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Arizona Corporation Commission
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July 12, 1999

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

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

Dear Mrs., Cole:

Pursuant to Procedural Order dated May 21, 1999, as modified on June 23, 1999, attached is the rebuttal testimony of Arizona Public Service Company ("APS" or "Company") and a list of the company's witness and identification of subject areas to be covered in there testimony at the hearing. The company's rebuttal testimony includes the following witnesses: Jack E. Davis, Alan Propper, Donald G. Robinson, Dr. John H. Landon, and Dr. William H. Hieronymus.

Sincerely yours,

Barbara A. Klemstine

Barbara A. Klemstine
Manager, Regulatory Affairs

cc: Docket Control
Parties of Record

BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
CHAIRMAN
JIM IRVIN
COMMISSIONER
WILLIAM A. MUNDELL
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS PLAN FOR STRANDED COST RECOVERY	DOCKET NO. E-01345A-98-0473
IN THE MATTER OF THE FILING OF ARIZONA PUBLIC SERVICE COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1601 *ET SEQ.*	DOCKET NO. E-01345A-97-0773
IN THE MATTER OF COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. RE-00000C-94-0165

Snell & Wilmer
LAW OFFICES
One Arizona Center
Phoenix, Arizona 85004-0001
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ARIZONA PUBLIC SERVICE COMPANY'S WITNESS LIST AND IDENTIFICATION OF SUBJECT AREAS TO BE COVERED AT THE HEARING

In accordance with the Chief Hearing Officer's Procedural Order dated May 21, 1999, as modified on June 23, 1999, Arizona Public Service Company ("APS") submits its list of witnesses and subject areas to the be covered at the hearing commencing on July 14, 1999.

. . .

. . .

. . .

A. Direct Witnesses and Subject Areas.

1. Mr. Jack E. Davis. Mr. Davis will address:
   - the background of the Agreement;
   - the provisions of the Agreement; and
   - the benefits of the Agreement.
2. Dr. John H. Landon. Dr. Landon will address:
   - the provisions of the Agreement;
   - the effect of the Agreement on competition;
   - rate reductions;
   - market power;
   - stranded costs and regulatory assets; and
   - the benefits of approving the Agreement.
3. Mr. Alan Propper. Mr. Propper will address:
   - unbundled and Standard Offer rates and tariffs;
   - cost allocation;
   - stranded costs and regulatory assets; and
   - transmission issues.

B. Rebuttal Witnesses and Subject Areas.

1. Mr. Jack E. Davis. Mr. Davis will address:
   - the effect of the Agreement on competition;
   - stranded costs;
   - the transfer of competitive assets;
   - transmission issues; and
   - waivers and exemptions from various provisions of Title 40 and the Commission's Rules.

. . .

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2. Mr. Donald G. Robinson. Mr. Robinson will address:

- the transfer of competitive assets;
- the adequacy of rate reductions; and
- APS's financial condition.

3. Mr. Alan Propper. Mr. Propper will address:

- pricing issues;
- the design of unbundled tariffs; and
- Standard Offer service issues.

4. Dr. William H. Hieronymus. Dr. Hieronymus will address:

- market power issues.

5. Dr. John Landon. Dr. Landon will address:

- the effect of the Agreement on competition; and
- the transfer of competitive assets.

Respectfully submitted this 12th of July, 1999.

SNELL & WILMER, L.L.P.

By ______________________
Steven M. Wheeler
Thomas L. Mumaw
Jeffrey B. Guldner
One Arizona Center
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CERTIFICATE OF SERVICE

The original and ten (10) copies of the foregoing document were filed with the Arizona Corporation Commission on this 12th day of July, 1999, and service was completed by mailing or hand-delivering a copy of the foregoing document this 12th day of July, 1999, to all parties of record herein.

Sharon Madden

Snell & Wilmer
LAW OFFICES
One Arizona Center
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(602) 382-6000

BEFORE THE

ARIZONA CORPORATION COMMISSION

REBUTTAL 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

July 12, 1999

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REBUTTAL TESTIMONY

OF

JACK E. DAVIS

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. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

2.A. Yes

3.Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

3.A. I will rebut certain of the statements and conclusions made in the testimony of the Enron witnesses Kingerski, Delany, Rosenberg and Frankena; Commonwealth Energy witness Bloom; and PG&E Energy Services witness Ogelsby. Collectively, these will be referred to as the "ESP Witnesses." To a somewhat lesser degree, I will also rebut Staff witness Williamson and Staff consultant Smith.

I will not directly respond to the non-evidentiary "Comments" submitted by Commonwealth Energy, the Arizona Consumers

Council, the Arizona Transmission Dependent Utility Group, and others. Many of these represent legal assertions concerning "fair value," rate case procedures, and certain technical provisions of the Settlement Agreement dated May 14, 1999 ("Agreement" or "Settlement Agreement"). Others are simply arguments about what the author believes the evidence shows or doesn't show, or whether the evidence is or will be "substantial." Arizona Public Service Company ("APS" or "Company"), the other signatories to the Agreement, and, I believe, the Commission's own counsel disagree with these legal assertions, and I find the "weight of the evidence" arguments curious at this point, since the Commission hasn't even held its hearing yet. In any event, APS will respond to legal issues in any such post-hearing briefs or memoranda as are believed necessary by the Chief Hearing Officer. Moreover, my rebuttal testimony as well as the rebuttal testimony of other witnesses, will, of necessity, address some of the same issues as contained in the various "Comments."

A second goal of my Rebuttal Testimony is to explain and hopefully clarify certain aspects of the Agreement. It is evident from my review of the ESP Witnesses' testimony that they may not fully understand the terms of this Agreement, and in some instances they have completely misstated those terms.

4.Q. WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

4.A. Yes. The Agreement, as negotiated by the Company and all of its major customer group constituencies, allows Electric Service Providers ("ESPs") to compete on fair and equal terms to provide competitive electric services in the APS distribution service area. It does not and should not subsidize competitors and competition on the backs of Standard Offer customers. The Agreement is fully consistent with the proposed Electric Competition Rules, and in some respects goes further than such Rules in both promoting competitive opportunities for ESPs and limiting the actions of incumbent providers such as the Company.

The calculation of net mitigated stranded costs, which are only partially recoverable under the Agreement, uses one of the approved methodologies from Decision No. 61677 (April 27, 1999). It is, in every respect, a conservatively low calculation. Much of the criticism of the Agreement's calculation of net mitigated stranded costs comes from the parties' underlying disagreement with either the Electric Competition Rules themselves or Decision No. 61677. In other instances, witnesses engage in unsupported speculation to challenge this aspect of the Agreement.

The Agreement's provisions on the transfer of competitive assets are fully consistent with and even required by the pending Electric Competition Rules. Proposals to double-count either stranded costs or stranded benefits (negative stranded costs) or, worse yet, to double-count the latter and ignore the former will unfairly punish the Company, while at the same time providing no benefit to competitors.

Although transmission is largely a non-jurisdictional issue, falling under the exclusive authority of the Federal Energy Regulatory Commission ("FERC"), the Agreement does promote the concepts of fair and equal access to the Company's transmission system. It does so by its support for the Arizona Independent Scheduling Administrator ("AISA") and, eventually, a regional independent scheduling organization ("ISO") to be named "Desert Star."

Finally, the Agreement would grant APS and its competitive affiliates waivers of certain Commission rules and of statutory provisions, as well as make certain findings necessary for the APS generation affiliate contemplated by the Agreement to qualify as an "Exempt Wholesale Generator" ("EWG") under federal law. The waivers are, in part, necessary in order for APS to timely comply with other terms of the Agreement or with the Electric Competition Rules. The rules waivers are based on both the previous waivers agreed to by Commission Staff in the subsequently withdrawn 1998 settlement and on those granted to competitive telecommunications service providers. The statutory waivers are pursuant to specific legislation now embodied in A.R.S. § 40-202. EWG designation [which designation will be made by the Securities and Exchange Commission ("SEC") but which also requires this Commission to make certain specific findings as set forth in the Agreement] merely preserves the status quo for Pinnacle West Capital Corporation ("PinnWest") under the Public Utilities Holding Company Act of 1935 ("PUHCA").

II. COMPETITION ISSUES

5.Q. THE ESP WITNESSES HAVE ALLEGED THAT THERE WOULD BE NO COMPETITION UNDER THE TERMS OF THE AGREEMENT. DO YOU AGREE?

5.A. Of course not. These witnesses, and to some extent Staff witness Williamson and Staff consultant Smith, have expressed concern over the "spread" between the proposed unbundled distribution (direct access) rates and the Company's present tariffs (Standard Offer) rates. This differential is loosely referred to as the customer's "shopping credit" since it represents the "bogey" that a direct access customer generally must meet or beat if such customer is to procure electricity at a lower delivered cost than under the Company's Standard Offer. The ESP witnesses also point to what they would have the Commission believe are the insurmountable advantages of the incumbent (APS) – even though those advantages (to the extent they exist) are neither insurmountable nor a product of the Agreement.

6.Q. IS THE "SHOPPING CREDIT" THAT RESULTS FROM THE AGREEMENT INADEQUATE TO PERMIT COMPETITION?

6.A. No. During the long and sometimes heated discussions that led to the Settlement Agreement, Arizonans for Electric Choice and Competition ("AECC"), Enron, and APS were acutely aware of the need to create a reasonable opportunity for efficient ESPs to compete while at the same time providing tangible benefits to all Standard Offer customers. These are mutually inconsistent goals, and thus the issue engendered considerable thought and analysis. As is discussed by AECC witness Higgins in his direct testimony, the "shopping credit" resulting from the instant Agreement is larger than that previously agreed-to by Staff, including Staff consultant Smith, for virtually all customers in the 1998 settlement. It is also significantly larger than that allowed by SRP for over 99% of APS customers. Even at the lower SRP-determined level of "shopping credit", and despite the numerous other SRP- imposed impediments to competition – impediments that would not exist in the case of APS – direct access customers in the SRP distribution service area are already signing agreements and/or letters of intent with APS Energy Services Company, Inc. ("APSES"), an indirect affiliate of the Company and a competitive ESP.

In addition to Mr. Higgins' analysis and the real world experience of APSES in the SRP distribution service area, we have conducted our own analysis. We specifically looked at APS general service customers between 40 and 200 kW. Almost all of the load-serving ESPs certificated by the Commission (except APSES and Commonwealth) have expressed an exclusive interest in commercial customers, and this group (40 to 200 kW) comprises over 80% of those general service customers eligible to take direct access in the initial phase of retail competition. Their individual average load factor is 41%, producing a generation and transmission "shopping credit" of 4.59¢ per kWh. I could simply compare this with Ms. Smith's figure of 4.17¢ for market generation plus transmission and conclude that there is a considerable opportunity here for profitable sales, even before adding in the metering and billing credits overlooked in Ms. Smith's analysis. Additionally, an ESP would not be serving one or even a few isolated individual customers but would instead aggregate groups of such customers with load diversity. Thus, we believe a delivered market price alternative of 37.2¢ is more realistic. This creates 8.7 mils per kWh for ESP margins, or approximately 23% mark-up over cost. Attachment JED-1R provides more detail on this calculation.

All of these calculations, as well as those done by Enron and Staff consultant Smith, assume that an ESP can't beat the Palo Verde hub price for electricity. In reality, our own energy traders beat that price on bulk purchases. In fact, if an ESP doesn't use proper power portfolio acquisition techniques to secure power cheaper than just buying it at the relevant trading hub at the prevailing market price, a strong argument can be made that the ESP is not creating any new value. In other words, it ought to be difficult to make money in a competitive market. It is the struggle to do things cheaper, better, and more efficiently than the next guy that creates additional value for both the buyer and the seller and produces the long term benefits of competition.

7.Q. HAVEN'T OTHER REGULATORY COMMISSIONS REQUIRED HIGHER "SHOPPING CREDITS?"

7.A. Yes. Pennsylvania has required higher "shopping credits" for its high-cost electric utilities (e.g., Philadelphia Electric), with lower "shopping credits" for lower-cost Pennsylvania utilities (e.g., Allegheny Power). It is also my understanding that New Jersey presently contemplates higher "shopping credits." These higher "shopping credits" are either paid for by standard offer customers of those states' utilities in the form of no or reduced rate reductions for such customers, or by stretching out stranded cost recovery for direct access customers, or by effectively borrowing against a hoped-for windfall premium from divestiture of the incumbent's generating assets. If that windfall fails to materialize or greater numbers of customers than expected avail themselves of the inflated "shopping credits," the incumbent utility may have the right to obtain additional stranded cost recovery in the future.

8.Q. DOES APS SUPPORT SUBSIDIZING COMPETITORS AND COMPETITION BY ANY OF THE METHODS DESCRIBED ABOVE?

8.A. No. I agree with Dr. Alfred Kahn, perhaps this nation's leading expert on both regulation and deregulation, who recently referred to this as "bribing customers to leave." A copy of the complete text of Dr. Kahn's article in *The Electricity Journal* is set forth in Attachment JED-2R.

9.Q. WOULD A HIGHER SHOPPING CREDIT RESULT IN DIRECT ACCESS CUSTOMERS PAYING A LOWER SHARE OF STRANDED COSTS THAN A COMPARABLE STANDARD OFFER CUSTOMER?

9.A. That would necessarily be the result. I also agree with Dr. Kahn in the above-cited article that this would be both unfair and provide a subsidy to ESPs rather than a benefit to customers as a group. Moreover, my understanding is that all versions of the Commission's Electric Competition Rules, including those currently pending before the Commission, would not support this result. *See* A.A.C. R14-2-1607 (G).

10.A. WOULD A HIGHER "SHOPPING CREDIT" RESULT IN LOWER OVERALL ELECTRIC COSTS FOR AT LEAST THOSE APS CUSTOMERS CHOSING DIRECT ACCESS?

10.A. No. It may even result in higher bills. A higher "shopping credit" will not lower the market-clearing price of electricity. It <u>will</u> produce higher profits for ESPs. Indeed, if this larger "shopping credit" is created by keeping Standard Offer rates higher than would otherwise be the case, it could have the effect of artificially propping up the price of competitive electricity to direct access customers.

11.Q. SHOULD THE COMMISSION BE SURPRISED THAT THE ESP WITNESSES WANT HIGHER "SHOPPING CREDITS?"

11.A. Absolutely not. If I were in their position, I'd be arguing for as high a "shopping credit" as possible and for as many restrictions on the incumbent provider as I could conjure up. This would make my job as a competitor both easier and more profitable.

12.Q. AT PAGES 15 THROUGH 17 OF HER TESTIMONY, STAFF CONSULTANT SMITH HAS PROPOSED AN "INTERIM SHOPPING CREDIT" THAT IS SOMEWHAT LARGER THAN UNDER THE SETTLEMENT AGREEMENT WITH THE IDEA

THAT APS COULD COME BACK LATER IF THE HIGHER MARKET PRICES SUGGESTED BY MS. SMITH DID NOT MATERIALIZE. IS THIS ACCEPTABLE TO THE COMPANY?

12.A. No. This is just a variant on the Pennsylvania scheme except we are borrowing today against higher hoped-for market prices in the future instead of against higher sales prices for divested generation. Rather than end uncertainty for APS, its customers, and the ESPs, it creates new uncertainties. Ms. Smith's proposal also ignores that one of the bargained-for elements of the Agreement (for which APS agreed to forgo all CTC recovery in excess of $350 million regardless of future market prices or its ability to actually achieve the future cost mitigation inherent in the $533 million stranded costs figure) was the possibility (however remote) that actual stranded costs would be less than $533 million, thus making the $183 million present value "haircut" less punitive to our shareholders. In other words, it's the same type of asymmetrical and unfair proposal I discuss in Section III of my Rebuttal Testimony.

In addition, my accountants assure me that we would not be able to record the stranded cost recoveries deferred under Ms. Smith's scheme as regulatory assets because of the contingency surrounding their eventual recovery. Thus, rather than getting all the "pain" out of the way in 1999, there would be a downward drag on Company earnings throughout the transition period.

13.Q. WHAT ABOUT THE ESP WITNESSES' COMPLAINT ABOUT INCUMBENT MARKET POWER?

13.A. These ESP complaints are to be expected. They manifest themselves in several distinct assertions that I will paraphrase as follows:

a. the Agreement does not require divestiture of APS generation to a non-affiliated party;

b. the Agreement does not impose sufficient restrictions on the affiliate transactions between APS and the new competitive affiliates (i.e. code of conduct issues); and,

c. APS enjoys advantages over new entrants in the form of name recognition, superior knowledge of the APS distribution service areas and its customers, etc.

14.Q. DOES THE AGREEMENT REQUIRE APS TO DIVEST ITS GENERATION TO A NON-AFFILIATED PARTY?

14.A. No. Mandatory divestiture to a non-affiliated party has never been required by any of the several permutations of the Commission's Electric Competition Rules. Mandatory divestiture is neither required nor even authorized by H.B. 2663 ("The Retail Electric Competition Act"). Yet each of these ESPs, and many others for that matter, have still lined up to get CC&Ns to serve in the APS distribution service area. New Jersey and Pennsylvania, the two jurisdictions most often cited by the ESP Witnesses as "getting it right," have not mandated divestiture, although some utilities in those states have agreed to voluntarily divest. Simply put, these ESP Witnesses don't like the Commission's Electric Competition Rules.

15.Q. HAS ANY PARTY PROVIDED EVIDENCE OF APS MARKET POWER?

15.A. Not in my estimation. Although Dr. Hieronymus and Dr. Landon are the market power experts, I don't see where any party has provided any evidence of APS having significant market power outside of a few load pocket situations.

16.Q. HOW DOES THE SETTLEMENT AGREEMENT RESOLVE THE LOAD POCKET SITUATIONS DESCRIBED BY ENRON WITNESSES FRANKENA AND DELANEY?

16.A. The Agreement did not cause, exacerbate, and cannot directly resolve this situation. Load pockets represent transmission-constrained areas. As such, they are largely FERC issues. I discuss this more thoroughly in Section V of my Rebuttal Testimony.

17.Q. WHAT DO THE PROPOSED COMMISSION ELECTRIC COMPETITION RULES REQUIRE AS REGARDS A CODE OF CONDUCT?

17.A. The pending Electric Competition Rules require APS to propose a code of conduct within 90 days of the effective date of such Rules. It says nothing about an interim code of conduct. By mandating APS to submit an interim code of conduct within 30 days of the approval of the Agreement, the Settlement Agreement goes beyond what is being considered in the pending Electric Competition Rules. When and if the Electric Competition Rules are finally adopted, APS would submit a "permanent" code of conduct for Commission approval.

18.Q. WHAT IF THE ELECTRIC COMPETITION RULES REQUIRE A MORE RESTRICTIVE OR PRESCRIPTIVE CODE OF CONDUCT THAN THE INTERIM CODE OF CONDUCT FILED BY APS UNDER TERMS OF THE AGREEMENT?

18.A. APS would have to comply with the more stringent requirements. The same is true should the Commission decide to reinstate all or part of the particular provisions of "old" Rule 1617, which prescribed and prohibited specific affiliate relationships and transactions. The interim code of conduct under the Agreement supplements whatever provision the Commission adopts by rule – it does not replace it.

19.Q. WHAT IF THE FINAL ELECTRIC COMPETITION RULES DO NOT REQUIRE A CODE OF CONDUCT OF ANY SORT?

19.A. I judge such a result to be an extremely unlikely outcome, but in that event, APS would continue to abide by the interim code of conduct filed pursuant to the Agreement.

20.Q. WHAT WOULD BE THE ELEMENTS OF THE INTERIM CODE OF CONDUCT?

20.A. The Agreement requires APS to consult with the other signatories on this interim code of conduct. However, it is probably safe to say that the interim code of conduct will be designed to prevent subsidization of competitive services by non-competitive services. Second, there will be no unlawful discrimination in the provision by APS of non-competitive services to an ESP or its customers. Third, it will assure equal access by all ESPs to customer-specific information (with, of course, the customer's permission) upon reasonable terms and conditions. This necessarily means no preferential access to such information by any competitive affiliate of APS. Fourth, it will address Commission access to affiliate books and records necessary to assure compliance by APS with the interim code of conduct.

21.Q. WILL APSES AND THE COMPETITIVE GENERATION AFFILIATE REFERENCED IN THE AGREEMENT BE SUBJECT TO THIS INTERIM CODE OF CONDUCT?

21.A. The contemplated generation affiliate, which is to be a direct PinnWest subsidiary, will not offer retail services in Arizona, and thus would be regulated by FERC and subject to the stringent FERC code of conduct on affiliated transactions as regards its relations with both APS and APSES. APSES is not a signatory to the Agreement and, as a direct PinnWest subsidiary, is no longer controlled by APS. Nevertheless, it will be effectively subject to the interim code of conduct because virtually all the restrictions inherent in such a code of conduct are imposed on APS. For example, if APS is expressly prohibited by the code of conduct from giving subsidies to APSES, obviously APSES is effectively prohibited from receiving such subsidies. Also APSES may be reselling excess purchases of power into the wholesale market, and thus would likewise become subject to FERC jurisdiction (as well as that of the Commission) and the FERC code of conduct.

22.Q. DO APS AND APSES HAVE ANY ADVANTAGES IN THE FORM OF NAME RECOGNITION, GOOD WILL, SUPERIOR

KNOWLEDGE OF THE ARIZONA MARKET AND ITS CUSTOMERS, ETC.?

22.A. APS may have these advantages, but APS will not be engaging in competitive electric services for the most part, so whatever incumbent advantages it possesses are pretty much irrelevant. APSES may also enjoy some of these advantages in areas served by APS or close to areas served by APS. However, these are advantages enjoyed by all successful incumbents, whether its Anheuser Busch (Budweiser beer) or AT&T (long-distance telecommunications).

III. STRANDED COSTS

23.Q. DOES THE AGREEMENT CREATE THE POSSIBILITY THAT APS WILL COLLECT MORE THAN THE AGREED UPON $350 MILLION DOLLARS THROUGH THE CTC?

23.A. No. All APS customers must fall into either of two categories: direct access or Standard Offer. The same CTCs, by class, are imputed to both sets. Thus, whether all eligible APS customers chose direct access, or none chose direct access, or any combination of direct access and Standard Offer customers in between those two extremes, recovery of the CTC is capped at $350 million. If the agreed-upon CTCs produce more revenue than anticipated due to higher than expected sales or deliveries of electricity between January 1, 1999 (the beginning of the recovery measurement period) and the end of 2004 (the end of the recovery period), the Agreement provides for a reconciliation procedure that first offsets any such over collection against amounts otherwise recoverable under the agreement.

24.Q. WOULD ANY SUCH OVERCOLLECTION CONSTITUTE AN INTEREST-FREE LOAN TO THE COMPANY?

24.A. No. By reducing the amounts deferred under the Agreement, these hypothetical over collections of the $350 million would similarly reduce APS' allowed returns on these deferrals. In the unlikely event that the CTC over collection of the $350 million was greater than the additional costs deferrable under the Agreement, there would be a negative balance that should accrue a return similar to that of a positive balance. However, this is the sort of structural detail that the Commission and affected parties would work out in the proceeding contemplated by the last paragraph of Section 2.6

25.Q. WOULD APS COLLECT STRANDED COSTS BOTH FROM THE MARKET RATES CHARGED BY ITS GENERATING AFFILIATE AND THROUGH THE CTC?

25.A. No. The generation affiliate would recover market rates while the CTC is, by definition, the difference between book value and market rates. There is no overlap between the two.

26.Q. WHAT IF MARKET ELECTRICITY PRICES TURN OUT TO BE LOWER OR HIGHER THAN ANTICIPATED?

26.A That's a different question. If that turns out to be true and all else remains equal, itself an unlikely event, APS' stranded costs would be higher or lower than $533 million (although not necessarily or even likely less than the $350 million cap).

27.Q. WHAT IF THE ACTUAL STRANDED COSTS DO TURN OUT TO BE LESS THAN $350 MILLION?

27.A. That is extremely unlikely. However, such a hypothetical result is inherent with choosing a fixed number for CTC recovery. APS bears all of the risk that stranded costs will exceed expectations. Customers bear only part of the risk that they will be less than expected. Proposals such as that of Staff consultant Smith, which place none of the risk for overestimation on customers but all of the risk for underestimation on shareholders, are both asymmetrical and, to put it more simply, unfair. As such, they are similar to the asymmetrical "risk sharing" schemes denounced by the Commission more than a decade ago:

> It would take many pages for us to discuss the numerous arguments for and against "value-based pricing," "risk sharing," and "market-based pricing," . . . Fortunately, it is not necessary for us to examine in minute detail the many assumptions which form the foundation of the otherwise objective-looking calculations of present worth and opportunity cost. After reviewing the various proposals presented, we find ourselves in agreement with APS witness [Dr. Alfred] Kahn that, as formulated, **these proposals are simply unfair.** In Decision No. 55118, the Commission indicated that if one wishes to chose an absolute (per se) standard for utility performance, one must be prepared to give [shareholders] credit for performance above the standard as for below. Although we are intrigued with these concepts, as formulated and offered, they ignore this fundamental principle [of reciprocity] and will, therefore, be rejected at this time.
> [Emphasis supplied.]

Decision No. 55228 (October 9, 1986).

28.Q. WHY DO YOU BELIEVE IT SO UNLIKELY THAT APS' ACTUAL STRANDED COSTS WOULD BE LESS THAN $350 MILLION?

28.A. It is unlikely that APS' stranded costs will be less than the $533 million figure cited in the Agreement, let alone $350 million. This is true for the following reasons:

a. APS estimates of market price are at the high end of reasonableness, and higher market prices mean lower stranded costs;

b. APS has already significantly improved its generation cost efficiency and has factored even more significant cost mitigation into its calculation of stranded costs;

c. Other utilities in the region are likely making similar efforts to reduce generation costs, but this factor suppressing market prices was ignored in APS' study;

d. APS has assumed that operating margins from "must-run" units will not be constrained by regulation, thus decreasing stranded costs;

29.Q. HOW DO APS' MARKET PRICE PROJECTIONS COMPARE TO THOSE OF OTHER EXPERTS?

29.A. We are clearly more "bullish" about future market prices than SRP. A comparison of the market prices used in the APS stranded cost calculation and those adopted by SRP are shown in my Attachment JED-3R. APS has also compared its projections with those of EPIS and CERA, both established consulting firms that do this sort of analyses. APS is higher than either of these consultants' price forecasts using either unified or Balkanized market assumptions. Those comparisons are also shown on Attachment JED-3R.

30.Q. DIDN'T STAFF CONSULTANT SMITH COME UP WITH SOME HIGHER MARKET PRICES IN MAKING HER RECOMMENDATION?

30.A. Yes. These prices are based on just a few months experience in 1999, which she then extrapolates out through the year 2004. I found Staff consultant Smith's use of these prices particularly puzzling because during the course of negotiating the 1998 settlement agreement, we had shared the detail of all our market pricing assumptions with Staff's stranded cost expert, Dr. Kenneth Rose. Dr. Rose did not express disagreement with our overall results. In fact, Dr. Rose shared his own market price analysis with the Company. Dr. Rose relied heavily on a study by the United States Energy Information Administration ("USEIA"). A comparison of those projections with those of APS shows that USEIA's prices are lower than the Company's. *See* Attachment JED-3R. Therefore, Staff consultant Rose's figures would have produced higher stranded cost estimates than those proposed by APS.

31.Q. IS THERE A FURTHER REASON TO BELIEVE THAT THE COMPANY'S MARKET PRICE ESTIMATES ARE ON THE HIGH SIDE?

31.A. Yes. Additional capacity in the form of efficient gas-powered generation will have a suppressing effect on market price. It's the old law of supply and demand. APS has assumed far less in the way of new generation supply market entry than the announced plans of both incumbent utilities and merchant builders. APS' stranded cost calculation is, in effect, counting on some two-thirds of these projects being cancelled or delayed significantly. As noted earlier, APS has also ignored the likely improvements in plant operating efficiencies from existing plants other than its own.

32.Q. PLEASE DISCUSS APS' ASSUMPTIONS ABOUT COST MITIGATION?

32.A. The combination of past and future reduced O&M for generation have reduced APS' stranded generating costs (ACC jurisdiction) by $137 million (present value) during the period 1999-2004. APS has assumed that even greater capacity factors can be achieved in the future. I should note that some of the APS units being considered in the stranded cost calculation will be over 50 years old by the time of their retirement, and yet APS has assumed that they will operate more efficiently than they did some 20 years earlier.

33.Q. AT PAGE 13 OF HER TESTIMONY, STAFF CONSULTANT SMITH HAS CRITICIZED THE COMPANY'S CLAIM OF HIGHER CAPACITY FACTORS AS EXAGGERATED AND IGNORING THE IMPACT OF LOWER APS CAPACITY FACTORS ON MARKET PRICE. ARE SUCH CRITICISMS VALID?

33.A. No. As can be seen by Attachment JED-4R, which was previously provided to Staff, APS has not compared its prospective capacity factors with a single aberrant year or even a few years, but against the entire prior decade's historical operating experience of each unit. APS also acknowledges that industry capacity factors have improved slightly in recent years, but they are still well below those projected by APS in its stranded cost calculation. Ms. Smith also fails to note that if other utilities increase their capacity factors, that will have a depressing impact on future market prices.

Ms. Smith also claims that had APS used lower capacity factors for its own generating units, it may have increased the market price. APS has made analyses of precisely that impact and has found the trade-off between lower assumed output (i.e., lower capacity factors) and higher market prices leaves APS a big loser. The impact of lower output totally dominates that of higher prices causing significantly higher stranded costs. APS has also shared these analyses with Staff during the course of the last settlement.

34.Q. PLEASE EXPLAIN HOW THE INCLUSION OF "MUST-RUN" UNITS IN APS' STRANDED COST CALCULATION REDUCED THE $533 MILLION ESTIMATE.

34.A Virtually everyone, including APS, is proposing that "must-run" units must be rate-regulated because of the micro-market power they possess in certain load pockets within the state within a limited number of hours in the year. The $533 million stranded cost estimate did not impose such a constraint and assumed that these units could sell their output at market prices whenever their operating costs put them "in the money" (market price above variable O&M). Since, in general, market prices exceed the embedded cost-of-service for these older, largely or fully-depreciated units, this produced higher revenues (and lower stranded costs) than had we constrained prices to cost-of-service levels.

35.Q. HAVE YOU SUMMARIZED THE IMPACT ON THE COMPANY'S ESTIMATE OF STRANDED COSTS OF THESE VARIOUS ASSUMPTIONS?

35.A. Yes. As can be seen on Attachment JED-5R, APS' stranded cost estimate would increase to $774 million simply if the SRP market price assumptions were substituted for the Company's. The other market price assumptions previously discussed would produce stranded cost estimates of between $546 million and $845 million. Adding in the impact of aggressive O&M mitigation, higher APS capacity factors, and increased market entry would have increased this figure by at least another $300 million.

36.Q. MS. SMITH ALSO CONTENDED THAT APS' TRUNCATION OF THE STRANDED COST CALCULATION AT YEAR 2004 LIKELY CAUSED AN OVERSTATEMENT OF STRANDED COSTS. IS THAT ACCRUATE?

36.A. No. Although Decision No. 61677 adopts truncation of the stranded cost calculation at the end of the five year transition period in its Option No. 1, APS has carried out the calculation to 2016, which is when APS predicts very significant unit retirements. Jurisdictional stranded costs would increase to $574 million. This information was likewise provided Staff, and thus I can not understand why anyone would attempt to give the Commission the false impression that APS had somehow "gamed" its calculation of the $533 million stranded cost figure cited in the Agreement.

IV. <u>TRANSFER OF COMPETITIVE ASSETS</u>

37.Q. WHY IS IT REASONABLE TO TRANSFER APS' GENERATING ASSETS TO THE CONTEMPLATED PINNWEST SUBSIDIARY AT BOOK VALUE?

37.A. Stranded costs are, by definition, the difference between book value and market value. That's not just my definition, but the definition of stranded costs used in the Commission's Electric Competition Rules. That difference is either a positive number (stranded costs) or negative (stranded benefits). Reflecting market price in the transfer would double-count either the losses (stranded costs) or the profits (stranded benefits). It's just that simple. I realize that not every party agrees with the Company's calculation of stranded costs, but that is a different issue from that of whether the same figure should be counted twice. I would hope that all of us could agree that such double-counting is wrong.

38.Q. IS THERE SOME GENERALLY-ACCEPTED ACCOUNTING RULE THAT SUCH A TRANSFER OF GENERATING PLANTS SHOULD BE AT THE LOWER OF MARKET OR BOOK VALUE AS WAS SUGGESTED BY ESP WITNESS OGLESBY AT PAGE 5 OF HIS TESTIMONY?

38.A. Not that I ever heard of. In fact, generally accepted accounting rules specifically mandate the transfer of assets between entities under common control (in this case, PinnWest) at book value. Mr. Ogelsby's proposal of transferring the above-book generating assets at that higher price while transferring below-book assets such as Palo

Verde at book value not only double-counts the above-book assets (which have already been considered in reducing APS' estimate of stranded costs to the $533 million figure cited both in the Agreement and in the Company's 1998 stranded cost filing with the Commission), it ignores the below-book losses attributable to the other individual generating supply assets. This is not only blatantly "unfair" (to again quote the Commission's own words), it does not meet the Commission's requirement in the Electric Competition Rules for measuring "net stranded costs" [emphasis supplied] because there would be no netting of above and below-market assets.

39.Q. HAS MR. OGELSBY PREVIOUSLY PROPOSED THIS TREATMENT OF GENERATING ASSETS IN ARIZONA?

39.A. No. Mr. Ogelsby made no mention of this in his previous testimony during the generic stranded cost proceeding. Similarly, although Mr. Ogelsby did not file testimony in either the SRP stranded cost proceeding or on the prior 1998 APS/Staff settlement agreement, PG&E Energy Services did submit testimony of other witnesses in the latter proceeding. Not surprisingly, the market generation or "shopping credit" was not high enough in that settlement to suit PG&E Energy Services, but it took no issue with the transfer of APS generating units to an affiliate at book value nor with any of the regulatory waivers sought by the Company.

40.Q. WAS SUCH A TRANSFER AT BOOK VALUE AN EXPRESS PART OF THE EARLIER 1998 SETTLEMENT?

40.A. Yes.

41.Q. DOES THE VALUE AT WHICH THE GENERATING ASSETS ARE TRANSFERRED TO AN APS AFFILIATE AFFECT THE PRICE IT CAN CHARGE FOR ELECTRICITY?

41.A. Of course not. This idea is a hold-over from cost-of-service regulation. Market price is determined by the law of supply and demand. Demand is independent of the individual supplier's costs. Only variable costs affect supply. In the short-run, only some portions of O&M are variable. In the long-run, marginal capital costs are also variable. However, sunk costs such as the fixed costs of existing generating units play no part in determining market price. If they did, the fact that the market value of APS generating units is less than book value would give the transferee a marketing advantage as compared to a transfer at book value, as called for in the Agreement.

42.Q. HAS COMMISSION STAFF SUPPORTED THIS TRANSFER AT BOOK VALUE?

42.A. Yes. Both in the withdrawn 1998 settlement agreement and in the current proceeding, this has not been as issue with Commission Staff.

43.Q. SEVERAL WITNESSES HAVE CRITICIZED THE COMPANY FOR NOT MORE CLEARLY INDICATING WHAT ASSETS WILL BE TRANSFERRED TO THE GENERATING AFFILIATE. CAN YOU BE MORE SPECIFIC?

43.A. The Company can not come up with the definitive list of assets to be transferred until both this Agreement is approved and the Electric Competition Rules are finalized. But with those caveats, I have attached as Attachment JED-6R a list and description of the assets APS presently intends to transfer to one or more new affiliates.

APS has already been authorized to transfer some limited assets to APSES per Commission Decision No. 61668 (April 21, 1999). It does not presently anticipate any further transfers to APSES. Similarly, APS has no present plans to engage in competitive metering for non-residential customers, meter reading, or billing. Thus, APS would not be transferring any assets related to these services to an affiliate. It will instead retain them for Standard Offer service (which by Commission rule is not a competitive service) and for the metering of direct access residential customers (which APS is permitted to do without divestiture under the proposed Electric Competition Rules).

44.Q. WILL APS BE PROVIDING "COMPETITIVE ELECTRIC SERVICES," AS DEFINED BY THE COMMISSION, PRIOR TO DIVESTITURE OF THE ABOVE-DESCRIBED ASSETS?

44.A. No, excepting the residential metering discussed in response to the previous question. The Electric Competition Rules would prohibit such competitive activities by APS, and the Agreement does not change that fact.

45.Q. WHY NOT SIMPLY DIVEST YOUR GENERATING PLANTS TO A THIRD PARTY?

45.A. Having never persuaded either the Commission or the legislature that mandatory divestiture was appropriate, I would have thought this "dead horse" ESP issue had long since been put to rest. As with code of conduct and other issues, the ESP Witnesses have injected old arguments over the Electric Competition Rules into this proceeding. Suffice it to say that none of these witnesses have addressed the very issues that led the Commission to reject their previous pleas for divestiture:

a. lack of authority to mandate or coerce divestiture;

b. cost of third-party divestiture;

c. the inability to sell the Company's interest in Palo Verde at any price (the NRC has never approved the transfer of the operator's interest in a nuclear power plant to a non-affiliated entity); and,

d. concerns related to jointly-owned units such as Palo Verde, Four Corners, Navajo or jointly-owned plant facilities such as Cholla (participant rights to extended prior notice, rights of first refusal, etc.).

One new suggestion that did surface in this proceeding is Mr. Ogelsby's proposal to sell-off everything but Palo Verde. The thought of a utility distribution company with a nuclear power plant as its sole generation asset is almost too horrible to imagine. When they did this in Great Britain, they realized that only the government could afford such an undiversified portfolio of generation.

V. AISA/ISO TRANSMISSION ISSUES

46.Q. IS THE AISA ADDRESSING ALL OF THE TRANSMISSION ISSUES RAISED BY ENRON AND THE OTHER PARTIES?

46.A. Yes. Through the AISA, of which Enron is not only a member, but also part of its governing body, "must-run" and other protocols are being developed. Enron was a very active participant in formulating and even drafting these AISA protocols. One of the 10 completed protocols specifically addresses "must-run" by requiring "must-run" generators to sell to the AISA at a pre-determined price based on incremental cost. In addition, all schedules will be posted on both the control area operators' and the AISA OASIS. Two days prior to schedule implementation, Scheduling Coordinator schedules will be similarly posted. If any Scheduling Coordinator for an ESP (or for a UDC, for that matter) believes that the control area operator is acting improperly, it can challenge the operator through the AISA Director, who must resolve the dispute prior to schedule implementation.

47.Q. ARE MR. DELANEY'S STATEMENTS ABOUT OASIS, THE TOTAL TRANSFER CALCULATION, AND AVAILABLE TRANSFER CAPABILITY, AS SET FORTH AT PAGES 11-16 OF HIS TESTIMONY, ACCURATE?

47.A. Absolutely not. Mr. Delaney's allegations and insinuations are completely false and inaccurate. I realize that the AISA is basically a FERC issue, with FERC having to approve the operating protocols and "must-run" pricing provisions, but Mr. Delaney does not help the Commission's understanding of the AISA process by these kinds of misrepresentations.

48.Q. WHAT ABOUT MR. DELANEY'S EXPRESSED CONCERNS ABOUT ENERGY IMBALANCE SERVICE?

48.A. I could not believe my eyes when I read his comments. The AISA energy imbalance protocol was developed by a sub-group of AISA members chaired by Enron! The bottom line as to this and the other

AISA issues raised by Enron is simple. The AISA is made up of a large number of highly diverse groups - power marketers and other load-serving ESPs such as Enron, transmission-owning utilities (both investor-owned and public power), transmission-dependent utilities, distribution cooperatives, G&T cooperatives, municipalities, etc. Not surprisingly given the multitude of represented interests, no one got everything they wanted in the development of the operating protocols. Just as obviously, the perceived "losers" in the "give and take" process of devising such protocols at AISA will, no doubt, try to get a second "bite at the apple" when the protocols are filed with FERC. However, to at this time interject this Commission and, even worse, this Settlement Agreement into that process is, quite frankly, irresponsible and only seeks to confuse the Commission with hyper-technical "red herrings."

VI. <u>REQUESTED WAIVERS AND EWG STATUS</u>

49.Q. WHY DID APS SEEK VARIOUS WAIVERS OF THE COMMISSION'S GENERAL AFFILIATE RULES (A.A.C. R14-2-801, *ET SEQ.*), AN EXTENSION OF THE TIME TO DIVEST UNDER RULE 1615, AND THE WHOLE OR PARTIAL RESCISION OF CERTAIN OLD COMMISSION ORDERS?

49.A. The delay in divesting APS generation to an affiliate was, to begin with, strictly a matter of cost. Provisions in the Palo Verde and West Phoenix sale/leaseback agreements and in our first mortgage bond indenture would have made divestiture in 2000 or even 2001 much more expensive. As I look at the situation today, I very much doubt we could physically accomplish a divestiture by year-end 2000, as was originally contemplated by the Electric Competition Rules. For example, over 60 agreements are involved in the transfer of these assets. Most require some manor of formal consent by the other party. For facilities located on Indian land, both tribal and Interior Department consents are necessary. NRC approval for the Palo Verde license transfer alone is expected to take 6 months. Air, water, and waste permits must also be transferred. Our "best case" estimate is 9-12 months for that. I could go on and on, but I think I've made my point. Thus, the delay takes on certain pragmatic considerations in addition to cost.

The affiliate rule waivers would largely impact only the Company's competitive affiliates, electric and otherwise. (APS has affiliates such as SunCor Development Company that have nothing to do with the electric business and never have.) These, along with the whole or partial recision of certain previous Commission orders are described in Exhibit D to the Settlement Agreement. As can be readily seen by just reading Exhibit D, these regulations would impede the competitive electric market as well as other competitive lines of business that PinnWest may seek to develop. The rescinded or amended orders, to which I do not believe any witness has taken issue, are equally relics of the past.

50.Q. WOULD YOU EXPLAIN EACH OF REQUESTED WAIVERS OF THE AFFILIATE RULES?

50.A. Rule 806 specifically authorizes the Commission to grant these waivers. It is also my understanding that such waivers are routinely granted competitive telecommunications entities such as MCI, AT&T, etc. The requested waivers or modifications include:

a. Rule 803 excepting as a proposed reorganization would involve APS. Absent this waiver, PinnWest's decision to sell SunCor or to buy a chain of pizza shops would arguably fall under this provision, which requires extensive Commission notice and review of such a "reorganization."

b. Rule 801(5), which embodies the definition of reorganization discussed above.

c. Rule 804 (A), which deals with access by the Commission to an affiliate's books and records – a subject that will be addressed in the interim and final code of conduct to which I have previously testified.

d. Rule 805 (A)(2) deals only with the business activities of APS' affiliates other than with APS. It is clearly not consistent with these affiliate's non-jurisdictional status to require this information, which has been waived for any competitive telecommunications provider that has requested it.

e. Rule 805 (A) (6) governs allocations of cost from PinnWest to affiliates. To the extent this applies to APS, it is covered by the code of conduct. PinnWest allocations to non-regulated enterprises is of no legitimate concern of the Commission.

f. Rule 805 (A) (9) – (11) refer to certain documents (contracts. leases, etc.) relating to transactions between APS and affiliates. This provision also overlaps with code of conduct issues. APS certainly does not object to providing such documents if and when it is seeking to include these costs in or exclude revenues from the determination of regulated rates, but does not believe they should be routinely filed with the Commission.

51.Q. WHAT ABOUT THE STATUTORY WAIVERS REQUESTED IN THE AGREEMENT?

51.A. A.R.S. § 40-202 specifically authorizes the Commission to waive the statutes cited in Section 4.3 of the Agreement. A.R.S. § 40-374 was omitted because of an oversight. No witness has argued that these provisions should apply to competitive services. In fact, at least one ESP (Phaser) has also sought exemption from at least some of these provisions. Staff witness Williamson says that there should be a generic investigation of this issue as regards all ESPs rather than a "piecemeal" approach. I have no particular objection to this as long as at least interim waivers are granted to APS and its affiliates pending completion of such a generic investigation. Unfortunately, generic dockets have a way of dragging on and on, and the uncertainty concerning these statutes' application in the meantime is not an acceptable situation.

52.Q. DOES APS OBJECT TO AN ESP SUCH AS ENRON, COMMONWEALTH OR PG&E ENERGY SERVICES RECEIVING SIMILAR WAIVERS?

52.A. Absolutely not. But APS should not be punished simply because it was the first to ask the Commission to use this provision of H.B. 2663.

53.Q. WHY SHOULD THE COMMISSION MAKE THE REQUISITE FINDINGS FOR THE COMPANY'S FUTURE GENERATING AFFILIATE TO QUALIFY AS AN EWG?

53.A. First of all, let's be clear that the "exempt" part of EWG means exempt from PUHCA – not that the generator is exempt from FERC regulation. An EWG may also apply to FERC for "market-based" rate authority, but that is a different issue. Second, the party that is actually "exempt" from PUHCA is PinnWest.

PinnWest is presently an exempt holding company under PUHCA. That exemption is based on the fact that PinnWest operates a single utility operating in a single state and subject to state regulation. Exemption from PUHCA is important because it frees PinnWest from onerous filing, reporting, and prior (SEC) approval provisions in PUHCA. Most public utility holding companies are exempt and strive mightily to preserve their exempt status.

If APS is split into retail functions regulated by the Commission and wholesale functions regulated by FERC, as is required in the proposed Electric Competition Rules, this addition of Genco as a new PinnWest subsidiary will threaten PinnWest's exempt status unless the generating company is determined to be an EWG. PUHCA requires the relevant state regulatory commission to make specific findings, much as A.R.S. § 40-301, *et seq.*, requires the Commission to make specific findings in approving an issuance of securities by APS. It is the Commission's Electric Competition Rules that have created this situation, and therefore the Commission needs to help preserve the *status quo*. It will also speed along the process of divestiture itself since this will be one additional thing that will not have to be done by year-end 2002.

VII. CONCLUSION

54.Q. IN CONCLUSION, WOULD YOU SUMMARIZE YOUR MAJOR POINTS ON REBUTTAL?

54.A. In my Direct Testimony, I warned the Commission against those who would kill this Agreement through the "death by a thousand cuts." Not only have we seen this, but several parties have tried to cut the very heart out of a settlement approved by representatives of virtually all our customers. Some look eagerly back to the days of two-year rate proceedings costing millions of dollars. Others would have you promote their business interests by punishing either the Company or its Standard Offer customers or both. I ask the Commission to reject their arguments and approve this Settlement Agreement. Is the Agreement perfect from my perspective – no. But it is fair. It is comprehensive. It has widespread support from the people the Commission is sworn to protect – the average utility customer of APS.

56.Q. DOES THIS CONCLUDE YOUR DIRECT WRITTEN REBUTTAL TESTIMONY?

56.A. Yes.

Attachment JED-1R

ESP MARGIN ANALYSIS

ESP Costs:	**Market Estimate: (mils/kwh)**
Load Weighted Wholesale Energy	25.7[1]
Transmission	3.4
Losses	1.8
Ancillary Services	1.1
Marketing	3.0
Risk Premia	2.2
Total ESP Costs	**37.2[2]**
"Shopping Credit":	**45.9[3]**
Margin:	**8.7**

[1] Uses Class (40-200kw) load factor

[2] Does not include cancellation credit, which should approximate 4.5 times the Risk Premia. Inclusion would decrease ESP costs (increase margins) by another 10 mils per kWh.

[3] Calculated as difference between Standard Offer billing and Direct Access billing for 40-200 kw customers at 41% individual load factors under Settlement Proposed Rates.

GUEST EDITORIAL *Alfred E. Kahn*

Bribing Customers to Leave and Calling It "Competition"

The large number of states that have decided to open their retail electricity markets to competition are now grappling with the task of ensuring that challengers of the franchised local utility company monopolies have a fair opportunity to compete.

The transition is complicated by the recognition by most of them of an obligation to offer the utility companies an opportunity to recover most or all of their "stranded" costs—investment costs historically incurred that competition might make it impossible for them to recover. I will not discuss here the merits of that commitment (See, however, my *Who Should Pay for Power Plant Duds?* WALL ST. J., Aug. 15, 1985.)

but it necessarily implies that customers not be able to escape their share of those costs by deserting their historical suppliers.

An additional complication is created by the understandable unwillingness of regulatory commissions to expose consumers to the risks of a possibly quite volatile unregulated wholesale price, to which the retail margin (still regulated because local distribution remains a monopoly) would be added. They have therefore insisted also on the utility companies freezing their retail prices (rather than just the retail margins).

This arrangement has therefore confronted regulators, in state after state, with the question of what credit or discount retail customers should receive from that frozen price of their utility supplier when they shift their patronage to a competitor—obviously an important determinant of the ability of those competitors to induce them to do so.

It is an elementary economic proposition that the way to ensure that production is carried out efficiently—i.e., with the minimum expenditure of society's scarce resources—is to distribute responsibility for production among suppliers on the basis of their incremental or avoidable costs. That is what competition tends to do. Following this reasoning, the efficient "shopping credit" for customers who desert their utility company suppliers should therefore clearly be whatever (incremental) costs each supplier would save or avoid because of their departure—the wholesale price of the power itself along with some, probably small, costs of retailing. That would be the margin within which the competing retail marketer would have to operate if it

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Some of the views expressed in this article were previously presented in regulatory proceedings in testimony by Mr. Kahn on behalf of two electric utility companies.

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were to compete effectively, so long as it offered the same services as the utility company. Clearly, any competitors with incremental costs higher than those of the incumbent would be unable to offer buyers a price sufficiently low to induce them to shift. Nor should they be, since their taking over the function of serving consumers would impose costs on society greater than the costs it would save by consumers shifting to them.

It may well be—indeed, consumer inertia makes it highly likely—that an inducement to customers to shift equal only to the costs that their historical suppliers would save would not create much of an opportunity for competitors, so even one with incremental costs no higher than those of the utility would probably still be unable to entice many customers away. If so, however, that would be because the mere resale of electric power, purchasable by incumbents and challengers alike from regional power pools at a competitive wholesale price, offers comparatively few opportunities for creative or socially useful competition, so long as the retail prices of the incumbent are frozen. The real opportunities for aggressive and innovative competitors selling electric power alone will emerge when the utility price caps come off. Consumers will be looking for protection from the risks of what could be highly volatile wholesale markets and, until then, in bundling sales of electric power with other energy-related services—audits, conservation, climate control, load management and the supply and servicing of energy-using equipment.

To the extent that a competitor can offer additional services of this kind, which customers value sufficiently to pay the additional cost of providing them, it can of course charge them more than the credit they would receive from the utility company upon their departure and thereby compete effectively. In either case, it would be consumers

who would be making the unbiased choices, depending upon whether those additional services were or were not worth the additional cost.

Unfortunately, regulators are always under strong political pressures to produce visible results. Confronted with a public demand for "competition," they are strongly tempted to produce some live competitors, regardless of their relative efficiency or the relative attractiveness of the bundled services they offer. The "shopping credit" given to departing customers presents an easy opportunity to succumb to that temptation.

The Pennsylvania Commission, for example, has intentionally required electric utility companies to offer a credit much greater than the costs they avoid when they lose a customer—some 50 percent higher than the California and Massachusetts commissions have prescribed. One of its commissioners has boasted that as a result more customers in Pennsylvania will have shifted to a new supplier than in the entire remainder of the country. He obviously believes he has stumbled upon the secret of perpetual motion: "Bigger shopping credits create greater consumer savings," he says, vacuously. The clear lesson for other states is to prescribe shopping credits twice as large as Pennsylvania's and in this way seize the leadership in the race to stimulate competition and generate such "consumer benefits."

The economist has the unpleasant job of reminding people that somebody has to pay for apparently free lunches. The Pennsylvania commissioner clearly believes that it will be the utility company: The more it pays the customers it loses than the costs it saves by their leaving, the less it will have left over to recover its stranded costs. That is in fact the case when the shopping credit is determined after the utility rates have been frozen.

That reasoning is nevertheless either naïve or disingenuous. If a state decides to permit a utility company recovery of something less than 100 percent of its stranded costs, the obvious and logical way—the only fair way—to do so is to order it to reduce rates to all its customers. If, having frozen rates at a level it considers sufficient to permit recovery of that predetermined proportion of the costs likely to be stranded, a commission then introduces a shopping credit with a built-in subsidy, it is clearly altering the terms of the stranded cost bargain with the utility company. In fact the Pennsylvania decision contemplates the possibility of the utility company being permitted to raise its rates to all customers in the future, if the inflated shopping credit results in stranded cost recovery less than the amounts previously agreed upon. In any event, to deny the company full recovery not in the form of an overall rate reduction, but by ordering a shopping credit greater than its avoided costs, is to benefit the customers who leave their historical supplier at the expense of the ones who remain. The bigger the benefit to the one group, the greater the sacrifice by the other. That's what we call economics. A system under which the only way to qualify for the saving is to shift patronage subsidizes competitors, not consumers as a group.

Of course, there is always the "infant industry" case for such special protection or subsidization of would-be entrants who would not otherwise be able to compete. The consensus view of economists about this possible biasing of competition would place a very heavy burden of proof on its proponents—a convincing demonstration that the asserted advantages of the incumbent are likely to be so overwhelming as to make competitive challenge impossible; and that the cost to consumers of such preferences are outweighed by the prospective benefits of the additional competition that they protect.

My own assessment has two parts. First, I am highly skeptical that the potential benefits of competition in the mere retailing of electric power as such are sufficiently attractive to justify deliberately subsidizing it by imposing a tax on the customers who remain with their historical supplier—and especially while the utility's rates are frozen. It is competition among *generators* in the wholesale market that promises the largest benefits by wringing inefficiencies and monopoly elements out of the price of the power itself, and forcing suppliers to bear the costs of investments that turn out badly, rather than passing them on to captive customers.

Second, as I have already pointed out, the real opportunity for aggressive and innovative competition at the retail level is in the offering of energy services generally, not just power alone. Here, however, there simply is no case for special protection or subsidy of competitors. In the offer of many of these services, it is the electric utility company that is the entrant. In the market for energy conservation services, it would have to compete with local builders and contractors in heating, ventilating, and air conditioning, with companies like Sears Roebuck, Montgomery Ward, General Electric, and Honeywell, which already provide such equipment and services in hundreds of localities and enjoy the advantages of incumbency and brand recognition.

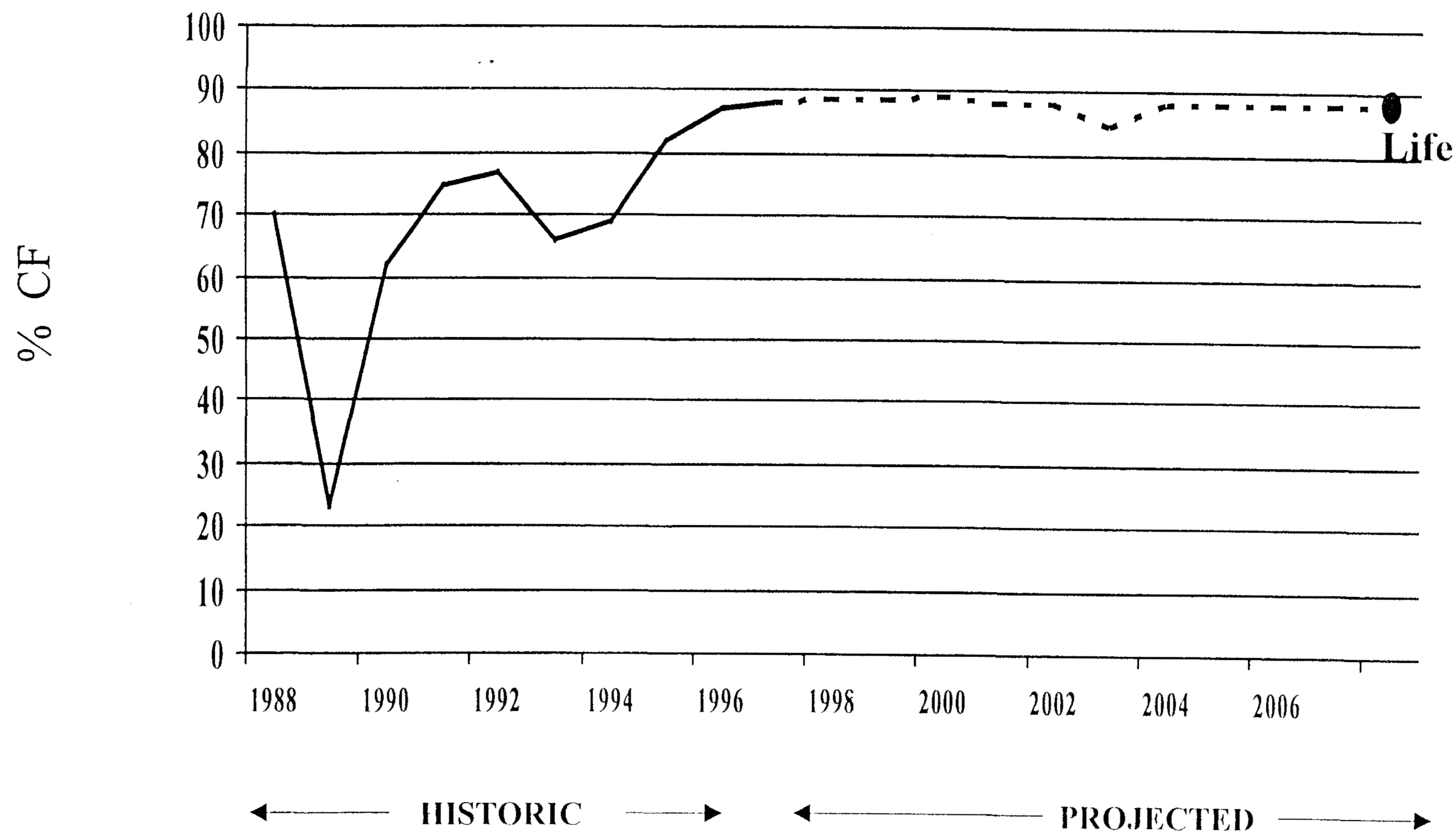
Playing with artificial competitive handicapping is playing with a tar baby. Once commissions decide to provide subsidies to competitors they will have to revisit them perennially, trying to decide how much is enough and when they should end—an intensely political process and a very odd kind of deregulation indeed. ■

Of course, there is always the "infant industry" case for special protection.

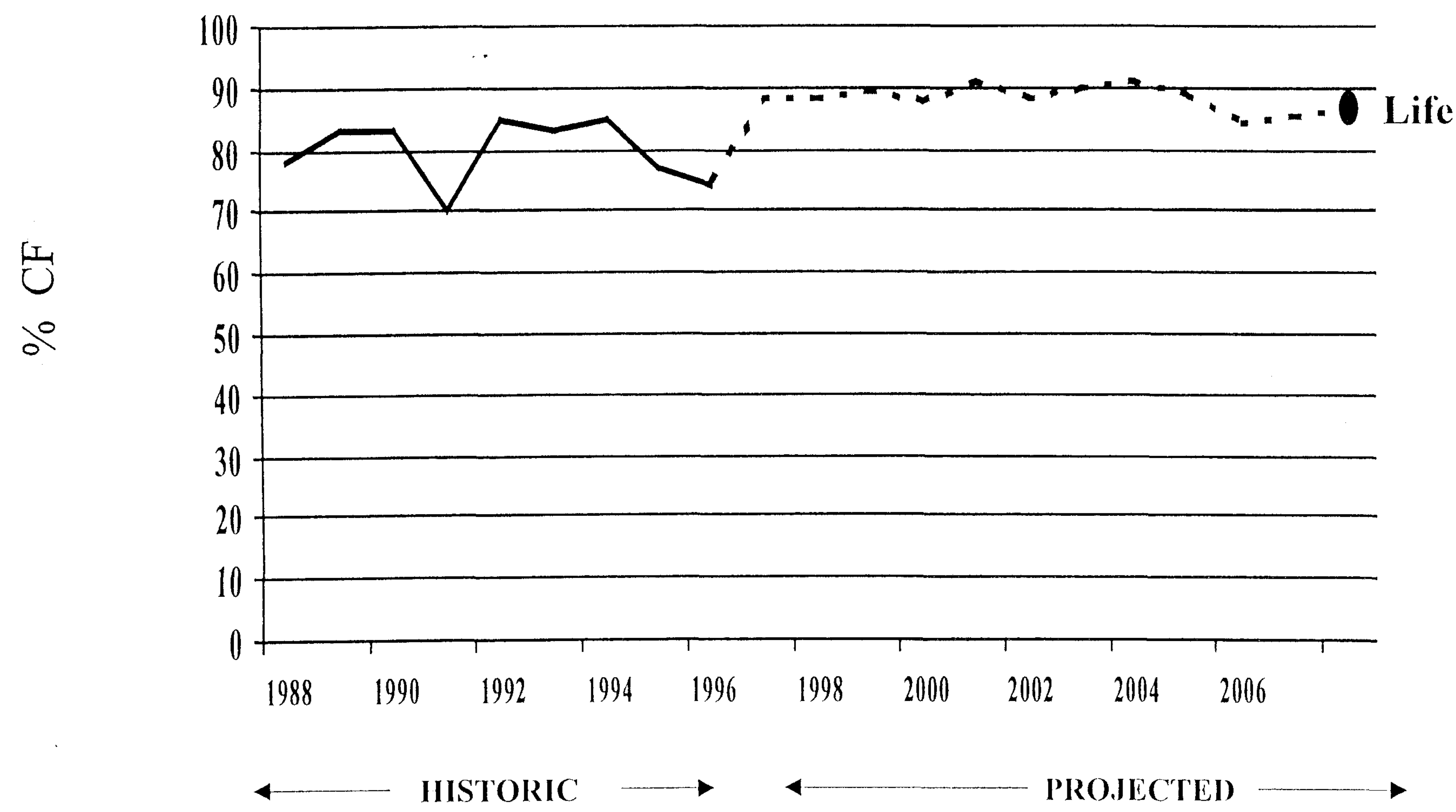
Market Price Forecast Comparison
($/MWH)

Year	APS	SRP	EPIS	EIA	CERA Unif.	CERA Balk.
1999	26.3	24.4		23.4	21.5	23.6
2000	25.7	24.6	20.1	25.0	24.3	26.2
2001	27.0	24.9	22.4	26.3	26.6	29.6
2002	28.3	25.3	24.2	27.6	29.3	28.9
2003	30.4	25.7	25.5	29.5	29.4	29.0
2004	32.2	26.3	28.4	31.4	29.9	29.1
2005	34.7	26.9	30.1	32.8	30.3	30.0
2006	35.4	27.6	32.0	33.1	31.4	30.0
2007	38.0	28.3	33.5	34.8	32.3	30.9
2008	39.5	28.9	34.6	35.5	34.4	32.2
2009	40.4	29.6	35.2	35.8	34.6	33.4
2010	40.8	30.3	37.9	36.2	34.9	34.8
2011	42.0	31.1	38.2	36.9	35.3	35.9
2012	43.2	31.8	39.0	38.4	36.0	36.6
2013	43.2	32.6	41.1	39.2	36.3	37.3
2014	43.9	33.4	41.9	39.6	36.5	37.8
2015	43.0	34.2	42.5	39.6	36.8	39.5

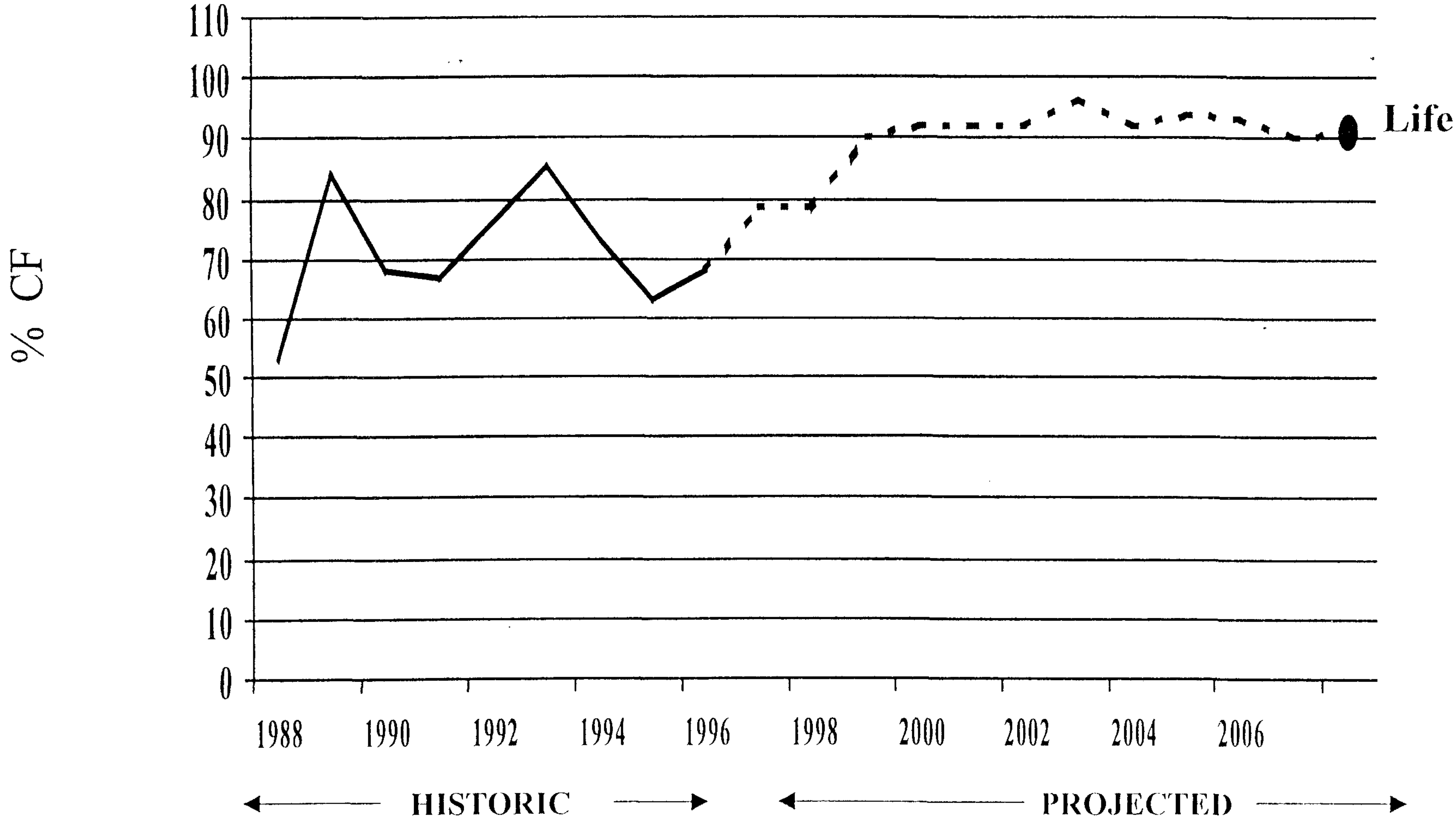
HISTORIC AND PROJECTED CAPACITY FACTORS (PALO VERDE)



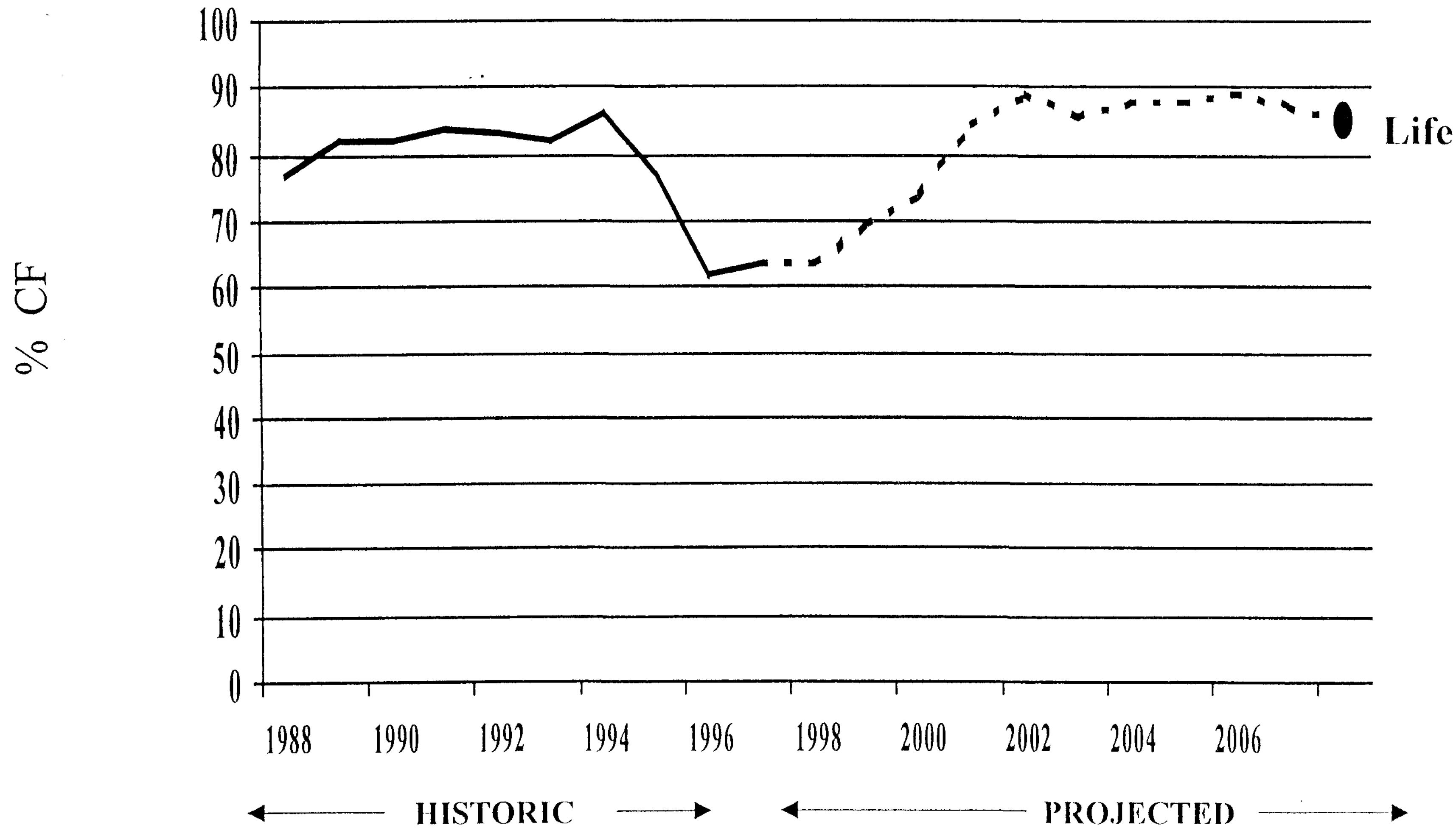
HISTORIC AND PROJECTED CAPACITY FACTORS (FOUR CORNERS)



HISTORIC AND PROJECTED CAPACITY FACTORS (CHOLLA)



HISTORIC AND PROJECTED CAPACITY FACTORS (NAVAJO)



Calculated Stranded Cost Based on Industry Market Price Forecast
1999-2004 CPW in Millions of Dollars

					CERA	
	APS	SRP	EPIS	EIA	Unif.	Balk.
1999-2004	533	774	845	593	594	546

Description of assets to transfer to New Generation Company

Four Corners Generating Station

Steam Generating Units 1, 2 and 3

Boilers, turbines, generators, coal pulverizers, flue gas scrubbers, flue gas chimneys, lime silos, coal belts, natural gas lines, land leases, ash ponds, evaporation ponds, emergency coal pile, circulating water pumps, maintenance buildings, materials and supplies inventory and other related facilities.

APS share of Steam Generating Units 4 and 5

Boilers, turbines, generators, coal pulverizers, bag houses, SO2 absorber towers, flue gas chimneys, lime silos, ash loading silos, circulating water pumps, land leases, maintenance buildings, auxiliary boiler, natural gas lines, coal belts, materials and supplies inventory and other related facilities.

APS share of Common Facilities

Coal sampler, water rights, materials and supplies inventory, administration building, warehouse buildings and yards, brine concentrator, condensate water demineralizer, cafeteria building, river pump station, potable water building, vehicle maintenance garage, vehicles, roads, land leases, parking lots, scales, fencing and other related facilities.

Rights and agreements

Coal purchase agreements, land leases, water rights, lime purchase agreements, SO2 allowances, natural gas agreements and all other rights and agreements required to operate the plant.

Cholla Generating Station

Steam Generating Units 1, 2, and 3

Boilers, turbines, generators, coal pulverizers, coal silos, flue gas scrubbers, flue gas chimneys, natural gas lines, land and land leases, circulating water pumps, maintenance building, cooling tower, lake and other related facilities.

APS share of common facilities

Coal inventory, materials and supplies inventory, well fields, warehouse, gas and oil lines, oil storage tank, coal belts, coal crusher towers, railroad, ash ponds, lime silos, evaporation ponds, planning and maintenance buildings, administration buildings, roads, parking lots, land and land rights, locomotives, vehicles, vehicle maintenance garage, fencing and other related facilities

Rights and agreements

Coal purchase agreements, railroad freight agreements, water rights, lime purchase agreements, SO2 allowances, natural gas agreements and all other rights and agreements required to operate the plant.

Navajo Generating Station

APS share of Steam Generating Units 1, 2 and 3 and other facilities

Boilers, turbines, generators, coal pulverizers, coal silos, flue gas scrubbers, flue gas chimneys, materials and supplies inventory, railroad, locomotives and rail cars, coal inventory, roads, fencing, warehouses, administration buildings, maintenance buildings, cooling towers, water rights, land leases, fencing, vehicles and power operated equipment and other related facilities.

Rights and agreements

Coal purchase agreements, land leases, water rights, lime purchase agreements, SO2 allowances, natural gas agreements and all other rights and agreements required to operate the plant.

Ocotillo Generating Station

Steam Generating Units 1 and 2
Boilers, turbines, generators, cooling towers, water wells and other related facilities.

Combustion Turbines 1 and 2
Combustion engine, generator and other related facilities.

Common Facilities
Land and land rights, fuel lines, maintenance buildings, administration buildings, roads, fences, vehicles and power operated equipment, storage tanks, warehouse and other related facilities.

Saguaro Generating Station

Steam Generating Units 1 and 2
Boilers, turbines, generators, cooling towers, water wells and other related facilities.

Combustion Turbines 1 and 2
Combustion engine, generator and other related facilities.

Common Facilities
Land and land rights, fuel lines, maintenance buildings, administration buildings, roads, fences, vehicles and power operated equipment, storage tanks, warehouse and other related facilities.

Yucca Combustion Turbines 1, 2, 3 and 4
Combustion engine, generator, administration building, storage and maintenance buildings, land and land rights including excess land, vehicles and power operated equipment, storage tanks, fuel lines, storage buildings, roads, fences and other related facilities.

Douglas Combustion Turbine
Combustion engine, generator, land, fencing, fuel lines and storage facilities, and other related facilities.

West Phoenix Generating Station

Steam Generating Units 4, 5 and 6
Boilers, turbines, generators, buildings and other related facilities

Combustion Turbines 1 and 2
Combustion engine, generator and other related facilities

Combined Cycle Units 1, 2 and 3
Combustion engine, generator, steam boiler and other related facilities.

Common facilities
Land and land rights, fencing, oil tanks, administration building, maintenance buildings, gas and oil lines, roads, wells, vehicles and power operated equipment and other related facilities.

Palo Verde Generating Station

Steam Generating Units 1, 2 and 3
Nuclear reactor, steam generator, turbine, generator, cooling towers, water reclamation facility, effluent water line, cooling ponds, evaporation ponds, maintenance buildings, warehouse,

administration buildings, fire protection building, low level radiological waste building, vehicle maintenance garage, containment building, emergency warning systems, fences, roads, parking lots, land, auxiliary generators, spent fuel pool, fuel and chemical tanks, vehicles and power operated equipment, security buildings, visitor information center, fuel building, railroad, technical support center and other related facilities.

Rights and agreements

Effluent water agreement, pipeline rights of way, fuel agreements, NRC operating license, DOE spent fuel disposal agreement, emergency evacuation agreements and all other rights and agreements to operate the plant.

Common to all generating stations

Employees, employee salaries and benefits, tools and equipment, vehicles and power operated equipment, miscellaneous storage facilities and tanks, office equipment and furniture, computer equipment, communication equipment, meters, piping, wiring, lighting, HVAC, land owned and leased relating to the generation business, etc.

Current assets and current liabilities as well as any other long-term assets related to the generation business will be determined as of the date of the transfers.

BEFORE THE

ARIZONA CORPORATION COMMISSION

REBUTTAL 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

July 12, 1999

REBUTTAL TESTIMONY OF ALAN PROPPER

Q. WHAT IS YOUR NAME?

A. My name is Alan Propper.

Q. ARE YOU THE SAME ALAN PROPPER WHO PRESENTED DIRECT TESTIMONY ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (APS OR COMPANY) IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF THIS REBUTTAL TESTIMONY?

A. The purpose of this testimony is to provide comments and rebuttal on certain pricing related aspects of the testimonies of Staff Witness Williamson and Staff Consultant Smith, Enron Corporation's Witness Kingerski, PG&E Energy Services Corporation's Witness Oglesby, and Commonwealth Energy Corporation's Witness Bloom.

Q. ARE YOU SPONSORING ANY ATTACHMENTS IN CONJUNCTION WITH THIS TESTIMONY?

A. Yes. Attachment AP-1R is APS's proposed format for the second page of a Standard Offer Service customer's bill.

Q. WHAT COMMENTS DO YOU WISH TO MAKE REGARDING STAFF WITNESS WILLIAMSON'S TESTIMONY?

A. Mr. Williamson proffers the view that the pricing provisions in the Settlement Agreement could be readily altered to accommodate Staff Consultant Smith's after-the-fact inputs. He seems to miss or ignore the point that these provisions have been the result of months of negotiations among the parties, and that the resulting rate provisions of the Settlement Agreement satisfy a set of guidelines and parameters that were agreed to by the parties. These guidelines and parameters encompassed overall revenue requirements, relative Standard Offer and Direct Access class rate levels and rate designs, cost allocation and functionalization, annual rate reductions, Stranded Cost recovery through explicitly negotiated annual and class Competitive Transition Charges (CTC), patterning for the recovery of costs associated with Regulatory Assets, credits and charges for certain Electric Service Provider (ESP) provided services, etc. The result of these complex and lengthy negotiations are pricing provisions that fit together like a puzzle and are not conducive to basic conceptual changes and general after-the-fact tweaking and tinkering of the type Mr. Williamson recommends to the Arizona Corporation Commission (ACC).

Q. WOULD YOU DISCUSS THE SPECIFIC AREAS IN WHICH YOU DISAGREE WITH MR. WILLIAMSON'S RECOMMENDED CHANGES?

A. Mr. Williamson's summary of recommendations were detailed in the testimony of Staff Consultant Smith. Ms. Smith's first proposed change to the Settlement Agreement concerns APS's use of avoided or decremental costs in the calculation of credits for those customers using the services of an ESP for their Metering, Meter Reading, and Billing requirements. Avoided costs were used in these calculations because most embedded costs are not eliminated for APS when a customer chooses an ESP for these services. This fact was discussed in some length in my Direct Testimony. Ms. Smith prefers the use of the higher embedded cost based credits. The use of embedded costs would unfairly penalize APS unless the $350 million Stranded Cost provision is correspondingly increased and/or the level of Standard Offer Service rate decreases are reduced to reflect Ms. Smith's preference.

Ms. Smith seems to have two bases for her recommendation to revise the Settlement Agreement to incorporate embedded cost credits. The first is that the previously withdrawn "1998 Settlement" used embedded credits for revenue cycle services. The "1998 Settlement", for those of us who were not part of the APS deregulation history, also included different Stranded Cost provisions, lower Standard Offer Service rate reductions, a swap of Tucson Electric Power Generation assets with APS Transmission assets, and other provisions unique to that historical and never to be implemented settlement. As her second basis, Ms. Smith states that using avoided costs in developing the credits is anti-competitive since customers choosing an ESP to provide these services will end up continuing to pay APS for some portion of these costs. This belief appears to be shared by Enron Witness Kingerski. What seems to have been forgotten by Ms. Smith and Mr. Kingerski is that a customer choosing to have an ESP provide these services is still responsible for the costs he caused and continues to cause APS to incur. To ignore the difference between embedded and avoided costs would create a revenue shortfall for APS and a shift of revenue requirements to other customers that I believe would be unfair. In addition, Ms. Smith's observation that the use of avoided cost will make it more difficult for an ESP to provide these services at a competitive rate is not a reason for APS or its Standard Offer Service customers to subsidize an ESP's business development costs. At any rate, such a change would cause a reduction to APS's projected revenues and therefore would require altering the tariff as agreed to by the parties and proposed in the Settlement Agreement. It should be noted that in California the issue of avoided cost versus embedded cost for Metering, Meter Reading, and Billing credits was thoroughly reviewed and resulted in that state's decision to use an avoided cost approach as presented in this Settlement Agreement. California Public Utilities Commission ("CPUC") rejected the assertions of Enron, Cellnet, and other metering providers for an embedded cost treatment of metering, meter reading and billing services, provided by competitors. The CPUC described its policy objective: "Here, as in previous cases, we must balance competing objectives to promote competition, provided the utilities with a reasonable opportunity to recover costs and protect customers from unfair pricing", Decision 98-09-070 (California P.U.C. September 17, 1998), at 10. Then, in rejecting Enron's analysis for embedded cost treatment, the CPUC wrote: "For example, Enron proposes that revenue cycle services credits reflect depreciation and other capital costs that are "sunk". These costs do not fall when the utility stops offering service to a customer; the utility must still recover them or assume an associated loss.

We agree with Edison's observation that a fully-allocated cost method assumes inappropriately that all costs are variable, even at low levels of penetration", Decision 98-09-070 (California P.U.C. September 17, 1998) at 11. The same policy justification – not shifting costs upon Standard Offer Customers – is appropriate in Arizona.

Q. WHAT WAS THE NEXT AREA OF MS. SMITH'S PROPOSED CHANGES TO THE PRICING COMPONET OF THE SETTLEMENT AGREEMENT?

A. Ms. Smith has a concern that Standard Offer Service customers will not be able to determine the dollars they would have available to shop for an ESP to provide them with Generation, Transmission, and Ancillary Services. APS understands this concern, but does not believe that Standard Offer Service unbundling as suggested by Ms. Smith will in any way resolve this perceived problem. It probably would make it worse. In order to provide the necessary information for Standard Offer Service customers to make informed choices concerning switching to Direct Access Service, APS has designed a "Page 2" to the format of the bill that will be sent to all Standard Offer Service customers. This additional page would contain the Standard Offer Service customer's alternative billing amount under Direct Access Service. In addition, the bill would contain the amount APS would have billed the customer's Scheduling Coordinator for Transmission and Ancillary Services. The difference between the Standard Offer Service bill and the sum of the Direct Access Service bill plus the charge for Transmission and Ancillary Service would give the customer or a potential ESP the total dollar amount, as well as cents per kilowatthour, of what could be paid by the customer for Generation without exceeding the Standard Offer Service bundled rate. This amount, which is the amount available to pay a supplier other than APS for Generation, would be clearly indicated on the Standard Offer Service bill. The proposed "Page 2" information is what Standard Offer Service customers actually require to make knowledgeable decisions as to whether they should convert to Direct Access Service. The unbundling approach is not just impractical to implement for APS's Standard Offer Service rates, it simply does not provide useful information to our customers, and deprives them of the information really needed for decision making. Attachment AP-1R illustrates the billing information that would be made available on all Standard Offer Service bills.

Q. WAS THERE A THIRD AREA OF MS. SMITH'S PROPOSED PRICING RELATED CHANGES TO THE SETTLEMENT AGREEMENT THAT YOU WISH TO REBUT?

A. Ms. Smith is of the opinion that the difference between the Standard Offer Service bill and the Direct Access Service bill, or "shopping credit" as I call it, or "market generation credit" (MGC) as she calls it, is not sufficient in most instances to create competition in the generation market. Mr. Kingerski also makes this claim. I do not agree, and believe that there is a sufficient difference between Standard Offer and Direct Access pricing to allow for fairly widespread competition amongst the ESPs and APS Standard Offer Service. It should be noted that the objectives for the transition to a fully competitive electric energy market should not include a guaranteed profit for ESPs, and that the effective shopping credits must not be somehow artificially increased to meet such an objective. It should also be noted that the APS "shopping credit" is generally greater than that available to customers of the Salt River Project. Relative "shopping credits" are discussed further in Mr. Davis' testimony. I would like to make it very clear that Ms. Smith's remedies to increase competition are far from "minor" and would lead to a quick unraveling of the carefully pieced together Settlement Agreement.

Q. **AT PAGE 21 OF HER TESTIMONY, MS. SMITH STATED THAT THERE IS A PROBLEM WITH THE PROPOSED CTC FOR GENERAL SERVICE CUSTOMERS BECAUSE IT IS A DEMAND CHARGE AND CERTAIN GENERAL SERVICE CUSTOMERS DO NOT HAVE DEMAND METERS. DO YOU AGREE THAT THIS IS A PROBLEM AT THIS TIME?**

A. No. Under the phase-in of the proposed Competition Rules, only General Service customers of 40 kW or greater are eligible for Direct Access Service prior to January 1, 2001. Thus, every customer that may take Direct Access Service until that time must have an hourly consumption measuring meter and customers must have such a meter to comply with the Company's Direct Access Service rates. The only General Service customers that are not subject to a demand rate are those with unmetered service less than 5 kW. The Direct Access issues associated with customers receiving unmetered service have yet to be fully resolved, but the Company will file a Direct Access Service rate schedule for such customers for approval by the Commission prior to January 1, 2001.

Q. DO YOU WISH TO REBUT THE TESTIMONY OF MR. KINGERSKI IN ANY ADDITIONAL AREAS?

A. Yes. Mr. Kingerski is of the opinion that the Standard Offer Service rates should not be APS's current rates, but instead be fully unbundled and cost based in a manner that he finds acceptable. Perhaps this opinion would be realistic at some future time if, at that time, APS's individual rate schedules were each totally based on costs. Although APS's overall tariff is currently cost based, APS has over 50 individual rate schedules whose origins had numerous bases. Even at their inception, the rates did not truly reflect the functionalization and classification of costs inherent in the cost-of-service study, as a result of ACC actions. In addition, rate designs, as well as the rates of return by class and even by rate schedule, varied widely. Over the years, the rates moved further from their original cost relationships as a result of across-the-board price reductions and other ACC approved changes. It should be noted that the original rates and subsequent changes were reasonable at the time they were implemented and consistent with the pricing regime under which APS and the electric utility industry were operating. These circumstances, together with the fact that today's costs may vary from those inherent in an old cost-of-service study, make APS's current rates unsuited for the type of unbundling advocated by Staff and the ESPs. Any attempt to unbundle the rates based on functionalized costs would end up with the total of the unbundled pieces not adding up equal to actual individual bills. In many instances the differences would be substantial, and in all instances confusing and even misleading to our customers. There would have to be some type of line item to indicate the overcollection or undercollection from true and current costs. I do not believe that this is a realistic option. Another option would be to discontinue our current tariff, and develop a completely new set of cost based unbundled rates for Standard Offer Service. However, such an action would cause extreme dislocations in class revenues and individual customer bills. I presume that such imposed increases to so many customers' bills would force the requirement for a full rate case and thereby destroy any possibility for an expeditious settlement and implementation of competition.

Q. WHERE ELSE DO YOU DISAGREE WITH MR. KINGERSKI'S TESTIMONY?

A. Mr. Kingerski seems to believe that a whole new set of cost based unbundled Direct Access Service rates should have been developed instead of the using the apportionment process to relate the functionalized revenue requirements of the current bundled Standard Offer Service rates to the Direct Access Service rates. Once again, this might be a realistic opinion if the individual Standard Offer Service rates were totally cost based. However, since they are not, it was necessary to have a paralleling relationship between the two sets of rates so that the transition to a Direct Access Service option would be rational as well as orderly. Once the transition period is complete, consideration could be given to Direct Access and Standard Offer rates that are totally cost based, though this philosophy could also prove to have its own drawbacks.

Q. ON PAGES 14 AND 15 OF HIS TESTIMONY, MR. KINGERSKI'S IMPLIES THAT APS WILL BILL ESPS FOR DISTRIBUTION

SERVICE AND THAT THERE WILL THEN BE A DOUBLE RECOVERY OF BILLING COSTS. IS THIS A TRUE ASSESSMENT OF THE FACTS?

A. No. Mr. Kingerski is mistaken on how APS will bill and recover payment for Distribution service. Any retail customer electing to secure power and energy from an ESP will be billed directly by APS for Distribution service. Therefore, even though a retail customer elects Direct Access Service, APS still must render a bill to that customer for the Distribution service APS provides.

Q. **MR. KINGERSKI STATES THAT APS'S ONLY MOTIVATION FOR USING AN APPORTIONMENT PROCESS TO DERIVE DIRECT ACCESS SERVICE RATES WAS TO PRESERVE APS'S REVENUE AND THAT THERE WAS NO INTENTION TO HAVE UNBUNDLED RATES REFLECT THE COST OF THE UNBUNDLED SERVICE. IS THIS A CORRECT CONCLUSION?**

A. No, it is not. By apportioning current rates, which through the ACC approved 1996 rate reduction mechanism are assured of being cost based in the aggregate, and using the appropriate functional cost ratios from the APS's latest cost-of-service study, the Direct Access Service rates are assured of being cost based in the aggregate to the extent approved by the ACC. This process also fulfills the ACC's stated objective that the introduction of competition should not increase customers' rates. Mr. Kingerski's proposal to completely redesign all of APS's rates so that each will be cost based would create major rate dislocations for most of APS's customers.

Q. MR. KINGERSKI MADE VARIOUS STATEMENTS REGARDING THE RECOVERY OF ENERGY IMBALANCE COSTS. DO YOU HAVE A GENERAL COMMENT TO MAKE ON THIS SUBJECT?

A. Yes. Mr. Kingerski correctly noted that Energy Imbalance issues relate to the Arizona Independent Scheduling Administrator (AISA) and to the Federal Energy Regulatory Commission (FERC). The AISA has not completed its protocols at this time, much less filed them with FERC. In addition, it is not known whether FERC will accept whatever AISA files, whether a full hearing will be required before FERC, or whether it will be necessary for APS to make its own separate FERC filing.

Q. MR. KINGERSKI CONTENDS THAT APS SHOULD UNBUNDLE ENERGY IMBALANCE IN ITS STANDARD OFFER SERVICE PRICE. IN ADDITION, HE CONTENDS THAT IF THIS SERVICE COMPONENT IS NOT UNBUNDLED, A DIRECT ACCESS SERVICE CUSTOMER WILL PAY FOR IT TWICE—ONCE THROUGH APS'S DIRECT ACCESS RATE AND AGAIN THROUGH THE ESP'S CHARGES TO THE CUSTOMER. DO YOU AGREE?

A. No. Energy Imbalance costs are one of FERC's wholesale related Ancillary Services. Scheduling Coordinators providing services for ESPs would be the entities subject to this charge under APS' Open Access Transmission Tariff (OATT). The Scheduling Coordinator would pass this cost on to the ESPs, who presumably would again pass this cost on to its aggregated retail customers. Service to a public utility's Standard Offer Service customers is considered retail native load and, as prescribed under FERC's Order No. 888, is not taken under an OATT. It should be understood that the very nature of bundled retail service precludes Energy Imbalances. APS's loads within its own control area (which are predominantly retail native loads) are dynamically linked to certain generation units which automatically ramp up or down as needed. As such, these loads never are out of balance. Furthermore, since APS's Standard Offer Service rates include the costs associated with purchased power and all of APS's generation resources, Standard Offer Service customers are already paying for the resources used to preclude Energy Imbalance. At such time when APS must secure energy through competitive bid on the open market, APS would consider revising its Standard Offer Service rates to provide for recovery of Energy Imbalance costs, or alternatively, propose an adjustment clause for the effective recovery of such costs.

Q. **DO YOU AGREE WITH MR. KINGERSKI'S CONTENTION THAT ESPs SHOULD HAVE THE RIGHT TO PURCHASE ENERGY FROM APS AT THE SAME BELOW MARKET PRICE RATES AS HE BELIEVES IS INHERENT IN CERTAIN COMPONENTS IN THE STANDARD OFFER SERVICE RATE AT CERTAIN TIMES OF THE YEAR?**

A. Absolutely not. The generation component of APS's Standard Offer Service rates is not based on the market price, nor should it be until such time as APS is required to secure energy for Standard Offer Service customers through competitive bidding. APS planned and constructed an integrated system consisting of diverse generation resources and transmission facilities in order to supply power and energy to its customers at the lowest cost possible. To the extent that APS generation resources produce power and energy cheaper than the "market price", APS's Standard Offer Service customers, who have and are presently paying for these facilities, are entitled to be served at costs recognizing these facilities. APS's system was not built to provide below market priced power to Enron or other ESPs.

Q. MR. KINGERSKI ALSO SUGGESTS THAT APS'S STANDARD OFFER SERVICE RATES SHOULD BE INCREASED, SO THAT THESE RATES WILL BE COMPETITIVE WITH THOSE OF ESPS. DO YOU AGREE WITH THIS PHILOSOPHY?

A. No. I do not believe that competition should be fostered by artificially increasing or decreasing the price of one of the potential supplying parties.

Q. DO YOU HAVE ANY PRICING RELATED COMMENTS ON MR. OGLESBY'S TESTIMONY?

A. Yes. Mr. Oglesby believes that the one year's advance notice requirement that will be placed on Direct Access Service customers over 3MW desiring to return to Standard Offer Service is anti-competitive. The purpose of the one year notice policy is to recognize that APS's planning process, cost incurrence, and cost recovery are on a minimum one-year cycle, and APS does not want its larger customers shifting back and forth between Direct Access Service and Standard Offer Service with the possibility of creating costs that others will have to pay. Also, it should be noted that the currently proposed Competition

Rules would allow APS to refuse service to returning Standard Offer Service customers whose annual electric consumption exceeds 100,000 kWh, which would include all customers over 3 mW.

Q. DO YOU HAVE ANY COMMENTS ON MR. BLOOM'S TESTIMONY?

A. Yes. Mr. Bloom states that the Basic Service Charge should be eliminated, since with unbundled rates there is no need for non-cost based charges. Mr. Bloom does not seem to realize that Basic Service Charges are in effect to cover certain non-variable customer related costs. These charges cannot be eliminated unless the costs they are designed to collect were artificially transferred or tilted to the demand or energy component of the rate. Such a move would only exacerbate the problems many electric utilities are now experiencing by having rates that do not follow costs. In addition, Mr. Bloom's comments on the Direct Access Service rates not showing a "shopping credit" seem to miss the point. It is the Standard Offer Service customer that needs to know his potential shopping credit should such customer opt for Direct Access Service. A Direct Access Service customer has no "shopping credit". The ESP will be buying Generation, Transmission, and Ancillary Services on the marketplace for that customer.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes. It does.

ARIZONA PUBLIC SERVICE COMPANY

Informational Unbundling for Standard Offer
Proposed Standard Offer Bill

Typical Summer Bill on Rate E-12 at 7/1/99 Rate Levels
The following information is proposed to be shown on the customer's monthly bill:

Standard Offer Bill Calculation:

Your total kWh usage is	991
Basic Service Charge	$ 7.50
Charge for kWh used	101.80
Regulatory Assessment	0.20
Sales Tax	7.17
TOTAL	$ 116.67

Informational Unbundling:

Your total usage for this month was:	991 kWh	
You Standard Offer Bill was (see page 1):		$ 116.67

If you had chosen direct access to an ESP, your APS bill for delivery service would have been:

Basic Delivery Service:	$ 10.00	
Distribution Service:	$ 41.20	
System Benefits:	$ 1.14	
Competition Transition Charge:	$ 9.22	
Regulatory Assessment:	$ 0.12	
Sales Tax:	$ 4.04	
Total Amount for **APS Delivery Service Only**:	$ 65.72	$ 65.72
Residual Transmission & Generation Amount:		$ 50.95
Transmission and Ancillary Services billed to your ESP:		$ 5.09
Residual Generation Amount:		$ 45.86
Transmission & Generation Shopping Credit		**5.14** ¢/kWh

If you are provided Metering, Meter Reading and Consolidated Billing by a competitive supplier of these services, your monthly bill from APS would be reduced by $1.90. You may then be charged for these services by your ESP.

ARIZONA PUBLIC SERVICE COMPANY

Informational Unbundling for Standard Offer
Proposed Standard Offer Bill

Typical Summer Bill on Rate E-32 at Proposed 7/1/99 Rate Levels
The following information is proposed to be shown on the customer's monthly bill:

Standard Offer Bill Calculation:

Your total kWh usage is	36,500	
Your total kW usage is	100	
Basic Service Charge		$ 12.50
Charge for kWh used		3,171.91
Charge for kW Demand		175.75
Regulatory Assessment		4.71
Sales Tax		220.25
TOTAL		$3,585.12

Informational Unbundling:

Your total usage for this month was:	36,500 kWh	
You Standard Offer Bill was (see page 1):		$ 3,585.12
If you had chosen direct access to an ESP, your APS bill for delivery service would have been:		
Basic Delivery Service:	$ 12.50	
Distribution Service:	$ 1,289.85	
System Benefits:	$ 41.98	
Competition Transition Charge:	$ 243.00	
Regulatory Assessment:	$ 2.22	
Sales Tax:	$ 104.04	
Total Amount for **APS Delivery Service Only**:	$ 1,693.59	$ 1,693.59
Residual Transmission & Generation Amount:		$ 1,891.53
Transmission and Ancillary Services billed to your ESP:		$ 156.40
Residual Generation Amount:		$ 1,735.13
Transmission & Generation Shopping Credit		**5.18** ¢/kWh

If you are provided Metering, Meter Reading and Consolidated Billing by a competitive supplier of these services, your monthly bill from APS would be reduced by $4.60. You may then be charged for these services by your ESP.

BEFORE THE

ARIZONA CORPORATION COMMISSION

REBUTTAL TESTIMONY OF DONALD G. ROBINSON

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

July 12, 1999

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald G. Robinson, and my business address is 400 North Fifth Street, Phoenix, Arizona 85004.

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

A. I am Director of Strategic Financial Planning for Arizona Public Service Company. My qualifications are set forth in Attachment DGR-1.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. To address certain issues related to post-divestiture capital structure and the magnitude of proposed APS rate reductions.

Q. ENRON WITNESS ROSENBERG (P.8) RECOMMENDS "AN AFFIRMATIVE SHOWING BY APS THAT ITS DECISIONS ON CAPITALIZATION OF ITS AFFILIATES DO NOT DISADVANTAGE CUSTOMERS OR UNDULY ADVANTAGE ITS UNREGULATED AFFILIATE". IS THIS A REASONABLE PROPOSAL?

A. No. Dr. Rosenberg seems to be suggesting that the Commission should be concerned about the capital structure of both the Commission-regulated utility (APS) and the FERC-regulated 'Genco". The regulated utility will receive consideration from Genco for its generation assets equal to the book value of the transferred property. This consideration will necessarily include the assumption of some APS debt (for pollution control bonds and debt associated with the sale/leaseback)-debt which must remain with the generation assets. The form of the remainder of the purchase price will be determined at the time of the transfer and could include cash or other compensation. The actual capital structure of Genco will be determined by its board.

APS itself has every incentive to maintain a reasonable capital structure because it will continue to need access to the capital markets on reasonable terms. In addition, because the Commission retains the power to review its capital structure in the next rate case and to make any justifiable rate adjustments it finds are supported by the evidence (in the form of a "hypothetical" capital structure), APS cannot impose the higher cost of an unreasonable capital structure on customers. Furthermore, during the term of the Settlement, the Company's rates are decreasing, which is inconsistent with increasing the percentage of equity in its capital structure, as is apparently feared by Mr. Rosenberg.

Q. WHY SHOULD THE COMMISSION BE INDIFFERENT TO THE CAPITAL STRUCTURE OF GENCO?

A. The capital structure of Genco should be no more the concern of this Commission than the capital structure of other wholesale generators who sell into the Arizona wholesale market. An individual generator's capital structure does not determine or even influence market prices in the fully competitive wholesale market.

Q. ON PAGE 8, LINES 11 THROUGH 13, DR. ROSENBERG STATES THE FOLLOWING: "IF THE MARKET VALUE IS ALSO LESS THAN THE BOOK VALUE IT IS POSSIBLE THAT SOME OF THESE PLANTS COULD BE SOLD AT A LOSS, GIVING RISE TO A TAX LOSS." DO YOU AGREE WITH DR. ROSENBERG'S ASSERTION?

A. No. A sale of APS' generating plants (even if feasible) will almost certainly produce the opposite effect. Even though the auction could result in a "loss" for financial reporting purposes, it will most likely result in a "gain" for income tax reporting purposes. A taxable gain will, in turn, result in an additional cash tax liability. The reason for the difference between the financial statement result (i.e., big loss) and the income tax result (i.e., gain) is the accelerated depreciation methods and shorter depreciable lives allowed pursuant to the Internal Revenue Code for income tax reporting purposes. The adjusted tax basis of the Company's generating assets is far less than the net book value of the generating assets. For example, the tax life of Palo Verde is 10 years compared to a book life of approximately 35 years. Therefore, the current tax basis for the majority of Palo Verde is zero. It is unlikely that the generating plants would be sold for an amount less than their adjusted tax basis and, therefore, a tax loss simply would not occur.

Q. SEVERAL PARTIES (E.G., STAFF WITNESS SMITH AND THE ARIZONA CONSUMERS COUNCIL) HAVE SUGGESTED THAT THE PROPOSED RATE REDUCTIONS MIGHT, IN SOME SENSE, BE "INADEQUATE". DO YOU AGREE?

A. No, and I would note that no party has presented any evidence whatsoever that a greater rate reduction is warranted or would be fair to the Company. In their comments, the Arizona Consumers Council speculate that rates may be too high post-divestiture because rate base has not been reduced to reflect the generation assets transferred to an affiliate. This suggestion fails to consider three significant facts that should alleviate any such concern. First, the assets will not be transferred until December 31, 2002, by which time APS will have reduced rates to standard offer customers by 6%. Second, once the assets are sold, any "reduction" in revenue requirements associated with the transferred assets may be more than offset by: (1) the significant increase in operating expenses of the regulated utility caused by the need to acquire replacement power from the market; and (2) higher costs associated with new distribution plant investment. Thirdly, the general rate case required by Section 2.6 to the Agreement would, under present Commission rules, use a test period that reflected the net impact (if any) of the asset divestiture on APS' revenue requirements and would represent the first opportunity for the Commission to consider such impact even in the absence of the Agreement.

Q. STAFF WITNESS SMITH (PP. 18-20) APPEARS TO BE SOMEWHAT DISMISSIVE OF THE MAGNITUDE OF THE RATE DECREASES IN HER TESTIMONY. DO YOU HAVE ANY COMMENTS?

A. Yes. I am somewhat surprised that Ms. Smith questions the adequacy of the proposed rate reductions, because she supported smaller reductions in our previous settlement with Staff. She attempts to base her belated reservations about the level of rate decreases on a comment that the "Company's Form 10-K notes that its 1998 revenues were lower than normal by $33 million because of milder than normal weather". This is a rather cursory "analysis" upon which to question the adequacy of the Agreement's rate reduction. It also suffers the deficiencies of being: 1) a factually incorrect statement; and 2) a distortion of the actual situation. The Company's Form 10-K (p. 20) does discuss the effects of "milder weather", but that "milder weather" is compared to the hotter than normal 1997 weather, not "normal" weather as Ms. Smith asserts. In fact, 1998 had virtually 100% "normal" weather, therefore, there would be no impact of weather in a traditional rate case.

The Company provided the calculation of the 1999 rate decrease as part of Mr. Propper's direct testimony. It showed a rate decrease of .68%, which is considerably less than the Company's proposed decreases of 1.5%. Even if one added back the APS share of unit cost savings (described at page 20 of Ms. Smith's testimony), one could not produce a 1.5% rate reduction.

Q. DO YOU BELIEVE THAT MS. SMITH'S DISCUSSION OF RATE REDUCTIONS IN OTHER JURISDICTIONS IS HELPFUL?

A. No. Her comments regarding rate reductions in other jurisdictions are irrelevant - they ignore both the specific cost structure of APS and the previous reductions APS already made in anticipation of competition. These total 8.4% and should be added to the 7.5% reductions in the Agreement before making any such comparison.

Q. DO YOU SHARE MS. SMITH'S CONCERNS ABOUT THE ADJUSTMENT CLAUSES CONTAINED IN THE PROPOSED SETTLEMENT?

A. No. First, Ms. Smith refers to them as "automatic" adjustment clauses. The Agreement nowhere uses such a term. Parties will be able to review the prudence of these costs. The form of the clauses and the mechanics of their operation would have to be approved by the Commission. I further anticipate that no collection of any deferred costs would happen until there had been a Commission finding that the deferred costs were reasonable, prudent, and within the categories described in the Agreement. Second, adjustment clauses only allow recovery of costs. Third, adjustment clauses are a widely used method of efficiently tracking and recovering costs largely beyond a utility's control, such as purchased power.

Q. THE ARIZONA CONSUMERS COUNCIL CLAIMS IN ITS COMMENTS (P.2) THAT: "NO FINANCIAL INFORMATION OF ANY KIND" HAS BEEN PRESENTED TO JUSTIFY THE RATE PROVISIONS OF THE SETTLEMENT. IS THIS AN ACCURATE CRITICISM?

A. Not at all. Leaving aside the fact that this is not a rate increase proceeding (and thus the traditional Commission rate case filing requirements are not applicable), APS has presented financial information from which the Commission can conclude that the Settlement's rate provision are just and reasonable. This information includes:

(1) APS financial performance information for 1998 (Schedule AP-3); and

(2) Adjusted test year financial data, including return on rate base (Schedule AP-4).

I have also provided Attachment DGR-2, which shows our projected 1999 earnings to be $114.8 million with a return on equity of 5.8%, far below the Company's "allowed" return of 11.25%. Even after adding back the effects of the write-off, the return would be 10.9%, still below the level last found reasonable by the Commission.

Q. WOULD THE TYPE OF FULL RATE CASE NORMALLY REQUIRED FOR A PROPOSED RATE INCREASE, AS SUGGESTED BY THE CONSUMERS COUNCIL, PROMOTE THE START OF COMPETITION?

A. No. A full rate case would result in a very significant delay in competition. APS' last two litigated rate cases took 23 months and 29 months to complete. While both of these cases included the contentious issue of Palo Verde, neither contained any significant rate design issues. A full rate case now would include the equally contentious issue of stranded costs and the even more difficult issue of rate design. It is safe to assume that a rate proceeding addressing these issues would last at least the 12-13 months contemplated by the Commission's rules (A.A.C. R14-2-103 B.11) and probably many more. Because customers will logically need to know the final determination of these issues before they would be able to make an informed decision on electric service, competition would be delayed many more months if not years.

Q. IS THE 11.25% RETURN ON EQUITY APPROVED BY THE COMMISSION IN THE 1996 SETTLEMENT AGREEMENT STILL REASONABLE?

A. Yes, and in fact it may be somewhat low.

Q. WHY DO YOU THINK 11.25% IS REASONABLE?

A. The average return on equity granted by the state commissions for electric utilities throughout the country has increased in the last two years; in 1997 it was 11.4% and 11.7% in 1998, both above the 11.25% currently authorized. Additionally, since the end of 1998, the Treasury bill yield has increased by approximately 43 basis points, which would indicate that the appropriate return on equity could be above 11.7%.

Q. **HOW CAN THE COMMISSION DETERMINE A RETURN ON FAIR VALUE SHOULD IT BELIEVE SUCH A DETERMINATION APPROPRIATE?**

A. The Commission has always, at least as long as I can remember, set a return on fair value that would allow APS to recover its embedded cost of capital, which is merely the cost of equity weighted with the embedded cost of the Company's debt and preferred stock (if applicable). I have provided a weighted cost of capital calculation in Attachment DGR-3.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Statement of Witness Qualifications

Donald G. Robinson is Director of Strategic Financial Planning for Arizona Public Service Company. Mr. Robinson is responsible for the Company's financial planning, budgeting, forecasting and strategic analysis areas as well as certain regulatory areas.

Mr. Robinson was previously Director of Pricing, Regulation and Planning for Arizona Public Service Company. In this position I've had responsibility for the Company's regulatory activities before the Arizona Corporation Commission and the Federal Energy Regulatory Commission, as well as the Company's pricing and planning functions.

Mr. Robinson joined the Company in 1978 and held a number of supervisory positions in the accounting department. In 1981, he was named manager of Regulatory Affairs and in 1998, Manager of Rates and Regulation. Mr. Robinson was a principal in the consulting firm Micon from 1992-1996. Mr. Robinson has a Bachelor of Science degree in Accounting.

Arizona Public Service Company
Projected 1999 Income Statement - $ in Millions

Line #		1999
1	Revenues	$ 1,791
2	Operating Expenses	733
3	Depreciation and Amortization	387
4	Income Taxes:	
5	Income Taxes excluding ITC Amortization	307
6	ITC Amortization	(27)
7	Total Income Taxes	280
8	Interest Expense	135
9	Regulatory Disallowance Write-Off	234
10	Deferred Income Taxes - Regulatory Disallowance Write-Off	(94)
11	Net Income	$ 116
12	Return on Average Common Equity	5.9%
13	Return on Average Common Equity (Excluding ITC Amortization per ACC)	4.5%
14	Return on Average Common Equity (Excluding ITC Amortization, $234m write-off and its associated regulatory asset amortization)	10.9%

ARIZONA PUBLIC SERVICE COMPANY
Summary Cost of Capital
December 31, 1998
(Thousands of Dollars)

Description	Amount	Capital Ratio	Cost Rate	Weighted Cost
Long Term Debt	$1,890,802	47.72%	6.75%	3.22%
Preferred Stock	95,241	2.40%	6.08%	0.15%
Common Equity	1,976,368	49.88%	11.25%	5.61%
Total	$3,962,411	100.00%		8.98%

BEFORE THE

ARIZONA CORPORATION COMMISSION

REBUTTAL

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

July 12, 1999

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I. Introduction

Q. Please state your name and business address.

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

Q. Are you the same John Landon that submitted direct testimony in this proceeding?

A. Yes, I am.

Q. Please summarize the purpose of your rebuttal testimony.

A. The Arizona Public Service Company (APS, or the Company) has asked me to respond to certain issues addressed by intervenors in their direct testimony on the proposed Settlement Agreement (Settlement). Specifically, I will respond to intervenors' concerns about the Settlement related to its effects on competition and the transfer of assets from APS to its FERC regulated affiliate.

II. Settlement's Effects on Competition

A. Rate Reductions and the Goals of Competition

Q. Witness Oglesby claims that rate cuts agreed to by APS will "deter competition" (p. 10) because they will make it difficult for ESPs to offer a lower price for service than APS. Do you share his concern?

A. No. The goal of regulatory policy should be to deliver competitive results for consumers without being unfair to producers. Competitive results include prices closer to the marginal cost of production and products and services better suited to consumer needs. Competitivê markets will result in the long-term growth and prosperity of firms that deliver value to consumers and the decline and failure of those that do not.

Q. What relation do these competitive objectives have to concerns expressed by Mr. Oglesby?

A. The concerns do not appear to be focused on the interests of the consumer. Mr. Oglesby appears more concerned with the short-term financial interests of his company than with moving rapidly toward a more competitive result.

Q. What do you see as the substantive issue that this witness raises?

A. He appears to be in favor of higher prices by the incumbent and large credits for services provided by entrants, both of which would make entry more profitable and induce more customers to switch rapidly to alternative providers.

Q. Isn't this consistent with having more effective competition?

A. No. Competition is focused on the benefits to consumers and the long-run fairness of the playing field for producers. It does not focus on rules that will enhance the ability of entrants to profit at the expense of consumers and/or incumbent producers. Rate cuts are beneficial to consumers and, as long as rates cover at least marginal costs of production, are consistent with efficient competition. Requiring incumbents to charge higher rates and/or to provide credits for services bought from alternative suppliers that exceed marginal costs will financially advantage entrants at the expense of consumers and incumbent producers.

Q. What is the real issue here?

A. In my view, the real issue is whether we want to get to a fully competitive industry in Arizona quickly and at little cost to consumers or whether we want to delay the process and financially assist entrants by forcing consumers to accept higher current rates. Where, as here, there is the potential to create near-term benefits to consumers and still move to full competition in a relatively short period, I believe it is desirable to do so.

Q. But if the difference between the access rate and the bundled rate is too small to be profitable for some entrants, isn't this a problem?

A. While it is clearly a problem for the prospective entrants that don't find entry as profitable as they would like, it is not a problem in terms of consumer welfare, creating a level playing field or promoting an efficient level of entry. Getting through the transition period quickly so the state can enjoy all the fruits of competition is important. Moving rates to a level consistent with competition (e.g., marginal cost) is also important. Whether specific entrants will be able to profitably enter based on the initial difference between the access rate and the bundled rate is not of concern.

Q. Witness Kingerski provides an example that purports to show that ESPs will not be able to compete with APS's Standard Offer tariff. (pp. 21-4) Have you reviewed this example?

A. Yes I have.

Q. Please briefly describe his analysis.

A. Mr. Kingerski compares his estimate of the market price that ESPs will pay for energy (based on the Palo Verde NYMEX futures price), with his estimate of the shopping credits implicit in the bundled standard offer tariff for selected customers. The shopping credit is calculated by subtracting non-energy related charges from the bundled standard offer rate. He concludes that since the shopping credits are about equal to the ESP' commodity price that ESP's will be unable to compete with APS.

Q. Do you agree with his conclusion?

A. No. The fact that his computation of the ESP's commodity price is roughly equal to his computation of the shopping credit does not mean that EPSs will be unable to compete. An ESP would be able to compete, in the sense of making a contribution to fixed cost recovery, as long as its marginal cost is less than the market price. This is expected to be the case for efficient producers in the western United States. Moreover, the fact that the average Power Exchange (PX) price for California market is less than the shopping credit he computes suggests that this is clearly the case.

Q. Are there any other examples where the shopping credits are roughly equal to the market price?

A. Yes. This is the situation in California where the shopping credit is based on the Average Power Exchange price. Consequently, for California, the shopping credit and the market price are roughly equal.

Q. Witness Kingerski suggests that a reduction of the CTC charge would help encourage competitive entry. (p. 24) What are the merits of this suggestion?

A. Any merits are more than offset by the harm that reducing the CTC would inflict. If the level of the CTC falls, either the collection period must be extended to produce the same present value of collections or the amount collected would be reduced. A longer collection period would postpone the decline of energy costs to competitive levels. This delay would harm consumers by postponing the full benefits of competition. It would have no offsetting effect in lowering customer bills if larger credits merely resulted in higher cost entrants. Lower monthly CTCs would not guarantee lower prices to customers, but instead higher profits to competitors.

If lower CTC payments were not made up for by a longer period of collection, the balance of the Settlement would be further tilted against APS's stockholders.

B. Shopping Credits

Q. **Witness Kingerski expresses support for the "shopping credit" policies instituted by New Jersey and Pennsylvania and contrasts these states with California, which has experienced minimal consumer switching to new providers. (pp. 25-8) Has shopping in Pennsylvania been fairly uniform across all utilities?**

A. No. The shopping experience for Allegheny, generally conceded to be one of the lowest cost generators in Pennsylvania, is similar to that of California. The Allegheny experience is to be contrasted with the experience of GPU, one of the higher cost producers in Pennsylvania. For GPU the percentage of shopping is significantly greater than that in California. For example, the percent of industrial customers shopping is 76% compared to 33% in California.

Q. **Do you agree with his implied point that generous shopping credits are necessary to create effective competition?**

A. No. Shopping credits should reflect the marginal cost of provision of services. In lower marginal-cost states such as Arizona, large shopping credits will encourage inefficient entry by higher-cost producers, which will serve to raise rates for customers.

Q. What are the other considerations that have a bearing on the issue?

A. The length of the transition period should not be altered to produce a greater level of shopping. Larger shopping credits would require a longer transition period over which CTCs are collected. Lengthening the transition period has negative consequences: it delays the benefits associated with full competition and it increases the total cost of stranded cost recovery because of increases in capital costs. It also harms customers to raise current rates to create profitable entry conditions for less efficient firms.

New Jersey and Pennsylvania have both opted for long transition periods. For example, Pennsylvania's transition period varies from seven to ten years, compared with California's four-year transition period. One of the principal reasons that Pennsylvania and New Jersey opted for a long transition period was because both states have several utilities with very high levels of stranded costs. Attempting to recover these costs over a shorter transition period would have resulted in unacceptable rate increases. All else equal, large shopping credits depend on high bundled rates and long transition periods, neither of which is or should be the case with the APS agreement.

Furthermore, the size of the shopping credit and the resulting rate of shopping vary substantially with the level of a utility's initial rates. Since the shopping credit is determined by subtracting nongeneration-related charges (including CTC charges) from a utility's bundled rate, everything else equal, the greater the initial unbundled rate the higher the shopping credit. Consequently, states, such as Arizona, which have lower rate levels, would be expected to have lower shopping credits than states that have higher rates such as Pennsylvania and New Jersey. Making Arizona a higher-cost state so that higher-cost entrants can succeed is not a reasonable objective.

Q. Are there utilities in other states that are expected to have relatively short transition periods and low shopping credits?

A. Yes. According to a July 5, 1999 *Electricity Week Article*, Baltimore Gas and Electric (BG&E) recently signed a restructuring settlement that will allow it to recover its $528 million in stranded costs over four to six years. The article mentions that one of the reasons that BG&E's shopping credits are lower than those of Pennsylvania or New Jersey is that BG&E's rates are lower to begin with.

Q. What conclusion do you draw from these data?

A. These data indicate that shopping appears to be tied more heavily to utility costs and the desire to protect ratepayers from increased rates than to an attempt by a particular state to encourage uneconomic competitive entry.

C. Credits for Other Services

Q. Witness Kingerski asserts that APS's proposed pricing structure for competitive services is inappropriate and can lead to customers being double charged. (p. 14) Do you agree?

A. No. The approach proposed in the Settlement sets credits for services provided by ESPs that are appropriate because the credits:

- provide the proper price signal; and
- encourage efficient entry.

Q. Please discuss what you mean by an appropriate price signal and discuss how the approach proposed in the Settlement is able to accomplish this objective.

A. By appropriate price signal, I mean that credit should be set to maximize allocative efficiency. Allocative efficiency means that society's scarce resources are allocated to their highest-valued use. This occurs when the price of a service (or the credit in the case of revenue cycle services) is set equal to its marginal (or short-term avoided) cost. Marginal (or short-term avoided) cost is the increase (or decrease) in cost that occurs when output is increased (or decreased) by a small amount. For the purpose of pricing credits for revenue cycle services, marginal or avoided cost is the net decrease in cost that occurs when there is a reduction in the level of the service provided. The net reduction should reflect both incumbent costs that are reduced and those that are increased (e.g., additional billing costs) if the service is provided by another supplier.

The efficiency reason that the metering and billing credits should be set equal to marginal or net avoided cost is that marginal cost is the economic cost that a customer's continued use of the service imposes on the economy. Thus, if credits are set equal to marginal costs, the savings from ending existing service arrangements will be the same as the savings to society (in terms of the reductions in scarce resources that are consumed). It should be noted that California uses a decremental cost approach for its shopping credits.

If the price is not set equal to the marginal cost, inefficiencies are introduced. To see this, assume that the net cost the utility avoids for a particular revenue cycle service is \$5, and the credit for the service is set at \$8. Assume further than an ESP can provide the service for \$6. In this situation, the ESP could charge the customer a price slightly below the credit, say \$7. At this price the ESP will be able to attract the customer since the customer would save \$1 (8-7), and the supplier could make a profit of \$1 (7-6). However, the utility will lose \$3 (8-5), which will have to be either added to the CTC or to Standard Offer rates. More of society's scarce resources will be used because a less efficient supplier will provide the service.

If instead the credit were set equal to the utility's net avoided cost, then consumers would not choose the higher-cost ESP to provide the service, since its marginal cost of providing the service exceeds the credit. Only those providers with a marginal cost of provision below that of the utility would be able to attract customers. Thus, setting the credit equal to marginal cost provides the proper price signal that the more efficient provider should serve the customer.

Q. Please discuss how the approach used in the Settlement sends the correct price signal.

A. According to the Settlement, credits are based on short-run avoided or decremental cost. As such, they reflect the costs that the utility is able to avoid or save when an ESP provides the competitive service. As previously discussed, use of marginal or avoided cost will maximize allocation efficiency, resulting in society's scarce resources being allocated to their highest-valued use.

Q. How does the approach proposed in the Settlement prevent cross-subsidies and encourage efficient entry?

A. Since the credit is set equal to the net cost the utility avoids when an ESP provides the service, the utility will receive the same contribution to the CTC and recovery of other costs, irrespective of who provides the service. From an efficiency standpoint, setting this credit equal to marginal or avoided cost provides the opportunity for the utility to recover its costs and ensures that the service will be provided by the competitor who can do so at lowest cost.

It should be noted that setting credits in excess of avoided cost would result in cross-subsidies from the utility to competitors. This occurs because the credit given to the ESP will exceed the cost that the utility saves. Since rates are fixed, the shortfall will have to be made up by the utility.

Q. Do the credits prevent double counting?

A. Yes. Customers receive a credit equal to the cost the utility avoids if the ESP provides the service. Hence, the customer is not being double charged since the credit for the decremental costs of the utility is subtracted from the customer's distribution bill. Only costs that are not avoided are still paid by the customer.

Q. Witness Kingerski assert that competitive entry cannot occur unless APS provides an embedded cost credit for ESP-provided services. (p. 20). What is your response?

A. Entry is appropriate when it reduces the cost of supplying the service. The Commission's focus should be on providing an efficient competitive process, not on encouraging entry per se. The goal should be to set credits that correctly reflect actual marginal or avoided costs and let competitors enter when they can do so profitably.

Including costs that cannot be saved in the credit for competitive services will send an inappropriate price signal because the credits will exceed marginal or avoided cost and will result in inefficient entry. By obligating the incumbent to deliver a credit that is greater than the marginal cost of service--the true savings realized by the incumbent not having to provide the service--the utility would be forced to create an undue incentive for customers to switch providers from incumbent to entrants. This would lead to uneconomic bypass by inefficient competitors, and ratepayers may be adversely affected by resulting increases in the CTC, Standard Offer rates, or length of time required to recover stranded costs.

III. TRANSFER OF APS ASSETS FROM REGULATED UTILITY TO AFFILIATE

A. Transfer of Assets at Book vs. Market Value

Q. Witnesses Oglesby (p. 5), Rosenberg (p. 4), and Delaney (p. 3) argue that the provisions in the Agreement for the transfer of the Company's generation assets will understate the value of the assets. Do you agree?

A. No. The Agreement provides for the transfer of the Company's generation assets at book value. As I stated in my direct testimony (p. 10), I believe that the book value of APS's generation portfolio will be greater than the market value of the assets at the time of the transfer. I believe this for two reasons. First, the

Company has used very conservative assumptions in the estimation of stranded costs. It is very likely that the Company's stranded costs will be well in excess of the $533 million estimate that has been filed with the Commission. Second, as part of the Agreement the company has limited its recovery of stranded costs to $350 million. For these two reasons, I think it is incorrect to assert that APS's generation assets will be undervalued at the time they are transferred to a subsidiary.

B. Auctioning of Assets

Q. Both Dr. Rosenberg and Mr. Delaney (p. 6) suggest that APS auction its generation assets instead of transferring them to an affiliate. Do you agree with this recommendation?

A. No. First, I understand that there is considerable debate as to whether or not the Commission has the authority to force the utility to divest its assets to a third party. Throughout this debate, the Commission has repeatedly decided not to order generation divestiture.

Notwithstanding the issue of the Commission's authority, auctioning would be a draconian way of determining the market value of generation assets. It would be like killing a fly with explosives. It can be effective, but is likely to cause greater harm. In my view, management, not the Commission, should decide whether to sell assets and, if so, how and when. In addition, forced auctions have other disadvantages. These include:

- For the most part, only physical assets (primarily generating stations) can be auctioned or sold. Other sources of stranded costs (such as regulatory assets or purchased power contracts) often cannot be valued in this way and will still require the use of another method.

- Conducting an auction can require considerable time and expense. Consequently, until the auction is completed, it will be necessary to use some other method to estimate the stranded costs of generating plants. Also, the cost of the auction will add to the magnitude of stranded costs.
- It will be very difficult, if not impossible, to establish the value of nuclear plants through an auction process. There are substantial restrictions on the transfer of ownership and operation of nuclear generation plants. Moreover, nuclear plants that have been sold have resulted in negative prices; the "seller" had to pay the buyer to accept the assets.
- The sale of plants creates substantial transaction costs, such as paying taxes, transferring complex or interdependent power supply contracts, soliciting shareholder approvals, and obtaining the release of indentured property from bondholders.
- If regulations force inefficient auction or one held at an inappropriate time, valuations of the assets may be distorted, thereby reducing the efficiency of this market-based mechanism.
- The competitive market may reveal that vertical integration of generation with transmission and distribution yields efficiencies that

benefit consumers. Forced divestiture would unnecessarily eliminate those benefits to the harm of both consumers and the utility.

IV. CONCLUSIONS

Q. Please summarize your conclusions.

A. The Settlement Agreement serves the interests of ratepayers and shareholders and is fair to all potential competitors in Arizona. The Settlement introduces retail access for consumers, mandates explicit rate reductions, and partially compensates the utility for stranded costs. It will lay the foundation for fully competitive markets and the consumer benefits that go along with such markets. I believe that the intervenors' concerns discussed here are adequately addressed by the Settlement or by existing regulatory institutions. The Commission will serve the public interest by approving the Settlement.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE

ARIZONA CORPORATION COMMISSION

REBUTTAL TESTIMONY OF WILLIAM H. HIERONYMUS

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

July 12, 1999

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William H. Hieronymus. My business address is PHB Hagler Bailly, Inc., One Memorial Drive, Cambridge, Massachusetts 02142.

Q. By whom are you employed?

A. I am Senior Vice President of PHB Hagler Bailly, Inc., the commercial consulting subsidiary of Hagler Bailly. Hagler Bailly is a worldwide provider of consulting, research and other professional services to corporations and governments on energy, telecommunication, transportation and the environment.

Q. What is your educational background and work experience?

A. I received my Bachelor's degree from the University of Iowa in 1965, my Master's degree in economics in 1967 and a Doctoral degree in economics in 1969 from the University of Michigan, where I was a Woodrow Wilson Fellow and National Science Foundation Fellow. After serving in the U.S. Army, I began my consulting career. In 1973, I joined Charles River Associates Inc. as a specialist in antitrust economics. By the mid-1970s my focus was principally on the economics of energy and network industries. In 1978, 1 joined Putnam Hayes & Bartlett, Inc., where my consulting practice has focused almost exclusively on network industries, particularly electric utilities. Putnam, Hayes & Bartlett, Inc. merged with Hagler Bailly, Inc. in 1998.

During the past 25 years, I have completed numerous assignments for electric utilities; state and federal government agencies and regulatory bodies; energy and equipment companies; research organizations and trade associations; independent power producers and investors; international aid and lending agencies; and foreign governments. While I have worked on most economics-related aspects of the utility sector, a major theme has been public policies and their relation to the operation of utility companies.

Since about 1988, the main focus of my consulting has been on electric utility industry restructuring, regulatory innovation and privatization. In that year, I began work on the restructuring and privatization of the electric utility industry of the United Kingdom, an assignment on which I worked nearly full time through the completion of the restructuring in 1990. I also led a major study of the reorganization of the New Zealand electricity sector, focusing mainly on competition issues in the generating sector. Following privatization of the U.K. industry, I continued to work in the United Kingdom for electricity clients based there and I was also involved in restructuring studies concerning the former Soviet Union, Eastern Europe, the European Union and specific European countries.

Late in 1993, 1 returned to the United States, where I have worked on restructuring, regulatory reform and, increasingly, the competitive future of the U.S. electricity industry. In this context, I have testified before FERC and state commissions on market power issues concerned with several mergers, power pools and market rate applications. More generally, I have testified before state and federal regulatory commissions, federal and state courts and legislatures on numerous matters concerning the electric utility and other network industries. This includes testimony before the ACC on several occasions. My resume is included as Attachment WHH-1.

II. PURPOSE AND SUMMARY OF TESTIMONY

Purpose

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to those parts of the testimony of Enron witness, Mark W. Frankena that address APS. The essence of Dr. Frankena's testimony is that APS includes two load pockets in which APS and/or APS and SRP will have market power. Moreover, he asserts that there may be other areas in which APS or other utilities in

Arizona may have market power due to concentration of ownership of facilities that can serve load in those areas, though he concedes that he has done no analysis to identify such areas. Lastly, he asserts that nothing in the APS settlement agreement would fully prevent or mitigate APS's ability to exercise market power.

In my testimony, I discuss the regulatory mechanisms that will preclude APS from exercising market power in its load pockets. I also present an analysis that I have performed that looks at APS's market power outside of the load pockets.

Summary of Conclusions

Q. Please summarize your conclusions regarding APS's load pockets.

A. After APS's generating assets are transferred to a Pinnacle West generation subsidiary (hereafter, "Genco"), Genco will be a wholesale seller of power subject to FERC jurisdiction. APS intends that Genco will be an "Exempt Wholesale Generator", generally authorized to sell power at market based rates. Dr. Frankena notes correctly that portions of APS's territory are load pockets. These load pockets exist today, and are neither caused by or exacerbated by the proposed settlement. FERC will not grant market rate authority under circumstances where the seller has market power. FERC has previously found that load pockets can create market power and required that it be mitigated, fundamentally, by restricting the ability of the generator to sell at market rates in load pockets so that market power cannot be exercised when transmission constraints substantially narrow the range of competitive suppliers to retailers selling to customers in the pockets.

FERC has used a variety of means to control load pocket-related market power. APS informs me that its intent is to file cost-based tariffs for units that are "must run" due to load pocket constraints. This is similar to the procedure that FERC has accepted for must run units in California. APS will be required to sell power from these facilities at tariff rates. Entities selling power at retail within the load pockets, including APS and APSES, will be required to buy a portion of their energy at these tariff rates. The charge for capacity to serve customers in the load pockets, insofar as such capacity must be from units within the load pocket, is included in the distribution charges filed as part of the proposed settlement; retail sellers will not have to pay market-based capacity charges for these units. Assuming that FERC finds this approach acceptable, it will assure that APS's prices for power from these units are just and reasonable and reflect their cost of service.

Q. What do you conclude concerning Dr. Frankena's conjecture that APS may have market power outside of the load pockets?

A. I have examined whether Genco will have market power in its service area, other than under load pocket conditions. The methodology that I have used is the methodology specified in FERC's Merger Policy Statement, dated December, 1996. This methodology is FERC's implementation of the Merger Guidelines of the Departement of Justice and Federal Trade Commission, the two federal antitrust enforcement agencies. Based on this analysis, I conclude that the market structure of sellers of energy to customers located in APS's service area is workably competitive and that, according to the standard criterion, Genco will not have market power either acting alone or in tacit collusion with other sellers. Since Genco lacks market power in the area in which its facilities are located, it also will not have market power in any larger markets. As discussed below, the principal reasons why APS lacks market power are a) owners other than Pinnacle West own the majority of generation in the northern and central Arizona area, and b) that substantial inbound transmission capability allows wholesale customers serving retail loads in the area to buy substantial amounts of power from out-of-state generators.

III. MARKET POWER IN LOAD POCKETS

Q. What is a load pocket?

A. A load pocket is a geographic area in which the peak load exceeds the capability of the transmission system to allow power imported from outside the pocket to fully and reliably serve load. Usually, this limit is the thermal limit of the transmission lines entering the pocket. Since imports cannot fully meet load, it is necessary that some part of the load must be met by running generation located within the pocket. Other concerns, such as system stability and voltage problems, may also dictate that generation within the pocket must be run.

Q. Why do load pockets create market power concerns?

A. This is because only generation within the load pocket can meet the load that exceeds the import limit. If there is only one, or very few owners of generation in the pocket, and the prices that they charge are not regulated, the owner(s) may be able to charge excessive prices. This will be true even if the market in the area surrounding the pocket is competitive. For example, assume that the peak load in the pocket is 2,000 MW and the ability to import energy is limited to 1,800 MW. Assume also that the outside market is competitive. So long as load is below 1,800 MW, which will be the case in most hours, the price of power delivered into the pocket will be competitive. Even when load is above 1,800 MW, retail sellers serving 1,800 MW of load would be able to access the competitive outside market. However, the retail sellers of the last 200 MW would have to buy from generation inside the pocket. If there is a single seller, it will be able to charge very high prices in these few hours, since it will face no competition. If there are very few potential sellers inside the pocket there is a concern that they will tacitly collude to raise prices. This is especially likely if meeting the last 200 MW of load requires the generation from more than one potential seller.

Q. Are there load pockets within the APS service area?

A. Yes. APS's 'Must Run' Generation Report, which was provided to Enron and is attached to Dr. Frankena's testimony, shows three load pockets:

- **The Valley (Phoenix).** The 1998 peak load (forecasted in late 1997) is 6,983 MW and the thermal limit on imports is 6,180 MW. At least some APS and SRP generation inside the valley is required to meet load for 460 hours per year; stability and voltage concerns are shown to add about 200 hours per year in which some in-valley generation must be run. There are 1,948 MW of generation in the valley, all of which is owned by either APS or SRP. APS's Ocotillo and West Phoenix stations are must run during some hours.

- **Yuma.** Yuma load is approximately 250 MW. Transmission is limited to 175 MW. Transmission contingencies require that generation from APS's Yucca CTs, the only generation inside the pocket, must run whenever load exceeds 135 MW. This occurs in 2,744 hours per year.

- **Douglas.** Douglas is served radially by a single 115 kV transmission path. In the event that of an outage on that line, load can be met only by runningAPS's Douglas CT. APS's study estimates that this will occur for less than one hour per year.

Q. Does the existence of these load pockets mean that Genco could exercise market power in its pricing of the output of its in-pocket generating units?

A. In the case of the Yucca and Douglas CTs it would be able to charge above competitive prices during those hours when the units are must run in the absence of regulation. In the case of the valley units, APS competes with SRP, and SRP has sufficient generation in the valley that APS generation is not required. However, with only two sellers to meet the roughly 1,000 MW of peak load that cannot be met with imports, there may be a concern that the prices charged for in-valley generation will not be competitive.

Q. Could generation divestiture create competitive markets within the load pockets?

A. No. In the cases of Yuma and Douglas, there is only a single generating station inside the pocket. Divestiture might make the valley market more competitive, but only if a major portion of SRP's generation was divested. APS does not own sufficient generation to meet the needs of the load pocket. Moreover, all of its generation is only at two stations. Finally, since more than half of the in-valley generation is needed at peak load times, even the sale of one of APS's stations (creating a new competitor) would leave at most two generators competing at the margin to met valley loads.

Q. Will the planned generation additions at West Phoenix exacerbate the load pocket market power problem?

A. No, quite the contrary. The new combined cycle capacity likely will be in merit during all hours when load exceeds transmission capability. This will reduce pressure on the transmission system. Further, Calpine will be a new entrant into the valley; it will sell its share of the new capacity on its own account. While this is not, by itself, sufficient to ensure that the market is competitive, it does mean that during at least a part of the hours in which the existing generation is must run that there will be an additional competitor to meet a part of the load. Because SRP is the dominant generator inside the valley, adding to APS's capacity and adding Calpine as a generator will reduce the concentration of the in-valley market.

Q. Are you aware of any planned future events that are likely to impact the severity of the valley load pocket?

A. APS informs me that it plans to increase transmission capability into the valley with expanded transmission from Palo Verde to Estrella. It also believes that SRP is planning to expand transmission into the eastern part of the valley. Expanding transmission will reduce the number of hours during which the valley is a load pocket.

R. Please explain why APS will not be able to exercise market power in its pricing of generation within the load pockets.

A. APS' wholesale power sales are subject to FERC jurisdiction. FERC will not grant market rate authority (the right to sell at unregulated prices) under circumstances where it finds that the generator is likely to have market power. Where load pockets create market power, FERC has not granted market rate authority in respect of sales when and where the load pocket is constrained, but instead has required that market power be mitigated.

Q. Can you identify specific instances where FERC has required such mitigation?

A. Yes. There are three instances in which I was personally involved in which FERC required mitigation of load pocket-related market power. The first was in California. Each of the three large IOUs in California had load pockets in which specific generating stations, or a proportion of the generation owned by a single company, were must run due to transmission constraints. A second case is in NEPOOL, the power pool serving New England. There are a number of potential load pockets within NEPOOL. Pricing rules, applicable to all generation within a constrained area were required as a stand-by and automatically applicable mitigation of market power. The third was in New York, where load pockets were identified within Niagara Mohawk and Consolidated Edison's service areas. For Con Edison, in which the City of New York is a major load pocket requiring that up to 5,000 MW of in-City generation must run during peak hours, capacity must be sold at tariff prices and energy must be sold at either tariff rates or, in the case of generation that runs frequently during non-must run periods, must be bid into the New York Power Exchange at a bid price that is no higher than in like periods when it is not must run.

Q. Do the market power mitigation measures that the FERC has required in these cases lapse if the utility that historically has served the load pocket divests its generation?

A. No. The must run status of the units does not depend on ownership, but rather is inherent to the generating stations. Indeed, most of the must run generation in both New York and California has been divested, but the market power mitigation remains fully in effect.

Q. Can you explain more fully how the market power mitigation for the New York City load pocket works?

A. Yes. All entities serving load in New York City must purchase a portion of their capacity and energy from in-City units. The owners of that capacity (previously Con Edison, now three other generators) must sell capacity at a tariff rate that is based on Con Edison's cost of service rate computed using only the book value of its in-City generation. For units that run only in hours when the City is not constrained, energy is also sold at a cost of service rate. For lower cost units that do run when the City is not constrained and prices are set in the larger New York State market (which FERC has found to be workably competitive), the owners are allowed to bid prices in constrained periods that are no higher than the prices that they bid in unconstrained periods during which their generation was in merit. The energy price that they receive is the in-City market price, not their bid price. Since all in-City units are subject to mitigation, this energy price will be the variable cost of the most expensive unit that is required to meet in-City load.

Q. How did FERC mitigate load pocket market power in California?

A. In California, the ISO designates which units are must run do to transmission constraints or other factors. Must run units are compelled to enter into contracts with the ISO. While there are various types of contracts that differ principally in terms of the accounting for revenues earned when the units are not must run, the basic structure of the contracts is cost of service. The ISO pays a demand charge that covers the fixed cost of the units and buys energy at a variable cost rate.

Q. Will FERC require market power mitigation forAPS's units in its load pockets?

A. Yes, most assuredly. APS has made no secret of the must run character of these units and FERC will require that measures be put in place that assure that market power will not be exercised. Indeed, APS plans to file tariffs, either asamendements to its Open Access Transmission Tariff, or as part of the AISA tariff filing, that will mitigate its market power.

Q. Will FERC impose the same type of mitigation that it required in New York or California on APS's must run units?

A. No, not precisely. The California mitigation mechanism requires that an ISO is in place. The New York mechanism requires that there is a power exchange with location-specific pricing. Neither can be adopted directly for Arizona, since there is neither a ISO nor a power exchange. However, the same concepts can be employed in a slightly different form and are included in APS's planned filing.

Q. How can similar mitigation of load pocket-related market power be implemented in the absence of an ISO and/or power exchange?

A. Yes. The simplest way to do this is to require that the capacity and energy from must run units be sold at cost-based rates, effectively barring them from participation in market-based pricing. This is what FERC has done for New York City capacity and for energy from units that only run when the load pocket is constrained. This also is the essence of the California Must Run Agreements. While the California agreements are contracts with the ISO, the same could be accomplished with a tariff, provided at all sellers into the load pocket are required to purchase a like proportion of energy at the tariff rate.

Q. What does APS plan to propose as mitigation of the potential market power of its existing generation in the load pockets?

A. The planned proposal for mitigation of load pocket market power is described in the draft Must-Run Protocol of the AISA. In brief, the AISA proposal, with which APS concurs, defines four load pockets: APS valley, SRP valley, Yuma and Tucson. The existing generation within the load pockets is defined as Must Offer generation. The owners of that generation must offer to sell their output on a variable cost basis in amounts sufficient to satisfy the aggregate must run requirement for the load pocket. Schedule Coordinators (SCs) that aggregate the loads and resources of all Energy Service Providers (ESPs), selling in the load pockets, including APS as a provider of last resort and APSES as a competitive retailer, will be required to take the same proportion of their capacity and energy from the relevant must run units.[1] SRP will have an equivalent, though initially not identical, form of mitigation of its potential market power within the load pocket.

Q. Will retailers serving load in the load pockets have sufficient access to transmission that they will need to purchase only their pro rata share of must run capacity and energy from generation located inside the load pocket?

A. Yes. Initially, all SCs will have pro rata entitlements to transmission capacity into the load pocket. Ultimately, SCs will be allowed to trade entitlements among themselves and their must run requirements will be adjusted accordingly.

Q. How will the capacity of the must run units be priced?

A. APS has included the capacity cost of the must run units, (limited to the percentage of each must run generating unit's annual usage that is attributable to providing must run generation service in its distribution rates.

[1] Schedule Coordinators can, in the alternative, 1) contract for discretionary local generation, 2) curtail interruptible load or 3) (in the case of the valley) contract for additional transmission into the load pocket from another transmission service provider (i.e. SRP). Ultimately, but not initially, Schedule Coordinators will be able to meet their must-run requirement by purchasing transmission rights from other Schedule Coordinators.

Q. To the extent that ancillary services must be provided from generation inside of the load pockets, what assurance will there be that market power will not be exercised in providing them?

A. Ancillary services will continue to be provided by APS, as a transmission provider under tariffs that comply with FERC's Order 888 and that will be administered by the AISA.

IV. GENCO MARKET POWER OUTSIDE OF LOAD POCKETS

Q. How have you addressed Dr. Frankena's concern acceptance of the provisions of the settlement agreement that transfer APS's generation to an EWG could result in market power outside of the load pockets that you have discussed?

A. Dr. Frankena conjectures that "further investigation may show that there are additional relevant geographic markets for capacity and energy larger than the load pockets just discussed but still small enough so that APS, SRP and TEP would have substantial shares and concentration would be high." He concedes that he has made no analysis of this but presents data on transmission that suggests that transmission limits and congestion may create such submarkets.

Q. Have you performed an analysis to test whether APS is likely to have market power in areas of Arizona outside of the load pockets?

A. Yes.

Q. Please explain the basis for your analysis.

A. I have used the framework that normally is used for investigating mergers to analyze the market structure relevant to the provision of energy to customers located in the area served by SRP and APS. The specific framework is derived from FERC's Merger Policy Statement which, in turn, is intended by FERC to implement the U.S. Department of Justice's and Federal Trade Commission's Merger Guidelines.

Q. Since this is not a merger, why have you used a merger-related analytic standard to investigate APS's potential market power?

A. Antitrust enforcement to limit abuses of market power normally is on a reactive basis after an abuse has been alleged. The merger standards are the only available basis for judging the competitiveness of markets on a before-the-fact basis.

Q. Please explain how the merger standards analyze market power.

A. An analysis of market power begins with the definition of relevant geographic and product markets. A geographic market is defined by the antitrust authorities as a market in which a hypothetical monopolist could profitably sustain a price significantly above competitive levels. In its implementation of this definition the FERC has retained its prior definition of "destination markets" in which each utility control area is presumed to be a relevant market. However, parties are entitled to justify larger or smaller markets.

The relevant product markets are defined by the ability of consumers and producers to switch between the product in question and other products. Electricity is assumed by FERC to lack close substitutes. Moreover, it defines separate products comprising electricity: electric energy, capacity, and the various ancillary services.[2] Because electricity cannot readily be stored, FERC recognizes that market conditions may vary by season and/or day part (i.e. on-peak and off-peak) and requires analysis of market conditions by time of day.

Ultimately, the market power question is whether a firm, or group of firms acting independently (but taking into account the interdependence of their actions and the responses of competitors) can profitably sustain prices that significantly exceed the competitive level. In a merger context, the question is whether the combination of the merging firm makes the exercise of such market power significantly more likely. Here, the question is somewhat different: will the utilities in Arizona (and for purposes of my testimony, APS specifically) be able to charge super-competitive prices if their generation prices cease to be regulated on a cost-of-service basis?

The primary framework used by the antitrust agencies and FERC for assessing the likelihood that market power will exist or be enhanced is an analysis of market structure. Concentrated markets, wherein supply is dominated by one or a few firms, are deemed to be conducive to the exercise of market power. Unconcentrated markets are deemed not to be problematic. Hence, the main purpose of a market power analysis is to determine the extent to which the supply of a product to customers in a defined geographic market is concentrated.

Q. How is concentration measured?

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[2] Because ancillary services are provided as a regulated element of transmission service, ancillary services markets are not examined in the context of utility mergers.

A. The current measure of concentration used by both FERC and the antitrust agencies is called a Herfindahl-Hirschman Index (HHI). The HHI is simply the sum of the squares of the market shares of suppliers. A monopoly market has an HHI of 10,000. A market with 10 equal-sized participants has an HHI of $10^*(10)^2 = 1000$. In evaluating mergers, the focus is on the amount by which the HHI increases as a result of the merger. In considering the competitiveness of a market outside of a merger context, it is the level of the HHI that matters.

Q. What level of HHI is considered to represent a workably competitive market?

A. There is no single answer to this question that is generally applicable. However, the Justice Department has recommended, and FERC has tacitly adopted, the standard that in considering whether to deregulate prices in previously regulated industries, an HHI of 2,500 is acceptable, as is noted by Dr. Frankena on page 41 of the article that he attached to his testimony.

Q. Have FERC or the antitrust agencies adopted measures that address the market shares of large sellers in a market?

A. Yes. As noted by Dr. Frankena, FERC generally has used a threshold of a market share below 30 percent in determining whether to grant a wholesale supplier the right to sell at market, rather than regulated prices. The Merger Guidelines state that a merger resulting in a firm with a share of 35 percent or more will be subject to review.

Q. How have you implemented this guidance in your analysis of whether APS will have market power?

A. I have focused on the market structure for electric energy, the predominant market that is reviewed by FERC. Consistent with FERC's requirements in mergers, I have examined market structure under supply conditions applicable to different times of the year (i.e. by season and time of day).

The geographic market that I have focused on is the area served by APS and SRP. APS informs me that the SRP and APS control areas are so intertwined that it is not practicable to identify meaningful transmission limits that might divide them.[3]

FERC's analysis of energy markets uses the concept of "deliverable economic capacity". Deliverable economic capacity is defined as potential supply that can be delivered to a destination market (i.e. the APS/SRP area) both physically and economically. By economically, it means that the busbar variable cost of production, adjusted for losses and transmission tariffs, does not exceed the price in the destination market. By physically, it means that the aggregate of such supplies imported into the area cannot exceed the transmission capability into it. Thus, the potential supply considered in evaluating market structure consists of all economic supplies located within the area, plus the aggregate of economic supplies up to the amount of the transmission limit.

In determining market structure, the allocation of this inbound transmission capability matters, since not all economic capacity is able to access the market simultaneously. The proration of available transmission capability is accomplished using a model. In essence, the model allocates each defined transmission interface proportionately among all

[3] Formally, I modeled the APS control area with unconstrained transmission between SRP and APS. This means that there is a transmission charge and line losses that reduce SRP's share of the market and, therefore, increase APS's share.

economic supplies that can reach it. For example, suppliers in the Pacific Northwest have pro rata shares of the capacity into northern California and of the DC tie linking to southern California. Supplies that can reach northern California are pooled with economic generation located in northern California and receive proportionate shares of the link between northern and southern California. These are pooled with the energy coming down the DC tie and with the economic energy produced in southern California. This pool of economic capacity shares, pro rata, the links between southern California and the desert southwest. This is pooled, again, with the power located in the relevant part of the desert southwest (e.g. Palo Verde, Navajo or Marketplace) and receives a pro rata share of the transmission into the APS/SRP area. Thus, by the time it reaches the APS, the power from the Pacific Northwest has been "squeezed" progressively through several interfaces and also attracted transmission charges and line losses. The end result is that essentially none of it counts as deliverable to APS/SRP. Conversely, power that is located closer to APS/SRP is squeezed fewer times and receives lower transmission charges and line losses. A substantially higher proportion of it reaches, and counts as potential supply to, the APS/SRP market.

Q. How did you define what generation is inside the APS/SRP area?

A. All generation owned by APS and SRP is considered within the APS/SRP area except for Palo Verde, Navajo and Four Corners. Each of these stations is a separate node on the transmission system with a defined maximum capability to sell into the APS/SRP area.

Q. How did you define the capacity of the transmission system?

A. Transmission capability was defined as the total transfer capability (TTC) taken principally from OASIS web sites of the various utilities and the California ISO.[4] I usedTTCs rather than ATCs because the transmission reservations of integrated utilities to bring their shares of the jointly owned stations will no longer apply.

This requires a brief explanation. At present APS has, for example, firm transmission rights from Four Corners to its service area. After APS's generation is transferred to Genco, the Genco will no longer be assured of a firm transmission path to APS. Rather, it will have to compete with other owners of capacity at Four Corners, as well as imports that can reach the Four Corners node from Marketplace, PNM and the Navajo node for the transmission capability into APS/SRP.

Q. What is the transmission capability into APS/SRP that is defined in the model?

A. The inbound transmission paths are: Four Corners to APS, 1340 MW; Navajo to APS, 2264 MW; Palo Verde to APS, 3810; TEP to APS/SRP, 1344 MW; and WAPA to SRP, 450 MW. These links, together with the other links in the model, are shown on Attachment WHH-2.

Q. What price levels do you assume are market prices in the APS/SRP area for purposes of defining deliverable economic capacity?

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[4] ATCs are used outside of California, Arizona and New Mexico. In cases where desert southwest utilities have shares of remote units located outside of this region, such as SRP's share of Craig, Mohave and Hayden, the share of the unit is moved into their service area, since the ATC has been reduced to reflect their firm entitlements.

A. In order to assure that I am examining the market structure over the full range of market conditions, I examined deliverable economic capacity at prices ranging between $55 per MWh for the summer super-peak down to $10 per MWH for the spring/fall off-peak hours. In 1998 the highest monthly on-peak price at Palo Verde reported by Dow Jones was $48 per MWh and the summer average was $42 per MWh. The off-peak summer/fall prices averaged about $14 per MWh.

Q. Does you analysis take new construction into account, including the announced new AEP capacity to be built at West Phoenix?

A. I have performed two analyses. The first includes only that generation that exists today. A second analysis, which I call a 2001 analysis, includes most but not all of the new generation scheduled for completion by approximately the end of 2001. The new generation included in this latter analysis is shown on Attachment WHH-3. Note that this includes both the Phase I expansion at West Phoenix (130 MW owned solely by Genco) and the Phase II expansion (500 MW split between Genco and Calpine).

Q. You stated that you included "some but not all" announced new generation. Why did you not include all of it?

A. Several projects have been announced at locations near the California-Arizona or California-Nevada borders. I discussed these with APS's system planners and decided that it would not be realistic to include all of them. Excluding some of these projects is conservative; had I included all of them, the APS market would have been less concentrated and APS's share would have been smaller. I should note that while I have included some of these projects by name and excluded others, this does not reflect a specific conclusion that these are the specific projects that necessarily will be built.

Q. What did you use for transmission losses?

A. Losses were assessed at 2.8 percent per wheel.[5] Note that wheels are defined, hence losses are computed, for movement between nodes. Hence, power that moves from southern California to Palo Verde to APS is assumed to have losses of 5.6 percent.

Q. What did you use for transmission tariff rates?

A. Posted rates were used for all but California utilities. Based on discussion with personnel at the California ISO, we used the OATT rates for the exit utility (usually, SCE) as the transmission charge for through and out service from California.

Q. What exhibits show the results of your analyses?

A. The results of the analysis are summarized on Attachment WHH-4. Prices are reported for Super Peak (APS's highest 150 load hours in each season), Peak (the remainder of daytime weekday hours) and Off Peak (remaining hours) for each of three seasons. The seasons are summer, winter, and shoulder (spring and fall). The supplier report, showing the individual shares for each supplier in each time period, are shown on Attachments WHH-5 for the 1999 analysis and WHH-6 for the 2001 analysis. The abbreviations used in the supplier reports are defined on Attachment WHH-7. Attachments WHH-8 and

[5] In its April, 1999 Notice of Proposed Rulemaking, FERC suggests using 3.0percent per wheel. The 2.8 percent factor was derived from reviewing a sample of loss factors from OATT tariff filings.

WHH-9 show the transmission path reports for the 1999 and 2001 analyses. These reports show the line ratings and the flows on the lines into the APS market.

Q. What are the conclusions of your analyses?

A. As is shown on Attachment WHH-4, in the 1999 analysis, the market has an HHI of about 1200. This level of HHI is characterized by the antitrust agencies as only moderately concentrated. The level of concentration is only about half of the maximum acceptable in the context of price deregulation. By any reasonable measure, this is a workably competitive market, and participants should be able to charge unregulated prices. There is relatively little difference among seasons.

APS's share of the market is about 23 percent. This is within the range that FERC finds acceptable for granting market rate authority and well below the antitrust authorities' 35 percent threshold for investigating single firm market power.

The 2001 analysis shows similar results. The market is slightly less concentrated as a result of new entry. APS's market share is slightly higher (by less than 1 percentage point) as a result of its 380 MW of new generation.

V. Pricing in the WSCC: the California Factor

Q. Are there any other factors that you believe should be brought to the Commission's attention that relate to the market power issue?

A. Yes. The analysis that I have just discussed assumes that APS/SRP is a market. However, pricing in the desert southwest region cannot properly be understood without taking into account the influence of California. California is a big power "sink". Most of the time, California must import power to keep the lights on. All of the time it imports power on an economic basis. Arizona is connected to California by a very broad transmission "highway". This highway is rarely constrained. Moreover, the highway can be used to move power from California and beyond into Arizona if there is economic reason to do so.

Generators in Arizona can elect to sell power in Arizona or into California. If the price that they receive from California (taking into account transmission costs and line losses) is higher than they would earn in Arizona, they will sell into the California market. Similarly, if the Arizona price is higher, they will not export to California but will sell locally. Indeed, if the Arizona price rises above the California price by enough to cover transmission costs, the power flow will reverse. This arbitrage between markets means that under normal circumstances, power prices in Arizona will be "net back" from the California price.

Thus, prices in Arizona are not independent of prices in California. The same is true, to only a somewhat lesser degree, to the relationship between prices in California and the Pacific Northwest. Hence, the ability to raise prices in Arizona (and the non-load pocket portions of APS/SRP) will generally require the ability to raise prices in a far larger market, consisting at a minimum of the desert southwest and southern California. In this big pond, APS is a very small fish.

A second consideration relates to the type of generating plant that Genco will control. During the on-peak hours when markets generally are believed to be most prone to the exercise of market power, prices are set based on the cost of running gas steam units. Again this is because of the net back situation concerning California. The opportunity cost of Arizona generators (as can be quantified by the Palo Verde market hub price) will be based on the cost of gas-steam generation in the majority of hours. Most of Genco's capacity is either baseload coal or nuclear. It has little capacity that is nearly marginal at these prices and most of the near-marginal capacity that it does have will be must run. Hence, there is little capacity available to it that could be cheaply withdrawn from the market in order to drive up the price.

VI. Conclusions

Q. Can you please summarize your conclusions with respect to the concerns expressed by Dr. Frankena?

A. Yes. Dr. Frankena's first concern was that Arizona utilities would have market power in load pockets. The load pocket issue does not arise from the proposed settlement which does not, on its face, deal with the pre-existing load pocket problem. His concern that market power could exist in the absence of regulation that constrains its exercise is valid. However, he ignores the fact that wholesale sales will remain subject to FERC jurisdiction and that FERC will not permit market rates to be charged by firms that possess market power in load pockets. I have reviewed the proposed method for controlling such market power and find that it eliminates the ability and incentive of APS to seek to exercise market power by raising the prices charged in the valley and in Yuma when the areas are constrained. Hence, while he has identified a legitimate issue, there are specific mechanisms for solving it that are fully effective.

His second concern was that there might be other areas surrounding the load pockets where market power might be exercised. I have investigated the structure of the APS/SRP market area, the area in which APS would be most likely to have market power outside of the previously discussed load pockets. I found that the market structure is sufficiently unconcentrated to support price deregulation. I also found that APS's market share is low enough to eliminate the expectation that APS will be able to exercise market power.

Q. Does this complete your testimony?

A. Yes, it does.

WILLIAM H. HIERONYMUS **Senior Vice President**

William Hieronymus has consulted extensively to managements of electricity and gas companies, their counsel, regulators and policy makers. His principal areas of concentration are the structure and regulation of network utilities and associated management, policy and regulatory issues. He has spent the last several years working on restructuring and privatization of utility systems internationally and on changing regulatory systems and management strategies in mature electricity systems. In his twenty-plus years of consulting to this sector he also has performed a number of more specific functional tasks including the selection of investments, determining procedures for contracting with independent power producers, assistance in contract negotiation, tariff formation, demand forecasting and fuels market forecasting. Dr. Hieronymus has testified frequently on behalf of utility clients before regulatory bodies, federal courts and legislative bodies in the United States and United Kingdom. Since joining Putnam, Hayes & Bartlett, Inc. (PHB) (which merged with Hagler Bailly, Inc. in 1998) he has contributed to numerous projects, including the following:

ELECTRICITY SECTOR STRUCTURE, REGULATION AND RELATED MANAGEMENT AND PLANNING ISSUES

U.S. Assignments

- Dr. Hieronymus served as an advisor to an electric utility on restructuring and related regulatory issues and has worked with senior management in developing strategies for shaping and adapting to the emerging competitive market in electricity. As a part of this general assignment he has testified respecting, a settlement with the state regulatory commission staff that provides, among other things, for accelerated recovery of strandable costs. He also prepared numerous briefings for the senior management group on various topics related to restructuring.

- For several utilities seeking merger approval he has prepared and testified to market power analyses at FERC and before state commissions. He also has assisted in discussions with the Antitrust Division of the Department of Justice and in responding to information requests. The analyses he has sponsored cover the destination market-oriented traditional FERC tests, Justice Department-oriented market structure tests similar to the Order 592-required analyses, behavioral tests of market definition or of the ability to raise prices and examination of vertical market power arising from ownership of transmission and generation and from ownership of distribution facilities in the context of retail access. The mergers on which he has testified include both electricity mergers and combination mergers involving electricity and gas companies.

- For utilities seeking to sell or purchase generating assets, he has provided analyses concerning market power in support of submissions under

Sections 203 and 205 of the Federal Power Act and analyses required by state regulatory commissions.

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

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

- As part of a large PHB team he assisted a midwest utility in developing an innovative proposal for electricity industry restructuring. This work formed the basis for that utility's proposals in its state's restructuring proceeding.

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

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

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

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

- Dr. Hieronymus has made numerous presentations to U.S. utility managements on the U.K. electricity system and has arranged meetings with senior executives and regulators in the U.K. for the senior managements of U.S. utilities.

- For a task force of utilities, regulators, legislators and other interested parties created by the Governor's office of a northeastern state he prepared background and briefing papers as part of a PHB assignment to assist in developing a consensus proposal for electricity industry restructuring.

- For an East Coast electricity holding company, he prepared and testified to an analysis of the logic and implementation issues concerning utility-sponsored conservation and demand management programs.

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

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

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

- For an eastern Pennsylvania utility that suffered a nuclear plant shutdown due to NRC sanctions relating to plant management, he filed testimony regarding the extent to which replacement power cost exceeded the costs that would have occurred but for the shutdown.

WILLIAM H. HIERONYMUS
Senior Vice President

- For a major midwestern utility, he headed a team that assisted senior management in devising its strategic plans including examination of such issues as plant refurbishment/life extension strategies, impacts of increased competition and diversification opportunities.

- On behalf of two West Coast utilities, he testified in a needs certification hearing for a major coal-fired generation complex concerning the economics of the facility relative to competing sources of power, particularly unconventional sources and demand reductions.

- For a large western combination utility, Dr. Hieronymus participated in a major 18-month effort to provide it with an integrated planning and rate case management system. His specific responsibilities included assisting the client in design and integration of electric and gas energy demand forecasts, peak load and load shape forecasts and forecasts of the impacts of conservation and load management programs.

- For two midwestern utilities, he prepared an analysis of intervenor-proposed modifications to the utilities' resource plans. He then testified on their behalf before a legislative committee..

- For a major combination electric and gas utility, he directed the adaptation of a PHB-developed financial simulation model for use in resource planning and evaluation of conservation programs.

U.K. Assignments

- Following promulgation of the White Paper setting out the general framework for privatization of the electricity industry in the United Kingdom, Dr. Hieronymus participated extensively in the task forces charged with developing the new market system and regulatory regime. His work on behalf of the Electricity Council and the twelve regional electricity councils focused on the proposed regulatory regime, including the price cap and regulatory formulas, and distribution and transmission use of system tariffs. He was an active participant in industry-government task forces charged with creating the legislation, regulatory framework, initial contracts and rules of the pooling and settlements system. He also assisted the regional companies in the valuation of initial contract offers from the generators, including supporting their successful refusal to contract for the proposed nuclear power plants that subsequently were canceled as being non-commercial.

- During the preparation for privatization, he assisted several of the U.K. individual electricity companies in understanding the evolving system, in development of use of system tariffs, and in developing strategic plans and management and technical capabilities in power purchasing and contracting. He continued to advise a number of clients, including regional companies, power developers, large industrial customers and financial institutions on the U.K. power system for a number of years after privatization.

- Dr. Hieronymus assisted four of the regional electricity companies in negotiating equity ownership positions and developing the power purchase contracts for an 1,825 megawatt combined cycle gas station. He also assisted clients in evaluating other potential generating investments including cogeneration and non-conventional resources.

- He also has consulted on the separate reorganization and privatization of the Scottish electricity sector. PHB's role in that privatization included advising the larger of the two Scottish companies and, through it, the Secretary of State on all phases of the restructuring and privatization, including the drafting of regulations, asset valuation and company strategy.

- He has assisted one of the Regional Electricity Companies in England and Wales in the 1993 through 1995 regulatory proceedings that reset the price caps for its retailing and distribution businesses. Included in this assignment have been policy issues such as incentives for economic purchasing of power, the scope of the price control, and the use of comparisons among companies as a basis for price regulation. His model for determining network refurbishment needs was used by the regulator in determining revenue allowances for capital investments.

- He assisted this same utility in its defense against a hostile takeover, including preparation of its submission to the Cabinet Minister who had the responsibility for determining whether the merger should be referred to the competition authority.

Assignments Outside the U.S. and U.K.

- Dr. Hieronymus has assisted a large state-owned European electricity company in evaluating the impacts of the 1997 EU directive on electricity that *inter alia* requires retail access and competitive markets for generation. The assignment includes advice on the organizational solution to elements of the directive requiring a separate transmission system operator and the business need to create a competitive marketing function.

- For the European Bank for Reconstruction and Development he performed analyses of least cost power options, evaluation of the return on a major plant investment that the Bank was considering and forecasts of electricity prices in support of assessment of a major investment in an electricity intensive industrial plant.

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- For the OECD he performed a study of energy subsidies worldwide and the impact of subsidy elimination on the environment, particularly on greenhouse gases.
- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, he developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command and control system to a decentralized, corporatized system.
- For Iberdrola, the largest investor-owned Spanish electricity company, he assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution companies, its regulation and the phasing out of subsidies. He also has assisted the company in evaluating generation expansion options and in valuing offers for imported power.
- Dr. Hieronymus contributed extensively to a project for the Ukrainian Electricity Ministry, the goal of which is to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. The proposed reorganization will be based on regional electricity companies, linked by a unified central market, with market-based prices for electricity.
- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior managers for the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, he continued to advise the Russian energy and power ministry and government-owned generation and transmission company on restructuring and market development issues.
- On behalf of a large continental electricity company he analyzed the proposed directives from the European Commission on gas and electricity transit (open access regimes) and on the internal market for electricity. The purpose of this assignment was to forecast likely developments in the structure and regulation of the electricity sector in the common market and assist the client in understanding their implications.
- For the electric utility company of the Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.
- For a task force representing the Treasury, electric generating and electricity distribution industries in New Zealand, he undertook an analysis of industry

structure and regulatory alternatives for achieving economically efficient generation of electricity. The analysis explored how the industry likely would operate under alternative regimes and their implications for asset valuation, electricity pricing, competition and regulatory requirements.

TARIFF DESIGN METHODOLOGIES AND POLICY ISSUES

- Dr. Hieronymus participated in a series of studies for the National Grid Company of the United Kingdom and for ScottishPower on appropriate pricing methodologies for transmission, including incentives for efficient investment and location decisions.

- For a U.S. utility client, he directed an analysis of time-differentiated costs based on accounting concepts. The study required selection of rating periods and allocation of costs to time periods and within time periods to rate classes.

- For EPRI, he directed a study that examined the effects of time-of-day rates on the level and pattern of residential electricity consumption.

- For the EPRI-NARUC Rate Design Study, Dr. Hieronymus developed a methodology for designing optimum cost-tracking block rate structures.

- On behalf of a group of cogenerators, he filed testimony before the Energy Select Committee of the UK Parliament on the effects of prices on cogeneration development.

- For the Edison Electric Institute (EEI), he prepared a statement of the industry's position on proposed federal guidelines on fuel adjustment clauses. He also assisted EEI in responding to the U.S. Department of Energy (DOE) guideline on cost-of-service standards.

- For private utility clients, he assisted in the preparation of comments on draft Federal Energy Regulatory Commission (FERC) regulations and in preparing their compliance plans for PURPA Section l33.

- For the EEI Utility Regulatory Analysis Program, he co-authored an analysis of the DOE position on the purposes of the Public Utilities Regulatory Policies Act of 1978. The report focused on the relationship between those purposes and cost-of-service and ratemaking positions under consideration in the generic hearings required by PURPA.

- For a state utilities commission, Dr. Hieronymus assessed its utilities' existing automatic adjustment clauses to determine their compliance with PURPA and recommended modifications.

- For the DOE, he developed an analysis of automatic adjustment clauses currently employed by electric utilities. The focus of this analysis was on efficiency incentive effects.

- For the commissioners of a public utility commission, he assisted in preparation of briefing papers, lines of questioning and proposed findings of fact in a generic rate design proceeding.

SALES FORECASTING METHODOLOGIES FOR GAS AND ELECTRIC UTILITIES

- For the White House Sub-Cabinet Task Force on the future of the electric utility industry, Dr. Hieronymus co-directed a major analysis of "least-cost planning studies" and "low-growth energy futures." That analysis was the sole demand-side study commissioned by the task force and formed an important basis for the task force's conclusions concerning the need for new facilities and the relative roles of new construction and customer side-of-the-meter programs in utility planning.

- For a large eastern utility, he developed a load forecasting model designed to interface with the utility's revenue forecasting system- planning functions. The model forecasts detailed monthly sales and seasonal peaks for a 10-year period.

- For the DOE, he directed the development of an independent needs assessment model for use by state public utility commissions. This major study developed the capabilities required for independent forecasting by state commissions and constructed a forecasting model for their interim use.

- For several state regulatory commissions, Dr. Hieronymus has consulted in the development of service area level forecasting models of electric utility companies.

- For EPRI, he authored a study of electricity demand and load forecasting models. The study surveyed state-of-the-art models of electricity demand and subjected the most promising models to empirical testing to determine their potential for use in long-term forecasting.

- For a midwestern electric utility, he has provided consulting assistance in improving its load forecast and has testified in defense of the revised forecasting models.

- For an East Coast gas utility, he testified with respect to sales forecasts and provided consulting assistance in improving the models used to forecast residential and commercial sales.

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Senior Vice President

OTHER STUDIES PERTAINING TO REGULATED AND ENERGY COMPANIES

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These include both Sherman Act Section One and Two cases, contract negotiations, generic rate hearings, ITC hearings and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. For a major electrical equipment vendor he has testified on damages with respect to alleged defects and associated fraud and warranty claims. In connection with mergers for which he is the market power expert, he is assisting clients in responding to the Antitrust Division of the U.S. Department of Justice's Hart-Scott-Rodino requests.

- For a private client, he headed a project that examined the feasibility and value of a major synthetic natural gas project. The study analyzed both the future supply costs of alternative natural gas sources and the effects of potential changes in FPC rate regulations on project viability. The analysis was used in preparing contract negotiation strategies.

- For a industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, he developed an estimate of the potential market for the system by geographic area.

- For the U.S. Environmental Protection Agency (EPA), Dr. Hieronymus was the principal investigator in a series of studies for forecasting future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

Dr. Hieronymus has addressed a number of conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervenor strategies in utility regulatory proceedings, utility deregulation and utility-related opportunities for investment bankers.

Before joining PHB, Dr. Hieronymus was program manager for Energy Market Analysis at Charles River Associates. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving in the U.S. Army. He is a present or past member of the American Economics Association and the International Association of Energy Economists, and a past member of the Task Force on Coal Supply of the New England Energy Policy Commission. He is the author of a number of reports in the field of energy economics and has been an invited speaker at numerous conferences.

WILLIAM H. HIERONYMUS
Senior Vice President

Dr. Hieronymus received a B.A. from the University of Iowa and M.A. and Ph.D. degrees in economics from the University of Michigan.

Competitive Analysis Screening Model (CASm v7.3)

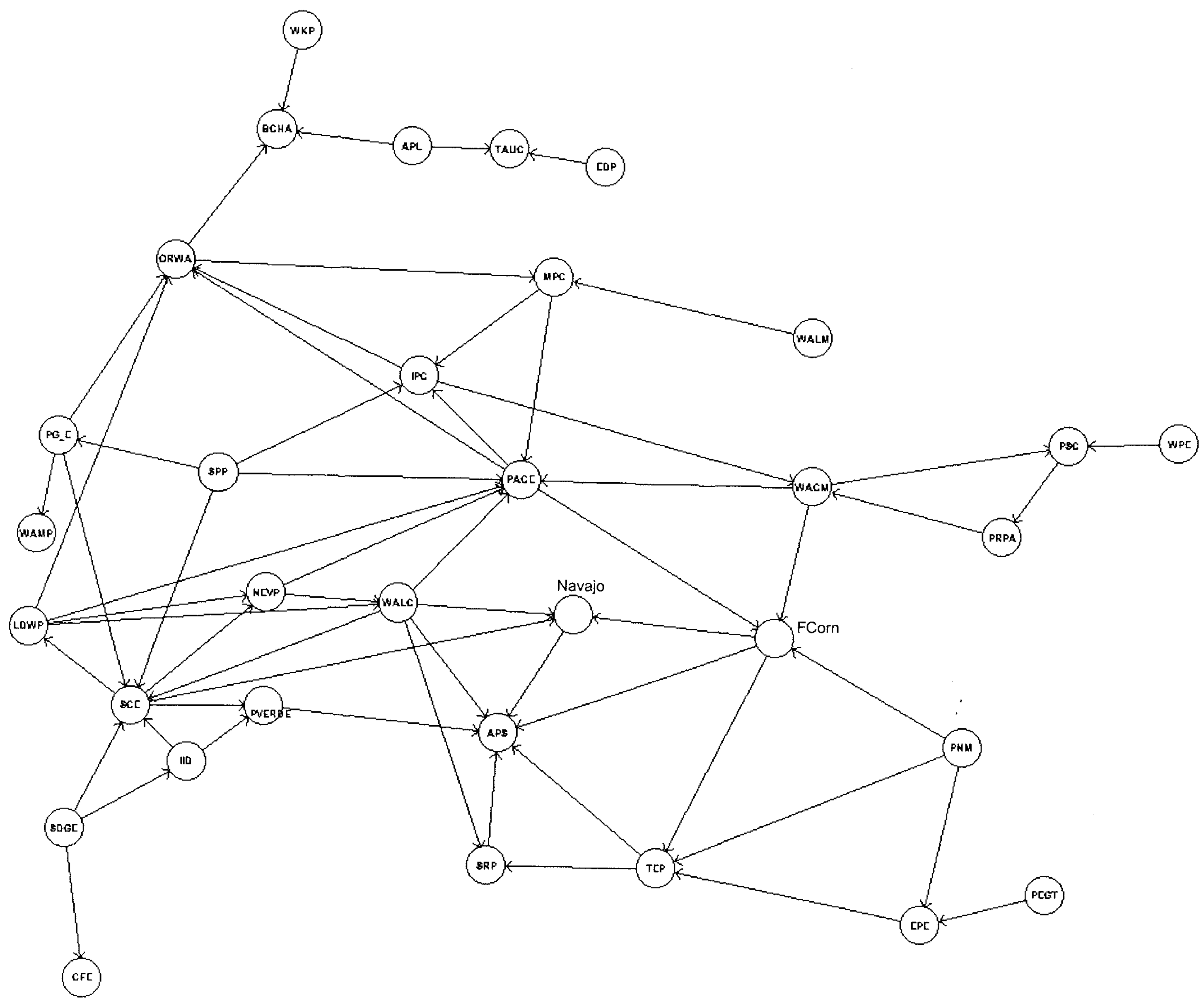
HHI Report

APS Market Power Analysis (Base Case)

Market	Season	Period	BASE APS Mkt Share	HHI
APS	Summer	Super-Peak	22.40%	1184
APS	Summer	Peak	21.90%	1170
APS	Summer	Off-Peak	22.00%	1195
APS	Winter	Super-Peak	24.10%	1219
APS	Winter	Peak	22.40%	1178
APS	Winter	Off-Peak	22.30%	1211
APS	Shoulder	Super-Peak	21.60%	1148
APS	Shoulder	Peak	24.00%	1332
APS	Shoulder	Off-Peak	9.90%	1347

Attachment WHH-2

Modeled Nodes In Market Power Analysis



Generating Capacity Additions in 2001 Case

Plant	Capacity	Node	Owner	Owner_Share
West Phoenix CC4	130	APS	APS	100%
West Phoenix CC5	500	APS	APS Houston Ind	50% 50%
Desert Basin	500	APS	Houston Ind	100%
Kingman	480	WALC	Houston Ind	100%
South Point	500	WALC	Calpine	100%
Person GT2	140	PNM	PNM	100%

Competitive Analysis Screening Model (CASm v7.3)

HHI Report

APS Market Power Analysis (Base Case)

Market	Season	Period	BASE APS Mkt Share	HHI
APS	Summer	Super-Peak	22.30%	1188
APS	Summer	Peak	21.90%	1197
APS	Summer	Off-Peak	22.00%	1277
APS	Winter	Super-Peak	24.10%	1225
APS	Winter	Peak	22.40%	1194
APS	Winter	Off-Peak	22.00%	1358
APS	Shoulder	Super-Peak	21.60%	1146
APS	Shoulder	Peak	24.30%	1412
APS	Shoulder	Off-Peak	10.00%	1896

Competitive Analysis Screening Model (CASm v7.3)

HHI Report.

APS Market Power Analysis (Including expected 2001 constructions)

Market	Season	Period	BASE APS Mkt Share	HHI
APS	Summer	Super-Peak	23.00%	1145
APS	Summer	Peak	22.70%	1144
APS	Summer	Off-Peak	22.00%	1276
APS	Winter	Super-Peak	24.70%	1186
APS	Winter	Peak	23.00%	1140
APS	Winter	Off-Peak	21.90%	1355
APS	Shoulder	Super-Peak	22.30%	1104
APS	Shoulder	Peak	24.90%	1328
APS	Shoulder	Off-Peak	10.00%	1901

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report
APS Market Power Analysis (Base Case)

Destination Market	APS
Period	Summer Super Peak
Destination Market Price	55
HHI	1188

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
AEPC	451	313	2
AES_CA_S	3199	244	1.5
ANHM	808	61	0.4
APS	4390	3565	22.3
BEPC	579	5	0
BHPL	351	3	0
CGC_CA_N	1009	0	0
CSU	501	4	0
DGT	252	2	0
DUK_CA_N	2052	0	0
EPE	1318	665	4.2
HOU_CA_S	3010	229	1.4
ICPA	340	11	0.1
IID	475	47	0.3
IPC	2374	38	0.2
LDWP	5640	1632	10.2
MPC	72	2	0
NCPA	533	0	0
NEVP	2145	1415	8.9
NRG_CA_S	1583	121	0.8
PACE	5140	510	3.2
PASA	257	27	0.2
PEGT	229	19	0.1
PG_E	11088	208	1.3
PNM	1533	770	4.8
PPL_MT	2089	0	0
PRPA	370	3	0
PV_PVER_MO	42	41	0.3
SCE	7839	1494	9.4
SDGE	617	47	0.3
SEI_CA_N	2400	0	0
SPP	638	4	0
SRP	3495	2780	17.4
TCK_CA_S	239	18	0.1
TEP	1481	661	4.1
TSGT	1043	8	0.1
UPD_CA_S	579	0	0
WACM	2428	54	0.3
WALC	1218	969	6.1
	74094	15971	100

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report

APS Market Power Analysis (Base Case)

Destination Market	APS
Period	Summer On-Peak
Destination Market Price	35
HHI	1197

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
AEPC	382	253	1.6
ANHM	767	81	0.5
APS	4040	3366	21.9
BEPC	577	9	0.1
BHPL	284	5	0
CGC_CA_N	1005	0	0
CSU	425	7	0
DGT	246	4	0
DUK_CA_N	1778	0	0
EPE	1133	686	4.5
HOU_CA_S	1793	190	1.2
ICPA	339	15	0.1
IID	467	59	0.4
IPC	1909	56	0.4
LDWP	3131	1820	11.9
MPC	11	0	0
NCPA	403	0	0
NEVP	1962	1189	7.7
NRG_CA_S	799	85	0.6
PACE	5086	947	6.2
PASA	83	16	0.1
PEGT	228	24	0.2
PG_E	7583	288	1.9
PNM	1382	988	6.4
PPL_MT	1933	0	0
PRPA	369	6	0
PV_PVER_MO	42	40	0.3
SCE	7298	1792	11.7
SDGE	614	65	0.4
SPP	580	6	0
SRP	3255	2438	15.9
TEP	1288	622	4.1
TSGT	954	15	0.1
WACM	1244	75	0.5
WALC	307	203	1.3
	55891	15350	100

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report

APS Market Power Analysis (Base Case)

Destination Market	APS
Period	Summer Off-Peak
Destination Market Price	25
HHI	1277

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
AEPC	315	125	0.9
ANHM	710	131	0.9
APS	3376	3071	22
BEPC	567	11	0.1
BHPL	256	5	0
CGC_CA_N	977	0	0
CSU	411	8	0.1
DGT	239	4	0
EPE	586	556	4
ICPA	330	15	0.1
IID	301	64	0.5
IPC	1335	57	0.4
LDWP	2252	1234	8.8
MPC	11	0	0
NCPA	302	0	0
NEVP	1556	696	5
PACE	4699	782	5.6
PASA	81	21	0.2
PEGT	222	48	0.3
PG_E	5257	490	3.5
PNM	1169	1133	8.1
PPL_MT	1710	0	0
PRPA	363	7	0
PV_PVER_MO	41	40	0.3
SCE	6060	2336	16.7
SDGE	517	95	0.7
SPP	222	6	0
SRP	2547	2272	16.2
TEP	1045	622	4.5
TSGT	927	17	0.1
WACM	634	69	0.5
WALC	164	65	0.5
	39272	13981	100

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report

APS Market Power Analysis (Base Case)

Destination Market	APS
Period	Winter Super Peak
Destination Market Price	55
HHI	1225

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
AEPC	451	296	1.8
AES_CA_S	3199	232	1.4
ANHM	812	59	0.4
APS	4596	3908	24.1
BEPC	578	7	0
BHPL	378	5	0
CGC_CA_N	1009	0	0
CSU	495	6	0
DGT	253	3	0
DUK_CA_N	2051	0	0
EPE	1336	692	4.3
HOU_CA_S	3039	221	1.4
ICPA	345	14	0.1
IID	426	41	0.3
IPC	2498	52	0.3
LDWP	5652	1594	9.8
MPC	72	3	0
NCPA	533	0	0
NEVP	2184	1333	8.2
NRG_CA_S	1618	118	0.7
PACE	5165	609	3.8
PASA	258	26	0.2
PEGT	229	18	0.1
PG_E	11066	198	1.2
PNM	1537	963	5.9
PPL_MT	2096	0	0
PRPA	370	5	0
PV_PVER_MO	42	41	0.3
SCE	7839	1421	8.8
SDGE	617	45	0.3
SEI_CA_N	2399	0	0
SPP	670	6	0
SRP	3561	2735	16.9
TCK_CA_S	239	17	0.1
TEP	1481	660	4.1
TSGT	1059	13	0.1
UPD_CA_S	579	0	0
WACM	2354	85	0.5
WALC	1205	789	4.9
	74569	16214	100

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report
APS Market Power Analysis (Base Case)

Destination Market	APS
Period	Winter On-Peak
Destination Market Price	35
HHI	1194

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
AEPC	382	293	1.9
ANHM	770	86	0.6
APS	4121	3451	22.4
BEPC	577	9	0.1
BHPL	284	5	0
CGC_CA_N	1005	0	0
CSU	413	7	0
DGT	248	4	0
DUK_CA_N	1777	0	0
EPE	1143	689	4.5
HOU_CA_S	1793	202	1.3
ICPA	343	16	0.1
IID	425	57	0.4
IPC	2275	60	0.4
LDWP	3069	1566	10.1
MPC	11	1	0
NCPA	354	0	0
NEVP	2001	1401	9.1
NRG_CA_S	799	90	0.6
PACE	5130	1140	7.4
PASA	82	16	0.1
PEGT	228	23	0.2
PG_E	7029	307	2
PNM	1385	994	6.4
PPL_MT	2024	0	0
PRPA	369	6	0
PV_PVER_MO	42	41	0.3
SCE	6915	1615	10.5
SDGE	613	69	0.4
SPP	611	6	0
SRP	3274	2465	16
TEP	1288	622	4
TSGT	953	16	0.1
WACM	1045	72	0.5
WALC	130	100	0.6
	55031	15428	100

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report

APS Market Power Analysis (Base Case)

Destination Market	APS
Period	Winter Off-Peak
Destination Market Price	15
HHI	1358

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
ANHM	423	98	0.8
APS	3243	2617	22
BHPL	25	1	0
CGC_CA_N	987	0	0
CSU	183	2	0
DGT	240	3	0
EPE	595	580	4.9
IID	12	12	0.1
IPC	438	124	1
LDWP	1447	1034	8.7
MPC	11	3	0
NCPA	293	0	0
NEVP	958	614	5.1
PACE	512	151	1.3
PASA	9	8	0.1
PG_E	5095	624	5.2
PNM	497	488	4.1
PPL_MT	122	0	0
PV_PVER_MO	42	41	0.3
SCE	5175	2554	21.4
SDGE	523	121	1
SPP	99	25	0.2
SRP	1917	1600	13.4
TEP	1048	905	7.6
WACM	518	248	2.1
WALC	109	69	0.6
	26336	11921	100

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report

APS Market Power Analysis (Base Case)

Destination Market	APS
Period	Shoulder Super Peak
Destination Market Price	55
HHI	1146

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
AEPC	418	299	1.9
AES_CA_S	2856	239	1.6
ANHM	771	64	0.4
APS	4025	3321	21.6
BEPC	510	5	0
BHPL	340	3	0
CGC_CA_N	958	0	0
CSU	457	4	0
DGT	227	2	0
DUK_CA_N	1811	0	0
EPE	1211	617	4
HOU_CA_S	2702	226	1.5
ICPA	309	11	0.1
IID	441	45	0.3
IPC	2277	43	0.3
LDWP	5178	1659	10.8
MPC	72	3	0
NCPA	521	0	0
NEVP	2021	1378	9
NRG_CA_S	1455	122	0.8
PACE	4604	552	3.6
PASA	240	27	0.2
PEGT	208	18	0.1
PG_E	10640	228	1.5
PNM	1386	759	4.9
PPL_MT	1924	0	0
PRPA	331	3	0
PV_PVER_MO	36	36	0.2
SCE	7336	1390	9
SDGE	557	46	0.3
SEI_CA_N	2142	0	0
SPP	617	5	0
SRP	3187	2568	16.7
TCK_CA_S	224	19	0.1
TEP	1345	628	4.1
TSGT	934	8	0.1
UPD_CA_S	536	0	0
WACM	2395	60	0.4
WALC	1216	1008	6.5
	68701	15393	100

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report
APS Market Power Analysis (Base Case)

Destination Market	APS
Period	Shoulder On-Peak
Destination Market Price	35
HHI	1412

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
AEPC	350	126	1
ANHM	730	64	0.5
APS	3682	3010	24.3
BEPC	508	6	0.1
BHPL	274	3	0
CGC_CA_N	953	0	0
CSU	376	5	0
DGT	221	3	0
DUK_CA_N	1549	0	0
EPE	1030	614	5
ICPA	308	10	0.1
IID	436	47	0.4
IPC	1881	43	0.3
LDWP	2849	1066	8.6
MPC	11	0	0
NCPA	367	0	0
NEVP	1841	676	5.5
PACE	4550	557	4.5
PASA	74	13	0.1
PEGT	207	23	0.2
PG_E	6968	240	1.9
PNM	1243	788	6.4
PPL_MT	1789	0	0
PRPA	330	4	0
PV_PVER_MO	36	36	0.3
SCE	6674	1912	15.4
SDGE	553	49	0.4
SPP	559	5	0
SRP	2929	2368	19.1
TEP	1156	585	4.7
TSGT	846	10	0.1
WACM	959	47	0.4
WALC	212	76	0.6
	50638	12387	100

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report
APS Market Power Analysis (Base Case)

Destination Market	APS
Period	Shoulder Off-Peak
Destination Market Price	10
HHI	1896

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
ANHM	403	144	1.8
APS	797	797	10
BHPL	25	3	0
CSU	3	0	0
DGT	3	0	0
EPE	430	430	5.4
IID	24	15	0.2
IPC	392	269	3.4
LDWP	706	706	8.9
MPC	10	6	0.1
NEVP	511	511	6.4
PACE	134	134	1.7
PASA	7	7	0.1
PG_E	4644	166	2.1
PNM	278	278	3.5
PPL_MT	116	0	0
PV_PVER_MO	36	36	0.5
SCE	4001	3108	39
SDGE	450	161	2
SPP	75	42	0.5
SRP	518	518	6.5
WACM	496	496	6.2
WALC	132	132	1.7
	15456	7962	100

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report

APS Market Power Analysis (Including expected 2001 constructions)

Destination Market	APS
Period	Summer Super Peak
Destination Market Price	55
HHI	1145

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
AEPC	452	276	1.6
AES_CA_S	3204	239	1.4
ANHM	810	60	0.4
APS	4741	3917	23
BEPC	563	6	0
BHPL	342	3	0
CGC	1459	273	1.6
CSU	488	5	0
DGT	245	2	0
DUK_CA_N	2057	0	0
EPE	1320	665	3.9
HOU	4134	1177	6.9
ICPA	341	10	0.1
IID	475	46	0.3
IPC	2380	38	0.2
LDWP	5648	1493	8.8
MPC	73	2	0
NCPA	534	0	0
NEVP	2148	1258	7.4
NRG_CA_S	1586	118	0.7
PACE	5148	466	2.7
PASA	257	27	0.2
PEGT	230	19	0.1
PG_E	11116	204	1.2
PNM	1654	769	4.5
PPL_MT	2094	0	0
PRPA	360	4	0
PV_PVER_MO	42	41	0.2
SCE	7851	1463	8.6
SDGE	618	46	0.3
SEI_CA_N	2406	0	0
SPP	640	4	0
SRP	3498	2785	16.4
TCK_CA_S	240	18	0.1
TEP	1482	661	3.9
UPD_CA_S	580	0	0
WACM	2362	58	0.3
WALC	1219	858	5
	75084	17011	100

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report

APS Market Power Analysis (Including expected 2001 constructions)

Destination Market	APS
Period	Summer On-Peak
Destination Market Price	35
HHI	1144

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
AEPC	382	223	1.4
ANHM	769	79	0.5
APS	4391	3716	22.7
BEPC	560	11	0.1
BHPL	276	6	0
CGC	1454	260	1.6
CSU	412	8	0.1
DGT	239	5	0
DUK_CA_N	1781	0	0
EPE	1134	687	4.2
HOU	2914	1126	6.9
ICPA	340	15	0.1
IID	467	58	0.4
IPC	1912	57	0.3
LDWP	3134	1649	10.1
MPC	11	0	0
NCPA	404	0	0
NEVP	1964	1052	6.4
NRG_CA_S	800	83	0.5
PACE	5092	863	5.3
PASA	83	16	0.1
PEGT	229	24	0.1
PG_E	7597	283	1.7
PNM	1502	987	6
PPL_MT	1937	0	0
PRPA	359	7	0
PV_PVER_MO	42	40	0.2
SCE	7306	1749	10.7
SDGE	615	63	0.4
SPP	581	6	0
SRP	3256	2438	14.9
TEP	1289	622	3.8
WACM	1208	81	0.5
WALC	307	179	1.1
	56943	16395	100

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report

APS Market Power Analysis (Including expected 2001 constructions)

Destination Market	APS
Period	Summer Off-Peak
Destination Market Price	25
HHI	1276

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
AEPC	316	125	0.9
ANHM	712	131	0.9
APS	3378	3071	22
BEPC	545	14	0.1
BHPL	246	6	0
CGC	980	0	0
CSU	395	10	0.1
DGT	230	6	0
EPE	587	556	4
ICPA	331	15	0.1
IID	301	64	0.5
IPC	1338	61	0.4
LDWP	2255	1234	8.8
MPC	11	0	0
NCPA	303	0	0
NEVP	1558	697	5
PACE	4707	782	5.6
PASA	81	21	0.2
PEGT	222	48	0.3
PG_E	5271	490	3.5
PNM	1170	1133	8.1
PPL_MT	1714	0	0
PRPA	349	9	0.1
PV_PVER_MO	41	40	0.3
SCE	6070	2336	16.7
SDGE	519	95	0.7
SPP	223	6	0
SRP	2549	2272	16.2
TEP	1046	623	4.5
WACM	610	75	0.5
WALC	164	65	0.5
	38312	13985	100

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report

APS Market Power Analysis (Including expected 2001 constructions)

Destination Market	APS
Period	Winter Super Peak
Destination Market Price	55
HHI	1186

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
AEPC	452	261	1.5
AES_CA_S	3204	228	1.3
ANHM	814	58	0.3
APS	4947	4257	24.7
BEPC	563	8	0
BHPL	368	6	0
CGC	1459	258	1.5
CSU	482	7	0
DGT	246	4	0
DUK_CA_N	2056	0	0
EPE	1338	692	4
HOU	4164	1155	6.7
ICPA	345	14	0.1
IID	426	40	0.2
IPC	2504	52	0.3
LDWP	5661	1451	8.4
MPC	73	3	0
NCPA	534	0	0
NEVP	2187	1182	6.8
NRG_CA_S	1620	115	0.7
PACE	5173	564	3.3
PASA	258	26	0.1
PEGT	230	18	0.1
PG_E	11094	195	1.1
PNM	1658	962	5.6
PPL_MT	2102	0	0
PRPA	360	5	0
PV_PVER_MO	42	41	0.2
SCE	7850	1405	8.1
SDGE	618	44	0.3
SEI_CA_N	2405	0	0
SPP	671	6	0
SRP	3564	2736	15.9
TCK_CA_S	239	17	0.1
TEP	1482	661	3.8
UPD_CA_S	580	0	0
WACM	2290	92	0.5
WALC	1206	696	4
	75542	17256	100

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report

APS Market Power Analysis (Including expected 2001 constructions)

Destination Market	APS
Period	Winter On-Peak
Destination Market Price	35
HHI	1140

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
AEPC	382	256	1.6
ANHM	771	83	0.5
APS	4472	3789	23
BEPC	560	12	0.1
BHPL	276	6	0
CGC	1454	300	1.8
CSU	401	8	0.1
DGT	240	5	0
DUK_CA_N	1780	0	0
EPE	1144	688	4.2
HOU	2913	1173	7.1
ICPA	344	15	0.1
IID	425	55	0.3
IPC	2278	61	0.4
LDWP	3072	1414	8.6
MPC	11	0	0
NCPA	355	0	0
NEVP	2003	1230	7.5
NRG_CA_S	800	87	0.5
PACE	5135	1026	6.2
PASA	83	16	0.1
PEGT	228	23	0.1
PG_E	7040	296	1.8
PNM	1506	988	6
PPL_MT	2027	0	0
PRPA	359	8	0
PV_PVER_MO	42	41	0.2
SCE	6922	1580	9.6
SDGE	614	66	0.4
SPP	612	6	0
SRP	3276	2454	14.9
TEP	1288	622	3.8
WACM	1015	76	0.5
WALC	130	87	0.5
	56082	16473	100

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report

APS Market Power Analysis (Including expected 2001 constructions)

Destination Market	APS
Period	Winter Off-Peak
Destination Market Price	15
HHI	1355

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
ANHM	424	98	0.8
APS	3245	2617	21.9
BHPL	24	1	0
CGC	990	0	0
CSU	176	1	0
DGT	232	3	0
EPE	595	580	4.9
IID	12	12	0.1
IPC	439	129	1.1
LDWP	1449	1034	8.7
MPC	11	3	0
NCPA	294	0	0
NEVP	959	614	5.1
PACE	513	151	1.3
PASA	9	8	0.1
PG_E	5111	625	5.2
PNM	497	488	4.1
PPL_MT	123	0	0
PV_PVER_MO	42	41	0.3
SCE	5184	2555	21.4
SDGE	524	122	1
SPP	100	25	0.2
SRP	1919	1601	13.4
TEP	1049	906	7.6
WACM	500	257	2.2
WALC	109	69	0.6
	25505	11940	100

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report

APS Market Power Analysis (Including expected 2001 constructions)

Destination Market	APS
Period	Shoulder Super Peak
Destination Market Price	55
HHI	1104

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
AEPC	419	263	1.6
AES_CA_S	2861	234	1.4
ANHM	773	63	0.4
APS	4370	3667	22.3
BEPC	496	5	0
BHPL	331	4	0
CGC	1400	276	1.7
CSU	445	5	0
DGT	221	2	0
DUK_CA_N	1816	0	0
EPE	1213	617	3.8
HOU	3806	1164	7.1
ICPA	310	11	0.1
IID	442	45	0.3
IPC	2283	42	0.3
LDWP	5186	1511	9.2
MPC	73	2	0
NCPA	522	0	0
NEVP	2024	1224	7.5
NRG_CA_S	1457	119	0.7
PACE	4612	502	3.1
PASA	240	26	0.2
PEGT	209	18	0.1
PG_E	10667	224	1.4
PNM	1505	758	4.6
PPL_MT	1929	0	0
PRPA	322	3	0
PV_PVER_MO	36	36	0.2
SCE	7347	1366	8.3
SDGE	558	45	0.3
SEI_CA_N	2147	0	0
SPP	619	5	0
SRP	3189	2573	15.7
TCK_CA_S	224	18	0.1
TEP	1346	628	3.8
UPD_CA_S	537	0	0
WACM	2330	64	0.4
WALC	1217	893	5.4
	69762	16415	100

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report

APS Market Power Analysis (Including expected 2001 constructions)

Destination Market	APS
Period	Shoulder On-Peak
Destination Market Price	35
HHI	1328

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
AEPC	350	115	0.9
ANHM	731	63	0.5
APS	4026	3343	24.9
BEPC	493	8	0.1
BHPL	266	4	0
CGC	1393	144	1.1
CSU	365	6	0
DGT	214	3	0
EPE	1031	614	4.6
HOU	2672	815	6.1
ICPA	308	10	0.1
IID	437	46	0.3
IPC	1884	44	0.3
LDWP	2851	999	7.4
MPC	11	0	0
NCPA	367	0	0
NEVP	1842	618	4.6
PACE	4555	520	3.9
PASA	74	13	0.1
PEGT	208	24	0.2
PG_E	6979	237	1.8
PNM	1360	788	5.9
PPL_MT	1792	0	0
PRPA	320	5	0
PV_PVER_MO	36	36	0.3
SCE	6680	1855	13.8
SDGE	554	48	0.4
SPP	560	4	0
SRP	2930	2348	17.5
TEP	1156	585	4.4
WACM	930	50	0.4
WALC	212	69	0.5
	51759	13415	100

Competitive Analysis Screening Model (CASm v7.3)

Supplier Report

APS Market Power Analysis (Including expected 2001 constructions)

Destination Market	APS
Period	Shoulder Off-Peak
Destination Market Price	10
HHI	1901

Supplier	BASE Available (MW)	Supplied (MW)	Market Share (%)
ANHM	404	145	1.8
APS	798	798	10
BHPL	24	3	0
CSU	3	0	0
DGT	3	0	0
EPE	431	431	5.4
IID	24	15	0.2
IPC	393	270	3.4
LDWP	708	708	8.9
MPC	10	6	0.1
NEVP	512	512	6.4
PACE	135	135	1.7
PASA	7	7	0.1
PG_E	4654	167	2.1
PNM	278	278	3.5
PPL_MT	116	0	0
PV_PVER_MO	36	36	0.5
SCE	4006	3114	39.1
SDGE	451	162	2
SPP	76	42	0.5
SRP	519	519	6.5
WACM	482	482	6.1
WALC	132	132	1.7
	15466	7962	100

Abbreviations Used

Node Name	Full Company Name
AEPC	Arizona Electric Power Coop.
AES_CA_S	AES Corp.
ANHM	Anaheim CA, City of
APL	Alberta Power Limited
APS	Arizona Public Service Company
BCHA	British Columbia Hydro & Power Authority
BEPC	Basin Electric Power Cooperative
BHPL	Black Hills Power & Light
BPA	Bonneville Power Authority
CCSF	San Francisco, City of
CDWR	Department of Water Resources/California
CFE	Comision Federal de Electricidad
CGC_CA_N	Calpine Geysers Co., L.P.
CHPD	Chelan County PUD No. 1
CLPD	Clark Public Utilities
CSU	Colorado Springs Utilities
DGT	Deseret Generation & Transmission Co-operative
DOPD	Douglas County PUD No. 1
DUK_CA_N	Duke
DYN_CA_S	Dynegy
EDP	Edmonton Power
EPE	El Paso Electric Company
FPL_CA_N	FPL Group
GCPD	Grant County PUD
HOU_CA_S	Houston Industries
ICPA	Intermountain Consumer Power Association
IID	Imperial Irrigation District
IPC	Idaho Power Company
LDWP	Los Angeles Department of Water and Power (Non_WESCO)
MPC	Montana Power Company
NCPA	Northern California Power Agency
NEVP	Nevada Power Company
NRG_CA_S	NRG
PACE	PacifiCorp East
PACW	Pacificorp West
PASA	Pasadena CA, City of
PEGT	Plains Electric G&T Coop
PG&E	Pacific Gas & Electric Company
PGE	Portland General Electric
PNM	Public Service of New Mexico
PPL_MT	PPL
PRPA	Platte River Power Authority
PSC	Public Service of Colorado
PSE	Puget Sound Power & Light
SCE	Southern California Edison Company
SCL	Seattle City Light
SDGE	San Diego Gas & Electric
SEI_CA_N	SEI

Abbreviations Used

SMUD	Sacramento Municipal Utility District
SPP	Sierra Pacific
SRP	Salt River Project
TAUC	Transalta Utilities Corp.
TCK_CA_S	Thermo Ecotek
TCL	Tacoma City Light
TEP	Tucson Electric Power Company
TID	Turlock Irrigation District
TSGT	Tri-Sate Generation and Transmission Association
UPD_CA_S	San Diego Unified Port District
USLC	U.S. Bureau of Reclamation - Lower Colorado
WACM	WAPA - CM
WALC	WAPA - DSW
WALM	WAPA - LM
WAMP	WAPA - SN
WAOR	Washinton-Oregon Composite
WKP	West Kootenay Power Ltd.
WPE	WestPlains Energy
WWPC	Washington Water Power Company

Non-Node Companies Making Purchases or Sales

Abbreviation	Company Name
ACC	Altamont Cogeneration Corp.
AETC	Amoco Energy Trading Corp.
AGV	Amedee Geothermal Venture I
AHAD	U.S. Army Hawthorne Ammo Depot
AMAT	American Atlas No. 1, Ltd.
AMOR	Amor II Empire Farms
APPA	Arizona Power Pooling Assoc.
ARCO	ARCO Oil & Gas
AZSA	Azusa Light & Water Dept.
BCH	Birch Creek Hydro
BCL	Badger Creek, Ltd.
BCOG	Brush Cogeneration Partners
BCWW	Big Creek Water Works, Ltd.
BEP	BIO-Energy Partners
BFP	Burney Forest Products
BGEO	Beowawe Geothermal
BGI	Billings Generation, Inc.
BHC	Big Horn County Electric Coop, Inc.
BIO	Biomass One, L.P.
BLED	Blanding Electric Dept.
BML	Bear Mountain, Ltd.
BMP	Burney Mountain Power
BNNG	Banning Electric Dept.
BOUL	Boulder 75th Street
BOYD	Boyd, James
BPAC	Bonneville Pacific Corp.

Abbreviations Used

BPC	Berry Petroleum Co.
BPP	Brady Power Partners
BREM	Bremerton, Port of
BRIG	Brigham City Light & Power
BROW	Brownsville, Port of
BURL	Burlington Municipal Light & Power
BVLC	Big Valley Lumber Co.
CALR	CalResources, L.L.C.
CANB	Canby Electric Board
CARD	Cardinal Cogen
CBET	Boulder/Betasso, City of
CBRT	Boulder City of/Roberts Tunnel
CCA	Container Corp. of America
CCCL	Chalk Cliff Cogen, Ltd.
CCOG	Coalinga Cogeneration Co.
CCWD	Calaveras County Water District
CDMH	CDM Hydro
CDN	California Dept of Navy
CECO	Cook Electric Co.
CEMC	Commercial Energy Management Co.
CEN	Colstrip Energy, L.P.
CGP	Calistoga Geothermal Partners
CHEV	Chevron USA, Inc.
CLFC	Cheyenne Light, Fuel & Power Co.
CMT	Central Montana Electric Power Coop
CMU	Center Municipal Utility System
CODM	Des Moines, City of
COID	Central Oregon Irrigation District
COLL	Collins Pine Co.
COLT	Colton Electric Utility Dept.
COO	Ouray, City of
COOH	Oak Harbor, City of
COPP	Colorado Power Partners
COSF	San Francisco, City & County of
COSS	Strontia Springs, City of
COV	Vallelito, City of
COWW	Walla Walla, City of
COXE	Cogentrix Energy, Inc.
CROC	Crockett Cogen
DCC	Dow Chemical Co.
DCL	Double C, Ltd.
DDP	Dillon Dam Project
DEX	Dexzel, Inc.
DMS	Denver Metro Sewage
DPPP	Desert Peak Power Plant
DRJL	D.R. Johnson Lumber Co.
DWGI	Diamond Walnut Growers, Inc.
DYN	Dynamis, Inc.
EGP	Energy Growth Partnership I

Abbreviations Used

ELDH	El Dorado Hydro (Montgomery Creek)
ENSI	Energy Services, Inc.
EWEB	Eugene Water & Electric Board
EWEB	Eugene Water & Electric Board
FAIR	Fairhaven Power Co.
FALE	Fale-Safe, Inc.
FCHP	Falls Creek HP, L.P.
FID	Farmers Irrigation District
FLOW	Flowind Corp.
FMES	Fallon Municipal Electric System
FNA	Fiberweb North America
FNA	Fiberweb North America
FOOT	Foothills Water Treatment
FPA	Friant Power Authority
FRITO	Frito Lay, Inc.
GALL	Gallup Electric Utility
GATX	GATX-Calpine Cogen.-Agnews, Inc.
GCC	Gaylord Container Corp.
GDH	Galesville Dam Hydro
GEP	Geothermal Energy Partners, L.P.
GILL	Gillette Municipal Power Dept.
GLPC	Garland Light & Power Co.
GPC	Georgia Pacific Corp.
GREEL	Greeley Gas Co. Division of Atmos Energy
GUOA	Greenleaf Unit One Associates, Inc.
GUTA	Greenleaf Unit Two Associates, Inc.
GVR	Grand Valley Rural Power Line, Inc.
GWF	GWF Power Systems, L.P.
HADS	Hadson Corp.
HANF	Hanford, L.P.
HAYH	Haypress Hydroelectric, Inc.
HCE	Holy Cross Electric Assoc., Inc.
HCLP	Helper City Light & Power Dept.
HCUS	Hershey Chocolate USA
HERM	Hermiston Generating Co., L.P.
HLPC	Honey Lake Power Co.
HMWD	Humboldt Bay Municipal Water District
HSL	High Sierra, Ltd.
HWI	Howden Windparks, Inc.
HYDY	Hydrodynamics, Inc.
IMTR	Intermountain Rural Electric Association
IPA	Intermountain Power Agency
ISCI	IPT SRI Cogeneration, Inc.
ITRI	International Turbine Research, Inc.
IVHP	Indian Valley Hydroelectric Partners
JMK	J.M. Keating (Rock Creek)
JULE	Julesburg Municipal Power & Light
JVEP	Jackson Valley Energy Partners, L.P.
KESK	KES Kingsburg, L.P.

Abbreviations Used

KFL	Kern Front, Ltd.
KING	Kingston, Port of
KWI	Kenetech Windpower, Inc.
LGP	Landfill General Partnership I
LGRS	Laidlaw Gas Recovery Systems, Inc.
LID	Lacomb Irrigation District
LMUD	Lassen Municipal Utility District
LOL	Live Oak, Ltd.
MBPL	Mendota Biomass Power, Ltd.
MCC	Midset Cogeneration Co.
MCH	Mink Creek Hydro
MCKL	McKittrick, Ltd.
MCLP	Martinez Cogen, L.P.
MCPA	Madera-Chowchilla Power Authority
MDNR	Montana Dept. of Natural Resources
MEGA	MEGA Renewables
MELP	Modesto Energy, L.P.
MERC	Merced Irrigation District
MHLP	Malacha Hydro, L.P.
MID	Middlefork Irrigation District
MLP	Mount Lassen Power
MONT	Monterey County Flood Center & Water Conservation
MPCC	Mount Poso Cogeneration Co.
MPLP	Midsun Partners, L.P.
MSCC	Midway Sunset Cogen Co.
MTEH	Mount Elbert Hydro
MVDI	Marsh Valley Development, Inc.
MWWR	Metropolitan Waste Water Reclamation District
NCPI	Nelson Creek Power, Inc.
NEI	Northwind Energy, Inc.
NFS	North Fork Sprague
NGCE	NGC Energy Systems, Inc. (Agrico Cogeneration)
NID	Nevada Irrigation District
NOVE	Nove Investments, Inc.
NSFH	NID & Scotts Flat Hydro
NTUA	Navajo Tribal Utility Authority
NUEV	Nuevo Energy Co.
NWPC	Northwest Pipeline Corp.
OCP	Oildale Cogeneration Partners, L.P.
OLSE	OLS Energy Berkeley
OPPI	Olsen Power Partners, Inc.
OSH	Opal Springs Hydro
OTCC	Oregon Trail Electric Consumer Coop, Inc.
OWD	Olcese Water District
PACE	Pacific Energy
PACL	Pacific Lumber
PCLC	PUD No. 1 of Clark County
PCOC	PUD No. 1 of Cowlitz County
PCU	Price City Utilities

Abbreviations Used

PKCO	PUD No. 1 of Kittitas County
PLGC	Palo Alto Landfill Gas Corp.
POKC	PUD No. 1 of Okanogan County
POP	Pacific Oroville Power
POUL	Poulsbo Port District
PPC	POSDEF Power Co., L.P.
PPW	Patterson Pass Windfarm, L.L.C.
PRC	Power Resources Coop.
PUCH	Pacific Ultrapower Chinese
RBN	Ross, Burgess Norman
RBP	Rio Bravo Poso
RDNG	Redding Electric Dept.
RIPC	Ripon Cogeneration, Inc.
RPBC	Rhone-Poulenc Basic Chemicals
RVSD	Riverside Utilities Dept.
RWPC	Redlands Water & Power Co.
SCCC	Sargent Canyon Cogeneration Co.
SCHA	Slate Creek Hydro Assoc., L.P.
SCOG	Stockton Cogeneration Co.
SCPI	Shell California Production, Inc.
SCWA	Sonoma County Water Agency
SDC	Steamboat Development Corp.
SDCH	Stauffer Dry Creek Hydro
SEAT	Seattle, Port of
SEAW	Seawest Windfarms, Inc.
SEHA	SEH America, Inc.
SES	Steamboat Environ Systems
SGS	Star Group Stillwater I
SISK	Lake Siskiyou
SJC	San Jose Cogeneration
SJCL	San Joaquin CoGen, Ltd.
SJID	South San Joaquin Irrigation District
SJPC	San Joaquin Power Co.
SKAG	Skagit County, Port of
SMHL	Snow Mountain Hydro, L.L.C.
SNPD	PUD No. 1 of Snohomish County
SODA	Soda Lake, L.P.
SPII	Sierra Pacific Industries, Inc.
SRCC	Salinas River Cogeneration Co.
STAGE	Stagecoach
STSH	STS Hydropower, Ltd.
SUB	Springfield Utility Board
SUNH	Sunshine Hydro
SVP	Silicon Valley Power
SWE	Stanislaus Waste Energy
TCI	Truckee Carson Irrigation
TDPA	Tri-Dam Power Authority
TEDP	Thermal Energy Development Partners, L.P.
TEXO	Texaco Oil

Abbreviations Used

THCI	Thermo Carbonic, Inc.
THII	Thermo Industries, Inc.
TKO	TKO
TOPM	Texas-Ohio Power Marketing, Inc.
TOSH	Toshiba America, Inc.
TOUA	Tohono O'Odham Utility Authority
TPUD	Truckee-Donner Public Utility District
UCO	University of Colorado
UCOG	United Cogen, Inc.
UMPA	Utah Municipal Power Agency
UNCO	University of Northern Colorado
USMV	USBIA-Mission Valley Power
VLPD	Vernon Light & Power Dept.
WAFE	Wafertech
WBC	WEA Baker Creek
WBPL	Woodland Biomass Power, Ltd.
WELP	Wadham Energy, L.P.
WICK	Wickenburg Utilities System
WILL	Williams, City of
WLI	Wheelabrator Lassen, Inc.
WMI	WindMaster, Inc.
WSPE	Warm Springs Power Enterprises
WTI	Wheelabrator Technologies, Inc.
YAMP	Yampa Valley Electric Assoc., Inc.
YANK	Yankee Caithness Joint Venture, L.P.
YCA	Yountville Cogeneration Assoc.
YCCP	Yuba City Cogen Partners, L.P.
YCWA	Yuba County Water Agency
YEPI	Yolo Energy Partners, Inc.
YTID	Yakima-Tieton Irrigation District
ZOND	Zond Systems, Inc.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report

APS Market Power Analysis (Base Case)

Destination	APS (APS)
Load Type	Summer Super Peak

		BASE	
From	To	Limit (MW)	Flow (MW)
AEPC	WALC	90000	326
AES_CA_S	SCE	90000	96
ANHM	SCE	90000	1002
BEPC	WACM	90000	5
BHPL	WACM	90000	3
CGC_CA_N	PG_E	90000	0
CSU	WACM	90000	4
DGT	WACM	90000	2
DUK_CA_N	PG_E	90000	0
EPE	TEP	519	177
FCORN	APS	1340	1340
FCORN	NAVAJO	1903	11
FCORN	TEP	1554	199
FC_APS	FCORN	90000	299
FC_EPE	FCORN	90000	35
FC_PNM	FCORN	90000	65
FC_SCE	FCORN	90000	239
FC_SRP	FCORN	90000	50
HOU_CA_S	SCE	90000	90
ICPA	PACE	90000	12
IID	PVERDE	1	1
IID	SCE	600	13
IPC	WACM	768	48
LDWP	WALC	2410	1272
MPC	IPC	2	2
MPC	PACE	400	1
NAVAJO	APS	2264	2264
NAV_APS	NAVAJO	90000	164
NAV_LDWP	NAVAJO	90000	162
NAV_NEVP	NAVAJO	90000	86
NAV_SRP	NAVAJO	90000	352
NCPA	PG_E	90000	0
NEVP	WALC	90000	1432
NRG_CA_S	SCE	90000	48
PACE	FCORN	600	559
PASA	SCE	90000	7
PEGT	EPE	90000	20
PG_E	SCE	3000	85
PNM	FCORN	597	196
PNM	TEP	224	224
PPL_MT	MPC	90000	0
PRPA	WACM	90000	3

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report

APS Market Power Analysis (Base Case)

PVERDE	APS	3810	3810
PV_APS	PVERDE	90000	805
PV_EPE	PVERDE	90000	499
PV_IID	PVERDE	90000	12
PV_LDWP	PVERDE	90000	305
PV_PASA	PVERDE	90000	8
PV_PNM	PVERDE	90000	322
PV_PVER_MO	PVERDE	90000	42
PV_SCE	PVERDE	90000	499
PV_SRP	PVERDE	90000	358
SCE	NAVAJO	1505	805
SCE	PVERDE	1011	988
SDGE	SCE	2440	69
SEI_CA_N	PG_E	90000	0
SPP	IPC	192	5
SRP	APS	90000	3134
TCK_CA_S	SCE	90000	7
TEP	APS	672	672
TEP	SRP	672	593
TSGT	WACM	90000	9
UPD_CA_S	SDGE	90000	0
WACM	FCORN	200	132
WALC	APS	2800	2800
WALC	NAVAJO	6024	727
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report
APS Market Power Analysis (Base Case)

Destination APS (APS)
Load Type Summer On-Peak

From	To	BASE Limit (MW)	Flow (MW)
AEPC	WALC	90000	264
ANHM	SCE	90000	1088
BEPC	WACM	90000	10
BHPL	WACM	90000	5
CGC_CA_N	PG_E	90000	0
CSU	WACM	90000	7
DGT	WACM	90000	4
DUK_CA_N	PG_E	90000	0
EPE	TEP	519	179
FCORN	APS	1340	1340
FCORN	NAVAJO	1903	788
FCORN	TEP	1554	214
FC_APS	FCORN	90000	521
FC_EPE	FCORN	90000	61
FC_PNM	FCORN	90000	113
FC_SCE	FCORN	90000	418
FC_SRP	FCORN	90000	87
HOU_CA_S	SCE	90000	59
ICPA	PACE	90000	17
IID	PVERDE	1	1
IID	SCE	600	14
IPC	WACM	768	69
LDWP	WALC	2410	1551
MPC	IPC	2	1
NAVAJO	APS	2264	2264
NAV_APS	NAVAJO	90000	91
NAV_LDWP	NAVAJO	90000	90
NAV_NEVP	NAVAJO	90000	48
NAV_SRP	NAVAJO	90000	194
NCPA	PG_E	90000	0
NEVP	WALC	90000	1411
NRG_CA_S	SCE	90000	26
PACE	FCORN	600	600
PACE	NEVP	300	185
PACE	WALC	250	250
PASA	SCE	90000	2
PEGT	EPE	90000	26
PG_E	SCE	3000	92
PNM	FCORN	597	380
PNM	TEP	224	224
PPL_MT	MPC	90000	0
PRPA	WACM	90000	6

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report
APS Market Power Analysis (Base Case)

PVERDE	APS	3810	3810
PV_APS	PVERDE	90000	805
PV_EPE	PVERDE	90000	499
PV_IID	PVERDE	90000	12
PV_LDWP	PVERDE	90000	305
PV_PASA	PVERDE	90000	8
PV_PNM	PVERDE	90000	322
PV_PVER_MO	PVERDE	90000	42
PV_SCE	PVERDE	90000	499
PV_SRP	PVERDE	90000	358
SCE	NAVAJO	1505	759
SCE	PVERDE	1011	988
SDGE	SCE	2440	75
SPP	IPC	192	7
SRP	APS	90000	2867
TEP	APS	672	672
TEP	SRP	672	569
TSGT	WACM	90000	17
WACM	FCORN	200	195
WALC	APS	2800	2800
WALC	NAVAJO	6024	348
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report

APS Market Power Analysis (Base Case)

Destination APS (APS)
Load Type Summer Off-Peak

From	To	BASE Limit (MW)	Flow (MW)
AEPC	WALC	90000	140
ANHM	SCE	90000	1415
BEPC	WACM	90000	11
BHPL	WACM	90000	5
CGC_CA_N	PG_E	90000	0
CSU	WACM	90000	8
DGT	WACM	90000	5
EPE	TEP	519	51
FCORN	APS	1340	1340
FCORN	NAVAJO	1903	547
FCORN	TEP	1554	284
FC_APS	FCORN	90000	644
FC_EPE	FCORN	90000	75
FC_PNM	FCORN	90000	140
FC_SCE	FCORN	90000	516
FC_SRP	FCORN	90000	108
ICPA	PACE	90000	17
IID	PVERDE	1	1
IID	SCE	600	12
IPC	WACM	768	71
LDWP	WALC	2410	1595
MPC	IPC	2	1
NAVAJO	APS	2264	2264
NAV_APS	NAVAJO	90000	342
NAV_LDWP	NAVAJO	90000	337
NAV_NEVP	NAVAJO	90000	180
NAV_SRP	NAVAJO	90000	731
NCPA	PG_E	90000	0
NEVP	WALC	90000	905
PACE	LDWP	1200	346
PACE	NEVP	300	300
PACE	WALC	250	250
PASA	SCE	90000	3
PEGT	EPE	90000	53
PG_E	SCE	3000	120
PNM	FCORN	597	509
PNM	TEP	224	224
PPL_MT	MPC	90000	0
PRPA	WACM	90000	7
PVERDE	APS	3810	3810
PV_APS	PVERDE	90000	805
PV_EPE	PVERDE	90000	499

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report

APS Market Power Analysis (Base Case)

PV_IID	PVERDE	90000	12
PV_LDWP	PVERDE	90000	305
PV_PASA	PVERDE	90000	8
PV_PNM	PVERDE	90000	322
PV_PVER_MO	PVERDE	90000	42
PV_SCE	PVERDE	90000	499
PV_SRP	PVERDE	90000	358
SCE	LDWP	550	550
SCE	NAVAJO	1505	147
SCE	PVERDE	1011	988
SCE	WALC	602	374
SDGE	SCE	2440	98
SPP	IPC	192	7
SRP	APS	90000	2109
TEP	APS	672	672
TEP	SRP	672	514
TSGT	WACM	90000	19
WACM	FCORN	200	198
WALC	APS	2800	2800
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report

APS Market Power Analysis (Base Case)

Destination APS (APS)

Load Type Winter Super Peak

From	To	BASE Limit (MW)	Flow (MW)
AEPC	WALC	90000	307
AES_CA_S	SCE	90000	92
ANHM	SCE	90000	958
BEPC	WACM	90000	8
BHPL	WACM	90000	5
CGC_CA_N	PG_E	90000	0
CSU	WACM	90000	6
DGT	WACM	90000	3
DUK_CA_N	PG_E	90000	0
EPE	TEP	519	178
FCORN	APS	1340	1340
FCORN	NAVAJO	1903	784
FCORN	TEP	1554	182
FC_APS	FCORN	90000	516
FC_EPE	FCORN	90000	60
FC_PNM	FCORN	90000	112
FC_SCE	FCORN	90000	414
FC_SRP	FCORN	90000	86
HOU_CA_S	SCE	90000	87
ICPA	PACE	90000	16
IID	SCE	600	12
IPC	WACM	869	67
LDWP	WALC	2410	1301
MPC	IPC	9	3
NAVAJO	APS	2264	2264
NAV_APS	NAVAJO	90000	91
NAV_LDWP	NAVAJO	90000	90
NAV_NEVP	NAVAJO	90000	48
NAV_SRP	NAVAJO	90000	194
NCPA	PG_E	90000	0
NEVP	WALC	90000	1382
NRG_CA_S	SCE	90000	46
PACE	FCORN	600	600
PACE	WALC	250	67
PASA	SCE	90000	7
PEGT	EPE	90000	20
PG_E	SCE	3000	81
PNM	FCORN	597	353
PNM	TEP	224	224
PPL_MT	MPC	90000	0
PRPA	WACM	90000	5
PVERDE	APS	3810	3810

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report
APS Market Power Analysis (Base Case)

PV_APS	PVERDE	90000	807
PV_EPE	PVERDE	90000	501
PV_IID	PVERDE	90000	12
PV_LDWP	PVERDE	90000	306
PV_PASA	PVERDE	90000	8
PV_PNM	PVERDE	90000	323
PV_PVER_MO	PVERDE	90000	42
PV_SCE	PVERDE	90000	501
PV_SRP	PVERDE	90000	359
SCE	NAVAJO	1505	558
SCE	PVERDE	1011	979
SDGE	SCE	2440	66
SEI_CA_N	PG_E	90000	0
SPP	IPC	158	6
SRP	APS	90000	3182
TCK_CA_S	SCE	90000	7
TEP	APS	672	672
TEP	SRP	672	577
TSGT	WACM	90000	14
UPD_CA_S	SDGE	90000	0
WACM	FCORN	200	196
WALC	APS	2800	2800
WALC	NAVAJO	6024	552
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report

APS Market Power Analysis (Base Case)

Destination APS (APS)
Load Type Winter On-Peak

From	To	BASE Limit (MW)	Flow (MW)
AEPC	WALC	90000	305
ANHM	SCE	90000	1138
BEPC	WACM	90000	10
BHPL	WACM	90000	5
CGC_CA_N	PG_E	90000	0
CSU	WACM	90000	7
DGT	WACM	90000	4
DUK_CA_N	PG_E	90000	0
EPE	TEP	519	179
FCORN	APS	1340	1340
FCORN	NAVAJO	1903	824
FCORN	TEP	1554	205
FC_APS	FCORN	90000	529
FC_EPE	FCORN	90000	62
FC_PNM	FCORN	90000	115
FC_SCE	FCORN	90000	424
FC_SRP	FCORN	90000	88
HOU_CA_S	SCE	90000	61
ICPA	PACE	90000	18
IID	SCE	600	14
IPC	WACM	869	73
LDWP	WALC	2410	1357
MPC	IPC	9	1
NAVAJO	APS	2264	2264
NAV_APS	NAVAJO	90000	98
NAV_LDWP	NAVAJO	90000	96
NAV_NEVP	NAVAJO	90000	51
NAV_SRP	NAVAJO	90000	209
NCPA	PG_E	90000	0
NEVP	WALC	90000	1746
NRG_CA_S	SCE	90000	27
PACE	FCORN	600	600
PACE	LDWP	1200	92
PACE	NEVP	300	300
PACE	WALC	250	250
PASA	SCE	90000	3
PEGT	EPE	90000	26
PG_E	SCE	3000	96
PNM	FCORN	597	386
PNM	TEP	224	224
PPL_MT	MPC	90000	0
PRPA	WACM	90000	6

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report

APS Market Power Analysis (Base Case)

PVERDE	APS	3810	3810
PV_APS	PVERDE	90000	807
PV_EPE	PVERDE	90000	501
PV_IID	PVERDE	90000	12
PV_LDWP	PVERDE	90000	306
PV_PASA	PVERDE	90000	8
PV_PNM	PVERDE	90000	323
PV_PVER_MO	PVERDE	90000	42
PV_SCE	PVERDE	90000	501
PV_SRP	PVERDE	90000	359
SCE	NAVAJO	1505	621
SCE	PVERDE	1011	979
SDGE	SCE	2440	78
SPP	IPC	158	7
SRP	APS	90000	2875
TEP	APS	672	672
TEP	SRP	672	560
TSGT	WACM	90000	17
WACM	FCORN	200	198
WALC	APS	2800	2800
WALC	NAVAJO	6024	417
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report
APS Market Power Analysis (Base Case)

Destination APS (APS)
Load Type Winter Off-Peak

From	To	BASE Limit (MW)	Flow (MW)
ANHM	SCE	90000	1546
BHPL	WACM	90000	1
CGC_CA_N	PG_E	90000	0
CSU	WACM	90000	2
DGT	WACM	90000	3
FCORN	APS	1340	1340
FCORN	TEP	1554	239
FC_APS	FCORN	90000	305
FC_EPE	FCORN	90000	97
FC_PNM	FCORN	90000	180
FC_SCE	FCORN	90000	665
FC_SRP	FCORN	90000	139
IPC	PACE	1100	140
LDWP	WALC	2410	559
MPC	PACE	400	3
NAVAJO	APS	2264	2264
NAV_APS	NAVAJO	90000	430
NAV_LDWP	NAVAJO	90000	424
NAV_NEVP	NAVAJO	90000	226
NAV_SRP	NAVAJO	90000	732
NCPA	PG_E	90000	0
NEVP	WALC	90000	718
PACE	NEVP	300	150
PACE	WALC	250	250
PASA	SCE	90000	0
PG_E	SCE	3000	132
PPL_MT	MPC	90000	0
PVERDE	APS	3810	3810
PV_APS	PVERDE	90000	807
PV_EPE	PVERDE	90000	501
PV_IID	PVERDE	90000	12
PV_LDWP	PVERDE	90000	306
PV_PASA	PVERDE	90000	8
PV_PNM	PVERDE	90000	323
PV_PVER_MO	PVERDE	90000	42
PV_SCE	PVERDE	90000	501
PV_SRP	PVERDE	90000	359
SCE	NAVAJO	1505	464
SCE	PVERDE	1011	979
SCE	WALC	602	602
SDGE	SCE	2440	108
SPP	PACE	150	29

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report
APS Market Power Analysis (Base Case)

SRP	APS	90000	1425
TEP	APS	672	672
TEP	SRP	672	494
WACM	FCORN	200	200
WACM	PACE	785	74
WALC	APS	2800	1702
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report
APS Market Power Analysis (Base Case)

Destination APS (APS)
Load Type Shoulder Super Peak

From	To	BASE Limit (MW)	Flow (MW)
AEPC	WALC	90000	311
AES_CA_S	SCE	90000	90
ANHM	SCE	90000	1050
BEPC	WACM	90000	5
BHPL	WACM	90000	3
CGC_CA_N	PG_E	90000	0
CSU	WACM	90000	4
DGT	WACM	90000	2
DUK_CA_N	PG_E	90000	0
EPE	TEP	519	185
FCORN	APS	1340	1340
FCORN	NAVAJO	1903	31
FCORN	TEP	1554	225
FC_APS	FCORN	90000	285
FC_EPE	FCORN	90000	33
FC_PNM	FCORN	90000	62
FC_SCE	FCORN	90000	228
FC_SRP	FCORN	90000	48
HOU_CA_S	SCE	90000	85
ICPA	PACE	90000	12
IID	SCE	600	13
IPC	WACM	822	54
LDWP	WALC	2410	1346
MPC	IPC	2	2
MPC	PACE	400	1
NAVAJO	APS	2264	2264
NAV_APS	NAVAJO	90000	157
NAV_LDWP	NAVAJO	90000	154
NAV_NEVP	NAVAJO	90000	82
NAV_SRP	NAVAJO	90000	335
NCPA	PG_E	90000	0
NEVP	WALC	90000	1398
NRG_CA_S	SCE	90000	46
PACE	FCORN	600	600
PACE	WALC	250	4
PASA	SCE	90000	7
PEGT	EPE	90000	20
PG_E	SCE	3000	89
PNM	FCORN	597	225
PNM	TEP	224	224
PPL_MT	MPC	90000	0
PRPA	WACM	90000	3

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report

APS Market Power Analysis (Base Case)

PVERDE	APS	3810	3515
PV_APS	PVERDE	90000	715
PV_EPE	PVERDE	90000	443
PV_IID	PVERDE	90000	10
PV_LDWP	PVERDE	90000	271
PV_PASA	PVERDE	90000	7
PV_PNM	PVERDE	90000	286
PV_PVER_MO	PVERDE	90000	37
PV_SCE	PVERDE	90000	443
PV_SRP	PVERDE	90000	319
SCE	NAVAJO	1505	748
SCE	PVERDE	1011	1011
SDGE	SCE	2440	72
SEI_CA_N	PG_E	90000	0
SPP	IPC	233	5
SRP	APS	90000	2973
TCK_CA_S	SCE	90000	7
TEP	APS	672	672
TEP	SRP	672	592
TSGT	WACM	90000	9
UPD_CA_S	SDGE	90000	0
WACM	FCORN	200	143
WALC	APS	2800	2800
WALC	NAVAJO	6024	801
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report
APS Market Power Analysis (Base Case)

Destination APS (APS)
Load Type Shoulder On-Peak

From	To	BASE Limit (MW)	Flow (MW)
AEPC	WALC	90000	131
ANHM	SCE	90000	859
BEPC	WACM	90000	7
BHPL	WACM	90000	4
CGC_CA_N	PG_E	90000	0
CSU	WACM	90000	5
DGT	WACM	90000	3
EPE	TEP	519	186
FCORN	APS	1340	1340
FCORN	TEP	1554	202
FC_APS	FCORN	90000	289
FC_EPE	FCORN	90000	34
FC_PNM	FCORN	90000	63
FC_SCE	FCORN	90000	232
FC_SRP	FCORN	90000	48
ICPA	PACE	90000	11
IID	SCE	600	11
IPC	WACM	822	53
LDWP	WALC	2410	910
MPC	IPC	2	0
NAVAJO	FCORN	1731	153
NAVAJO	WALC	6024	737
NAV_APS	NAVAJO	90000	176
NAV_LDWP	NAVAJO	90000	174
NAV_NEVP	NAVAJO	90000	93
NAV_SRP	NAVAJO	90000	377
NCPA	PG_E	90000	0
NEVP	WALC	90000	628
PACE	FCORN	600	357
PACE	WALC	250	250
PASA	SCE	90000	2
PEGT	EPE	90000	26
PG_E	SCE	3000	73
PNM	FCORN	597	256
PNM	TEP	224	224
PPL_MT	MPC	90000	0
PRPA	WACM	90000	4
PVERDE	APS	3810	3515
PV_APS	PVERDE	90000	715
PV_EPE	PVERDE	90000	443
PV_IID	PVERDE	90000	10
PV_LDWP	PVERDE	90000	271

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report

APS Market Power Analysis (Base Case)

PV_PASA	PVERDE	90000	7
PV_PNM	PVERDE	90000	286
PV_PVER_MO	PVERDE	90000	37
PV_SCE	PVERDE	90000	443
PV_SRP	PVERDE	90000	319
SCE	LDWP	236	236
SCE	NAVAJO	1505	73
SCE	PVERDE	1011	1011
SCE	WALC	602	602
SDGE	SCE	2440	59
SPP	IPC	233	5
SRP	APS	90000	2650
TEP	APS	672	672
TEP	SRP	672	527
TSGT	WACM	90000	11
WACM	FCORN	200	135
WALC	APS	2800	2800
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report
APS Market Power Analysis (Base Case)

Destination APS (APS)
Load Type Shoulder Off-Peak

From	To	BASE Limit (MW)	Flow (MW)
ANHM	SCE	90000	2223
BHPL	WACM	90000	5
CSU	WACM	90000	1
DGT	WACM	90000	1
FCORN	APS	1340	778
IID	SCE	600	1
IPC	PACE	1100	472
LDWP	WALC	2410	701
MPC	IPC	2	2
MPC	PACE	400	7
NAVAJO	APS	2264	1463
NEVP	WALC	90000	624
PACE	FCORN	600	600
PACE	NEVP	300	83
PACE	WALC	250	250
PASA	SCE	90000	0
PPL_MT	MPC	90000	0
PVERDE	APS	3810	3515
PV_APS	PVERDE	90000	715
PV_EPE	PVERDE	90000	443
PV_IID	PVERDE	90000	10
PV_LDWP	PVERDE	90000	271
PV_PASA	PVERDE	90000	7
PV_PNM	PVERDE	90000	286
PV_PVER_MO	PVERDE	90000	37
PV_SCE	PVERDE	90000	443
PV_SRP	PVERDE	90000	319
SCE	LDWP	236	236
SCE	NAVAJO	1505	1505
SCE	PVERDE	1011	1011
SCE	WALC	602	602
SDGE	SCE	2440	26
SPP	IPC	233	62
SRP	APS	90000	653
WACM	FCORN	200	200
WACM	PACE	785	334
WALC	APS	2800	1802
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report.
APS Market Power Analysis (Including expected 2001 constructions)

Destination APS (APS)
Load Type Summer Super Peak

From	To	BASE Limit (MW)	Flow (MW)
AEPC	WALC	90000	287
AES_CA_S	SCE	90000	94
ANHM	SCE	90000	984
BEPC	WACM	90000	6
BHPL	WACM	90000	4
CGC_CA_N	PG_E	90000	0
CGC_WALC	WALC	90000	284
CSU	WACM	90000	5
DGT	WACM	90000	3
DUK_CA_N	PG_E	90000	0
EPE	TEP	519	177
FCORN	APS	1340	1340
FCORN	TEP	1554	200
FC_APS	FCORN	90000	298
FC_EPE	FCORN	90000	35
FC_PNM	FCORN	90000	65
FC_SCE	FCORN	90000	239
FC_SRP	FCORN	90000	50
HOU_CA_S	SCE	90000	89
HOU_APS	APS	90000	690
HOU_WALC	WALC	90000	273
ICPA	PACE	90000	11
IID	PVERDE	1	1
IID	SCE	600	13
IPC	WACM	768	48
LDWP	PACE	1400	41
LDWP	WALC	2410	1078
MPC	IPC	2	2
MPC	PACE	400	0
NAVAJO	APS	2264	2264
NAV_APS	NAVAJO	90000	167
NAV_LDWP	NAVAJO	90000	165
NAV_NEVP	NAVAJO	90000	88
NAV_SRP	NAVAJO	90000	358
NCPA	PG_E	90000	0
NEVP	WALC	90000	1261
NRG_CA_S	SCE	90000	47
PACE	FCORN	600	549
PASA	SCE	90000	7
PEGT	EPE	90000	20
PG_E	SCE	3000	83
PNM	FCORN	597	196

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report.

APS Market Power Analysis (Including expected 2001 constructions)

PNM	TEP	224	224
PPL_MT	MPC	90000	0
PRPA	WACM	90000	4
PVERDE	APS	3810	3810
PV_APS	PVERDE	90000	805
PV_EPE	PVERDE	90000	499
PV_IID	PVERDE	90000	12
PV_LDWP	PVERDE	90000	305
PV_PASA	PVERDE	90000	8
PV_PNM	PVERDE	90000	322
PV_PVER_MO	PVERDE	90000	42
PV_SCE	PVERDE	90000	499
PV_SRP	PVERDE	90000	358
SCE	NAVAJO	1505	757
SCE	PVERDE	1011	988
SDGE	SCE	2440	68
SEI_CA_N	PG_E	90000	0
SPP	IPC	192	5
SRP	APS	90000	3134
TCK_CA_S	SCE	90000	7
TEP	APS	672	672
TEP	SRP	672	594
UPD_CA_S	SDGE	90000	0
WACM	FCORN	200	132
WALC	APS	2800	2800
WALC	NAVAJO	6024	772
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report.

APS Market Power Analysis (Including expected 2001 constructions)

Destination APS (APS)
Load Type Summer On-Peak

From	To	BASE Limit (MW)	Flow (MW)
AEPC	WALC	90000	232
ANHM	SCE	90000	1067
BEPC	WACM	90000	13
BHPL	WACM	90000	6
CGC_CA_N	PG_E	90000	0
CGC_WALC	WALC	90000	271
CSU	WACM	90000	9
DGT	WACM	90000	5
DUK_CA_N	PG_E	90000	0
EPE	TEP	519	179
FCORN	APS	1340	1340
FCORN	NAVAJO	1903	783
FCORN	TEP	1554	219
FC_APS	FCORN	90000	520
FC_EPE	FCORN	90000	61
FC_PNM	FCORN	90000	113
FC_SCE	FCORN	90000	417
FC_SRP	FCORN	90000	87
HOU_CA_S	SCE	90000	58
HOU_APS	APS	90000	690
HOU_WALC	WALC	90000	261
ICPA	PACE	90000	16
IID	PVERDE	1	1
IID	SCE	600	14
IPC	WACM	768	70
LDWP	WALC	2410	1363
MPC	IPC	2	1
NAVAJO	APS	2264	2264
NAV_APS	NAVAJO	90000	91
NAV_LDWP	NAVAJO	90000	90
NAV_NEVP	NAVAJO	90000	48
NAV_SRP	NAVAJO	90000	194
NCPA	PG_E	90000	0
NEVP	WALC	90000	1173
NRG_CA_S	SCE	90000	26
PACE	FCORN	600	600
PACE	NEVP	300	92
PACE	WALC	250	250
PASA	SCE	90000	2
PEGT	EPE	90000	26
PG_E	SCE	3000	91
PNM	FCORN	597	379

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report.

APS Market Power Analysis (Including expected 2001 constructions)

PNM	TEP	224	224
PPL_MT	MPC	90000	0
PRPA	WACM	90000	8
PVERDE	APS	3810	3810
PV_APS	PVERDE	90000	805
PV_EPE	PVERDE	90000	499
PV_IID	PVERDE	90000	12
PV_LDWP	PVERDE	90000	305
PV_PASA	PVERDE	90000	8
PV_PNM	PVERDE	90000	322
PV_PVER_MO	PVERDE	90000	42
PV_SCE	PVERDE	90000	499
PV_SRP	PVERDE	90000	358
SCE	NAVAJO	1505	703
SCE	PVERDE	1011	988
SDGE	SCE	2440	74
SPP	IPC	192	6
SRP	APS	90000	2872
TEP	APS	672	672
TEP	SRP	672	574
WACM	FCORN	200	198
WALC	APS	2800	2800
WALC	NAVAJO	6024	408
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report.
APS Market Power Analysis (Including expected 2001 constructions)

Destination APS (APS)
Load Type Summer Off-Peak

From	To	BASE Limit (MW)	Flow (MW)
AEPC	WALC	90000	140
ANHM	SCE	90000	1415
BEPC	WACM	90000	15
BHPL	WACM	90000	7
CGC_CA_N	PG_E	90000	0
CSU	WACM	90000	11
DGT	WACM	90000	6
EPE	TEP	519	51
FCORN	APS	1340	1340
FCORN	NAVAJO	1903	542
FCORN	TEP	1554	288
FC_APS	FCORN	90000	643
FC_EPE	FCORN	90000	75
FC_PNM	FCORN	90000	140
FC_SCE	FCORN	90000	516
FC_SRP	FCORN	90000	107
ICPA	PACE	90000	17
IID	PVERDE	1	1
IID	SCE	600	12
IPC	WACM	768	70
LDWP	WALC	2410	1600
MPC	PACE	400	1
NAVAJO	APS	2264	2264
NAV_APS	NAVAJO	90000	342
NAV_LDWP	NAVAJO	90000	337
NAV_NEVP	NAVAJO	90000	180
NAV_SRP	NAVAJO	90000	731
NCPA	PG_E	90000	0
NEVP	WALC	90000	905
PACE	LDWP	1200	351
PACE	NEVP	300	300
PACE	WALC	250	250
PASA	SCE	90000	3
PEGT	EPE	90000	53
PG_E	SCE	3000	120
PNM	FCORN	597	509
PNM	TEP	224	224
PPL_MT	MPC	90000	0
PRPA	WACM	90000	10
PVERDE	APS	3810	3810
PV_APS	PVERDE	90000	805
PV_EPE	PVERDE	90000	499

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report.

APS Market Power Analysis (Including expected 2001 constructions)

PV_IID	PVERDE	90000	12
PV_LDWP	PVERDE	90000	305
PV_PASA	PVERDE	90000	8
PV_PNM	PVERDE	90000	322
PV_PVER_MO	PVERDE	90000	42
PV_SCE	PVERDE	90000	499
PV_SRP	PVERDE	90000	358
SCE	LDWP	550	550
SCE	NAVAJO	1505	152
SCE	PVERDE	1011	988
SCE	WALC	602	369
SDGE	SCE	2440	98
SPP	IPC	192	2
SPP	PACE	150	5
SRP	APS	90000	2113
TEP	APS	672	672
TEP	SRP	672	518
WACM	FCORN	200	200
WALC	APS	2800	2800
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report.

APS Market Power Analysis (Including expected 2001 constructions)

Destination APS (APS)
Load Type Winter Super Peak

From	To	BASE Limit (MW)	Flow (MW)
AEPC	WALC	90000	271
AES_CA_S	SCE	90000	90
ANHM	SCE	90000	940
BEPC	WACM	90000	9
BHPL	WACM	90000	6
CGC_CA_N	PG_E	90000	0
CGC_WALC	WALC	90000	268
CSU	WACM	90000	8
DGT	WACM	90000	4
DUK_CA_N	PG_E	90000	0
EPE	TEP	519	178
FCORN	APS	1340	1340
FCORN	NAVAJO	1903	782
FCORN	TEP	1554	185
FC_APS	FCORN	90000	516
FC_EPE	FCORN	90000	60
FC_PNM	FCORN	90000	112
FC_SCE	FCORN	90000	413
FC_SRP	FCORN	90000	86
HOU_CA_S	SCE	90000	86
HOU_APS	APS	90000	690
HOU_WALC	WALC	90000	257
ICPA	PACE	90000	15
IID	SCE	600	11
IPC	WACM	869	67
LDWP	WALC	2410	1146
MPC	IPC	9	3
MPC	PACE	400	0
NAVAJO	APS	2264	2264
NAV_APS	NAVAJO	90000	91
NAV_LDWP	NAVAJO	90000	90
NAV_NEVP	NAVAJO	90000	48
NAV_SRP	NAVAJO	90000	194
NCPA	PG_E	90000	0
NEVP	WALC	90000	1218
NRG_CA_S	SCE	90000	46
PACE	FCORN	600	600
PACE	WALC	250	18
PASA	SCE	90000	7
PEGT	EPE	90000	20
PG_E	SCE	3000	80
PNM	FCORN	597	352

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report.

APS Market Power Analysis (Including expected 2001 constructions)

PNM	TEP	224	224
PPL_MT	MPC	90000	0
PRPA	WACM	90000	6
PVERDE	APS	3810	3810
PV_APS	PVERDE	90000	807
PV_EPE	PVERDE	90000	501
PV_IID	PVERDE	90000	12
PV_LDWP	PVERDE	90000	306
PV_PASA	PVERDE	90000	8
PV_PNM	PVERDE	90000	323
PV_PVER_MO	PVERDE	90000	42
PV_SCE	PVERDE	90000	501
PV_SRP	PVERDE	90000	359
SCE	NAVAJO	1505	527
SCE	PVERDE	1011	979
SDGE	SCE	2440	65
SEI_CA_N	PG_E	90000	0
SPP	IPC	158	6
SRP	APS	90000	3185
TCK_CA_S	SCE	90000	7
TEP	APS	672	672
TEP	SRP	672	580
UPD_CA_S	SDGE	90000	0
WACM	FCORN	200	200
WALC	APS	2800	2800
WALC	NAVAJO	6024	585
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report.

APS Market Power Analysis (Including expected 2001 constructions)

Destination APS (APS)
Load Type Winter On-Peak

From	To	BASE Limit (MW)	Flow (MW)
AEPC	WALC	90000	267
ANHM	SCE	90000	1094
BEPC	WACM	90000	13
BHPL	WACM	90000	6
CGC_CA_N	PG_E	90000	0
CGC_WALC	WALC	90000	313
CSU	WACM	90000	9
DGT	WACM	90000	6
DUK_CA_N	PG_E	90000	0
EPE	TEP	519	179
FCORN	APS	1340	1340
FCORN	NAVAJO	1903	795
FCORN	TEP	1554	210
FC_APS	FCORN	90000	521
FC_EPE	FCORN	90000	61
FC_PNM	FCORN	90000	113
FC_SCE	FCORN	90000	417
FC_SRP	FCORN	90000	87
HOU_CA_S	SCE	90000	59
HOU_APS	APS	90000	690
HOU_WALC	WALC	90000	300
ICPA	PACE	90000	17
IID	SCE	600	13
IPC	WACM	869	74
LDWP	WALC	2410	1112
MPC	IPC	9	1
NAVAJO	APS	2264	2264
NAV_APS	NAVAJO	90000	91
NAV_LDWP	NAVAJO	90000	90
NAV_NEVP	NAVAJO	90000	48
NAV_SRP	NAVAJO	90000	194
NCPA	PG_E	90000	0
NEVP	WALC	90000	1540
NRG_CA_S	SCE	90000	26
PACE	FCORN	600	600
PACE	NEVP	300	270
PACE	WALC	250	250
PASA	SCE	90000	2
PEGT	EPE	90000	26
PG_E	SCE	3000	93
PNM	FCORN	597	380
PNM	TEP	224	224

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report.

APS Market Power Analysis (Including expected 2001 constructions)

PPL_MT	MPC	90000	0
PRPA	WACM	90000	8
PVERDE	APS	3810	3810
PV_APS	PVERDE	90000	807
PV_EPE	PVERDE	90000	501
PV_IID	PVERDE	90000	12
PV_LDWP	PVERDE	90000	306
PV_PASA	PVERDE	90000	8
PV_PNM	PVERDE	90000	323
PV_PVER_MO	PVERDE	90000	42
PV_SCE	PVERDE	90000	501
PV_SRP	PVERDE	90000	359
SCE	NAVAJO	1505	558
SCE	PVERDE	1011	979
SDGE	SCE	2440	75
SPP	IPC	158	7
SRP	APS	90000	2880
TEP	APS	672	672
TEP	SRP	672	565
WACM	FCORN	200	199
WALC	APS	2800	2800
WALC	NAVAJO	6024	542
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report.

APS Market Power Analysis (Including expected 2001 constructions)

Destination APS (APS)
Load Type Winter Off-Peak

From	To	BASE Limit (MW)	Flow (MW)
ANHM	SCE	90000	1546
BHPL	WACM	90000	1
CGC_CA_N	PG_E	90000	0
CSU	WACM	90000	2
DGT	WACM	90000	3
FCORN	APS	1340	1340
FCORN	TEP	1554	237
FC_APS	FCORN	90000	305
FC_EPE	FCORN	90000	97
FC_PNM	FCORN	90000	180
FC_SCE	FCORN	90000	663
FC_SRP	FCORN	90000	138
IPC	PACE	1100	145
LDWP	WALC	2410	559
MPC	PACE	400	3
NAVAJO	APS	2264	2264
NAV_APS	NAVAJO	90000	430
NAV_LDWP	NAVAJO	90000	424
NAV_NEVP	NAVAJO	90000	226
NAV_SRP	NAVAJO	90000	732
NCPA	PG_E	90000	0
NEVP	WALC	90000	740
PACE	NEVP	300	173
PACE	WALC	250	250
PASA	SCE	90000	0
PG_E	SCE	3000	132
PPL_MT	MPC	90000	0
PVERDE	APS	3810	3810
PV_APS	PVERDE	90000	807
PV_EPE	PVERDE	90000	501
PV_IID	PVERDE	90000	12
PV_LDWP	PVERDE	90000	306
PV_PASA	PVERDE	90000	8
PV_PNM	PVERDE	90000	323
PV_PVER_MO	PVERDE	90000	42
PV_SCE	PVERDE	90000	501
PV_SRP	PVERDE	90000	359
SCE	NAVAJO	1505	464
SCE	PVERDE	1011	979
SCE	WALC	602	602
SDGE	SCE	2440	108
SPP	PACE	150	29

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report.

APS Market Power Analysis (Including expected 2001 constructions)

SRP	APS	90000	1422
TEP	APS	672	672
TEP	SRP	672	491
WACM	FCORN	200	200
WACM	PACE	785	93
WALC	APS	2800	1724
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report.

APS Market Power Analysis (Including expected 2001 constructions)

Destination APS (APS)
Load Type Shoulder Super Peak

From	To	BASE Limit (MW)	Flow (MW)
AEPC	WALC	90000	273
AES_CA_S	SCE	90000	88
ANHM	SCE	90000	1031
BEPC	WACM	90000	6
BHPL	WACM	90000	4
CGC_CA_N	PG_E	90000	0
CGC_WALC	WALC	90000	287
CSU	WACM	90000	5
DGT	WACM	90000	3
DUK_CA_N	PG_E	90000	0
EPE	TEP	519	185
FCORN	APS	1340	1340
FCORN	TEP	1554	227
FC_APS	FCORN	90000	284
FC_EPE	FCORN	90000	33
FC_PNM	FCORN	90000	62
FC_SCE	FCORN	90000	228
FC_SRP	FCORN	90000	47
HOU_CA_S	SCE	90000	84
HOU_APS	APS	90000	678
HOU_WALC	WALC	90000	275
ICPA	PACE	90000	12
IID	SCE	600	13
IPC	WACM	822	53
LDWP	PACE	1400	21
LDWP	WALC	2410	1163
MPC	IPC	2	2
MPC	PACE	400	1
NAVAJO	APS	2264	2264
NAV_APS	NAVAJO	90000	159
NAV_LDWP	NAVAJO	90000	157
NAV_NEVP	NAVAJO	90000	84
NAV_SRP	NAVAJO	90000	341
NCPA	PG_E	90000	0
NEVP	WALC	90000	1230
NRG_CA_S	SCE	90000	45
PACE	FCORN	600	570
PASA	SCE	90000	7
PEGT	EPE	90000	20
PG_E	SCE	3000	87
PNM	FCORN	597	225
PNM	TEP	224	224

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report.
APS Market Power Analysis (Including expected 2001 constructions)

PPL_MT	MPC	90000	0
PRPA	WACM	90000	4
PVERDE	APS	3810	3515
PV_APS	PVERDE	90000	715
PV_EPE	PVERDE	90000	443
PV_IID	PVERDE	90000	10
PV_LDWP	PVERDE	90000	271
PV_PASA	PVERDE	90000	7
PV_PNM	PVERDE	90000	286
PV_PVER_MO	PVERDE	90000	37
PV_SCE	PVERDE	90000	443
PV_SRP	PVERDE	90000	319
SCE	NAVAJO	1505	708
SCE	PVERDE	1011	1011
SDGE	SCE	2440	71
SEI_CA_N	PG_E	90000	0
SPP	IPC	233	5
SRP	APS	90000	2975
TCK_CA_S	SCE	90000	7
TEP	APS	672	672
TEP	SRP	672	593
UPD_CA_S	SDGE	90000	0
WACM	FCORN	200	144
WALC	APS	2800	2800
WALC	NAVAJO	6024	859
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report.

APS Market Power Analysis (Including expected 2001 constructions)

Destination APS (APS)
Load Type Shoulder On-Peak

From	To	BASE Limit (MW)	Flow (MW)
AEPC	WALC	90000	119
ANHM	SCE	90000	848
BEPC	WACM	90000	9
BHPL	WACM	90000	5
CGC_CA_N	PG_E	90000	0
CGC_WALC	WALC	90000	149
CSU	WACM	90000	6
DGT	WACM	90000	4
EPE	TEP	519	187
FCORN	APS	1340	1340
FCORN	TEP	1554	208
FC_APS	FCORN	90000	289
FC_EPE	FCORN	90000	34
FC_PNM	FCORN	90000	63
FC_SCE	FCORN	90000	232
FC_SRP	FCORN	90000	48
HOU_APS	APS	90000	678
HOU_WALC	WALC	90000	143
ICPA	PACE	90000	11
IID	SCE	600	11
IPC	WACM	822	54
LDWP	WALC	2410	848
MPC	IPC	2	0
NAVAJO	FCORN	1731	199
NAVAJO	WALC	6024	576
NAV_APS	NAVAJO	90000	166
NAV_LDWP	NAVAJO	90000	164
NAV_NEVP	NAVAJO	90000	87
NAV_SRP	NAVAJO	90000	355
NCPA	PG_E	90000	0
NEVP	WALC	90000	571
PACE	FCORN	600	317
PACE	WALC	250	250
PASA	SCE	90000	2
PEGT	EPE	90000	26
PG_E	SCE	3000	72
PNM	FCORN	597	255
PNM	TEP	224	224
PPL_MT	MPC	90000	0
PRPA	WACM	90000	6
PVERDE	APS	3810	3515
PV_APS	PVERDE	90000	715

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report.

APS Market Power Analysis (Including expected 2001 constructions)

PV_EPE	PVERDE	90000	443
PV_IID	PVERDE	90000	10
PV_LDWP	PVERDE	90000	271
PV_PASA	PVERDE	90000	7
PV_PNM	PVERDE	90000	286
PV_PVER_MO	PVERDE	90000	37
PV_SCE	PVERDE	90000	443
PV_SRP	PVERDE	90000	319
SCE	LDWP	236	236
SCE	NAVAJO	1505	4
SCE	PVERDE	1011	1011
SCE	WALC	602	602
SDGE	SCE	2440	59
SPP	IPC	233	5
SRP	APS	90000	2656
TEP	APS	672	672
TEP	SRP	672	533
WACM	FCORN	200	137
WALC	APS	2800	2800
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

Transmission Report.

APS Market Power Analysis (Including expected 2001 constructions)

Destination APS (APS)
Load Type Shoulder Off-Peak

From	To	BASE Limit (MW)	Flow (MW)
ANHM	SCE	90000	2223
BHPL	WACM	90000	6
CSU	WACM	90000	1
DGT	WACM	90000	1
FCORN	APS	1340	778
IID	SCE	600	1
IPC	PACE	1100	472
LDWP	WALC	2410	701
MPC	IPC	2	2
MPC	PACE	400	7
NAVAJO	APS	2264	1463
NEVP	WALC	90000	624
PACE	FCORN	600	600
PACE	NEVP	300	83
PACE	WALC	250	250
PASA	SCE	90000	0
PPL_MT	MPC	90000	0
PVERDE	APS	3810	3515
PV_APS	PVERDE	90000	715
PV_EPE	PVERDE	90000	443
PV_IID	PVERDE	90000	10
PV_LDWP	PVERDE	90000	271
PV_PASA	PVERDE	90000	7
PV_PNM	PVERDE	90000	286
PV_PVER_MO	PVERDE	90000	37
PV_SCE	PVERDE	90000	443
PV_SRP	PVERDE	90000	319
SCE	LDWP	236	236
SCE	NAVAJO	1505	1505
SCE	PVERDE	1011	1011
SCE	WALC	602	602
SDGE	SCE	2440	26
SPP	IPC	233	62
SRP	APS	90000	653
WACM	FCORN	200	200
WACM	PACE	785	334
WALC	APS	2800	1802
WALC	SRP	450	450

Note: Limits of 90,000 MW indicate unconstrained flows.