in APS's OATT filing with FERC and support APS's revisions; or b) provide a letter to FERC in support of APS's revisions which APS would include as part of its filing to FERC. In addition, FERC's rules normally require 60 days before changes to rates or tariffs can be implemented. If the ACC were to issue an Order approving the Settlement Agreement on August 1, absent requesting a waiver of FERC's Notice requirements, retail access would not be available on a practical basis prior to September 30. Therefore, the ACC's support of APS' request to FERC for waiver of FERC's Notice requirements would be desirable.

Q. How does APS intend to implement the rate decreases for Standard Offer Service rates specified in Section 2.2 of the Settlement Agreement?

A. APS intends to use the same method that has been used for the last three annual decreases under the 1996 Settlement. That is, each year APS will calculate for each major class of service the decrease percentage applicable to the Demand and Energy charges that yields the overall class decrease as specified in Section 2.2 of the Settlement Agreement. This method allows the Basic Service Charge in each of the Standard Offer rates to remain unchanged.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Appendix - A

Qualifications of

ALAN PROPPER

Alan Propper is Arizona Public Service Company's Director of Pricing & Regulation. He is a veteran of the electric and gas utility industry with over 30 years of experience in utility company management and as an industry consultant. Mr. Propper holds the degrees of Mechanical Engineer from Stevens Institute of Technology and Master of Business Administration from San Francisco State University. The Arizona State Community College Certification Board has certified him as an Instructor of Engineering and Business Administration. In addition, Mr. Propper has completed Advanced Alternative Dispute Resolution Training and has been certified to act as a Mediator by the Northwest Regional Transmission Association and by the Western Regional Transmission Association. He is a contributing author of the widely used utility industry text, Gas Rate Fundamentals, Fourth Edition, published by the American Gas Association.

Mr. Propper's areas of expertise include pricing and rate design, embedded and marginal cost analyses, marketing and load management programs, state and federal regulatory matters, contract negotiations between utilities concerning resale and wheeling services, contract negotiations between utilities and their major retail customers, and organizational training and planning. He is also a highly experienced expert witness, having testified on numerous occasions on contract, pricing, and cost matters before many state and federal regulatory agencies.

Prior to rejoining APS earlier this year after an eight year absence and seventeen years of service, Mr. Propper served as Regional Manager and Managing Executive Consultant for Resource Management International and Principal Consultant and Director of Consulting Services for A&C Enercom. Prior to initially joining APS, Mr. Propper was employed as Supervisor of Rates for Consumers Power Company, Executive Consultant for Commonwealth Services, Forecast Engineer and Rate Engineer for Pacific Gas and Electric Company, and in Power Plant Operations for Public Service Electric and Gas Company.

**** ARIZONA PUBLIC SERVICE ****
COST OF SERVICE STUDY
4 CP Allocation
Adjusted
TYE 12/31/96

LINE NO	SUMMARY	<------- ELECTRIC TOTAL	GJ ACC JURISD.	-------> ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GE-1 GENERAL SERVICE	STREET LIGHTING	-------> DUSK TO DAWN	<------- GE GEN. SER. (OVER 3MW)	-------> GEN. SER. (LESS 3MW)
====	*** REVENUES ***										
	*** OPERATING EXPENSES ***										
1	OPERATION & MAINTENANCE EXPENSE	617081	581906	35175	581906	279072	296139	5466	1228	75288	220851
2	ADMINISTRATIVE & GENERAL EXPENSE	71644	68971	2673	68971	43784	23918	913	356	4669	19249
3	DEPRECIATION & AMORT. EXPENSE	209324	198335	10989	198335	107022	88316	2426	572	17389	70927
4	AD VALOREM & OTHER TAXES	121685	115165	6520	115165	63160	50022	1600	383	9703	40320
5	AMORTIZATION OF GAINS	-4548	-4288	-260	-4288	-2027	-2261	0	0	-501	-1760
6	REG. ASSETS & DECOM. EXPENSE	178280	170444	7836	170444	76494	93651	234	66	22859	70792
7	SALES TAXES	0	0	0	0	0	0	0	0	0	0
8	REGULATORY EXPENSE (FERC)	701	0	701	0	0	0	0	0	0	0
9	INCOME TAXES	126500	122182	4318	122182	30455	91071	9	648	7529	83542
10	TOTAL OPERATING EXPENSES	1320667	1252715	67951	1252715	597961	640856	10647	3252	136935	503921
	*** RATE BASE ***										
11	PROD., TRANMS., & DISTR. PLANT	6773502	6387718	385784	6387718	3385120	2910727	74974	16898	577116	2333611
12	GENERAL & INTANG. PLANT	474077	454155	19922	454155	287565	157714	6678	2199	29086	128628
13	FUTURE USE PLANT / CWIP	0	0	0	0	0	0	0	0	0	0
14	RESERVE FOR DEPREC. & AMORIT.	-2755471	-2567454	-188017	-2567454	-1336129	-1202172	-23534	-5620	-249274	-952897
15	** NET PLANT **	4492108	4274419	217689	4274419	2336556	1866269	58117	13477	356927	1509342
16	REGULATORY ASSETS & DECOM.	1292649	1239189	53460	1239189	570853	667252	846	238	155649	511603
17	GAIN FROM PLANT	-86939	-81970	-4969	-81970	-38745	-43225	0	0	-9582	-33643
18	MATERIAL & SUPPLIES	139185	130180	9005	130180	58980	70407	636	157	17520	52887
19	CUSTOMER ADVANCES	-24044	-24044	0	-24044	-11301	-12743	0	0	-8	-12735
20	CUSTOMER DEPOSITS	-32137	-32137	0	-32137	-15104	-17033	0	0	-11	-17022
21	WORKING CASH/PREPAYMENTS	-256288	-242754	-13534	-242754	-122311	-118399	-1563	-482	-27358	-91041
22	ACCUM. DEFERRED TAXES	-1462067	-1380236	-81831	-1380236	-688856	-681827	-7760	-1793	-145435	-536392
23	TOTAL RATE BASE	4062467	3882647	179820	3882647	2090073	1730701	50276	11597	347702	1382999

**** ARIZONA PUBLIC SERVICE *****
COST OF SERVICE STUDY
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LINE NO	INCOME TAX CALCULATION	ELECTRIC TOTAL	GJ ACC JURISD.	GJ ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GE-1 GENERAL SERVICE	GE-1 STREET LIGHTING	GE-1 DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GE GEN. SER. (LESS 3MW)
====	*** OPERATING EXPENSES ***										
1	OPERATION & MAINTENANCE EXPENSE	617081	581906	35175	581906	279072	296139	5466	1228	75288	220851
2	ADMINISTRATIVE & GENERAL EXPENSE	71644	68971	2673	68971	43784	23918	913	356	4669	19249
3	DEPRECIATION & AMORIT. EXPENSE	209324	198335	10989	198335	107022	88316	2426	572	17389	70927
4	AD VALOREM & OTHER TAXES	121685	115165	6520	115165	63160	50022	1600	383	9703	40320
5	AMORTIZATION OF GAIN	-4548	-4288	-260	-4288	-2027	-2261	0	0	-501	-1760
6	REG. ASSETS & DECOM. EXPENSE	178280	170444	7836	170444	76494	93651	234	66	22859	70792
7	SALES TAXES	0	0	0	0	0	0	0	0	0	0
8	REGULATORY EX. (FERC)	701	0	701	0	0	0	0	0	0	0
9	TOTAL EXPENSE	1194167	1130533	63634	1130533	567506	549785	10638	2604	129406	420380
10	**OPERATING INCOME BEFORE TAXES**	459531	442365	17166	442365	150667	287846	1831	2022	31163	256682
	INTEREST EXPENSE										
11	RATE BASE	4062467	3882647	179820	3882647	2090073	1730701	50276	11597	347702	1382999
12	LONG TERM DEBT RATE	3.60%									
13	INTEREST EXP. (RB * LTD)	146249	139775	6474	139775	75243	62305	1810	417	12517	49788

**** ARIZONA PUBLIC SERVICE ****
COST OF SERVICE STUDY
4 CP Allocation
Adjusted
TYE 12/31/96

LINE No.	PROD/TRANM/DIST PLANT		<------ GJ		------>	:------	------ GE-1		------	------>	<------ GE	------>
			ELECTRIC TOTAL	ACC JURISD.	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
====	PRODUCTION ******											
1	DEMAND	D-01	3582144	3377390	204754	3377390	1596405	1780985	0	0	394812	1386173
2	ANC.-REGULATION	D-01	77604	73168	4436	73168	34585	38583	0	0	8553	30030
3	ANC.-SPINNING RES.	D-01	99788	94084	5704	94084	44471	49613	0	0	10998	38615
4	ANC.-READY RES.	D-01	26188	24691	1497	24691	11671	13020	0	0	2886	10134
5	SPEC AFUDC	DS-07	-120009	-115425	-4584	-115425	-54558	-60867	0	0	-13493	-47374
6	ENERGY	E-01	0	0	0	0	0	0	0	0	0	0
7	ENERGY-REGULATION	E-01	0	0	0	0	0	0	0	0	0	0
8	TOTAL PRODUCTION		3665715	3453908	211807	3453908	1632573	1821335	0	0	403757	1417578
	TRANSMISSION *****											
9	SUBSTATION	D-02	298760	259854	38906	259854	122826	137028	0	0	30377	106651
10	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
11	SUBTOTAL SUBSTAT		298760	259854	38906	259854	122826	137028	0	0	30377	106651
12	LINES	D-02	450838	392128	58710	392128	185349	206779	0	0	45839	160940
13	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
14	-SPEC AFUDC	DS-03	-2490	-2490	0	-2490	-1177	-1313	0	0	-291	-1022
15	SUBTOTAL LINES		448348	389638	58710	389638	184172	205466	0	0	45548	159918
16	TOTAL TRANSMISSION		747108	649491	97617	649491	306998	342494	0	0	75925	266569
	DISTRIBUTION *****											
17	SUBSTATION	D-07	176053	170708	5345	170708	94357	74857	1188	306	15268	59589
	O.H. LINES											
18	-OH PRIMARY	D-09	433167	422799	10368	422799	240762	178224	3032	781	27814	150409
19	-OH SECONDARY	D-11	125686	125669	17	125669	107240	17045	1100	284	0	17045
	U.G. LINES											
20	-UG PRIMARY	D-14	738181	731981	6200	731981	421980	303319	5313	1369	47804	255515
21	-UG SECONDARY	D-17A	37859	37859	0	37859	32974	4519	291	75	0	4519
	LINE TRANSFORMER											
22	-OH LINE TRANS.	D-12	138656	134961	3695	134961	93162	41060	588	151	1967	39094
23	-UG LINE TRANS.	D-12A	273030	273030	0	273030	188468	83066	1189	306	3979	79087
	SERVICES											
24	-O.H. SERVICES	C-08	39159	38816	343	38816	33447	5369	0	0	0	5369
25	-U.G. SERVICES	C-09	142132	141578	554	141578	127718	13860	0	0	284	13575
26	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
27	METERS-ALLOCABLE	C-03	132839	131020	1819	131020	105440	25580	0	0	318	25261
28	DUSK TO DAWN	CS-13	13625	13625	0	13625	0	0	0	13625	0	0
29	STREET LIGHTING	CS-12	62272	62272	0	62272	0	0	62272	0	0	0
			0	0	0	0	0	0	0	0	0	0
30	TOTAL DISTRIBUTION		2312659	2284319	28340	2284319	1445549	746898	74974	16898	97435	649464
31	CUSTOMER ACCOUNTS	C-04	0	0	0	0	0	0	0	0	0	0
32	CUST SERV & INFO	DS-03	0	0	0	0	0	0	0	0	0	0
33	SALES	DS-05	0	0	0	0	0	0	0	0	0	0
34	TOTAL DEMAND		6335455	6000407	335048	6000407	3118514	2865919	12702	3273	576513	2289405
35	TOTAL ENERGY		0	0	0	0	0	0	0	0	0	0
36	TOTAL CUSTOMER		390027	387311	2716	387311	266606	44808	62272	13625	603	44206
37	TOTAL (EX SCE)		6725482	6387718	337764	6387718	3385120	2910727	74974	16898	577116	2333611
38	500 KV SCE	S-10	48020	0	48020	0	0	0	0	0	0	0
39	TOTAL COMPANY		6773502	6387718	385784	6387718	3385120	2910727	74974	16898	577116	2333611

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LINE No.			ELECTRIC TOTAL	GJ ACC JURISD.	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GE-1 GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
====	GENERAL & INTANG PLANT											
	PRODUCTION ******											
1	DEMAND	D-01	105836	99786	6050	99786	47166	52620	0	0	11665	40955
2	ANC.-REGULATION	D-01	2191	2066	125	2066	976	1089	0	0	241	848
3	ANC.-SPINNING RES.	D-01	2498	2355	143	2355	1113	1242	0	0	275	967
4	ANC.-READY RES.	D-01	357	337	20	337	159	177	0	0	39	138
5	ENERGY	E-01	41363	38481	2882	38481	15388	22886	162	45	6508	16378
6	ENERGY-REGULATION	E-01	906	843	63	843	337	501	4	1	143	359
7	TOTAL PRODUCTION		153151	143868	9283	143868	65140	78516	166	46	18872	59645
	TRANSMISSION ******											
8	SUBSTATION	D-02	4809	4183	626	4183	1977	2206	0	0	489	1717
9	SUBTOTAL SUBSTAT		4809	4183	626	4183	1977	2206	0	0	489	1717
10	LINES	D-02	39209	34103	5106	34103	16120	17983	0	0	3987	13997
11	SUBTOTAL LINES		39209	34103	5106	34103	16120	17983	0	0	3987	13997
12	TOTAL TRANSMISSION		44018	38286	5732	38286	18097	20189	0	0	4476	15714
	DISTRIBUTION *****											
13	SUBSTATION	D-07	18580	18016	564	18016	9958	7900	125	32	1611	6289
	O.H. LINES											
14	-OH PRIMARY	D-09	27489	26831	658	26831	15279	11310	192	50	1765	9545
15	-OH SECONDARY	D-11	7977	7976	1	7976	6806	1082	70	18	0	1082
	U.G. LINES											
16	-UG PRIMARY	D-14	32763	32488	275	32488	18729	13462	236	61	2122	11341
17	-UG SECONDARY	D-17A	1681	1681	0	1681	1464	201	13	3	0	201
	LINE TRANSFORMER											
18	-OH LINE TRANS.	D-12	2405	2341	64	2341	1616	712	10	3	34	678
19	-UG LINE TRANS.	D-12	4735	4609	126	4609	3181	1402	20	5	67	1335
	SERVICES											
20	-O.H. SERVICES	C-08	2485	2463	22	2463	2123	341	0	0	0	341
21	-U.G. SERVICES	C-09	6306	6281	25	6281	5667	615	0	0	13	602
22	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
23	METERS-ALLOCABLE	C-03	49476	48799	677	48799	39271	9527	0	0	119	9409
24	DUSK TO DAWN	CS-13	719	719	0	719	0	0	0	719	0	0
25	STREET LIGHTING	CS-12	5758	5758	0	5758	0	0	5758	0	0	0
26	TOTAL DISTRIBUTION		160374	157962	2412	157962	104094	46552	6425	891	5731	40822
27	CUSTOMER ACCOUNTS	C-04	100787	100581	206	100581	88405	10986	77	1113	7	10979
28	CUST SERV & INFO	C-04A	4230	4230	0	4230	3718	462	3	47	0	462
29	SALES	C-04	9247	9228	19	9228	8111	1008	7	102	1	1007
30	REGULATORY ASSETS	D-01	0	0	0	0	0	0	0	0	0	0
31	SYSTEM BENEFITS	D-01	0	0	0	0	0	0	0	0	0	0
32	TOTAL DEMAND		250530	236771	13759	236771	124546	111387	667	172	22296	89091
33	TOTAL ENERGY		42269	39324	2945	39324	15725	23388	166	46	6651	16737
34	TOTAL CUSTOMER		179008	178059	949	178059	147294	22939	5845	1981	139	22800
35	TOTAL (EX SCE)		471807	454155	17652	454155	287565	157714	6678	2199	29086	128628
36	500 KV SCE	S-10	2270	0	2270	0	0	0	0	0	0	0
37	TOTAL COMPANY		474077	454155	19922	454155	287565	157714	6678	2199	29086	128628

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LINE No.	RESERVE FOR DEPREC & AMORIT		GJ			GE-1					GE	
====			ELECTRIC TOTAL	ACC JURISD.	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
	PRODUCTION *******											
1	DEMAND	D-01	-1476614	-1392211	-84403	-1392211	-658062	-734149	0	0	-162747	-571401
2	ANC.-REGULATION	D-01	-47755	-45025	-2730	-45025	-21282	-23743	0	0	-5263	-18480
3	ANC.-SPINNING RES.	D-01	-55590	-52412	-3178	-52412	-24774	-27638	0	0	-6127	-21512
4	ANC.-READY RES.	D-01	-18192	-17152	-1040	-17152	-8107	-9045	0	0	-2005	-7040
5	SPEC AFUDC	DS-08	43181	41512	1669	41512	19622	21890	0	0	4853	17038
6	ENERGY	E-01	-20934	-19476	-1458	-19476	-7788	-11583	-82	-23	-3294	-8289
7	ENERGY-REGULATION	E-01	-405	-377	-28	-377	-151	-224	-2	0	-64	-160
8	TOTAL PRODUCTION		-1576309	-1485142	-91167	-1485142	-700543	-784492	-84	-23	-174648	-609844
	TRANSMISSION ******											
9	SUBSTATION	D-02	-116931	-101704	-15227	-101704	-48073	-53631	0	0	-11889	-41742
10	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
11	SUBTOTAL SUBSTAT		-116931	-101704	-15227	-101704	-48073	-53631	0	0	-11889	-41742
12	LINES	D-02	-194771	-169407	-25364	-169407	-80074	-89333	0	0	-19803	-69529
13	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
14	-SPEC AFUDC	DS-03	1382	1382	0	1382	653	729	0	0	162	567
15	SUBTOTAL LINES		-193389	-168025	-25364	-168025	-79421	-88604	0	0	-19642	-68962
16	TOTAL TRANSMISSION		-310320	-269729	-40591	-269729	-127494	-142235	0	0	-31531	-110704
	DISTRIBUTION *****											
17	SUBSTATION	D-07A	-46575	-44460	-2115	-44460	-24575	-19496	-309	-80	-3976	-15520
	O.H. LINES											
18	-OH PRIMARY	D-09A	-129121	-123867	-5254	-123867	-70536	-52214	-888	-229	-8149	-44065
19	-OH SECONDARY	D-11	-37466	-37461	-5	-37461	-31967	-5081	-328	-85	0	-5081
	U.G. LINES											
20	-UG PRIMARY	D-14A	-214034	-212042	-1992	-212042	-122240	-87866	-1539	-397	-13848	-74018
21	-UG SECONDARY	D-17A	-10978	-10978	0	-10978	-9561	-1310	-84	-22	0	-1310
	LINE TRANSFORMER											
22	-OH LINE TRANS.	D-12A	-38749	-37372	-1377	-37372	-25797	-11370	-163	-42	-545	-10825
23	-UG LINE TRANS.	D-12A	-76301	-76301	0	-76301	-52669	-23214	-332	-86	-1112	-22102
	SERVICES											
24	-O.H. SERVICES	C-08A	-11714	-11544	-170	-11544	-9947	-1597	0	0	0	-1597
25	-U.G. SERVICES	C-09A	-41360	-41134	-226	-41134	-37107	-4027	0	0	-83	-3944
26	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
27	METERS-ALLOCABLE	C-03	-57249	-56465	-784	-56465	-45441	-11024	0	0	-137	-10887
28	DUSK TO DAWN	CS-13	-4012	-4012	0	-4012	0	0	0	-4012	0	0
29	STREET LIGHTING	CS-12	-19399	-19399	0	-19399	0	0	-19399	0	0	0
			0	0	0	0	0	0	0	0	0	0
30	TOTAL DISTRIBUTION		-686958	-675035	-11923	-675035	-429842	-217199	-23043	-4951	-27850	-189349
31	CUSTOMER ACCOUNTS	C-04	-42999	-42911	-88	-42911	-37716	-4687	-33	-475	-3	-4684
32	CUST SERV & INFO	C-04A	-1893	-1893	0	-1893	-1664	-207	-1	-21	0	-207
33	SALES	C-04	-4138	-4130	-8	-4130	-3630	-451	-3	-46	0	-451
34	REGULATORY ASSETS	D-01	0	0	0	0	0	0	0	0	0	0
35	SYSTEM BENEFITS	E-01	-95504	-88615	-6889	-88615	-35240	-52901	-370	-104	-15243	-37659
36	TOTAL DEMAND		-2514018	-2366114	-147904	-2366114	-1192685	-1168372	-4014	-1043	-245693	-922679
37	TOTAL ENERGY		-21339	-19852	-1487	-19852	-7938	-11807	-84	-23	-3357	-8449
38	TOTAL CUSTOMER		-182764	-181488	-1276	-181488	-135506	-21992	-19437	-4553	-223	-21769
39	TOTAL (EX SCE)		-2718121	-2567454	-150667	-2567454	-1336129	-1202172	-23534	-5620	-249274	-952897
40	500 KV SCE	S-10	-37350	0	-37350	0	0	0	0	0	0	0
41	TOTAL COMPANY		-2755471	-2567454	-188017	-2567454	-1336129	-1202172	-23534	-5620	-249274	-952897

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LINE No.	GAIN FROM PLANT		ELECTRIC TOTAL	GJ: ACC JURISD.	GJ: ALL OTHER	TOTAL RETAIL	GE-1: RESIDENTIAL	GE-1: GENERAL SERVICE	GE-1: STREET LIGHTING	GE-1: DUSK TO DAWN	GE: GEN. SER. (OVER 3MW)	GE: GEN. SER. (LESS 3MW)
====	PRODUCTION ******											
1	DEMAND	D-01	-86939	-81970	-4969	-81970	-38745	-43225	0	0	-9582	-33643
2	ENERGY	E-01	0	0	0	0	0	0	0	0	0	0
3	SPECIFIC	D-01A	0	0	0	0	0	0	0	0	0	0
4	TOTAL PRODUCTION		-86939	-81970	-4969	-81970	-38745	-43225	0	0	-9582	-33643
	TRANSMISSION ******											
5	SUBSTATION	D-02	0	0	0	0	0	0	0	0	0	0
6	SUBTOTAL SUBSTAT		0	0	0	0	0	0	0	0	0	0
7	LINES	D-02	0	0	0	0	0	0	0	0	0	0
8	SUBTOTAL LINES		0	0	0	0	0	0	0	0	0	0
9	TOTAL TRANSMISSION		0	0	0	0	0	0	0	0	0	0
	DISTRIBUTION *****											
10	SUBSTATION	D-07	0	0	0	0	0	0	0	0	0	0
11	O.H. LINES											
12	-PRIMARY	D-09	0	0	0	0	0	0	0	0	0	0
13	" -SECONDARY	D-11	0	0	0	0	0	0	0	0	0	0
14	U.G. LINES	D-14	0	0	0	0	0	0	0	0	0	0
15	"LINE TRANSFORMER	D-12	0	0	0	0	0	0	0	0	0	0
16	" O.H. SERVICES	C-08	0	0	0	0	0	0	0	0	0	0
17	" U.G. SERVICES	C-09	0	0	0	0	0	0	0	0	0	0
18	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
19	" -ALLOCABLE	C-03	0	0	0	0	0	0	0	0	0	0
20	DUSK TO DAWN	CS-13	0	0	0	0	0	0	0	0	0	0
21	STREET LIGHTING	CS-12	0	0	0	0	0	0	0	0	0	0
22	TOTAL DISTRIBUTION		0	0	0	0	0	0	0	0	0	0
23	CUSTOMER ACCOUNTS	C-04	0	0	0	0	0	0	0	0	0	0
24	CUST SERV & INFO	DS-03	0	0	0	0	0	0	0	0	0	0
25	SALES	DS-05	0	0	0	0	0	0	0	0	0	0
26	TOTAL DEMAND		-86939	-81970	-4969	-81970	-38745	-43225	0	0	-9582	-33643
27	TOTAL ENERGY		0	0	0	0	0	0	0	0	0	0
28	TOTAL CUSTOMER		0	0	0	0	0	0	0	0	0	0
29	TOTAL (EX SCE)		-86939	-81970	-4969	-81970	-38745	-43225	0	0	-9582	-33643
30	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
31	TOTAL COMPANY		-86939	-81970	-4969	-81970	-38745	-43225	0	0	-9582	-33643

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LINE No.	MATERIALS & SUPPLIES		<----- GJ ELECTRIC TOTAL	ACC JURISD.	ALL OTHER ----->	TOTAL RETAIL	RESIDENTIAL	GE-1 GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN ----->	<----- GE GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW) ----->
====	PRODUCTION *******											
1	DEMAND	D-01	50461	47577	2884	47577	22488	25088	0	0	5562	19527
2	ANC.-REGULATION	D-01	583	550	33	550	260	290	0	0	64	226
3	ANC.-SPINNING RES.	D-01	1004	947	57	947	447	499	0	0	111	389
4	ANC.-READY RES.	D-01	351	331	20	331	156	175	0	0	39	136
5	ENERGY	E-01	64182	59711	4471	59711	23877	35512	251	71	10098	25414
6	ENERGY-REGULATION	E-01	883	821	62	821	328	489	3	1	139	350
7	TOTAL PRODUCTION		117464	109936	7528	109936	47557	62053	255	72	16013	46040
	TRANSMISSION ******											
8	SUBSTATION	D-02	7579	6592	987	6592	3116	3476	0	0	771	2706
9	SUBTOTAL SUBSTAT		7579	6592	987	6592	3116	3476	0	0	771	2706
10	LINES	D-02	2370	2061	309	2061	974	1087	0	0	241	846
11	SUBTOTAL LINES		2370	2061	309	2061	974	1087	0	0	241	846
12	TOTAL TRANSMISSION		9949	8653	1296	8653	4090	4563	0	0	1012	3552
	DISTRIBUTION *****											
13	SUBSTATION	D-07	896	869	27	869	480	381	6	2	78	303
	O.H. LINES											
14	-OH PRIMARY	D-09	2205	2152	53	2152	1226	907	15	4	142	766
15	-OH SECONDARY	D-11	640	640	0	640	546	87	6	1	0	87
	U.G. LINES											
16	-UG PRIMARY	D-14	3758	3726	32	3726	2148	1544	27	7	243	1301
17	-UG SECONDARY	D-17A	193	193	0	193	168	23	1	0	0	23
	LINE TRANSFORMER											
18	-OH LINE TRANS.	D-12	706	687	19	687	474	209	3	1	10	199
19	-UG LINE TRANS.	D-12	1390	1353	37	1353	934	412	6	2	20	392
	SERVICES											
20	-O.H. SERVICES	C-08	199	197	2	197	170	27	0	0	0	27
21	-U.G. SERVICES	C-09	723	720	3	720	650	71	0	0	1	69
22	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
23	METERS-ALLOCABLE	C-03	676	667	9	667	537	130	0	0	2	129
24	DUSK TO DAWN	CS-13	69	69	0	69	0	0	0	69	0	0
25	STREET LIGHTING	CS-12	317	317	0	317	0	0	317	0	0	0
26	TOTAL DISTRIBUTION		11772	11591	181	11591	7333	3791	382	86	495	3295
27	CUSTOMER ACCOUNTS	C-04	0	0	0	0	0	0	0	0	0	0
28	CUST SERV & INFO	DS-03	0	0	0	0	0	0	0	0	0	0
29	SALES	DS-05	0	0	0	0	0	0	0	0	0	0
30	TOTAL DEMAND		72136	67678	4458	67678	33419	34178	65	17	7279	26899
31	TOTAL ENERGY		65065	60532	4533	60532	24205	36001	255	72	10237	25763
32	TOTAL CUSTOMER		1984	1970	14	1970	1356	228	317	69	3	225
33	TOTAL (EX SCE)		139185	130180	9005	130180	58980	70407	636	157	17520	52887
34	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
35	TOTAL COMPANY		139185	130180	9005	130180	58980	70407	636	157	17520	52887

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			<---- GJ ---->			GE-1				<---- GE ---->	
LINE No.	REGULATORY ASSET & DECOMMISSIONING		ELECTRIC TOTAL	ACC JURISD.	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
====	PRODUCTION *******											
1	DEMAND -ACC	D-01A	0	0	0	0	0	0	0	0	0	0
2	DEMAND-ALLOCABLE	D-01	0	0	0	0	0	0	0	0	0	0
3	ENERGY-ALLOCABLE	E-01	0	0	0	0	0	0	0	0	0	0
4	TOTAL PRODUCTION		0	0	0	0	0	0	0	0	0	0
	TRANSMISSION ******											
5	SUBSTATION	D-02	0	0	0	0	0	0	0	0	0	0
6	SUBTOTAL SUBSTAT		0	0	0	0	0	0	0	0	0	0
7	LINES	D-02	0	0	0	0	0	0	0	0	0	0
8	SUBTOTAL LINES		0	0	0	0	0	0	0	0	0	0
9	TOTAL TRANSMISSION		0	0	0	0	0	0	0	0	0	0
	DISTRIBUTION *****											
10	SUBSTATION	D-07	0	0	0	0	0	0	0	0	0	0
11	O.H. LINES											
12	-PRIMARY	D-09	0	0	0	0	0	0	0	0	0	0
13	" -SECONDARY	D-11	0	0	0	0	0	0	0	0	0	0
14	U.G. LINES	D-14	0	0	0	0	0	0	0	0	0	0
15	"LINE TRANSFORMER	D-12	0	0	0	0	0	0	0	0	0	0
16	" O.H. SERVICES	C-08	0	0	0	0	0	0	0	0	0	0
17	" U.G. SERVICES	C-09	0	0	0	0	0	0	0	0	0	0
18	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
19	METERS ALLOCABLE	C-03	0	0	0	0	0	0	0	0	0	0
20	DUSK TO DAWN	CS-13	0	0	0	0	0	0	0	0	0	0
21	STREET LIGHTING	CS-12	0	0	0	0	0	0	0	0	0	0
22	TOTAL DISTRIBUTION		0	0	0	0	0	0	0	0	0	0
23	CUSTOMER ACCOUNTS	C-04	0	0	0	0	0	0	0	0	0	0
24	CUST SERV & INFO	DS-03	0	0	0	0	0	0	0	0	0	0
25	SALES	DS-05	0	0	0	0	0	0	0	0	0	0
26	REGULATORY ASSETS	E-01	79096	73586	5510	73586	29425	43764	310	87	12445	31319
27	REGULATORY ASSETS	D-01	78113	73648	4465	73648	34812	38837	0	0	8609	30227
28	REGULATORY ASSETS	D-01	516722	487186	29536	487186	230280	256906	0	0	56951	199955
29	REGULATORY ASSETS	D-01	71778	67675	4103	67675	31988	35687	0	0	7911	27776
30	REGULATORY ASSETS	D-01A	-5108	-5108	0	-5108	-2414	-2694	0	0	-597	-2096
31	REGULATORY ASSETS	E-01	42462	39504	2958	39504	15796	23494	166	47	6681	16813
32	REGULATORY ASSETS	D-01A	414082	414082	0	414082	195726	218356	0	0	48406	169951
33	SYSTEM BENEFITS	E-01	95504	88615	6889	88615	35240	52901	370	104	15243	37659
34	TOTAL DEMAND		1171091	1126099	44992	1126099	525632	599993	370	104	136523	463470
35	TOTAL ENERGY		121558	113090	8468	113090	45221	67259	476	134	19126	48133
36	TOTAL CUSTOMER		0	0	0	0	0	0	0	0	0	0
37	TOTAL (EX SCE)		1292649	1239189	53460	1239189	570853	667252	846	238	155649	511603
38	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
39	TOTAL COMPANY		1292649	1239189	53460	1239189	570853	667252	846	238	155649	511603

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LINE No. ====	WORKING CASH / PREPAYMENTS		ELECTRIC TOTAL	GJ ACC JURISD.	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GE-1 GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
	PRODUCTION ******											
1	DEMAND	D-01	-125351	-118186	-7165	-118186	-55863	-62323	0	0	-13816	-48507
2	ANC.-REGULATION	D-01	-1347	-1270	-77	-1270	-600	-670	0	0	-148	-521
3	ANC.-SPINNING RES.	D-01	-1629	-1536	-93	-1536	-726	-810	0	0	-180	-630
4	ANC.-READY RES.	D-01	-334	-315	-19	-315	-149	-166	0	0	-37	-129
5	ENERGY	E-01	-72546	-67492	-5054	-67492	-26988	-40140	-284	-80	-11414	-28726
6	ENERGY-REGULATION	E-01	-271	-252	-19	-252	-101	-150	-1	0	-43	-107
7	TOTAL PRODUCTION		-201478	-189051	-12427	-189051	-84428	-104258	-285	-80	-25638	-78620
	TRANSMISSION *****											
8	SUBSTATION	D-02	-3265	-2840	-425	-2840	-1342	-1498	0	0	-332	-1166
9	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
10	SUBTOTAL SUBSTAT		-3265	-2840	-425	-2840	-1342	-1498	0	0	-332	-1166
11	LINES	D-02	-1156	-1005	-151	-1005	-475	-530	0	0	-118	-413
12	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
13	-SPEC AFUDC	DS-03	0	0	0	0	0	0	0	0	0	0
14	SUBTOTAL LINES		-1156	-1005	-151	-1005	-475	-530	0	0	-118	-413
15	TOTAL TRANSMISSION		-4421	-3845	-576	-3845	-1818	-2028	0	0	-450	-1578
	DISTRIBUTION *****											
16	SUBSTATION	D-07	-1940	-1881	-59	-1881	-1040	-825	-13	-3	-168	-657
	O.H. LINES											
17	-OH PRIMARY	D-09	-6447	-6293	-154	-6293	-3583	-2653	-45	-12	-414	-2239
18	-OH SECONDARY	D-11	-1870	-1870	0	-1870	-1596	-254	-16	-4	0	-254
	U.G. LINES											
19	-UG PRIMARY	D-14	-9441	-9362	-79	-9362	-5397	-3879	-68	-18	-611	-3268
20	-UG SECONDARY	D-17A	-485	-485	0	-485	-422	-58	-4	-1	0	-58
	LINE TRANSFORMER											
21	-OH LINE TRANS.	D-12	-1359	-1323	-36	-1323	-913	-402	-6	-1	-19	-383
22	-UG LINE TRANS.	D-12	-2678	-2607	-71	-2607	-1799	-793	-11	-3	-38	-755
	SERVICES											
23	-O.H. SERVICES	C-08	-580	-575	-5	-575	-495	-80	0	0	0	-80
24	-U.G. SERVICES	C-09	-1816	-1809	-7	-1809	-1632	-177	0	0	-4	-173
25	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
26	METERS-ALLOCABLE	C-03	-6479	-6390	-89	-6390	-5143	-1248	0	0	-16	-1232
27	DUSK TO DAWN	CS-13	-183	-183	0	-183	0	0	0	-183	0	0
28	STREET LIGHTING	CS-12	-1102	-1102	0	-1102	0	0	-1102	0	0	0
29	TOTAL DISTRIBUTION		-34380	-33879	-501	-33879	-22020	-10368	-1265	-225	-1270	-9098
30	CUSTOMER ACCOUNTS	C-04	-11058	-11035	-23	-11035	-9699	-1205	-8	-122	-1	-1205
31	CUST SERV & INFO	C-04A	-1554	-1554	0	-1554	-1366	-170	-1	-17	0	-170
32	SALES	C-04	-3397	-3390	-7	-3390	-2980	-370	-3	-38	0	-370
33	REGULATORY ASSETS	E-01	0	0	0	0	0	0	0	0	0	0
34	REGULATORY ASSETS	D-01	0	0	0	0	0	0	0	0	0	0
35	REGULATORY ASSETS	D-01	0	0	0	0	0	0	0	0	0	0
36	TOTAL DEMAND		-157302	-148972	-8330	-148972	-73907	-74860	-163	-42	-15881	-58979
37	TOTAL ENERGY		-72817	-67744	-5073	-67744	-27089	-40290	-285	-80	-11457	-28833
38	TOTAL CUSTOMER		-26169	-26039	-130	-26039	-21315	-3250	-1114	-360	-20	-3229
39	TOTAL (EX SCE)		-256288	-242754	-13534	-242754	-122311	-118399	-1563	-482	-27358	-91041
40	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
41	TOTAL COMPANY		-256288	-242754	-13534	-242754	-122311	-118399	-1563	-482	-27358	-91041

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			<--------------	GJ	------------------>	:------------------	------------------	GE-1	------------------	------------------>	<------------------ GE	------------------>
LINE No. ====	DEFERRED TAXES RATE BASE - ALLOC PRODUCTION *******		ELECTRIC TOTAL	ACC JURISD.	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
1	DEMAND	D-01	-532144	-501727	-30417	-501727	-237153	-264573	0	0	-58651	-205922
2	ANC.-REGULATION	D-01	-14924	-14071	-853	-14071	-6651	-7420	0	0	-1645	-5775
3	ANC.-SPINNING RES.	D-01	-19165	-18070	-1095	-18070	-8541	-9529	0	0	-2112	-7416
4	ANC.-READY RES.	D-01	-5009	-4723	-286	-4723	-2232	-2490	0	0	-552	-1938
5	ENERGY	E-01	-4462	-4151	-311	-4151	-1660	-2469	-17	-5	-702	-1767
6	ENERGY-REGULATION	E-01	-86	-80	-6	-80	-32	-48	0	0	-14	-34
7	TOTAL PRODUCTION		-575790	-542821	-32969	-542821	-256270	-286529	-18	-5	-63676	-222853
	TRANSMISSION ******											
8	SUBSTATION	D-02	-38154	-33185	-4969	-33185	-15686	-17500	0	0	-3879	-13620
9	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
10	SUBTOTAL SUBSTAT		-38154	-33185	-4969	-33185	-15686	-17500	0	0	-3879	-13620
11	LINES	D-02	-68674	-59731	-8943	-59731	-28233	-31498	0	0	-6982	-24515
12	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
13	-SPEC AFUDC	D-01A	0	0	0	0	0	0	0	0	0	0
14	SUBTOTAL LINES		-68674	-59731	-8943	-59731	-28233	-31498	0	0	-6982	-24515
15	TOTAL TRANSMISSION		-106828	-92916	-13912	-92916	-43919	-48997	0	0	-10862	-38135
	DISTRIBUTION *****											
16	SUBSTATION	D-07	-18827	-18255	-572	-18255	-10090	-8005	-127	-33	-1633	-6372
	O.H. LINES											
17	-OH PRIMARY	D-09	-49184	-48007	-1177	-48007	-27337	-20236	-344	-89	-3158	-17078
18	-OH SECONDARY	D-11	-14271	-14269	-2	-14269	-12177	-1935	-125	-32	0	-1935
	U.G. LINES											
19	-UG PRIMARY	D-14	-83323	-82623	-700	-82623	-47631	-34237	-600	-155	-5396	-28842
20	-UG SECONDARY	D-17A	-4274	-4274	0	-4274	-3722	-510	-33	-8	0	-510
	LINE TRANSFORMER											
21	-OH LINE TRANS.	D-12	-15564	-15149	-415	-15149	-10457	-4609	-66	-17	-221	-4388
22	-UG LINE TRANS.	D-12	-30648	-29831	-817	-29831	-20592	-9076	-130	-33	-435	-8641
	SERVICES											
23	-O.H. SERVICES	C-08	-4458	-4419	-39	-4419	-3808	-611	0	0	0	-611
24	-U.G. SERVICES	C-09	-16087	-16024	-63	-16024	-14456	-1569	0	0	-32	-1537
25	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
26	METERS-ALLOCABLE	C-03	-16561	-16334	-227	-16334	-13145	-3189	0	0	-40	-3149
27	DUSK TO DAWN	CS-13	-1547	-1547	0	-1547	0	0	0	-1547	0	0
28	STREET LIGHTING	CS-12	-7154	-7154	0	-7154	0	0	-7154	0	0	0
29	TOTAL DISTRIBUTION		-261898	-257888	-4010	-257888	-163416	-83978	-8579	-1914	-10914	-73064
30	CUSTOMER ACCOUNTS	C-04	-3526	-3519	-7	-3519	-3093	-384	-3	-39	0	-384
31	CUST SERV & INFO	C-04A	-495	-495	0	-495	-435	-54	0	-5	0	-54
32	SALES	C-04	-1083	-1081	-2	-1081	-950	-118	-1	-12	0	-118
33	REGULATORY ASSETS	D-01	21007	19806	1201	19806	9362	10444	0	0	2315	8129
34	REGULATORY ASSETS	E-01	-30911	-28758	-2153	-28758	-11499	-17103	-121	-34	-4864	-12240
35	REGULATORY ASSETS	D-01	-57085	-53822	-3263	-53822	-25440	-28382	0	0	-6292	-22090
36	REGULATORY ASSETS	D-01	-10608	-10002	-606	-10002	-4728	-5274	0	0	-1169	-4105
37	REGULATORY ASSETS	D-01	-225834	-212925	-12909	-212925	-100644	-112281	0	0	-24891	-87390
38	REGULATORY ASSETS	D-01	-87723	-82709	-5014	-82709	-39094	-43614	0	0	-9669	-33946
39	SYSTEM BENEFITS	D-01	0	0	0	0	0	0	0	0	0	0
40	TOTAL DEMAND		-1254404	-1183567	-70837	-1183567	-591049	-590726	-1425	-367	-124369	-466357
41	TOTAL ENERGY		-35459	-32989	-2470	-32989	-13191	-19620	-139	-39	-5579	-14041
42	TOTAL CUSTOMER		-50911	-50573	-338	-50573	-35886	-5925	-7158	-1603	-72	-5853
43	TOTAL (EX SCE)		-1340774	-1267129	-73645	-1267129	-640127	-616271	-8721	-2010	-130021	-486250
44	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
45	TOTAL COMPANY		-1340774	-1267129	-73645	-1267129	-640127	-616271	-8721	-2010	-130021	-486250

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LINE No.	DEFERRED TAXES RATE BASE - FERC		ELECTRIC TOTAL	GJ ACC JURISD.	GJ ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GE-1 GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GE GEN. SER. (LESS 3MW)
====	PRODUCTION ******											
1	DEMAND	D-01F	-4448	0	-4448	0	0	0	0	0	0	0
2	ANC.-REGULATION	D-01F	-36	0	-36	0	0	0	0	0	0	0
3	ANC.-SPINNING RES.	D-01F	-45	0	-45	0	0	0	0	0	0	0
4	ANC.-READY RES.	D-01F	-11	0	-11	0	0	0	0	0	0	0
5	ENERGY	E-01F	-53	0	-53	0	0	0	0	0	0	0
6	ENERGY-REGULATION	E-01F	-1	0	-1	0	0	0	0	0	0	0
7	TOTAL PRODUCTION		-4594	0	-4594	0	0	0	0	0	0	0
	TRANSMISSION ******											
8	SUBSTATION	D-02F	-416	0	-416	0	0	0	0	0	0	0
9	SUBTOTAL SUBSTAT		-416	0	-416	0	0	0	0	0	0	0
10	LINES	D-02F	-521	0	-521	0	0	0	0	0	0	0
11	SUBTOTAL LINES		-521	0	-521	0	0	0	0	0	0	0
12	TOTAL TRANSMISSION		-937	0	-937	0	0	0	0	0	0	0
	DISTRIBUTION *****											
13	SUBSTATION	D-07F	-280	0	-280	0	0	0	0	0	0	0
	O.H. LINES											
14	-OH PRIMARY	D-09F	-486	0	-486	0	0	0	0	0	0	0
15	-OH SECONDARY	D-11F	-141	0	-141	0	0	0	0	0	0	0
	U.G. LINES											
16	-UG PRIMARY	D-14F	-864	0	-864	0	0	0	0	0	0	0
17	-UG SECONDARY	D-14F	0	0	0	0	0	0	0	0	0	0
	LINE TRANSFORMER											
18	-OH LINE TRANS.	D-12F	-153	0	-153	0	0	0	0	0	0	0
19	-UG LINE TRANS.	D-12F	-301	0	-301	0	0	0	0	0	0	0
	SERVICES											
20	-O.H. SERVICES	C-08F	-44	0	-44	0	0	0	0	0	0	0
21	-U.G. SERVICES	C-09F	-159	0	-159	0	0	0	0	0	0	0
22	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
23	METERS-ALLOCABLE	C-03F	-166	0	-166	0	0	0	0	0	0	0
24	DUSK TO DAWN	CS-06	0	0	0	0	0	0	0	0	0	0
25	STREET LIGHTING	CS-06	0	0	0	0	0	0	0	0	0	0
26	TOTAL DISTRIBUTION		-2594	0	-2594	0	0	0	0	0	0	0
27	CUSTOMER ACCOUNTS	C-04F	-42	0	-42	0	0	0	0	0	0	0
28	CUST SERV & INFO	DS-05F	-6	0	-6	0	0	0	0	0	0	0
29	SALES	DS-05F	-13	0	-13	0	0	0	0	0	0	0
30	TOTAL DEMAND		-7721	0	-7721	0	0	0	0	0	0	0
31	TOTAL ENERGY		-54	0	-54	0	0	0	0	0	0	0
32	TOTAL CUSTOMER		-411	0	-411	0	0	0	0	0	0	0
33	TOTAL (EX SCE)		-8186	0	-8186	0	0	0	0	0	0	0
34	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
35	TOTAL COMPANY		-8186	0	-8186	0	0	0	0	0	0	0

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LINE No.	DEFERRED TAXES RATE BASE - ACC		GJ ELECTRIC TOTAL	GJ ACC JURISD.	GJ ALL OTHER	GE-1 TOTAL RETAIL	GE-1 RESIDENTIAL	GE-1 GENERAL SERVICE	GE-1 STREET LIGHTING	GE-1 DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GE GEN. SER. (LESS 3MW)
====	PRODUCTION *******											
1	DEMAND	D-01A	498	498	0	498	235	263	0	0	58	204
2	ANC.-REGULATION	D-01A	4	4	0	4	2	2	0	0	0	2
3	ANC.-SPINNING RES.	D-01A	5	5	0	5	2	3	0	0	1	2
4	ANC.-READY RES.	D-01A	1	1	0	1	0	1	0	0	0	0
5	ENERGY	E-01A	6	6	0	6	2	4	0	0	1	3
6	ENERGY-REGULATION	E-01A	0	0	0	0	0	0	0	0	0	0
7	*TOTAL PRODUCTION*		514	514	0	514	243	271	0	0	60	211
	TRANSMISSION ******											
8	SUBSTATION	D-02A	47	47	0	47	22	25	0	0	5	19
9	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
10	SUBTOTAL SUBSTAT		47	47	0	47	22	25	0	0	5	19
11	*LINES*	D-05A	59	59	0	59	28	31	0	0	7	24
12	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
13	-SPEC AFUDC	D-01A	0	0	0	0	0	0	0	0	0	0
14	*SUBTOTAL LINES*		59	59	0	59	28	31	0	0	7	24
15	TOTAL TRANSMISSION		106	106	0	106	50	56	0	0	12	44
	*DISTRIBUTION ******											
16	SUBSTATION	D-07A	2252	2252	0	2252	1245	988	16	4	201	786
	O.H. LINES											
17	-OH PRIMARY	D-09A	5544	5544	0	5544	3157	2337	40	10	365	1972
18	-OH SECONDARY	D-11A	1608	1608	0	1608	1372	218	14	4	0	218
	U.G. LINES											
19	-UG PRIMARY	D-14A	9447	9447	0	9447	5446	3915	69	18	617	3298
20	-UG SECONDARY	D-17A	484	484	0	484	422	58	4	1	0	58
	LINE TRANSFORMER											
21	-OH LINE TRANS.	D-12A	1774	1774	0	1774	1225	540	8	2	26	514
22	-UG LINE TRANS.	D-12A	3493	3493	0	3493	2411	1063	15	4	51	1012
	SERVICES											
23	-O.H. SERVICES	C-08A	501	501	0	501	432	69	0	0	0	69
24	-U.G. SERVICES	C-09A	1819	1819	0	1819	1641	178	0	0	4	174
25	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
26	METERS-ALLOCABLE	C-03A	1703	1703	0	1703	1371	332	0	0	4	328
27	DUSK TO DAWN	CS-13	174	174	0	174	0	0	0	174	0	0
28	STREET LIGHTING	CS-12	797	797	0	797	0	0	797	0	0	0
			0	0	0	0	0	0	0	0	0	0
29	TOTAL DISTRIBUTION		29596	29596	0	29596	18721	9697	962	216	1268	8430
30	CUSTOMER ACCOUNTS	C-04A	5	5	0	5	4	1	0	0	0	1
31	CUST SERV & INFO	C-04A	1	1	0	1	1	0	0	0	0	0
32	SALES	C-04A	1	1	0	1	1	0	0	0	0	0
33	REGULATORY ASSETS	D-01A	-143330	-143330	0	-143330	-67748	-75582	0	0	-16755	-58827
34	SYSTEM BENEFITS	D-01	0	0	0	0	0	0	0	0	0	0
35	TOTAL DEMAND		-118114	-118114	0	-118114	-52181	-66140	165	42	-15423	-50717
36	TOTAL ENERGY		6	6	0	6	2	4	0	0	1	3
37	TOTAL CUSTOMER		5001	5001	0	5001	3449	581	797	174	8	573
38	TOTAL (EX SCE)		-113107	-113107	0	-113107	-48729	-65556	962	217	-15415	-50142
39	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
40	TOTAL COMPANY		-113107	-113107	0	-113107	-48729	-65556	962	217	-15415	-50142

**** ARIZONA PUBLIC SERVICE *****
COST OF SERVICE STUDY
4 CP Allocation
Adjusted
TYE 12/31/96

LINE No.	OPERATING & MAINT EXPENSE		ELECTRIC TOTAL	GJ ACC JURISD.	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GE-1 GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
====	PRODUCTION *******											
1	DEMAND	D-01	132842	125249	7593	125249	59202	66047	0	0	14641	51406
2	ANC.-REGULATION	D-01	2260	2131	129	2131	1007	1124	0	0	249	875
3	ANC.-SPINNING RES.	D-01	2461	2320	141	2320	1097	1224	0	0	271	952
4	ANC.-READY RES.	D-01	390	368	22	368	174	194	0	0	43	151
5	ENERGY-OTHER	E-01	58015	53973	4042	53973	21582	32100	227	64	9128	22972
6	ENERGY-RELATED FUEL	E-04	271547	252630	18917	252630	101020	150248	1063	299	42725	107523
7	ENERGY	E-01	0	0	0	0	0	0	0	0	0	0
8	ENERGY-REGULATION	E-01	12837	11943	894	11943	4776	7103	50	14	2020	5083
9	ENERGY-REGULATION	E-01	860	800	60	800	320	476	3	1	135	341
10	TOTAL PRODUCTION		481212	449413	31799	449413	189177	258515	1344	378	69213	189301
	TRANSMISSION ******											
11	SUBSTATION	D-02	2432	2115	317	2115	1000	1115	0	0	247	868
12	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
13	SUBTOTAL SUBSTAT		2432	2115	317	2115	1000	1115	0	0	247	868
14	LINES	D-02	12695	11042	1653	11042	5219	5823	0	0	1291	4532
15	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
16	-SPEC AFUDC	D-01A	0	0	0	0	0	0	0	0	0	0
17	SUBTOTAL LINES		12695	11042	1653	11042	5219	5823	0	0	1291	4532
18	TOTAL TRANSMISSION		15127	13157	1970	13157	6219	6938	0	0	1538	5400
	DISTRIBUTION *****											
19	SUBSTATION	D-07A	19033	19026	7	19026	10516	8343	132	34	1702	6641
	O.H. LINES											
20	-OH PRIMARY	D-09A	9275	9268	7	9268	5278	3907	66	17	610	3297
21	-OH SECONDARY	D-11A	2691	2691	0	2691	2296	365	24	6	0	365
	U.G. LINES											
22	-UG PRIMARY	D-14A	11048	11048	0	11048	6369	4578	80	21	722	3857
23	-UG SECONDARY	D-17A	566	566	0	566	493	68	4	1	0	68
	LINE TRANSFORMER											
24	-OH LINE TRANS.	D-12A	434	434	0	434	300	132	2	0	6	126
25	-UG LINE TRANS.	D-12A	855	855	0	855	590	260	4	1	12	248
	SERVICES											
26	-O.H. SERVICES	C-08A	839	839	0	839	723	116	0	0	0	116
27	-U.G. SERVICES	C-09A	2127	2127	0	2127	1919	208	0	0	4	204
28	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
29	METERS-ALLOCABLE	C-03	10575	10430	145	10430	8394	2036	0	0	25	2011
30	DUSK TO DAWN	CS-13	222	222	0	222	0	0	0	222	0	0
31	STREET LIGHTING	CS-12	3724	3724	0	3724	0	0	3724	0	0	0
32	RENTS	CS-03	3517	2771	746	2771	1532	1215	19	5	248	967
33	TOTAL DISTRIBUTION		64906	64001	905	64001	38409	21228	4056	308	3329	17899
34	CUSTOMER ACCOUNTS	C-04	32934	32867	67	32867	28888	3590	25	364	2	3588
35	CUST SERV & INFO	C-04A	526	526	0	526	462	57	0	6	0	57
35	CUST SERV & INFO	C-04A	0	0	0	0	0	0	0	0	0	0
36	SALES	C-04	14972	14941	31	14941	13133	1632	11	165	1	1631
37	REGULATORY ASSETS	D-01	0	0	0	0	0	0	0	0	0	0
38	SYSTEM BENEFITS	E-01	0	0	0	0	0	0	0	0	0	0
39	SYSTEM BENEFITS	E-01A	7000	7000	0	7000	2784	4179	29	8	1204	2975
40	TOTAL DEMAND		203982	194113	9869	194113	96325	97358	342	89	20999	76359
41	TOTAL ENERGY		343259	319346	23913	319346	127697	189927	1344	378	54009	135918
42	TOTAL CUSTOMER		69436	68447	989	68447	55050	8855	3780	762	281	8574
43	TOTAL (EX SCE)		616677	581906	34771	581906	279072	296139	5466	1228	75288	220851
44	500 KV SCE	S-10	404	0	404	0	0	0	0	0	0	0
45	TOTAL COMPANY		617081	581906	35175	581906	279072	296139	5466	1228	75288	220851

**** ARIZONA PUBLIC SERVICE *****
COST OF SERVICE STUDY
4 CP Allocation
Adjusted
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LINE No.	ADMIN & GENERAL EXPENSE		ELECTRIC TOTAL	GJ ACC JURISD.	GJ ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GE-1 GENERAL SERVICE	GE-1 STREET LIGHTING	GE-1 DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GE GEN. SER. (LESS 3MW)
====	PRODUCTION ******											
1	DEMAND	D-01	11327	10680	647	10680	5048	5632	0	0	1248	4383
2	ANC.-REGULATION	D-01	826	779	47	779	368	411	0	0	91	320
3	ANC.-SPINNING RES.	D-01	934	881	53	881	416	464	0	0	103	361
4	ANC.-READY RES.	D-01	134	126	8	126	60	67	0	0	15	52
5	ENERGY	E-01	12894	11996	898	11996	4797	7134	50	14	2029	5106
6	ENERGY-REGULATION	E-01	327	304	23	304	122	181	1	0	51	129
7	TOTAL PRODUCTION		26442	24765	1677	24765	10810	13889	52	15	3537	10351
	TRANSMISSION ******											
8	SUBSTATION	D-02	552	480	72	480	227	253	0	0	56	197
9	SUBTOTAL SUBST		552	480	72	480	227	253	0	0	56	197
10	LINES	D-02	4538	3947	591	3947	1866	2081	0	0	461	1620
11	SUBTOTAL LINES		4538	3947	591	3947	1866	2081	0	0	461	1620
12	TOTAL TRANSMISSION		5090	4427	663	4427	2093	2335	0	0	518	1817
	DISTRIBUTION *****											
13	SUBSTATION	D-07	717	695	22	695	384	305	5	1	62	243
	O.H. LINES											
14	-OH PRIMARY	D-09	3673	3585	88	3585	2042	1511	26	7	236	1275
15	-OH SECONDARY	D-11	1066	1066	0	1066	910	145	9	2	0	145
	U.G. LINES											
16	-UG PRIMARY	D-14	4375	4338	37	4338	2501	1798	31	8	283	1514
17	-UG SECONDARY	D-17A	225	225	0	225	196	27	2	0	0	27
	LINE TRANSFORMER											
18	-OH LINE TRANS.	D-12	321	312	9	312	216	95	1	0	5	91
19	-UG LINE TRANS.	D-12	633	616	17	616	425	187	3	1	9	178
	SERVICES											
20	-O.H. SERVICES	C-08	330	327	3	327	282	45	0	0	0	45
21	-U.G. SERVICES	C-09	843	840	3	840	758	82	0	0	2	81
22	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
23	METERS-ALLOCABLE	C-03	6609	6519	90	6519	5246	1273	0	0	16	1257
24	DUSK TO DAWN	CS-13	96	96	0	96	0	0	0	96	0	0
25	STREET LIGHTING	CS-12	768	768	0	768	0	0	768	0	0	0
26	TOTAL DISTRIBUTION		19656	19387	269	19387	12958	5468	845	116	612	4855
27	CUSTOMER ACCOUNTS	C-04	13537	13509	28	13509	11874	1476	10	149	1	1475
28	CUST SERV & INFO	C-04A	2892	2892	0	2892	2542	316	2	32	0	316
29	SALES	C-04	3998	3990	8	3990	3507	436	3	44	0	436
30	REGULATORY ASSETS	E-01	0	0	0	0	0	0	0	0	0	0
31	SYSTEM BENEFITS	D-01	0	0	0	0	0	0	0	0	0	0
32	TOTAL DEMAND		29321	27730	1591	27730	14658	12976	77	20	2570	10406
33	TOTAL ENERGY		13221	12300	921	12300	4918	7315	52	15	2080	5235
34	TOTAL CUSTOMER		29073	28940	133	28940	24208	3627	784	322	19	3808
35	TOTAL (EX SCE)		71615	68971	2644	68971	43784	23918	913	356	4669	19249
36	500 KV SCE	S-10	29	0	29	0	0	0	0	0	0	0
37	TOTAL COMPANY		71644	68971	2673	68971	43784	23918	913	356	4669	19249

**** ARIZONA PUBLIC SERVICE **** COST OF SERVICE STUDY 4 CP Allocation Adjusted TYE 12/31/96			<------ GJ		------>	<------		GE-1		------>	<------ GE	------>
LINE No.	DEPREC & AMORIT EXPENSE		ELECTRIC TOTAL	ACC JURISD.	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
====	PRODUCTION ******											
1	DEMAND	D-01	110144	103848	6296	103848	49086	54762	0	0	12140	42622
2	ANC.-REGULATION	D-01	840	792	48	792	374	418	0	0	93	325
3	ANC.-SPINNING RES.	D-01	1071	1010	61	1010	477	532	0	0	118	414
4	ANC.-READY RES.	D-01	272	256	16	256	121	135	0	0	30	105
5	SPEC AFUDC	DS-09	3553	3414	139	3414	1614	1800	0	0	399	1401
6	ENERGY	E-01	1363	1268	95	1268	507	754	5	1	214	540
7	ENERGY-REGULATION	E-01	26	24	2	24	10	14	0	0	4	10
8	TOTAL PRODUCTION		117269	110613	6656	110613	52190	58416	5	2	12998	45418
	TRANSMISSION ******											
9	SUBSTATION	D-02	4733	4117	616	4117	1946	2171	0	0	481	1690
10	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
11	SUBTOTAL SUBSTAT		4733	4117	616	4117	1946	2171	0	0	481	1690
12	LINES	D-02	9256	8051	1205	8051	3805	4245	0	0	941	3304
13	-SPEC ACC	DS-03	0	0	0	0	0	0	0	0	0	0
14	-SPEC AFUDC	D-01A	73	73	0	73	35	38	0	0	9	30
15	SUBTOTAL LINES		9329	8124	1205	8124	3840	4284	0	0	950	3334
16	TOTAL TRANSMISSION		14062	12240	1822	12240	5786	6455	0	0	1431	5024
	DISTRIBUTION *****											
17	SUBSTATION	D-07	4934	4784	150	4784	2644	2098	33	9	428	1670
	O.H. LINES											
17	-OH PRIMARY	D-09	13587	13262	325	13262	7552	5590	95	25	872	4718
18	-OH SECONDARY	D-11	3943	3942	1	3942	3364	535	35	9	0	535
	U.G. LINES											
19	-UG PRIMARY	D-14	22602	22412	190	22412	12920	9287	163	42	1464	7823
20	-UG SECONDARY	D-17A	1159	1159	0	1159	1009	138	9	2	0	138
	LINE TRANSFORMER											
21	-OH LINE TRANS.	D-12	4114	4004	110	4004	2764	1218	17	4	58	1160
22	-UG LINE TRANS.	D-12	8101	7885	216	7885	5443	2399	34	9	115	2284
	SERVICES											
23	-O.H. SERVICES	C-08	1232	1221	11	1221	1052	169	0	0	0	169
24	-U.G. SERVICES	C-09	4367	4350	17	4350	3924	426	0	0	9	417
25	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
26	METERS-ALLOCABLE	C-03	5794	5715	79	5715	4599	1116	0	0	14	1102
27	DUSK TO DAWN	CS-13	423	423	0	423	0	0	0	423	0	0
28	STREET LIGHTING	CS-12	2031	2031	0	2031	0	0	2031	0	0	0
			0	0	0	0	0	0	0	0	0	0
29	TOTAL DISTRIBUTION		72287	71189	1098	71189	45273	22976	2417	523	2960	20016
30	CUSTOMER ACCOUNTS	C-04	3955	3947	8	3947	3469	431	3	44	0	431
31	CUST SERV & INFO	C-04A	109	109	0	109	96	12	0	1	0	12
32	SALES	C-04	238	238	0	238	209	26	0	3	0	26
33	TOTAL DEMAND		188382	179010	9372	179010	93156	85368	386	100	17148	68220
34	TOTAL ENERGY		1389	1292	97	1292	517	769	5	2	219	550
35	TOTAL CUSTOMER		18149	18033	116	18033	13349	2179	2034	470	23	2156
36	TOTAL (EX SCE)		207920	198335	9585	198335	107022	88316	2426	572	17389	70927
37	500 KV SCE	S-10	1404	0	1404	0	0	0	0	0	0	0
38	TOTAL COMPANY		209324	198335	10989	198335	107022	88316	2426	572	17389	70927

LINE No.	**** ARIZONA PUBLIC SERVICE ***** COST OF SERVICE STUDY 4 CP Allocation Adjusted TYE 12/31/96		ELECTRIC TOTAL	GJ ACC JURISD.	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GE-1 GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
	AD VALOREM & OTHER TAXES											
====	PRODUCTION *******											
1	DEMAND	D-01	48881	46087	2794	46087	21784	24303	0	0	5387	18915
2	ANC.-REGULATION	D-01	1434	1352	82	1352	639	713	0	0	158	555
3	ANC.-SPINNING RES.	D-01	1824	1720	104	1720	813	907	0	0	201	706
4	ANC.-READY RES.	D-01	460	434	26	434	205	229	0	0	51	178
5	ENERGY	E-01	2729	2539	190	2539	1015	1510	11	3	429	1081
6	ENERGY-REGULATION	E-01	53	49	4	49	20	29	0	0	8	21
7	TOTAL PRODUCTION		55381	52181	3200	52181	24476	27691	11	3	6235	21456
	TRANSMISSION ******											
8	SUBSTATION	D-02	4864	4231	633	4231	2000	2231	0	0	495	1736
9	SUBTOTAL SUBSTAT		4864	4231	633	4231	2000	2231	0	0	495	1736
10	LINES	D-02	9735	8467	1268	8467	4002	4465	0	0	990	3475
11	SUBTOTAL LINES		9735	8467	1268	8467	4002	4465	0	0	990	3475
12	TOTAL TRANSMISSION		14599	12698	1901	12698	6002	6696	0	0	1484	5212
	DISTRIBUTION *****											
13	SUBSTATION	D-07	3512	3405	107	3405	1882	1493	24	6	305	1189
	O.H. LINES											
14	-OH PRIMARY	D-09	8982	8767	215	8767	4992	3696	63	16	577	3119
15	-OH SECONDARY	D-11	2606	2606	0	2606	2224	353	23	6	0	353
	U.G. LINES											
16	-UG PRIMARY	D-14	15006	14880	126	14880	8578	6166	108	28	972	5194
17	-UG SECONDARY	D-17A	770	770	0	770	671	92	6	2	0	92
	LINE TRANSFORMER											
18	-OH LINE TRANS.	D-12	2740	2667	73	2667	1841	811	12	3	39	773
19	-UG LINE TRANS.	D-12	5394	5250	144	5250	3624	1597	23	6	77	1521
	SERVICES											
20	-O.H. SERVICES	C-08	813	806	7	806	694	111	0	0	0	111
21	-U.G. SERVICES	C-09	2889	2878	11	2878	2596	282	0	0	6	276
22	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
23	METERS-ALLOCABLE	C-03	3622	3572	50	3572	2875	697	0	0	9	689
24	DUSK TO DAWN	CS-13	279	279	0	279	0	0	0	279	0	0
25	STREET LIGHTING	CS-12	1329	1329	0	1329	0	0	1329	0	0	0
26			0	0	0	0	0	0	0	0	0	0
27	TOTAL DISTRIBUTION		47942	47209	733	47209	29978	15300	1587	345	1983	13317
28	CUSTOMER ACCOUNTS	C-04	2130	2126	4	2126	1868	232	2	24	0	232
29	CUST SERV & INFO	C-04A	299	299	0	299	263	33	0	3	0	33
30	SALES	C-04	654	653	1	653	574	71	1	7	0	71
31	TOTAL DEMAND		106208	100636	5572	100636	53255	47056	258	66	9250	37806
32	TOTAL ENERGY		2782	2588	194	2588	1035	1539	11	3	438	1102
33	TOTAL CUSTOMER		12015	11941	74	11941	8870	1427	1331	313	15	1412
34	TOTAL (EX SCE)		121005	115165	5840	115165	63160	50022	1600	383	9703	40320
35	500 KV SCE	S-10	680	0	680	0	0	0	0	0	0	0
36	TOTAL COMPANY		121685	115165	6520	115165	63160	50022	1600	383	9703	40320

LINE No.	**** ARIZONA PUBLIC SERVICE ***** COST OF SERVICE STUDY 4 CP Allocation Adjusted TYE 12/31/96		ELECTRIC TOTAL	GJ ACC JURISD.	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GE-1 GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
	AMORTIZATION											
	OF GAIN											
====	PRODUCTION *******											
1	DEMAND	D-01	-4548	-4288	-260	-4288	-2027	-2261	0	0	-501	-1760
2	ENERGY	E-01	0	0	0	0	0	0	0	0	0	0
3	TOTAL PRODUCTION		-4548	-4288	-260	-4288	-2027	-2261	0	0	-501	-1760
	TRANSMISSION ******											
4	SUBSTATION	D-02	0	0	0	0	0	0	0	0	0	0
5	SUBTOTAL SUBSTAT		0	0	0	0	0	0	0	0	0	0
6	LINES	D-05	0	0	0	0	0	0	0	0	0	0
7	SUBTOTAL LINES		0	0	0	0	0	0	0	0	0	0
8	TOTAL TRANSMISSION		0	0	0	0	0	0	0	0	0	0
	DISTRIBUTION *****											
9	SUBSTATION	D-07	0	0	0	0	0	0	0	0	0	0
10	O.H. LINES											
11	-PRIMARY	D-09	0	0	0	0	0	0	0	0	0	0
12	* -SECONDARY	D-11	0	0	0	0	0	0	0	0	0	0
13	U.G. LINES	D-14	0	0	0	0	0	0	0	0	0	0
14	*LINE TRANSFORMER	D-12	0	0	0	0	0	0	0	0	0	0
15	* O.H. SERVICES	C-08	0	0	0	0	0	0	0	0	0	0
16	* U.G. SERVICES	C-09	0	0	0	0	0	0	0	0	0	0
17	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
18	* -ALLOCABLE	C-03	0	0	0	0	0	0	0	0	0	0
19	DUSK TO DAWN	CS-13	0	0	0	0	0	0	0	0	0	0
20	STREET LIGHTING	CS-12	0	0	0	0	0	0	0	0	0	0
			0	0	0	0	0	0	0	0	0	0
21	TOTAL DISTRIBUTION		0	0	0	0	0	0	0	0	0	0
22	CUSTOMER ACCOUNTS	C-04	0	0	0	0	0	0	0	0	0	0
23	CUST SERV & INFO	DS-03	0	0	0	0	0	0	0	0	0	0
24	SALES	DS-05	0	0	0	0	0	0	0	0	0	0
25	TOTAL DEMAND		-4548	-4288	-260	-4288	-2027	-2261	0	0	-501	-1760
26	TOTAL ENERGY		0	0	0	0	0	0	0	0	0	0
27	TOTAL CUSTOMER		0	0	0	0	0	0	0	0	0	0
28	TOTAL (EX SCE)		-4548	-4288	-260	-4288	-2027	-2261	0	0	-501	-1760
29	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
30	TOTAL COMPANY		-4548	-4288	-260	-4288	-2027	-2261	0	0	-501	-1760

**** ARIZONA PUBLIC SERVICE *****
COST OF SERVICE STUDY
4 CP Allocation
Adjusted
TYE 12/31/96

LINE No.	REGULATORY ASSET & DECOM. EXPENSE		<------ GJ		------>	:------	------ GE-1	------	------>	<------ GE	------>
====			ELECTRIC TOTAL	ACC JURISD.	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
	PRODUCTION ******											
1	DEMAND	D-01	0	0	0	0	0	0	0	0	0	0
2	ACC SPEC-DEMAND	D-01A	0	0	0	0	0	0	0	0	0	0
3	TOTAL PRODUCTION		0	0	0	0	0	0	0	0	0	0
	TRANSMISSION ******											
4	SUBSTATION	D-02	0	0	0	0	0	0	0	0	0	0
5	SUBTOTAL SUBSTAT		0	0	0	0	0	0	0	0	0	0
6	LINES	D-05	0	0	0	0	0	0	0	0	0	0
7	SUBTOTAL LINES		0	0	0	0	0	0	0	0	0	0
8	TOTAL TRANSMISSION		0	0	0	0	0	0	0	0	0	0
	DISTRIBUTION *****											
9	SUBSTATION	D-07	0	0	0	0	0	0	0	0	0	0
10	O.H. LINES											
11	-PRIMARY	D-09	0	0	0	0	0	0	0	0	0	0
12	" -SECONDARY	D-11	0	0	0	0	0	0	0	0	0	0
13	U.G. LINES	D-14	0	0	0	0	0	0	0	0	0	0
14	'LINE TRANSFORMER	D-12	0	0	0	0	0	0	0	0	0	0
15	" O.H. SERVICES	C-08	0	0	0	0	0	0	0	0	0	0
16	" U.G. SERVICES	C-09	0	0	0	0	0	0	0	0	0	0
17	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
18	" -ALLOCABLE	C-03	0	0	0	0	0	0	0	0	0	0
19	DUSK TO DAWN	CS-13	0	0	0	0	0	0	0	0	0	0
20	STREET LIGHTING	CS-12	0	0	0	0	0	0	0	0	0	0
21	TOTAL DISTRIBUTION		0	0	0	0	0	0	0	0	0	0
22	CUSTOMER ACCOUNTS	C-04	0	0	0	0	0	0	0	0	0	0
23	CUST SERV & INFO	DS-03	0	0	0	0	0	0	0	0	0	0
24	SALES	DS-05	0	0	0	0	0	0	0	0	0	0
25	REGULATORY ASSETS	E-01	36590	34041	2549	34041	13612	20245	143	40	5757	14488
26	REGULATORY ASSETS	D-01A	35271	35271	0	35271	16672	18599	0	0	4123	14476
27	REGULATORY ASSETS	E-01	2076	1931	145	1931	772	1149	8	2	327	822
28	REGULATORY ASSETS	D-01A	19994	19994	0	19994	9451	10543	0	0	2337	8206
29	REGULATORY ASSETS	E-01	9678	9004	674	9004	3600	5355	38	11	1523	3832
30	REGULATORY ASSETS	D-01	9388	8851	537	8851	4184	4668	0	0	1035	3633
31	REGULATORY ASSETS	D-01	49493	46664	2829	46664	22057	24607	0	0	5455	19152
32	REGULATORY ASSETS	D-01	4847	4570	277	4570	2160	2410	0	0	534	1876
33	REGULATORY ASSETS	D-01A	-500	-500	0	-500	-236	-264	0	0	-58	-205
34	SYSTEM BENEFITS	E-01	11443	10618	825	10618	4222	6338	44	12	1826	4512
35	TOTAL DEMAND		129936	125468	4468	125468	58509	66902	44	12	15252	51650
36	TOTAL ENERGY		48344	44976	3368	44976	17985	26749	189	53	7606	19142
37	TOTAL CUSTOMER		0	0	0	0	0	0	0	0	0	0
38	TOTAL (EX SCE)		178280	170444	7836	170444	76494	93651	234	66	22859	70792
39	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
40	TOTAL COMPANY		178280	170444	7836	170444	76494	93651	234	66	22859	70792

ARIZONA PUBLIC SERVICE COMPANY
Pro Forma Adjustments to Expenses
Total Company
Test Year Twelve Months Ended 12/31/96

(Dollars inThousands)

Line No.	Description	(a) EEASE Fund, DSM & Renewables	(b) Accelerated Amortization Reg. Assets [6 Months]	(c) Miscellaneous Adjustments	(d) 1998 Expense Adjustment	(e) Regulatory & Franchise Assessments
1.	Operating Expenses:					
2.	Fuel Expenses					
3.	Operations & Maint. Exc. Fuel Expense	$ 1,136				
4.	Depreciation and Amortization		57,391		16,503	(24,969)
5.	Amortization of Gain					
6.	Administrative and General					
7.	Other Taxes			(7,626)	(28,282)	
					582	
8.	Total	1,136	57,391	(7,626)	(11,197)	(24,969)

(a) DSM & renewable adjustment from 1996 settlement
(b) Accelerated amortization of regulatory assets from 1996 settlement
(c) Pinnacle West charges, net of costs for shareholders services
(d) Adjustment to reflect 1998 expenses
(e) Adjustment to exclude regulatory and franchise assesments from both operating revenue and operating expense accounts to allow calculation of "base" operating revenue deficiency

Line No.	Description	(f) SRP T&C Adjustment	(g) Fuel Adjustment	(h) Normal Amortization Regulatory Assets	(i) Total Pro Forma Adjustment
1.	Operating Expenses:				
2.	Fuel Expenses		(8,404)		
3.	Operations & Maint. Exc. Fuel Expense	(16,700)		(2,413)	$ (10,817)
4.	Depreciation and Amortization			(604)	$ (24,634)
5.	Amortization of Gain			33,004	$ 90,395
6.	Administrative and General			-	$ -
7.	Other Taxes			-	$ (35,908)
				-	$ 582
8.	Total	(16,700)	0	32,400	$ 30,435

(f) Adjustment to reflect reduction in demand charges for SRP T&C purchases
(g) Adjustment to reflect 1998 generation fuel costs
(h) Reclassification of normal amortization associated with regulatory assets

ARIZONA PUBLIC SERVICE COMPANY
Pro Forma Adjustments to Original Cost Rate Base
Total Company
Test Year Twelve Months Ended 12/31/96

(Dollars in Thousands)

Line No.	Description		1998 Rate Base Adjustment Total Co.
1.	Production, Transmission, & Distribution Plant In Service	$	370,610
2.	General and Intangible Plant		105,852
3.	Reserve for Depreciation and Amortization		343,483
4.	** NET PLANT** (Line 1 + Line 2 less Line 3)		132,979
5.	Regulatory Assets & Decommissioning		
6.	Gain from Plant		
7.	Materials & Supplies		
	Less:		
8.	Customer Advances		
9.	Customer Deposits		
10.	Working Cash/Prepayments		
11.	Accumulated Deferred Income Taxes		-41,977
12.	Pro Forma Adjustment to Rate Base	$	174,956

SCHEDULE AP-3

1996 SETTLEMENT RATE REDUCTION

FILED MAY 21, 1999

APS

Commitment. Innovation. Energy.

RECEIVED

1999 MAY 21 P 2: 37

AZ CORP COMMISSION
DOCUMENT CONTROL

Barbara A. Klemstine
Manager
Regulatory Affairs

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

May 21, 1999

Mr. Ray Williamson
Acting Director, Utilities Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

Re: Docket No. E-01345-95-491 (U-1345-95-491)
Arizona Public Service Company
Reduction in Retail Rates Pursuant to Paragraph 15.B of the
Second Restated and Amended Rate Reduction Agreement

Dear Mr. Williamson:

Pursuant to Decision No. 59601 (April 18, 1996), Arizona Public Service Company ("APS") is filing the annual calculation to determine the reduction to base rates provided for under Paragraph 15.B of the Second Restated and Amended Rate Reduction Agreement ("1996 Agreement"). The 1996 Agreement provided for a $48.5 million decrease in APS' retail rates, effective July 1, 1996 and also established a moratorium period (through July 1, 1999) on rate increases, while providing consumers an opportunity to automatically receive future price reductions based on the Company's ability to continue to lower its average cost.

Future rate reductions through the term of the 1996 Agreement were to be based on a comparison of the Company's average price per kilowatt-hour and its average cost per kilowatt-hour resulting from operations for the proceeding calendar year as defined in Attachment 3 of the 1996 Agreement. Any reduction for the current year would become effective for usage on or after July 1, if approved by the Commission. Under this provision, APS has decreased retail rates on July 1, 1997 by $17.6, and by an additional $16.9 million effective July 1, 1998.

Based upon the Company's 1998 financial performance, as adjusted pursuant to Attachment 3 from the 1996 Agreement and calculated pursuant to Exhibit No. 1 attached to Decision No. 60225, APS is able to further reduce rates through the rate incentive mechanism established in the 1996 Agreement. More specifically, the Company proposes to reduce annual retail rates by approximately $10.8 million, or .68%, effective July 1, 1999.

APS

Arizona Public Service Company

COMPANY CORRESPONDENCE

The Company is requesting that this reduction be considered by the Commission for approval in conjunction with the 1999 Settlement Agreement, dated May 17, 1999. The 1999 Settlement Agreement (Article II, Section 2.2) provides for a 1.5% rate reduction, effective July 1, 1999, which is inclusive of the .68% reduction. The reduction will be applied with a uniform percent to customer's demand and energy charges, except as provided for in Attachment 2 of the 1996 Agreement.

Attached are: (1) a calculation of the proposed reduction in retail rates, (2) a copy of Attachment 3 from the 1996 Agreement, (3) a copy of Exhibit #1, Decision 60225, (4) a worksheet of adjustments to comply with the definitions from Attachment 3, (5) a worksheet that applies the reduction to eligible customers, and (6) a comparison of present and proposed rates.

Please call me at (602)250-2031 if you or your Staff have any questions.

Sincerely,

Barbara A. Klemstine

Barbara A. Klemstine
Manager
Regulatory Affairs

BAK/pb

Enclosures

Cc: Lori Hoover (w/o enclosures)
All Parities of Record- Docket No. U-1345-95-491
Docket Control

Arizona Public Service Company
Reduction In Retail Rates
Rate Reduction Agreement (Decision No. 59601 ¶15.B,Decision No. 60225 Exh. #1)
(000s)

1)	**Total Company Property Tax Expense**					
	1997			$107,060		
	1998			($101,761)		
	Decrease in Property Taxes			$5,299		
	¢/kWh Reduction in Property Taxes					
	1.1)	Decrease in Total Company Property Taxes / Annual Total Company mWh Sales	=	$5,299 / 21,873,475	=	0.0242 ¢/kWh
2)	**Comparison of Unit Price Ratio ("UPR") and Unit Cost Ratio ("UCR")**					
	2.1) UPR	Annual Total Company Electric Revenues / Annual Total Company mWh Sales	=	$1,744,983 / 21,873,475	=	7.9776 ¢/kWh
	2.2) UCR	Annual Total Company Electric Costs / Annual Total Company mWh Sales	=	$1,728,343 / 21,873,475	=	7.9015 ¢/kWh
	2.3)	Excess of UPR over UCR			=	0.0761 ¢/kWh
3)	**Excess of UPR over UCR Not Due to Property Taxes**					
	3.1)	Excess of UPR over UCR (Line 2.3) less ¢/kWh Reduction in Property Taxes (Line 1.1)			=	0.0519 ¢/kWh
	3.2)	Consumers' 55% Share (Line 3.1 x 55%)			=	0.0285 ¢/kWh
4)	**Retail Rate Reduction**					
	4.1)	100% of ACC Property Tax Expense Reductions				0.0242 ¢/kWh
	4.2)	Consumers' 55% Share				0.0285 ¢/kWh
	4.3)	Total ¢/kWh Reduction				0.0527 ¢/kWh
	4.4)	Retail Sales			x	20,463,083 mWh
	4.5)	Total Retail Rate Reduction				$10,784
5)	**Annual Retail Revenues Less Contracts Not Subject to Decrease**					$1,590,560
6)	**Percentage Decrease in Retail Rates Subject to Decrease**					0.68%

Attachment 3

Unit Cost Ratio and Unit Price Ratio Definitions
(The revenues and costs to be utilized in this calculation well be derived from
the actual audited financial statements of the Company)

Unit Cost Ratio (UCR): Annual cents-per-kilowatt-hour average cost of electric services.

$$UCR = \frac{\text{Annual Total Electric Costs}^{1/}}{\text{Annual Total Company kWh Sales}^{2/}}$$

Unit Price Ratio (UPR): Annual cent-per-kilowatt hour average price of electric services.

$$UPR = \frac{\text{Annual Electric Revenues}^{3/}}{\text{Annual Total Company kWh Sales}^{2/}}$$

1/ Excludes sales taxes (as in the case of the income statement), all ITC amortization (as required by federal tax laws), annual Pinnacle West charges net of costs for shareholder services, fuel expenses for non-traditional and interchange sales (generally defined as opportunity sales which are cost justified on an incremental basis), and non-utility income or deductions and related income tax effects.
Includes fuel, operations and maintenance, depreciation and amortization (including the accelerated amortization of regulatory assets), property and other taxes, cost of capital (consisting of long-term interest, debt discount, premium and expense, preferred stock dividend requirements, and a return on equity of 11.25% applied to the average annual equity balance), the gross profit margin on non-traditional and interchange sales, DSM and renewable expenditures (including net lost revenues and incentives), and income taxes on Operating Income including adjustments to income taxes for the above exclusions and inclusions.

2/ Excludes kwh sales for non-traditional and interchange sales.

3/ Includes miscellaneous revenues. Excludes sales taxes (as in the case of the income statement) and non-traditional and interchange revenues.

Exhibit N

Arizona Public Service Company
Reduction in Retail Rates
Rate Reduction Agreement (Decision No. 59601 ¶15.B)
(000s)

1) Total Company Property Tax Expense

1995	$127,773
1996	($104,900)
7/1/96 Reduction	($4,600)
Decrease in Property Taxes	$18,273

¢/kWh Reduction in Property Taxes = Decrease in Total Company Property Taxes / Annual Total Company mWh Sales = $18,273 / 20,510,966 = 0.0891 ¢/kWh

2) Comparison of Unit Price Ratio ("UPR") and Unit Cost Ratio ("UCR")

2.1) UPR	=	Annual Total Company Electric Revenues / Annual Total Company mWh Sales	= $1,683,822 / 20,510,966	= 8.209 ¢/kWh
2.2) UCR	=	Annual Total Company Electric Costs / Annual Total Company mWh Sales	= $1,664,325 / 20,510,966	= 8.114 ¢/kWh
2.3) Excess of UPR over UCR				= 0.095 ¢/kWh

3) Excess of UPR over UCR Not Due to Property Taxes = (.095 - .0981) ¢/kWh = .006 ¢/kWh

3.1) Consumers' 55% Share (0.006 ¢/kWh * .55%) = .0033 ¢/kWh

4) Retail Rate Reduction

4.1) 100% of ACC Property Tax Expense Reductions	0.0891 ¢/kWh
4.2) Consumers' 55% Share	0.0033 ¢/kWh
4.3) Total ¢/kWh Reduction	0.0924 ¢/kWh
4.4) Retail Sales	x 19,020,696 mWh
4.5) Total Retail Rate Reduction	$17,575

5) Annual Retail Revenues Less Contracts Not Subject to Decrease $1,513,379

6) Percentage Decrease in Retail Rates Subject to Decrease 1.16%

Arizona Public Se[illegible] Company
Reduction in Retail Rates
Rate Reduction Agreement (Decision No. 59601 ¶15.B, Decision No. 60225 Exh. #1)
Adjustments for Attachment 3
(000s)

	1998 Audited Financials	System Related Opportunity Sales (1)	DSM Net Lost Rev. & financial Incentives (2)	Pinnacle West charges net of costs (3)	Non-utility Income or Deductions (Net of Tax) (4)	Adjustment for 11.25% ROE (5)	Adjusted Total UCR & UPR (6)
Annual Electric Revenues							
Annual Electric Operation Revenues	$2,006,398	($165,999)			($95,416)		$1,744,983
Annual Total Electric Costs							
Fuel Expenses - Total	$537,501	($165,999)			($85,105)		$286,397
Other Operating Expenses:							
Operations & Maintenance (Ex. fuel expense)	$414,041		$557	($7,250)	($1,854)		$405,494
Depreciation & Amortization	$376,574						$376,574
Income Taxes	$192,207		($224)	$2,916	($3,401)	($10,240)	$181,258
Other Taxes	$115,264						$115,264
Total Other Operating Expenses	$1,098,066	$0	$333	($4,334)	($5,255)	($10,240)	$1,078,590
Cost of Capital:							
Interest on Long-Term Debt	$137,214						$137,214
Debt Discount, Premium & Expense	$7,580						$7,580
Preferred Stock Dividend Requirements	$9,703						$9,703
Earnings	$245,544		($333)	$4,334	($25,504)	($15,182)	$208,859
Total Cost of Capital	$400,041	$0	($333)	$4,334	($25,504)	($15,182)	$363,356
Annual Total Electric Costs	$2,035,628	($165,999)	$0	$0	($115,864)	($25,422)	$1,728,343

(1) System related opportunity sales revenue ($166.0M) and Fuel Expenses ($151.2M) are excluded. The benefit of the gross profit margin on the System Related Opportunity sales revenue ($14.8M) is reducing Fuel Expenses, per Attachment 3.

(2) DSM Net Loss Revenues ($0.28M) and Financial Incentives ($0.28M) are included as adjustment with the appropriate tax and earnings effect, per Attachment 3.

(3) Pinnacle West charges, net of costs for shareholders services ($1.8M), are excluded with the appropriate tax and earnings effects, per Attachment 3.

(4) Per Attachment 3, Non-utility Net Income ($5.056M) and Other Income Deductions ($20.448M) are excluded from Earnings Net of Tax. This also reflects the exclusion of ITC Amortization (27.6M), per Attachment 3.

(5) Per Attachment 3, an adjustment is applied to allow for only a 11.25% Return on Equity based on the average annual equity balance. The income tax effect is calculated by dividing the equity adjustment by (1-Tax rate) and then multiplying by the Company's Tax Rate of 40.22%.

Arizona Public Service Company
July 1, 1999 Rate Decrease
Summary of Retail Rate Reductions By Class
($000)

(A)	(B)	(C)				(D)	(E)	(F)
		1998 Actual Revenues						
Retail Class	1998 Actual MWH Sales	Total \$ [1]	Reg. Ass. \$	Base \$	BSC \$	Demand & Energy \$ [2]	Revenue Reduction By Class \$	% Decrease to Apply to Class Demand & Energy Charges[5]
				(3)-(4)-(5)			[0 678% x (C)] [3]	[(E)/(D)]
Residential	8,310,689	766,378	1,487	764,891	83,132	683,246	5,196	0.76%
General Service	11,976,827	871,312	1,196	870,116				
Less Contracts not subject to decrease	(1,602,572)	(64,872)	(92)	(64,780)				
Net General Service	10,374,255	806,440	1,104	805,336	14,479	791,961	5,468	0.69%
Irrigation	84,640	7,288	10	7,278	135	7,153	49	0.69%
Street & Highway Lighting	90,927	10,645	15	10,630				
Less E-67 Muni. Lighting	(5,078)	(191)	-	(191)				
Net Other	85,849	10,454	15	10,439	-	10,454	71	0.68%
TOTAL ELIGIBLE FOR DECREASE	18,855,433	1,590,560		1,587,944	97,747	1,492,813	10,784 [4]	0.678%

[1] Total retail revenues from sales, excluding sales tax.

[2] Revenues associated with demand and energy charges included in Total \$.

[3] % Class Reduction = Total Reduction/Total Retail Revenue subject to decrease = \$10,784/\$1,590,560 = 0 678%

[4] Total Retail Decrease as calculated on page 1.

[5] Pursuant to Rate Reduction Agreement, decrease will be allocated among customers by means of a uniform percent reduction in the demand and energy charges

ARIZONA PUBLIC SERVICE COMPANY
CHANGES TO RATE SCHEDULE PRICES
COMPARISON OF PRESENT AND PROPOSED 7/1/99 RATES
(Under Rate Reduction Agreement Decision No. 59601 and Decision No. 60225)

Rate Schedule	Description	Billing Designation	Season		Current Rates	Percent Change	Proposed Rates	Dollar Change
E-12	Residential Service	Rate	Summer	Basic Service Charge	$ 7.50 /mo		$ 7.50 /mo	$ - /mo
			(May-Oct)	First 400 kWh	0.08028 /kWh	0.76%	0.07967 /kWh	(0.00061) /kWh
				Next 400 kWh	0.11191 /kWh	0.76%	0.11106 /kWh	(0.00085) /kWh
				All additional kWh	0.13051 /kWh	0.76%	0.12952 /kWh	(0.00099) /kWh
			Winter	Basic Service Charge	$ 7.50 /mo		$ 7.50 /mo	$ - /mo
			(Nov-Apr)	All kWh	0.08047 /kWh	0.76%	0.07986 /kWh	(0.00061) /kWh
ET-1	Residential Service * Time of Use	Rate	Summer	Basic Service Charge	$ 15.00 /mo		$ 15.00 /mo	$ - /kWh
			(May-Oct)	All On-Peak kWh	0.13948 /kWh	0.76%	0.13842 /kWh	(0.00106) /kWh
				All Off Peak kWh	0.04495 /kWh	0.76%	0.04461 /kWh	(0.00034) /kWh
			Winter	Basic Service Charge	$ 15.00 /mo		$ 15.00 /mo	$ - /mo
			(Nov-Apr)	All On-Peak kWh	0.11598 /kWh	0.76%	0.11510 /kWh	(0.00088) /kWh
				All Off-Peak kWh	0.04495 /kWh	0.76%	0.04461 /kWh	(0.00034) /kWh
ECT-1R	Residential Service Time of Use with Demand Charge	Rate	Summer	Basic Service Charge	$ 15.00 /mo		$ 15.00 /mo	$ - /mo
			(May-Oct)	All On-Peak kW	12.33 /kW	0.76%	12.24 /kW	(0.09371) /kW
				All kWh (demand cap)	0.09864	0.76%	0.09792 /kWh	(0.00072) /kWh
				All On-Peak kWh	0.04976 /kWh	0.76%	0.04938 /kWh	(0.00038) /kWh
				All Off-Peak kWh	0.02767 /kWh	0.76%	0.02746 /kWh	(0.00021) /kWh
			Winter	Basic Service Charge	$ 15.00 /mo		$ 15.00 /mo	$ - /mo
			(Nov-Apr)	All On-Peak kW	8.83 /kW	0.76%	8.76 /kW	(0.06712) /kW
				All kWh (demand cap)	0.07064	0.76%	0.07008 /kWh	(0.00056) /kWh
				All On-Peak kWh	0.03938 /kWh	0.76%	0.03908 /kWh	(0.00030) /kWh
				All Off-Peak kWh	0.02767 /kWh	0.76%	0.02746 /kWh	(0.00021) /kWh
E-32	General Service	Rate	Summer	Basic Service Charge	$ 12.50 /mo		$ 12.50 /mo	$ - /mo
			(Jun-Oct)	All kW over 5	1.85 /kW	0.69%	1.84 /kW	(0.01276) /kW
				First 2,500 kWh	0.11018 /kWh	0.69%	0.10942 /kWh	(0.00076) /kWh
				Next 100 kWh per kW over 5	0.11018 /kWh	0.69%	0.10942 /kWh	(0.00076) /kWh
				Next 42,000 kWh	0.07550 /kWh	0.69%	0.07498 /kWh	(0.00052) /kWh
				All additional kWh	0.04756 /kWh	0.69%	0.04723 /kWh	(0.00033) /kWh
			Winter	Basic Service Charge	$ 12.50 /mo		$ 12.50 /mo	$ - /mo
			(Nov-May)	All kW over 5	1.67 /kW	0.69%	1.66 /kW	(0.01153) /kW
				First 2,500 kWh	0.09925 /kWh	0.69%	0.09857 /kWh	(0.00068) /kWh
				Next 100 kWh per kW over 5	0.09925 /kWh	0.69%	0.09857 /kWh	(0.00068) /kWh
				Next 42,000 kWh	0.06780 /kWh	0.69%	0.06733 /kWh	(0.00047) /kWh
				All additional kWh	0.04252 /kWh	0.69%	0.04223 /kWh	(0.00029) /kWh
		Minimum	Sum & Win	Basic Service Charge	$ 12.50 /mo		$ 12.50 /mo	$ - /mo
				Demand Charge	1.74 /kW	0.69%	1.73 /kW	(0.01201) /kW
E-34	Extra Large General Service	Rate	Sum & Win	Basic Service Charge	$ 2,430.00 /mo		$ 2,430.00 /mo	$ - /mo
				All kW	11.16 /kW	0.69%	11.09 /kW	(0.07704) /kW
				All kWh	0.03288 /kWh	0.69%	0.03265 /kWh	(0.00023) /kWh

ARIZONA PUBLIC SERVICE COMPANY
Fair Value Rate Base and Rate of Return
ACC Jurisdictional
Adjusted Test Year Ended 12/31/96

(Dollars inThousands)

Line No.	Description	Original Cost	RCND	Fair Value
1.	Gross Utlity Plant In Service	$ 6,841,873	$ 10,819,830	
2.	Less: Accumulated Depreciation & Amort.	2,567,454	3,919,356	
3.	Net Utility Plant In Service	4,274,419	6,900,474	
	Deductions:			
4.	Deferred taxes	1,380,236	1,380,236	
5.	Customer Advances for Construction	24,044	24,044	
6.	Customer Deposits	32,137	32,137	
7.	Deferred Gains from Sale of Utility Plant	81,970	81,970	
8.	Working Cash/Prepayments	242,754	242,754	
9.	Total Deductions	1,761,141	1,761,141	
	Additions:			
10.	Regulatory Assets & Decommissioning	1,239,189	1,239,189	
11.	Materials & Supplies	130,180	130,180	
12.	Total Additions	1,369,369	1,369,369	
13.	Total Rate Base	$3,882,647	$6,508,702	
a.	Adjusted Rate Base	$ 3,882,647	$ 6,508,702	$ 5,195,675
b.	Adjusted Operating Income	344,391	344,391	344,391
c.	Required Rate of Return	8.87%	5.29%	6.63%

ARIZONA PUBLIC SERVICE COMPANY
System Benefits Costs in Proposed Tariffs
Adjusted Test Year Twelve Months Ended 12/31/96

(Dollars in Thousands)

Line No.	Description	Total Retail
1.	DSM, Renewables, and Low Income Program	$7,000 /1/
2.	Decommissioning	10,618 /2/
3.	Low Income, E-3 & E-4	3,680 /3/
4.	Functionalized Franchise Fee	542
5.	Total	$21,840
6.	Retail Energy Sales (MWh)	18,957,939
7.	System Benefits Charge - ¢/kWh (Line 5/Line 6)	0.115

/1/ Pursuant to 1996 Settlement.
/2/ 1998 Funding Level.
/3/ Year ended 1996 Actual.

Schedule AP-6

ARIZONA PUBLIC SERVICE COMPANY

Unit Stranded Costs, Competition Transition Charges
And Total Stranded Costs, 1999 - 2004

	1999	2000	2001	2002	2003	2004	Totals
A. Class Unit Stranded Costs (¢/kWh)							
1. Residential	0.93	0.84	0.63	0.56	0.50	0.36	
2. <3MW	0.75	0.68	0.52	0.45	0.40	0.29	
3. >3MW	0.54	0.49	0.37	0.33	0.29	0.21	
4. Retail Average	0.67	0.61	0.54	0.48	0.43	0.31	
B. Class CTCs							
5. Residential, DA-R1 (¢/kWh)	0.93	0.84	0.63	0.56	0.50	0.36	
6. < 3 MW, DA-GS1 ($/kW/month)	2.43	2.20	1.66	1.46	1.30	0.94	
7. > 3 MW, DA-GS10 ($/kW/month)	2.82	2.55	1.89	1.72	1.51	1.09	
C. Direct Access Sales (MWh)							
8. Residential	149,835	334,829	9,278,962	9,638,006	10,007,458	10,378,922	39,788,012
9. <3MW	2,877,404	2,916,067	9,692,577	9,994,069	10,348,341	10,706,288	46,534,746
10. >3MW	2,387,620	2,455,855	3,644,756	3,644,756	3,644,756	3,644,756	19,422,499
11. Total DA	5,414,859	5,706,751	22,616,295	23,276,831	24,000,555	24,729,966	105,745,257
D. Direct Access Strandable Cost ($000) [A x C]							
12. Residential	1,393	2,813	58,457	53,973	50,037	37,364	204,038
13. <3MW	21,581	19,829	50,401	44,973	41,393	31,048	209,226
14. >3MW	12,893	12,034	13,486	12,028	10,570	7,654	68,664
15. Total -- Nominal Dollars	35,867	34,676	122,344	110,974	102,000	76,066	481,928
16. Total -- Net Present Value @ 1/1/99	32,966	29,293	94,994	79,196	66,905	45,858	349,213

ARIZONA PUBLIC SERVICE COMPANY

Direct Access Residential Rate DA-R1
Derivation of Distribution Prices
9/1/98 Rate Level

		(a)	(b)	(c)	(d)	(e)	(f)
	Billing Element	Bundled Rate	System Benefits	Energy Prices Less S/B (a) - (b)	Distribution Only (c) x L5	Regulatory Assets (c) x L5	1999 Tariff Distribution Prices (d) + (e)
	Summer						
1.	BDC	$ 10.00					$ 10.00
2.	All kWh	$ 0.08733	$0.00115	$ 0.08618	$0.02840	$0.01318	0.04158
	Winter						
3.	BDC	$ 10.00					$ 10.00
4.	All kWh	$ 0.07407	$0.00115	$ 0.07292	$0.02403	$0.01115	0.03518
5.	Percent of TY Rev. Req.				32.95%	15.29%	

Schedule AP-7
Schedule 2

ARIZONA PUBLIC SERVICE COMPANY

Direct Access General Service Rate DA-GS1 (0 to 2,999 kW)
Derivation of Distribution Prices
9/1/98 Rate Level

	Billing Element	(a) Standard Offer	(b) System Benefits	(c) Energy Prices Less S/B (a) - (b)	(d) Distribution Only (c) x L13	(e) Distribution Only @ Sec. Voltage (d) x 102%	(f) Regulatory Assets (c) x L13	(g) Adjusted Regulatory Assets (f) x 104%	(h) 1999 Tariff Distribution Prices (e) + (g)
	Summer								
1.	BDC	$ 12.50							$ 12.50
2.	kW per month	$ 1.850			$ 0.372	0.379	$ 0.329	$ 0.342	$ 0.721
3.	First 2,500	$ 0.11018	$0.00115	$ 0.10903	$ 0.02194	0.02238	$ 0.01939	$ 0.02017	$ 0.04255
4.	Next 100kWh/kW Over 5 kW	$ 0.11018	$0.00115	$ 0.10903	$ 0.02194	0.02238	$ 0.01939	$ 0.02017	$ 0.04255
5.	Next 42,000 kWh	$ 0.07550	$0.00115	$ 0.07435	$ 0.01496	0.01526	$ 0.01322	$ 0.01375	$ 0.02901
6.	All Additional kWh	$ 0.04756	$0.00115	$ 0.04641	$ 0.00934	0.00953	$ 0.00825	$ 0.00858	$ 0.01811
	Winter								
7.	BDC	$ 12.50							$ 12.50
8.	kW per month	$ 1.670			$ 0.336	0.343	$ 0.297	$ 0.309	$ 0.652
9.	First 2,500 kWh	$ 0.09925	$0.00115	$ 0.09810	$ 0.01974	0.02013	$ 0.01744	$ 0.01814	$ 0.03827
10.	Next 100kWh/kW Over 5 kW	$ 0.09925	$0.00115	$ 0.09810	$ 0.01974	0.02013	$ 0.01744	$ 0.01814	$ 0.03827
11.	Next 42,000 kWh	$ 0.06780	$0.00115	$ 0.06665	$ 0.01341	0.01368	$ 0.01185	$ 0.01232	$ 0.02600
12.	All Additional kWh	$ 0.04252	$0.00115	$ 0.04137	$ 0.00832	0.00849	$ 0.00736	$ 0.00765	$ 0.01614
13.	Percent of TY Rev. Req.				20.12%		17.78%		

Schedule AP-7
Schedule 3

ARIZONA PUBLIC SERVICE COMPANY

Direct Access General Service Rate DA-GS10 (3,000 kW or Greater)
Derivation of Distribution Prices
9/1/98 Rate Level

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Billing Element	Standard Offer	System Benefits	Energy Prices Less S/B (a) - (b)	Distribution Only (c) x L4	Distribution Only @ Sec. Voltage (d) x 108%	Regulatory Assets (c) x L4	Adjusted Regulatory Assets (f) x 104%	1999 Tariff Distribution Prices (e) + (g)
1. BDC	$ 2,430.00							$ 2,430.00
2. kW per month	$ 11.160			$ 1.20	1.30	$ 2.14	$ 2.23	$ 3.53
3. All kWh	$ 0.03288	$0.00115	$ 0.03173	$ 0.00340	0.00367	$ 0.00608	$ 0.00632	$ 0.00999
4. Percent of TY Rev. Req.				10.71%		19.18%		

Schedule AP-7
Schedule 4

ARIZONA PUBLIC SERVICE COMPANY

Revenue Requirements for Direct Access Services by Rate Class
Pro Forma Cost of Service Study
Test Year Ended 12/31/96
(Dollars in Thousands)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Production	Transmission	Distribution	BDC	Distribution Ex. BDC	Regulatory Assets	System Benefits	Totals Totals - (d) - (g)
Residential								
1. Revenue Requirement	$336,678	$31,649	$258,139	$79,498	$234,492	$108,790	$8,669	$799,776
2. Percent of (Total - BSC - S/B)	47.31%	4.45%	36.28%	11.17%	32.95%	15.29%	1.22%	$711,609
								100.00%
General Service (0 - 2,999 kW)								
3. Revenue Requirement	$317,041	$27,481	$113,312	$12,341	$111,635	$98,641	$9,256	$576,395
4. Percent of (Total - BSC - S/B)	57.15%	4.95%	20.42%	2.22%	20.12%	17.78%	1.67%	$554,798
								100.00%
GeneralService (3,000 kW +)								
5. Revenue Requirement	$105,031	$7,827	$18,628	$1,487	$17,242	$30,869	$3,750	$166,206
6. Percent of (Total - BSC - S/B)	65.25%	4.86%	11.57%	0.92%	10.71%	19.18%	2.33%	$160,969
								100.00%

ARIZONA PUBLIC SERVICE COMPANY

Direct Access Rates

1. DA-R1, Residential Service
2. DA-GS1, General Service
3. DA-GS10, Extra Large General Service
4. DA-GS11, Ralston Purina
5. DA-GS12, BHP Copper
6. DA-GS13, Cyprus Bagdad

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

(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	$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.

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

(CONTINUED ON REVERSE SIDE)

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.

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.

(CONTINUED ON REVERSE SIDE)

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.

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.

(CONTINUED ON REVERSE SIDE)

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.

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.

(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	\$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. 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.

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.

(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	$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. 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.

ARIZONA PUBLIC SERVICE COMPANY

Summary of Direct Access Monthly Rate Credits

	(a)	(b)	(c)
Competitively Supplied Service	Residential DA-R1	General Service Under 3 mW DA-GS1	General Service Over 3 mW DA-GS10
1. Metering	$1.30	$4.00	$55.00
2. Meter Reading	$0.30	$0.30	$0.30
3. Billing	$0.30	$0.30	$0.30