APS

ORIGINAL

000003586O

Jana Van Ness
Manager
State Regulations

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

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

RECEIVED
2001 DEC 12 P 4: 07
AZ CORP COMMISSION
DOCUMENT CONTROL

December 12, 2001

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

RE: ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606 ACC DOCKET NO. E01345A-01-0822
WITNESS TESTIMONY

Dear Sir or Madam:

Pursuant to the Procedural Order dated November 30, 2001, Docket No. E-01345A-01-0822, Arizona Public Service Company is hereby filing the direct testimony of Mr. Jack E. Davis, Dr. John H. Landon and Dr. William H. Hieronymus.

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

Sincerely,

Jana Van Ness

Jana Van Ness
Manager
State Regulations

Attachment

JVN/srm

Cc: Docket Control (Original, plus 10 copies)
Service List

Arizona Corporation Commission
DOCKETED
DEC 12 2001

DOCKETED BY	
	nac

RECEIVED
2001 DEC 12 P 4: 07
AZ CORP COMMISSION
DOCUMENT CONTROL

JACK E. DAVIS

BEFORE THE ARIZONA CORPORATION COMMISSION

DIRECT TESTIMONY
OF
JACK E. DAVIS

ON BEHALF OF
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-01-0822

DECEMBER 12, 2001

TABLE OF CONTENTS

TABLE OF FIGURES

DIRECT TESTIMONY
OF
JACK E. DAVIS

(DOCKET NO. E-01345A-01-0822)

I.
INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

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

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND EXPERIENCE.

A. A summary of my professional qualifications and experience is included in the Statement of Qualifications attached as Appendix A to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I explain and support the Company's request for a partial variance to the Standard Offer power procurement provisions of A.A.C. R14-2-1606(B) ("Rule 1606(B)") and for approval of the proposed purchased power agreement ("PPA") between APS and Pinnacle West Capital Corporation ("PWCC"). The PPA is attached to my testimony as Appendix B. I will demonstrate why such a variance and approval are in the public interest for each of the following reasons:

- The literal application of the power procurement provisions of Rule 1606(B) will threaten reliable and reasonably-priced service to the Company's Standard Offer customers.
- The present merchant generation market in Arizona is likely incapable of providing 50% of the Company's requirements beginning January 1, 2003.
- Obligating PWCC through the PPA to be the wholesale "provider of last resort" to the Company at reasonable prices, using a prudently diverse portfolio of existing and under-construction generation resources, represents a superior alternative to Rule 1606(B)'s requirements.
- Granting the requested variance and approving the proposed PPA will not adversely impact either the competitive wholesale market or retail access pursuant to the Electric Competition Rules, and would not be unfair to merchant plant owners who own or propose to construct new generating facilities in Arizona.

In doing so, my testimony will necessarily respond to some of the arguments made by certain intervenors in their requests for intervention and by Commission Staff in its Response to the application.

As part of my prepared testimony, I will discuss the APS customer service philosophy of reliability and price stability that was the genesis of our October filing. This involves a description of the significant steps we have taken and will take to realize those goals for our customers both in the recent past and in the future. The proposed PPA is a vital part of those efforts, and I was intimately involved in both the process by which that agreement was formulated and the assessment of its many advantages over the total dependence on the competitive market envisioned by Rule 1606(B). I will also describe the impact (or lack thereof) of the Company's application on the overall scheme of the Commission's Electric Competition Rules, including Rule 1606(B), and on the 1999 APS Rate Settlement Agreement ("1999 APS Settlement"). This discussion will of necessity encompass an explanation of the necessary linkage between the requested partial variance to Rule 1606(B) and approval of the PPA.

Finally, as noted above, my testimony will address the negligible effect of the requested variance and proposed PPA on the merchant generators that have intervened in this proceeding ("Merchant Intervenors"). That effect is in stark contrast to the dire consequences to reliability and price stability that APS strongly believes would accompany rejection of its requests for a variance to Rule 1606(B) and for approval of the PPA

II.
SUMMARY OF TESTIMONY

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. The requested variance and approval of the proposed PPA are in the public interest because they provide APS customers with a reliable, long-term source of power at rates based on the actual costs incurred in producing or procuring this power. In contrast to the months of analysis and negotiation that went into the final form of the PPA, the 50% competitive bid requirement of Rule 1606(B) was a last minute addition to the long process of developing the Commission's Electric Competition Rules.

But under the present provisions of Rule 1606(B), APS would be forced to obtain all of its Standard Offer generation requirements from the competitive wholesale market beginning no later than January 1, 2003. That market is presently unstable and volatile. APS believes it would be appropriate to modify the requirements of Rule 1606(B) as regards APS to permit the Company to enter into a long-term PPA with PWCC at relatively stable and, I believe, below long-term market rates. Such a variance is specifically permitted by A.A.C. R14-2-1614(C) if it is found by the Commission to be "in the public interest."

Rule 1606(B) in particular, and the Commission's Electric Competition Rules in general, are silent as to the obligation, if any, of an electric utility distribution company ("UDC") such as APS to provide reliable supplies (as contrasted to deliveries) of electrical energy to its customers. APS has continuously planned and operated its system on the assumption that it retained such an obligation, even under the Electric Competition Rules, both prior and subsequent to the divestiture of its generating assets as required by A.A.C. R14-2-1615. Specifically, the Company has worked closely with its power marketing and generation affiliates [PWCC and Pinnacle West Energy Corporation ("PWEC"), respectively] to assure reliable service to Arizona consumers at steadily declining prices as called for by the 1999 APS Settlement. To maintain that reliability, PWEC alone has invested over $1,000,000,000 in new generation such as West Phoenix and Redhawk. Reliability and reasonable prices are cornerstone components of a broader customer service program that the Company has promoted in response to industry restructuring.

The proposed PPA provides both economic and reliability benefits for APS customers. Economic benefits include stable prices based on real costs of providing service. Due to the mix of Dedicated Assets devoted to APS customers under terms of the PPA, these prices are below the long-run marginal cost of the new generation likely to set the long-run market price of wholesale power in the region.

They will also be less volatile than would be generation prices that are far more dependent upon natural gas prices. Another economic benefit realized by APS customers through the PPA is the latter's contribution to a balanced and prudent power procurement strategy. On the reliability side, APS customers receive the benefit of a diverse portfolio of assets—diverse from the standpoints of fuel source, operating characteristics and geographic location. These assets were designed, sited and constructed for service to the APS system and to APS customers. They also have a proven track record of excellent operating performance and reliability.

By approving the PPA and the requested variance, the Commission would not be undercutting either wholesale or retail competition. Indeed, the Commission itself was critical of the competitive bidding requirement added to Rule 1606(B) in the very Commission decision that adopted it. The requested variance is likewise not in contradiction to the 1999 APS Settlement with the Commission. And contrary to various assertions made by them in their interventions and subsequent pleadings, none of the Merchant Intervenors appear to have located facilities in Arizona solely on account of Rule 1606(B), and I doubt any will refuse to complete their facilities or build new ones based only on the Commission's approval of the requested variance or the PPA.

The Merchant Intervenors in this proceeding can, if they are interested in the Arizona segment of the Western bulk power market, participate in that market in many ways, both as suppliers to APS under the PPA and as suppliers to competitive Electric Service Providers ("ESPs") and regulated UDCs operating in Arizona. In doing so, however, they must face several competitive realities that exist independent of the PPA and the Company's requested variance.

One is the continued existence of the Dedicated Assets as competitors in that market. The low marginal costs of the coal and nuclear generating units that comprise a major portion of the Dedicated Assets make it very unlikely that they could be underbid on a consistent basis by one of the Merchant Intervenors.

Another fact is that it is not presently possible to obtain 50%, let alone 100%, of APS' requirements from the Palo Verde hub to the Company's primary and secondary load centers, and yet it is precisely in the Palo Verde area that most of the Merchant Intervenors have elected to either build their plants or to interconnect with the Arizona grid. Others, although located far from Palo Verde, are also positioned far from the APS transmission system, with no practical way to reach APS load. Even if these generators had located their plants in a manner that allowed them better access to the APS load, there is no assurance that they would not seek markets and customers elsewhere in the vast Western United States bulk power market.

All of the Merchant Intervenors are relying 100% on gas-fired generation in Arizona, as compared with only 30% from Dedicated Units under the PPA. This makes the Merchant Intervenors more susceptible to supply or transportation interruptions and shortages, as well as fluctuating gas prices, both of which make them less competitive than the Dedicated Assets and are negative factors that would continue to exist with or without the variance or the PPA.

The considerations discussed above should not be considered as criticisms of the vital role of merchant generators in the competitive wholesale market. As a major buyer from the competitive market under the PPA, APS has a large stake in that market developing to its full potential. But APS is cognizant both that it is a small player compared to the entire western wholesale market, and that the need of the Company's customers for reliable and reasonably-priced power must be its higher concern.

III.
ORIGIN OF RULE 1606(B), SECTION 4.1.3 OF THE 1999 APS SETTLEMENT AND SCOPE OF REQUESTED VARIANCE

Q. HOW DID THE COMPETITIVE BIDDING REQUIREMENT OF COMMISSION RULE 1606 (B) ORIGINATE?

A. This requirement was not included in the original electric competition regulations approved by the Commission in 1996. It also was not in the revisions to the rules proposed in early 1998 and approved on an emergency basis in Decision No. 61071 (August 10, 1998). In fact, none of the Merchant Intervenors ever proposed such a specific 50% requirement during the long rulemaking process that eventually resulted in the current Electric Competition Rules, and thus it was not subjected to the full "peer review" process that is a critical part of the normal rulemaking procedures.

It was not until the Commission's Open Meeting deliberations on the "permanent" adoption of the 1998 emergency rules in late September of 1999 [Decision No. 61969 (September 29, 1999)] that the Commission adopted this specific requirement. To the best of my knowledge, no analysis was conducted by the Commission, its Staff or any other party as to the impact of this requirement on customers, the appropriateness of "50%" (as compared with, say 25%) or whether such a requirement was even feasible given the expected level of available new generation and the even then known transmission limitations on the systems of APS and other Affected Utilities. Indeed, a competitive bidding requirement was actually rejected by the Commission in the Concise Explanatory Statement ("CES") attached to the Commission's final approval of the Electric Competition Rules in Decision No. 61969. I will quote from the CES: "We do not wish to impose the constraints on energy procurement that would be associated with a competitive bid process. . . Our clarification [of Rule 1606(B)] is not substantive." (Decision No. 61969 at App. B, pp. 27-28.)

Contrary to the present suggestions that the 50% competitive bid requirement was some sort of "cornerstone" of Arizona electric restructuring, it might best be characterized as an afterthought to the body of the Electric Competition Rules, which is not otherwise affected by the Company's request for a variance. In fact, my legal counsel tells me that the late addition of this competitive bidding requirement could not have been approved by the Commission without re-noticing the Electric Competition Rules unless the Commission were convinced that the change was non-substantive.

Q. HOW DO THE REQUESTED VARIANCE AND THE PPA AFFECT OTHER PORTIONS OF THE ELECTRIC COMPETITION RULES?

A. They don't. None of the provisions allowing for retail direct access, the granting of competitive CC&Ns to ESPs, the establishment of rates for ESPs, the unbundling of retail electric services, the separation of competitive and non-competitive services, support for Regional Transmission Organizations or Independent Scheduling Organizations, ESP and UDC reporting requirements, and consumer protection standards are altered in the slightest way by our October filing. Customers are still able to select Direct Access from willing ESPs should they believe market prices will be less than those obtained by APS through the PPA. Rather than "gutting" the Electric Competition Rules, the requested variance would barely scratch the essential framework for competition established by the Commission as far back as 1996.

Q. WAS THE 50% COMPETITIVE BIDDING REQUIREMENT A NEGOTIATED PART OF THE 1999 APS SETTLEMENT?

A. No—far from it. Section 4.1.3 of the 1999 APS Settlement was not a part of the Settlement Agreement signed by APS and all of its major customer group representatives in May of 1999. During proceedings to consider the 1999 APS Settlement, neither Staff nor any of the Merchant Intervenors (let alone any of the signatories to the agreement itself) suggested adding a competitive bidding requirement to the settlement. This was not particularly surprising since none of the Merchant Intervenors even participated in that proceeding and an earlier settlement agreement negotiated with Commission Staff in the fall of 1998 made no mention of a competitive bidding or even a market acquisition requirement for APS Standard Offer service.

As was the case with Rule 1606 (B), Section 4.1.3 was an *ad hoc* addition by the Commission to Decision No. 61973 during its Open Meeting deliberations on the settlement. As it is, Section 4.1.3 merely requires APS to follow the Electric Competition Rules as regards power procurement for Standard Offer customers <u>and does not expressly require APS to competitively bid 50% or any other specific percentage of its needs</u>. In contrast, the Electric Competition Rules expressly <u>do</u> permit requests for variances to any or all of the Electric Competition Rules, including Rule 1606 (B):

> The Commission may consider variations or exemptions from the terms or requirements of any of the Rules in this Article upon application of an affected party. The application must set forth the reasons why the public interest will be served by the variation or exemption from the Commission rules and regulations. Any variation or exemption granted shall require an order of the

> Commission. Where a conflict exists between these rules and an approved tariff or order of the Commission, the provisions of the approved tariff or order of the Commission shall apply.

(A.A.C. R14-2-1614(C).) The introduction to the 1999 APS settlement defines the "Electric Competition Rules" as including exemptions and variances thereto granted by the Commission, and thus the Company's request in this docket is entirely consistent with the 1999 APS Settlement with the Commission.

Q. DOES THE REQUESTED VARIANCE AFFECT <u>ANY</u> OF THE KEY COMPONENTS OF THE 1999 APS SETTLEMENT?

A. No. For example, the five rate reductions agreed to by APS remain unaffected. The $234,000,000 write-off of prudently-incurred costs required by Section 3.3 and taken in 1999 will not be restored as a result of our request. The accelerated schedule for opening the APS service territory to competition and the corresponding modification of its CC&N also agreed to by APS will not be undone. The unbundled rates approved in the 1999 APS Settlement are unchanged.

Q. PRECISELY HOW MUCH OF A VARIANCE TO RULE 1606(B) IS THE COMPANY REQUESTING?

A. Under the PPA, APS would still be required to competitively bid at least 1620 MW of load by 2008. This is nearly a quarter of the then-projected Standard Offer load. The PPA also calls for power acquisitions from the competitive wholesale market that are in addition to the mandatory competitive bidding amount, thus increasing that percentage further and perhaps significantly. To the extent ESPs are successful in gaining customers within the APS service area during the term of the PPA, that percentage of load available to the Merchant Intervenors would necessarily increase even more. This stands in stark contrast to Affected Utilities that have already been entirely exempted from Rule 1606(B), such as the electric cooperatives, or that have requested (and been granted on an interim basis) 100% waivers of the competitive bidding requirement, such as Citizens Communications Company. By 2008, APS would be <u>required</u> to competitively bid more load than any other Affected Utility or Public Power Entity, as that latter term is defined under the Arizona Electric Competition Act (H.B. 2663).

IV.
<u>BACKGROUND TO AND MOTIVATION FOR THE COMPANY'S FILING</u>

Q. MR. DAVIS, CAN YOU CHARACTERIZE THE MARKET ENVIRONMENT IN YOUR BUSINESS FOR THE LAST COUPLE OF YEARS?

A. The electric utility business environment in the western United States has been exceptionally volatile over the last two years. Electric wholesale price volatility, driven by generation scarcity and high natural gas prices, was made worse by California market imperfections and by a Western transmission system built in a different era and for a different purpose. As a result, wholesale electricity prices went on a roller coaster ride not unlike the high-tech stock market over the last few years.

Q. HOW HAVE APS CUSTOMERS FARED DURING THIS TIME OF UNPRECEDENTED VOLATILITY, CHANGE AND UNCERTAINTY?

A. During a time of price increases, some blackouts and general turmoil for most electric customers in the Western U.S., APS customers actually saw prices decrease. We achieved this by employing a combination of long- and short-range planning, operational excellence and risk management. This "value equation"—prudent planning plus efficient operations plus innovative risk management—kept APS and its customers largely insulated from volatile Western energy markets.

Q. CAN YOU ELABORATE ON THE COMPONENTS OF THE "VALUE EQUATION"?

A. Certainly. While Californians and residents of many other Western states experienced large rate increases over the last two years, APS customers received rate <u>decreases</u>. That value creation did not just happen. It was the result of:

- *Planning*. Prudent planning assesses the need for new supply resources and new delivery infrastructure. But planning also encompasses a host of regulatory and legal activities to avoid market failures such as occurred in California. With the cooperation and guidance of regulators and legislators, we achieved a restructuring plan that provided flexibility to the utility and protection for our customers.
- *Operational Excellence*. Although planning meant we had the plants and wires we needed to meet customers' needs, the plants have to be run efficiently, and the wires have to be maintained properly to provide customers with value. From top ratings for our nuclear units to national recognition for our customer call center, we strive to maintain the highest standards of operational excellence and efficiency.
- *Risk Management*. More difficult to grasp than planning and operations, risk management is the third part of our value equation. We managed this volatile aspect of our business using forward contracts and financial instruments to hedge our risk and protect customers from market forces.

Q. IN YOUR OPINION, HOW DO MOST CUSTOMERS DETERMINE VALUE?

A. For most power customers, value comes from the combination of two factors—reliability and price. Some customers will emphasize one factor more than the other, but both play a powerful role in a customer's perception of value.

Q. CAN YOU ELABORATE ON THE IMPORTANCE OF THE ARIZONA RESTRUCTURING PLAN AND YOUR SETTLEMENT AGREEMENT IN ACHIEVING VALUE FOR YOUR CUSTOMERS?

A. We believe that the protections provided to customers by the restructuring plan enabled us to avoid a California-style debacle. An all-important element of that plan was that it allowed PWEC to acquire the Company's generation assets, which gave us the potential for a larger degree of control over our costs. We were not forced to buy from an untested and illiquid spot market.

Q. HOW HAS APS PERFORMED IN THE AREA OF RELIABILITY?

A. During the year 2000 and into the winter of 2001, California and Western energy markets experienced unprecedented high prices and volatility. Perhaps worse than the high prices were the economic dislocations from rolling blackouts and threats of blackouts. It was feared that during 2001, California and other states would see even worse conditions, both in terms of price and outages.

Arizona remained largely insulated from the outages and high power prices experienced by other states during 2000 and 2001. During this time, we did not have a single supply interruption as a result of inadequate generating capacity. APS and PWEC still own most of the generation used to supply our customers, which gives us assurance of reliability and a measure of protection from high wholesale prices.

Careful planning allowed the company to meet its customers' needs economically with large plants with low fuel costs, with intermediate-size and small peaking plants with higher fuel costs and with judicious purchases. Planning also assured that we had the delivery "backbone" to minimize supply interruptions.

Q. DID APS MAKE ANY SPECIAL EFFORTS OR ARRANGEMENTS TO AVOID POWER INTERRUPTIONS THIS PAST SUMMER, WHEN MANY PREDICTED BLACKOUTS IN CALIFORNIA AND TIGHT SUPPLIES IN OTHER AREAS OF THE WEST?

A. To provide extra insurance that we would avoid unnecessary power outages, we bolstered our ability to provide peaking power last summer by reviving some older units and by PWEC's renting of some temporary generation for APS' use. The cost of these rental units alone was more than $30,000,000.

In addition to the temporary units, PWEC added a new state of the art combined-cycle unit. Further, our existing units performed very well, adding to this summer's capacity margin. This summer our nuclear capacity factor was 98%, and our overall large-unit capacity factor was 91%. As a result of short-term and long-term actions, our customers experienced <u>no</u> rolling blackouts or outages caused by a lack of generating resources.

Q. IN THE WAKE OF HIGH MARKET PRICES AND POSSIBLE SHORTAGES, DID YOUR COMPANY SEEK TO EDUCATE CUSTOMERS ABOUT THE IMPORTANCE OF CONSERVATION AND THE WAYS THEY COULD BENEFIT FROM REDUCING THEIR POWER USAGE?

A. Yes, we undertook an extensive "inform and educate" campaign to prepare our customers. Last March, we surveyed our customers on a variety of issues and found out that 52% of our residential customers were "very concerned" that the energy crisis occurring in California could happen in Arizona.

Arizona's energy situation was much more stable than that in California. However, while we felt strongly that we could get through another summer without power interruptions, the Company acknowledged that power supplies could be tight. Unanticipated events like severe weather or equipment failures could have stressed the our system.

Q. WHAT DID YOU DO IN RESPONSE TO THE CUSTOMER SURVEY RESULTS?

A. In response to the customer survey results, APS put together a comprehensive education campaign with three specific goals:

- Educate and reassure customers that the energy situations in California and Arizona were much different, and that no large power interruptions were expected in the state.
- Encourage customers to play a part in ensuring Arizona's power supplies were sufficient throughout the summer by taking simple steps to conserve energy.
- Reassure customers that we understood their concerns and were addressing potential issues and planning for the future.

Q. HOW DID YOU CARRY OUT THIS "INFORM AND EDUCATE" CAMPAIGN?

A. In order to accomplish these goals, APS carried out a widespread conservation education campaign throughout Arizona. While it would be nearly impossible to list all facets of this campaign, here are a few highlights:

- A comprehensive conservation campaign including television, print and outdoor ads.
- An organized effort in which APS senior management and community/media spokespeople made informative presentations and answered questions regarding the state's energy situation. Such presentations were made to government officials, civic groups and other concerned citizens throughout the state. At last count, more than 250 presentations had been made, reaching approximately 7,000 customers.

- The "APS Corporate Conservation Challenge" was developed to encourage Arizona companies to reduce their energy consumption. To date, more than 125 major companies had stepped up to the challenge.
- Use of APS' revamped Web site to provide tips for customers to reduce their energy usage, and educational information regarding the situation in California and how it differed from that in Arizona.

Q. WHAT WERE THE RESULTS OF YOUR "INFORM AND EDUCATE" CAMPAIGN?

A. APS' conservation education campaign was a tremendous success. In a June 2001 follow-up to the above-mentioned customer survey, the number of APS customers "very concerned" that California's energy issues could happen in Arizona had dropped 22% since March. In the same survey, 74% of customers said they had taken steps to reduce energy usage in the past six months—up 10% since March.

While these initial numbers were certainly encouraging, perhaps the most important result of this campaign was that unlike many other Western utilities, APS was able to get through the summer of 2001 without any significant power interruptions and still was able to lower retail customer prices.

Q. CAN YOU ADDRESS APS' PERFORMANCE IN THE AREA OF CUSTOMER PRICES?

A. By the end of our settlement period, APS customers will have enjoyed cumulative rate decreases of 16%. From 1993 to the present, we have reduced rates by approximately 13%. Considering inflation-adjusted prices—what economists call real prices—the price reduction is even more dramatic. During the period since 1993, the consumer price index has risen by 23%. This means prices have fallen by 29% in inflation-adjusted terms. Although it is impossible to continuously reduce or even maintain as constant the nominal price of electricity forever, the long-run downward trend in real prices will likely continue.

Q. HOW HAS YOUR PRICE PERFORMANCE FARED DURING THE WHOLESALE PRICE SPIKES?

A. Comparing our prices to Western wholesale price increases produces even more dramatic results. During the summer of 1999 (June, July and August), the average wholesale spot price at the Palo Verde switchyard was $33 per MWh. During the summer of 2000 and 2001 that average price was $153 and $56 per MWh, increases of 364% and 70% respectively, compared to 1999.

While these dramatic price increases were occurring through Western power markets, APS customers saw their rates drop. That is what we mean by providing "value." In contrast, imagine the impact on customers if these market prices had been reflected in retail rates as a result of the competitive bid requirements of Rule 1606(B), which originally would have been in effect as of January 1, 2001. We could have had another California or Nevada on our hands.

Q. HOW HAVE YOU MANAGED TO MAINTAIN HIGH LEVELS OF RELIABILITY WHILE ALSO PROVIDING THE INFRASTRUCTURE TO SUPPORT CUSTOMER GROWTH?

A. Managing customer growth and maintaining system reliability are closely related objectives, requiring consistent year-to-year planning, design and construction to upgrade our transmission and distribution system. For example, and in addition to the over $1,000,000,000 in new generation investment, APS plans on spending at least $1,000,000,000 on transmission and distribution infrastructure in just the next four years. We have managed these two related goals much better than many of our neighboring utilities because we have continued to make incremental improvements throughout the restructuring debates.

Q. HOW HAVE YOU MANAGED TO KEEP COSTS UNDER CONTROL DURING A PERIOD OF VOLATILE MARKET PRICES AND CONTINUING GROWTH?

A. One key to our success has been the power marketing section of our company. Marketing & Trading is part of the PWCC, which positions it to manage our enterprise-wide energy risk. When the electricity demands of our customers exceed our long-term resources—particularly during the hot summer months—Marketing & Trading supplements our existing resources with short-term purchases and reduces our financial exposure with hedging techniques. By purchasing wholesale power to serve our retail customers and selling available output from our generating facilities and other energy resources, this group optimizes the efficiencies of delivery and generation.

Q. WHAT HAVE YOU LEARNED ABOUT CUSTOMER SATISFACTION AND RELIABILITY OVER THE LAST COUPLE OF YEARS THAT SHAPES THE PHILOSOPHY OF THIS FILING?

A. Favorable prices always help create a positive response from customers. This year we reduced prices for the seventh time in eight years. We want to maintain the good customer relationships and the price performance that we have achieved over the last decade.

Although APS customers have been spared the price volatility and supply interruptions (or threats of supply interruptions) that have visited consumers elsewhere, it would be foolish, in my opinion, to ignore the events of the last two years in California. We cannot proceed as if a robust, liquid wholesale market already exists. Such a robust, liquid market is necessary for APS to buy large amounts of power with any sustainable hope of obtaining reasonable prices, fuel diversity and high levels of reliability.

V.
THE RELIABILITY CASE FOR THE PPA

Q. WILL THE PPA BE AN IMPORTANT CONTRIBUTION TO THE COMPANY'S GOAL OF RELIABILITY?

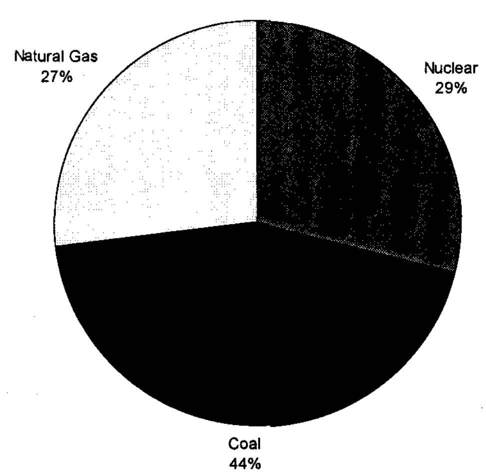
A. It's more than just important—it's critical to achieving that goal for our customers.

Q. WHY IS THAT?

A. As discussed in an earlier section of my testimony, the Electric Competition Rules have left a gap when it comes to supply reliability. The PPA fills that gap by making PWCC unambiguously responsible for securing adequate resources to serve APS Standard Offer customers. That alone is a vital component of reliability, but it is not the only contribution to reliability under the PPA.

Another such component of reliability is fuel diversity. In contrast to the new Arizona merchant plants that are or will be exclusively gas-fired, some 73% of the estimated Dedicated Units kWhs purchased by APS under the PPA in 2004 (the first year for which cost recovery of the PPA charges can be sought by the Company) will come from non-gas sources. Below in Figure 1, I present a simple chart showing the fuel diversity of the Dedicated Units:

Dedicated Units Fuel Diversity
2004 MWhs
(Figure 1)



Fuel diversity is more than just a pricing and price stability issue. Given the questions surrounding gas transportation capacity in Arizona, there are real concerns that gas-fired generators may face supply constraints during periods of peak gas usage.

A third component of reliability is geographic diversity. The Dedicated Units are located throughout the state (several are actually in New Mexico) and do not have to go through the Palo Verde hub to reach APS customers. This not only makes them less vulnerable to a catastrophic loss of one or two switchyards or lines (whether due to natural or manmade disasters), it allows these resources to avoid the transmission constraints that limit access from the Palo Verde hub to Metro-Phoenix. Again, this is no accident. The Dedicated Units were designed and sited to enhance their ability to reach APS customers and not the California market. This geographic diversity advantage makes them inherently more reliable resources than a collection of gas-fired power plants clustered around Palo Verde.

The new gas-fired units are premised on the belief that a technology originally designed for peaking and intermediate use can be reliably operated in a base load generation mode over the long haul. Although there are well-informed engineering bases for this belief, and the experience of some of the units to date has been encouraging, in point of fact these units have yet to be tested for long periods of time comparable to the experience of most of the Dedicated Units, and some of the newer plants in Arizona have undergone some significant shakedown before achieving commercial operation. In contrast, the Dedicated Units responsible for the overwhelming majority of kWh from Dedicated Units under the PPA have proven track records of excellent—even record breaking- performance over many years. Figure 2 below shows the equivalent availability factors (percentage of capacity available compared with nameplate capacity) for Palo Verde, Four Corners, Navajo and Cholla from 1991 to 2000:

Year	EAF (%)	Year	EAF (%)
1991	99.44	1996	85.83
1992	99.23	1997	86.24
1993	99.48	1998	86.97
1994	98.98	1999	88.81
1995	89.03	2000	89.79

(Figure 2)

Another aspect of reliability is the need for a proper blend of base, intermediate and peaking units—in other words, a diversity of operating characteristics. Although generally thought of only in economic terms, attempting to operate a peaking unit as base load or cycling a base load unit to act like a peaker or intermediate unit can both increase costs and lead to higher forced outage rates, if not premature unit retirement. The Dedicated Units provide APS with just such a balanced portfolio of generating options specifically designed for serving a utility the size of and with the seasonable and diurnal load characteristics of the APS system.

Q. ARE YOU SAYING THAT APS DOESN'T NEED OR WANT MERCHANT GENERATION IN OR NEAR ITS SERVICE AREA?

A. Absolutely not. I'm not casting any aspersions on the role of merchant generators in building a vibrant competitive wholesale market. APS encourages merchant generators to locate in Arizona at sites where they can access the APS service territory. APS and its customers will be very large consumers of merchant generation under the PPA, and the more competitive the wholesale market, the better price APS and its customers can anticipate from that market. However, the Company's primary obligation is necessarily to its customers, and it must balance the need to foster the greatest degree of wholesale competition with the needs of its customers for reliable and reasonably-priced energy.

VI.
THE ECONOMIC CASE FOR THE PPA

Q. WHAT WERE THE ECONOMIC CONSIDERATIONS THAT WENT INTO THE NEGOTIATION OF THE PPA?

A. Although reliability is obviously critical to our customers, so are reasonable prices. To APS, there are several aspects to what constitutes a reasonable price just as there were differing components to reliability. These include:

- relative price stability and predictability over both short and long term;
- probable price advantage over the term of any agreement as compared with the cost of power from the new generating units most likely to influence long-term market prices; and,
- compatibility of the proposed purchase with prudent power acquisition practices for Standard Offer service.

Q. HOW DOES THE PPA MEET THE FIRST CRITERION OF REASONABLE PRICES?

A. First of all, the PPA is a long-term contract for a very substantial portion of APS' Standard Offer requirements. Second, its price is not tied to the market and is not heavily influenced by natural gas prices. In Figures 3 and 4 below, I show daily power and natural gas prices for the period January 2000 through early December 2001:

Palo Verde Wholesale Power Prices
(1/1/00 - 12/03/01)

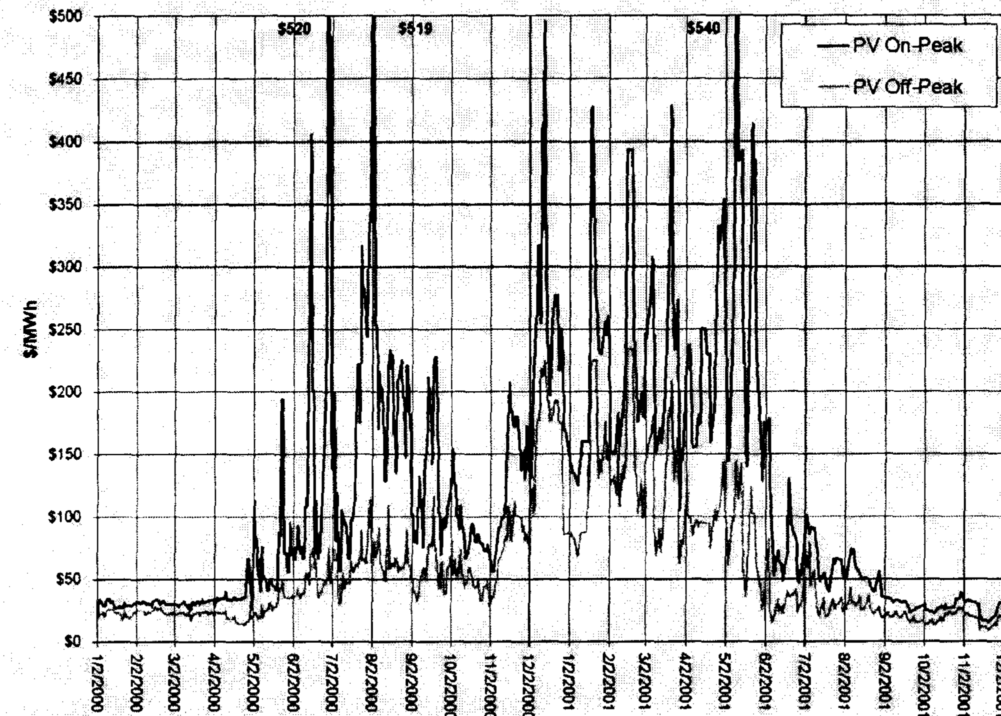


Figure 3

Henry Hub vs. Topock
Natural Gas Wholesale Prices
(1/1/00 - 12/04/01)

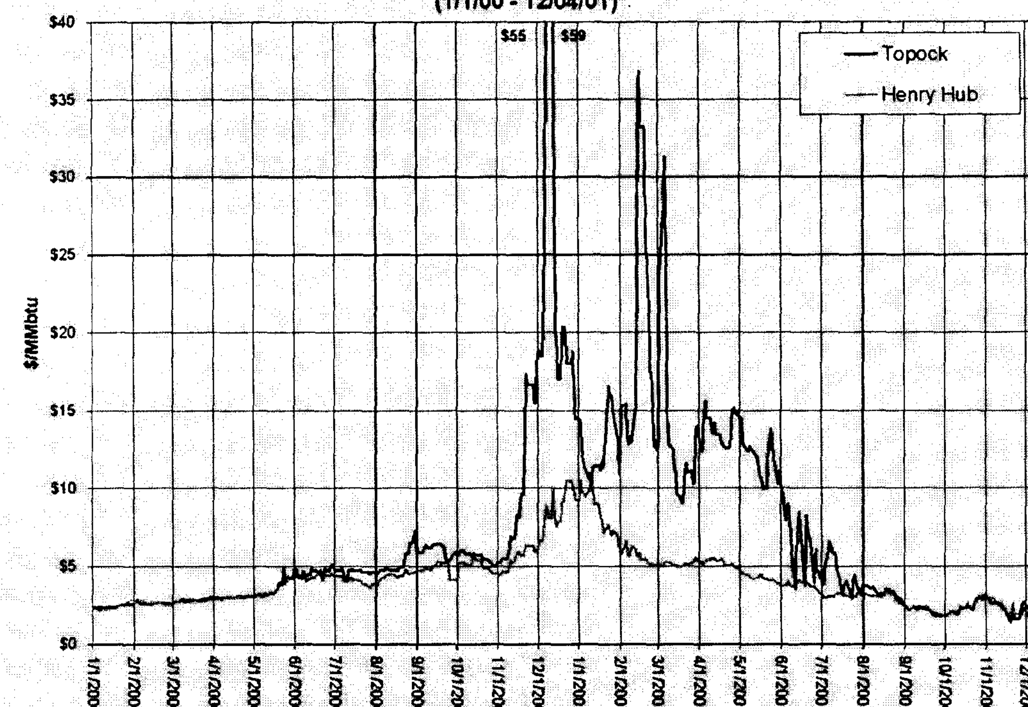


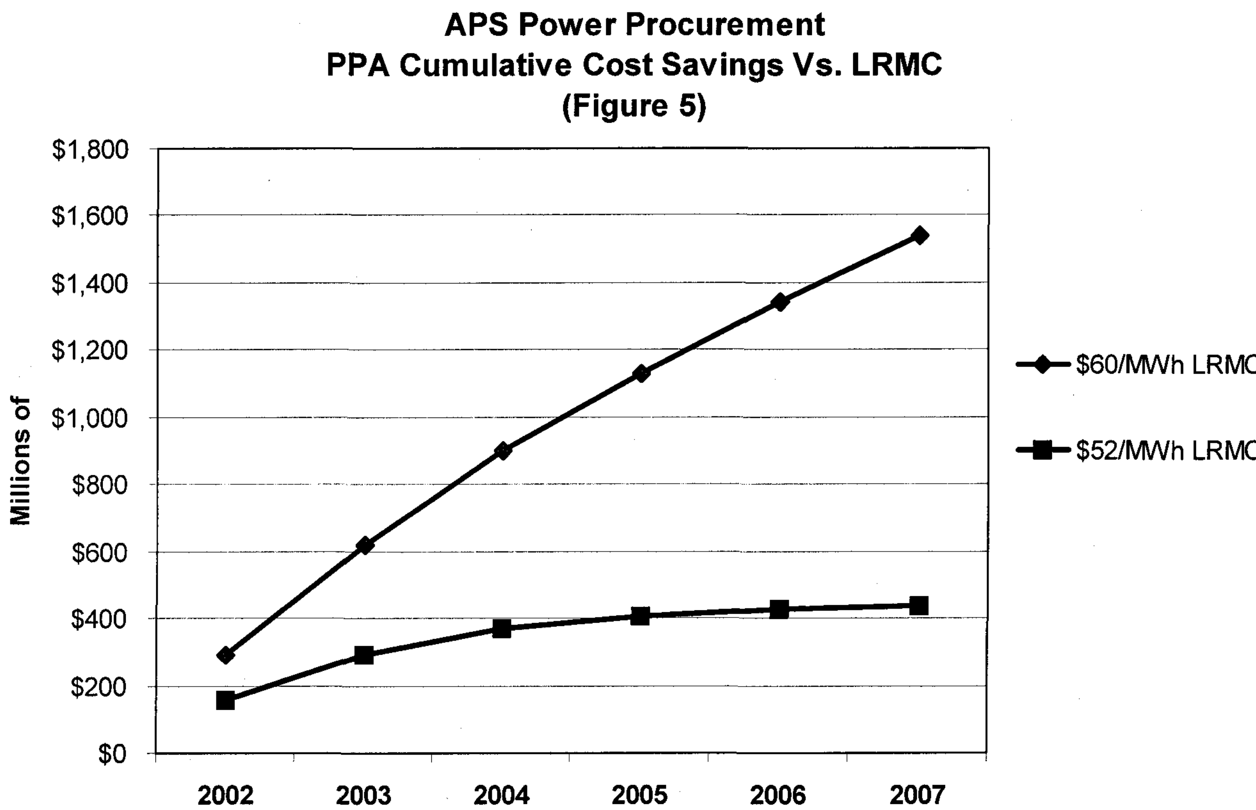
Figure 4

These charts demonstrate clearly the tremendous volatility of electric power and natural gas markets—a volatility that has led to significant rate increases in California and other Western states, and a volatility that APS customers have avoided and will continue to avoid under the PPA. Third, the cost-of-service formula used to adjust prices under the PPA is a relatively stable and predictable factor that could decline as well as increase over time, but in either event would not fluctuate over the term of the PPA as much as will the cost of new gas-fired generators. Fourth, even at that, the PPA allows changes to the Facilities Charge only once every three years and to kWh charges only on an annual basis.

Q. HOW ABOUT CRITERION NUMBER TWO—LIKELY LONG RUN PRICE ADVANTAGE?

A. I don't believe wholesale electric prices can be maintained below the long-run marginal cost of new generation for any significant period of time before creating supply shortages. Even as this testimony is being written, we are seeing the impact of today's lower market prices for power in the form of cancelled or delayed power plant projects. Thus, APS used the long-run cost of the new gas-fired combined cycle gas units as one criterion by which to measure the reasonableness of the PPA pricing scheme.

Below in Figure 5 is that comparison shown in terms of cumulative savings over the first six years of the PPA:



Based on a projected LRMC of between $52 and $60 per MWh, cumulative customer savings could be from over $400 million to some $1.5 billion. I have not carried out the analysis beyond 2007 because of the paucity of reliable data. However, I believe the savings would likely be even greater, especially under the $60 per MWh scenario.

Q. IS THE PPA A REASONABLE PART OF A PRUDENT OVERALL RESOURCE ACQUISITION STRATEGY?

A. Absolutely. Just as a traditional vertically-integrated utility operating under the Commission's Resource Planning Regulations (A.A.C. R14-2-701, *et seq.*) would construct a resource portfolio of base, intermediate and peaking units based on its load profile and risk management strategy, a UDC must consider doing the same through appropriately balanced contractual resources. The Dedicated Assets that provide much of the power under the PPA constitute a diverse resource portfolio.

Likewise, a diverse contractual portfolio must be comprised of a mix of long-term, intermediate and short-term obligations. Because the great majority of Standard Offer customers are residential and small commercial customers who are traditionally risk adverse, a correspondingly risk adverse resource portfolio strategy is appropriate.

VII.
THE PPA WILL NOT ADVERSELY AFFECT EITHER WHOLESALE OR RETAIL COMPETITION IN ARIZONA

Q. IN STAFF'S RESPONSE TO THE COMPANY'S FILING AND IN SOME OF THE INTERVENTION REQUESTS FILED BY THE MERCHANT INTERVENORS, IT IS ALLEGED THAT GRANTING THE VARIANCE REQUESTED BY THE COMPANY WILL HURT OR EVEN ELIMINATE THE POSSIBILITY OF WHOLESALE AND RETAIL ELECTRIC COMPETITION IN ARIZONA. DO YOU AGREE?

A. Absolutely not.

Q. WHY DO YOU SAY THAT?

A. There are many reasons. First, the approval or disapproval of the PPA will not change the fact that the Dedicated Assets will exist as competitors of the Merchant Intervenors. To the extent these assets are committed to serving APS Standard Offer customers, they will not be in a position to compete against the Merchant Intervenors for sales to ESPs, other Arizona UDCs, or to customers outside of Arizona. Second, the PPA allows at least seven opportunities for the Merchant Intervenors to sell power in the APS distribution service area:

- Competitively-Bid Energy Products under the PPA;
- Supplemental Energy Products under the PPA;

- Replacement Energy Products under the PPA;
- Power sold as an economic replacement to Dedicated Asset Energy Products under the PPA;
- Wholesale sales to ESPs operating in the APS service area;
- Direct retail sales to end-users in the APS; and
- Financial (non-commodity) forward sales.

Third, the APS load theoretically "taken off the market" by the PPA is insignificant compared to the size of the Western power market. Fourth, I say "theoretically" taken off the market because given the low marginal cost and geographic dispersion of the Dedicated Units, they likely would win any competitive bid for a large share of APS requirements, thus leaving the Merchant Intervenors in no better position. I will address each of these points below.

Q. WHY DO YOU SAY THAT THE DEDICATED ASSETS WOULD HAVE THE SAME COMPETITIVE IMPACT ON THE MERCHANT INTERVENORS IRRESPECTIVE OF THE PPA?

A. These assets don't disappear if the PPA is not approved. The PPA does not affect their location, fuel source, or operating characteristics. The ability of these assets to produce low cost energy and to get that energy out to the Western market is what gives them an advantage over the plants scheduled to be built by the Merchant Intervenors.

Q. WHAT ABOUT THE OTHER OPPORTUNITIES FOR THE MERCHANT INTERVENORS YOU SPOKE ABOUT ABOVE?

A. Although the entire APS service territory comprises only some 3.2% of the wholesale market of the Western United States and well less than half the Arizona market, there are many opportunities for the Merchant Intervenors to sell power within that service area. As noted above, there will be more competitively-bid power used to serve APS Standard Offer customers in 2008 than for any other UDC in Arizona. As APS load growth outstrips the combination of both the Dedicated Assets (which themselves will decline over time with the retirement of some Dedicated Units late in the term of the PPA) and the mandatory competitively-bid portion of the PPA, there will be a need for what the PPA terms "Supplemental Energy Products." If one or more of the Dedicated Units is experiencing an outage or if one of the Dedicated Contracts is defaulted or terminated (e.g., SRP can terminate the Territorial & Contingent Power Sales Agreement at any time with three years notice), there may be a need for either additional Supplemental Energy Products or what the PPA terms "Replacement Energy Products" from the Merchant Intervenors. Even if available, the Dedicated Units are subject to being replaced by power from the Merchant Intervenors on an economic dispatch basis. In the future, APS anticipates that ESPs will again be active within its service area. Obviously, they will look to suppliers such as the Merchant Intervenors for power, assuming that the Merchant Intervenors haven't already committed all their output to APS or some other UDC. Although none of the Merchant Intervenors has apparently requested authority to provide retail service in Arizona, they obviously have that option to directly market their power to end-use consumers in the APS service area. Finally, through the forward pricing market, generators can sell their output without making physical delivery.

Q. DO YOU BELIEVE THAT ALL THE MERCHANT INTERVENORS ARE INVESTING OR WILL INVEST "BILLIONS OF DOLLARS" IN ARIZONA TO SERVE APS STANDARD OFFER CUSTOMERS?

A. No. In fact, I don't believe <u>any</u> of them have located their proposed generating facilities in Arizona solely for that express purpose nor have I seen any public pronouncements to that effect. The siting of new power plants is primarily about land availability, fuel availability, the regulatory climate for the siting of power plants, transmission availability, and at least in the West, water availability and proximity to California. That's why you see tremendous building activity in states that don't even have retail access, let alone any competitive bidding requirement. I also believe my statement is correct because if any plant in Arizona had been planned on that basis, I'm sure they would have asked APS about making transmission available to reach the APS service area or the best location to site the plant to take advantage of existing transmission into the APS load centers. If a merchant generator were interested primarily in serving APS load, they should locate their plant within the Metro Phoenix area. They did not. Finally, the idea that the Merchant Intervenors would spend billions of dollars on the mere hope that they would be the successful bidder under Commission regulations that have been continuously under a court challenge since its inception in late 1999 (and which were declared unconstitutional in 2000) is, in my opinion, an unsupportable assertion.

At the time this testimony was filed, APS has not had any opportunity to conduct discovery on any of the Merchant Intervenors. Once that discovery is complete, I reserve the right to request the opportunity to supplement this portion of my remarks under whatever procedural schedule is determined by the Presiding Chief Administrative Law Judge.

Q. ARE THERE OTHER REASONS WHY YOU DON'T BELIEVE ANY OF THE MERCHANT INTERVENORS ARE LOCATING OR WILL LOCATE THEIR FACILITIES IN ARIZONA IN RELIANCE UPON RULE 1606(B)?

A. Yes. Some of the plants are being located in areas such as Mohave County that have no significant available transmission access to the APS service area. Those that are seeking to interconnect at Palo Verde are no doubt aware that the available transmission capacity from Palo Verde west to California exceeds that coming east to Metro Phoenix. Finally, the size of APS' load compared to the over 20,000 MW of proposed new merchant generation in Arizona would lead me to conclude that they had "bigger fish to fry" than APS. After all, the Merchant Intervenors can potentially access the entire Western wholesale generation market (approximately 150,000 MW) from the Palo Verde hub. Moreover, I doubt that a reduction of the APS load required to be competitively bid from roughly 3500 MW in 2008 to 1620 MW in that same year will result in a significant number of cancellations from that 20,000 MW of new generation.

VIII.
DESCRIPTION OF SELECTED PROVISIONS OF THE PPA

Q. IN GENERAL TERMS, HOW IS THE PPA STRUCTURED?

A. The PPA consists of a contract of 13 sections or "Articles", exhibits containing defined terms and points of contact for the performance of the PPA, and a Service Schedule. The Service Schedule contains two attachments, both of which address the calculation of the charges under the PPA. As is typical for contracts of this type, the detailed provisions regarding the services provided under the PPA are found in the Service Schedule and its attachments. For example, the Service Schedule provides details on the various types of Energy Products supplied under the PPA, and specifically describes how those Energy Products are priced and provided to APS. The contract portion of the PPA contains more general provisions relating to performance under the PPA such as metering, the billing process, the treatment of taxes, dispute resolution, and so forth. There are also provisions relating to defaults, the term and renewal of the PPA, and various representations and warranties of the parties. Finally, there are numerous general provisions—such as an assignment clause, confidentiality, and records retention provisions—that are fairly typical in commercial agreements.

Q. PLEASE DISCUSS THE DIFFERENT TYPES OF ENERGY PRODUCTS IN THE PPA?

A. There are essentially five types of Energy Products involved in providing APS' full load requirements. Two of these types of Energy Products are associated with assets of PWCC or PWEC that are dedicated to APS, and the rest will be procured from the competitive market. The two types of dedicated Energy Products are "Dedicated Units Energy Products" and "Dedicated Contracts Energy Products"—collectively referred to as the "Dedicated Energy Products." As the name implies, the Dedicated Units Energy Products are energy and capacity from the Dedicated Units, which are the generation plants specifically identified in the PPA. The Dedicated Units essentially consist of the existing generation serving APS customers plus the over $1,000,000,000 in new assets that PWEC has constructed or is constructing to serve growing APS loads.

The Dedicated Contracts Energy Products are energy and capacity from two agreements—the SRP Power Coordination and Territorial Agreement ("SRP Agreement") and the Pacificorp Power Exchange Agreement ("Pacificorp Agreement"). The SRP Agreement allows the purchase of certain power from SRP. The Pacificorp Agreement consists of a power swap between the winter-peaking Pacific Northwest and summer-peaking Arizona. The Pacificorp Agreement was, and still is, an innovative mechanism for the two companies to save money during their respective peak seasons. These contracts have helped provide for APS' energy needs for some time. Accordingly, it was appropriate to include these contracts along with the Dedicated Units.

The other three types of Energy Products will be obtained from the competitive market. The "Competitively-Bid Energy Products" are energy and capacity that will be procured for APS under a competitive bidding program administered by PWCC. "Supplemental Energy Products" will be purchased from the wholesale market when APS' energy requirements exceed the amounts provided from Dedicated Energy Products and Competitively-Bid Energy Products. Similarly, in the event of defaults by suppliers of Competitively-Bid Energy Products or Supplemental Energy Products, PWCC will obtain "Replacement Energy Products" from the wholesale market, and will pursue legal remedies from the defaulting party on behalf of APS. These latter two Energy Products effectively make PWCC a wholesale provider of last resort to APS. Collectively, these five Energy Products will supply all of the significant energy and capacity needs for APS' Standard Offer customers.

Q. WHAT ARE SOME OF THE MORE SIGNIFICANT PROVISIONS IN THE PPA?

A. Obviously, the pricing structure for all of the Energy Products, including the Dedicated Units, is a significant provision. I would also include the minimum availability of the Dedicated Units, the competitive bid requirement, and the term and renewal options of the agreement as among the most significant provisions of the PPA. I will discuss each of these in more detail.

Q. PLEASE DISCUSS THE PRICING OF THE DEDICATED UNITS ENERGY PRODUCTS.

A. The Dedicated Units Energy Products will be priced to mirror the terms of a purchase power agreement that will be entered into by PWCC and PWEC. The price will consist of four components: a fixed monthly Facilities Charge, a Base

Fuel Charge, a Fuel and Purchased Power Adjustment ("FPPA"), and a pass-through for transmission, losses and Ancillary Services costs incurred to deliver to the APS system.

The Facilities Charge is a fixed monthly charge calculated by applying a 9.38% rate of return to the average net value of the Dedicated Units, adding to that figure the projected average annual non-fuel operating expenses for the Dedicated Units, and subtracting ancillary services revenues associated with the Dedicated Units. The net value and annual operating expenses for the Dedicated Units are determined using a standard cost-of-service formula with components defined by the FERC Uniform System of Accounts or Generally Accepted Accounting Principles. Beginning in 2005, the Facilities Charge will be recalculated every three years using the specific formula in Attachment #1 to the Service Schedule. The specific Facilities Charge for the initial three years of the PPA are set forth in Section 3.2.2.1 of the Service Schedule.

The Base Fuel Charge reflects the average fuel costs associated with the Dedicated Units for the period of 2002 through 2004. The calculation of the Base Fuel Charge results in a per-kWh charge of 21 mills for 2002 (prior to the transfer of the Palo Verde Nuclear Generating Station assets) and 17.4 mills for 2003 and thereafter. Because the FPPA to the Base Fuel Charge may be either positive or negative, it is not necessary to recalculate the Base Fuel Charge after 2003.

Beginning in March 2003, the FPPA will be applied to the Base Fuel Charge. The FPPA reflects the projected difference in average fuel costs for Dedicated Units from the Base Fuel Charge for the then-current contract year, and incorporates a true-up mechanism for the prior contract year and a credit for a portion of the margin from any off-system sales from the Dedicated Units. Importantly, the average fuel cost calculation used to determine the FPPA reflects purchased power costs incurred when economic dispatch warrants obtaining such power from the market, rather than dispatching one of the Dedicated Units. Thus, the pricing mechanism for the Dedicated Units Energy Products allows purchases from the competitive market when it is more economical to do so from a dispatch standpoint.

The FPPA will be recalculated annually after March 2003. The Base Fuel Charge and FPPA are applied to the Dedicated Units Billing Energy, which is the quantity of energy billed each month to APS and is more specifically defined in the PPA.

Q. PLEASE EXPLAIN HOW OFF-SYSTEM SALES ARE TREATED UNDER THE PPA.

A. As I discussed earlier, the FPPA includes a credit called the "Off-System Sales Margin." There will undoubtedly be times when the Dedicated Units will not be needed to provide for APS load requirements, but could profitably sell off-system in the wholesale market. The Off-System Sales Margin that will be credited through the FPPA reflects 25% of the net margin obtained for such sales into the wholesale market. Providing PWEC the ability to pursue off-system sales not only provides a credit to APS that reduces the amount of the FPPA, but also gives a direct incentive to operate the Dedicated Units as economically as possible. In contrast, in the past off-system sales were only considered during general rate proceedings filed at the discretion of the Company.

Q. DOES THE PPA REQUIRE A MINIMUM AVAILABILITY FOR THE DEDICATED UNITS?

A. Yes, and the minimum availability is a key reliability ingredient of the PPA. Specifically, the PPA requires that PWCC make available certain minimum amounts of both capacity and energy from the Dedicated Units. The specific amounts vary depending on whether it is before or after the transfer of the Palo Verde Nuclear Generating Station. In 2003, following the transfer of Palo Verde, at least 4720 MW of capacity must be available at system peak, or APS' actual load at system peak if less than that figure. Additionally, after the transfer of Palo Verde, PWCC must make 21,090 GWh of energy available annually from the Dedicated Units.

Q. DOES THE PPA REQUIRE PWCC TO PROVIDE RESERVES?

A. Yes. The PPA requires PWCC to provide those reserves that are consistent with "good utility practice." Such a requirement underscores the notion that PWCC is APS' provider of last resort. A significant portion of this reserve requirement, at least initially, will be provided by the availability of the Dedicated Units.

Q. HOW ARE THE DEDICATED CONTRACTS ENERGY PRODUCTS PRICED UNDER THE PPA?

A. The Dedicated Contracts Energy Products will be provided to APS at the actual cost incurred by PWCC under each contract, including transmission and associated costs necessary to delivery these Energy Products. There will be no mark-up on these contracts.

Q. PLEASE DISCUSS HOW THE PPA ADDRESSES COMPETITIVELY-BID ENERGY PRODUCTS.

A. Starting in 2003, the PPA requires PWCC to obtain 270 MW at a 51% load factor through a competitive bid process. The amount of Competitively-Bid Energy

Products will increase by 270 MW per year through 2008, until 1620 MW is obtained through competitive bidding. This 1620 MW requirement will constitute roughly one-quarter of APS' peak load in 2008 which, as I pointed out earlier in my testimony, will exceed the amount of competitively-bid energy being procured by any other Affected Utility in the state.

Under the PPA, PWCC would administer the competitive bid process, but APS would have the right to participate in the design of the program, including the development of the associated contracts, specifications, and creditworthiness requirements. PWCC would also handle any defaults of suppliers under the competitive bid program, including the procurement of Replacement Energy Products and the prosecution of any claims against the defaulting supplier. In terms of pricing, APS would pay the costs and expenses incurred to acquire the Competitively-Bid Energy Products. Supplemental Energy Products may also be competitively bid.

Q. COULD PWCC PARTICIPATE IN THE COMPETITIVE BID PROCESS AS A BIDDER?

A. Only if it engaged a third party to administer the competitive bid process. APS would have to approve the third party administrator, and if PWCC was the successful bidder, APS and PWCC would enter into a separate contract for the Energy Products involved.

Q. HOW ARE SUPPLEMENTAL ENERGY PRODUCTS AND REPLACEMENT ENERGY PRODUCTS PRICED UNDER THE PPA?

A. Both Supplemental Energy Products and Replacement Energy Products are essentially passed through to APS at cost, including administrative and transmission-related costs. In the case of Replacement Energy Products, APS would also pay for the costs associated with pursuing any legal remedies against defaulted suppliers, but would keep all damages awarded.

Q. YOU INCLUDED THE TERM OF THE PPA AND THE RENEWAL OPTIONS AMONG ITS MORE SIGNIFICANT PROVISIONS. WHY?

A. One of the many advantages to the PPA is that it balances long-term dedicated resources priced using a cost-of-service methodology with increasing access to competitive wholesale markets. Given its overall structure, the initial term of the PPA—through 2015—offers a significant backstop of stability to APS' Standard Offer customers regardless of what happens to the competitive wholesale market. After that date, certain significant generating units included in what the PPA identifies as "Dedicated Units" are presently scheduled for retirement. During that term, however, both APS and its customers can increasingly avail themselves of that market if it is economical to do so. When considered with the three optional 5-year extensions, the total term of the PPA would approximate the weighted average remaining book life of the Dedicated Units. Having recourse to the Dedicated Units under the terms of the PPA over such a period is a significant advantage to APS and its customers, while still offering sufficient flexibility to pursue competitive wholesale opportunities when and where appropriate.

Q. WHAT IS THE CONNECTION OF THE PPA AND THE VARIANCE?

A. The variance is necessary to allow APS to enter into the PPA. Without the PPA, APS would not be in a position to seek the variance with the assurance that it had a more reasonable alternative to propose to the Commission.

IX.
CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. The requested variance to Rule 1606(B) and the associated PPA are necessary components of providing reliable and reasonably-priced power to the Company's nearly 900,000 Standard Offer customers. Neither will adversely impact the wholesale or retail competitive market in the Southwestern United States in general or Arizona in particular. Indeed, APS views the continued existence of a reliable and reasonably-priced Standard Offer service as an indispensable component of a viable competitive retail market, especially for residential and small commercial customers. Neither is prohibited in any way by the 1999 APS Settlement, which specifically acknowledged the possibility of future variances to the Electric Competition Rules – variances that to some extent have already taken place. The approval of both is clearly in the public interest, and I urge the Commission to grant the Company's application at the earliest possible time.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

APPENDIX A

STATEMENT OF WITNESS QUALIFICATIONS

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

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

Mr. Davis currently serves (i) Past-Chairman of the Western Systems Coordinating Council (WSCC) and is a member of its Board of Trustees; (ii) as past Chairman on the Western Systems Power Pool; (iii) as Past President of Western Energy and Supply Transmission (WEST) Associates; and (iv) is a member of the National Electric Reliability Council Board of Trustees. He is a registered professional Engineer in the State of Arizona.

APPENDIX B

PROPOSED PPA

OCTOBER 18, 2001

Purchase Power Agreement
Between
Pinnacle West Capital Corporation and
Arizona Public Service Company

Contract No. _____

Table of Contents

PURCHASE POWER AGREEMENT
BETWEEN
PINNACLE WEST CAPITAL CORPORATION AND
ARIZONA PUBLIC SERVICE COMPANY

Introduction

A. **Parties.** The Parties to this Agreement are Pinnacle West Capital Corporation ("PWCC") and Arizona Public Service Company ("APS").

B. **Agreement.** This Agreement is made under PWCC's Tariff and includes all attached exhibits and schedules, all of which are incorporated by reference. Defined terms used in this Agreement are set forth in Exhibit A.

C. **Purpose.** The Parties intend to enter into a purchase and sale agreement of Energy Products so that APS can adequately, economically, and reliably serve its retail customers under a pricing mechanism that combines general rate stability, long-term access to dedicated generation assets, recovery of the costs of those dedicated assets, and market-based opportunities for competitive wholesale providers.

Article 1
Services Provided

1.1 Purchase and Sale of Power.

(A) PWCC shall supply to APS, on a firm basis, APS' Full Load Requirements. PWCC shall be the exclusive provider of APS' Full Load Requirements during the term of this Agreement, except as otherwise provided in this Agreement.

(B) APS shall pay PWCC for the sales in Section 1.1(A) as provided in the attached Service Schedule and in accordance with PWCC's Tariff.

1.2 Firm Deliveries.

(A) PWCC shall provide Dedicated Energy Products on a firm basis, and shall include adequate reserves to satisfy Good Utility Practice.

(B) Subject to Section 2.1 of this Agreement and Section 3.2 of the Service Schedule, PWCC has the sole discretion to select or acquire the resources, including the determination of the adequacy of reserves, to provide Energy Products. Such discretion includes the right of PWCC, under economic dispatch and subject to the fuel and purchase power adjustment in Section 3.2 of the Service Schedule, to purchase power rather than schedule the Dedicated Units.

(C) PWCC shall also procure purchased power as necessary to satisfy the requirements of Section 1.1, as provided in the attached Service Schedule.

1.3 Relationship to Tariff.

(A) If the Agreement is or becomes inconsistent with PWCC's Tariff, the Tariff shall control with respect to such inconsistency.

(B) The Tariff and this Agreement together form a single agreement. The Parties would not have entered into this Agreement without such a relationship.

(C) This Agreement does not amend the Tariff.

1.4 Transfer of Title and Risk of Loss.

(A) As between the Parties, and except as expressly limited in the attached Service Schedule or Exhibit A, or unless the Parties have agreed in writing otherwise:

(1) Before Energy Products subject to this Agreement are delivered to APS, PWCC will be deemed to have exclusive control and possession of the Energy Products and will be responsible for all damages, injuries, and other losses occurring before such delivery.

(2) After Energy Products subject to this Agreement are delivered to APS, APS will be deemed to have exclusive control and possession of the Energy Products and APS will be responsible for all damages, injuries, and other losses occurring after such delivery.

(3) Ownership of the Energy Products and risk of loss shall pass from PWCC to APS at the Delivery Points.

(B) Except as provided in Section 1.4(C), the Parties each assume full responsibility for and shall indemnify and hold harmless the other Party for, from and against all liability, costs and expenses, including but not limited to those relating to the injury or death of persons, arising or caused after title to the Energy Product has passed to the indemnifying Party. Expenses include but are not limited to court costs, reasonable attorneys' fees, and litigation expenses.

(C) The indemnifying Party shall not be liable to the indemnified Party to the extent the liability, costs or expenses resulted from gross negligence or willful misconduct of the indemnified Party or from the indemnified Party's breach of this Agreement.

1.5 **Transmission and Ancillary Services Arrangements.** Except as expressly limited in the attached Service Schedule or Exhibit A, or unless the Parties have agreed otherwise in writing:

(A) PWCC shall make all arrangements necessary for transmission of the Dedicated Energy Products to the Delivery Points.

(B) PWCC is responsible for all costs, including but not limited to losses and Ancillary Services, associated with the transmission of the Dedicated Units Energy Products to the Delivery Points. Transmission and Ancillary Services costs associated with the Dedicated Contracts Energy Products, Competitively-Bid Energy Products, Supplemental Energy Products, and Replacement Energy Products shall be charged as provided in the Service Schedule.

(C) APS shall make all arrangements necessary for transmission of Energy Products from the Delivery Points.

(D) APS is responsible for all costs, including but not limited to losses and Ancillary Services, associated with the transmission of the Energy Products from the Delivery Points.

Article 2
<u>Reliability Guidelines</u>

2.1 **Reliability Guidelines.**

(A) Each Party shall adhere to:

(1) Good Utility Practice;

(2) all applicable operating policies, criteria, and guidelines of the NERC, the WSCC, the control area operator, and their respective successors; and

(3) all applicable regional and national reliability requirements;

(4) all applicable requirements of an RTO, to the extent not inconsistent with this Agreement.

(B) PWCC shall secure sufficient generating capacity to fulfill its Dedicated Units Energy Products obligations under this Agreement.

(C) As part of the obligation in Section 2.1(B) and concurrently with this Agreement, PWCC shall enter into an agreement with Pinnacle West Energy Corporation for rights to generating capacity to ensure the reliable delivery of APS' Full Load Requirements.

Article 3
Metering

3.1 Metering Procedures.

(A) Inspection and Testing.

(1) As long as APS is the control area operator, it shall conduct or provide for periodic inspection and testing of meters used to perform this Agreement. Inspection and testing shall be at APS' own expense and shall conform to APS' generator interconnection agreements and APS' transmission interconnection agreements.

(2) Inspection and testing under Section 3.1(A) shall be conducted as necessary to maintain a commercial standard of accuracy for the meters. APS shall repair or replace meters not meeting such standard.

(3) Upon request to APS, PWCC shall be provided the results of meter tests, be given notice of meter tests and inspections, and be given the opportunity to attend meter tests and inspections, to the extent allowed under APS' generator interconnection agreements and APS' transmission interconnection agreements.

(4) APS shall conduct or provide for additional meter testing at PWCC's request and in the presence of PWCC's representatives to the extent allowed under APS' generator interconnection agreements and APS' transmission interconnection agreements.

(B) Corrections for Inaccurate Meters. If testing or inspection in Section 3.1(A) shows that a meter is inaccurate by more than the amount specified in APS' generator interconnection agreements and APS' transmission interconnection agreements, then:

(1) PWCC shall correct the billings from the date the error can be definitely identified, or for the previous six billing months or from the date of the last test, whichever is most recent; and

(2) APS and PWCC shall correct the meter records for the elapsed period of the month in which the test was conducted.

(C) **Costs for Additional Testing.** The cost of inspection and testing requested by PWCC shall be borne by PWCC if the test does not require a correction under Section 3.1(B). Otherwise, APS shall bear the cost of inspection and testing.

(D) **Estimated Meter Data.** If at any time a meter fails to register or its registration is too erratic to be meaningful, then:

(1) the registration for billing purposes shall be based on the records of check meters, if available;

(2) the Parties shall mutually agree on the best available data to estimate the registration if check meters are not available; and

(3) APS shall in good faith remedy the meter inaccuracy using commercially reasonable means and in a reasonable period of time.

3.2 Availability of Meter Data.

(A) APS shall provide meter data or estimates to PWCC no later than three Business Days following the last day of each calendar month.

(B) APS may aggregate data when necessary to comply with confidentiality obligations.

Article 4
Billing, Payment and Netting

4.1 Invoices.

(A) PWCC shall endeavor to provide APS with a written invoice showing the Purchase Price and all other charges due by the 20th calendar day of the month following such delivery of Energy Products.

(B) Invoices issued pursuant to Section 4.1(A) shall contain sufficient detail for APS to confirm all calculations on the invoice.

(C) APS shall promptly provide to PWCC all information reasonably needed by PWCC to calculate the invoice.

(D) If data needed to calculate an invoice is unavailable, PWCC shall estimate the necessary data. PWCC shall revise such estimates when the necessary data becomes available and include a true-up adjustment in the next invoice, but all revisions must be made within 12 months of the estimated invoice.

(E) Invoices may be provided to APS by facsimile or another method agreed upon by the Parties.

4.2 Payment.

(A) Payment Due Dates. Invoices shall be paid no later than 10 calendar days after receipt of the invoice.

(B) Next Business Day. If the payment date specified in Section 4.2(A) is not a Business Day, the payment shall be due no later than the next Business Day.

(C) Method of Payment. APS shall pay by electronic funds transfer or another method that results in the payment being available for the account of PWCC on or before the payment date specified in Section 4.2(A) or Section 4.2(B).

(D) Late Payments. If either Party fails to remit an amount payable when due, Interest shall accrue on the net unpaid amount.

(E) Netting of Payments. If both Parties owe amounts accruing under this Agreement, such amounts shall be netted with the Party owing the greater amount paying the other Party the difference in the amounts owed.

4.3 Disputed Invoices or Payments.

(A) If either Party disputes an invoice, it shall nonetheless pay the full amount due on or before the due date and submit a written statement detailing the dispute to the other Party.

(B) Within 15 calendar days after receipt of the written statement described in Section 4.3(A), a written response shall be submitted to the Party disputing the invoice.

(C) In order to facilitate the negotiations provided in Section 4.3 (D), the statement and response described in Section 4.3(A) and Section 4.3(B) shall each include a statement of the Party's position, a summary of the arguments supporting that position, the name and title of the person who will represent that Party, and any other person who may accompany the Party's representative .

(D) The Parties shall attempt in good faith to resolve the dispute promptly through negotiation as follows:

(1) Within 30 calendar days after delivery of the statement described in Section 4.3(A), the Parties shall meet at a mutually agreed upon place and time.

(2) The Parties shall continue to meet as often as necessary to attempt to resolve the dispute in good faith.

(3) All negotiations pursuant to this Section 4.3 shall be confidential and subject to Rule 408 of state and federal rules of evidence.

(4) Each Party is responsible for its own costs, fees and expenses incurred in the negotiations.

(E) If the dispute has not been resolved within 60 calendar days after delivery of the statement described in Section 4.3(A), or if the Parties fail to meet in accordance with Section 4.3(D), then either Party may initiate the alternative dispute resolution provisions in Article 12.

4.4 **Refunds.** If either Party is owed a refund or additional payment, such refund or additional payment shall include Interest, unless otherwise directed by FERC.

Article 5
Representations and Warranties

5.1 **Mutual Representations and Warranties**. Each Party represents and warrants to the other Party that, as of the date it signs this Agreement and as of the date of each delivery of Energy Products to or from the Delivery Points, as applicable, that:

(A) It is duly organized, validly existing, and in good standing, under the laws of the jurisdiction of its organization or incorporation.

(B) It has the corporate, governmental and legal capacity, authority and power to execute, deliver, and perform this Agreement.

(C) The execution, delivery, and performance of this Agreement does not violate or conflict with any:

(1) laws or regulations applicable to the Party;

(2) organizational or corporate documents applicable to the Party;

(3) orders or judgments of any court or regulatory body applicable to the Party or its assets; or

(4) contractual restrictions applicable to the Party or its assets.

(D) No Event of Default under Article 7, including an event which with notice or lapse of time would constitute an Event of Default:

(1) has occurred and is continuing for the Party; or

(2) would occur as a result of the execution, delivery, or performance of this Agreement for the Party.

(E) It has executed this Agreement in connection with the conduct of its business and it has the ability to make or take delivery of Energy Products as provided in this Agreement.

(F) It is not relying on any representation of the other Party except for those expressly set forth in this Agreement, or on any Credit Support of the obligations of the other Party.

(G) It has executed this Agreement with a full understanding of the material terms and risks and is capable of assuming those risks.

(H) It has made its trading and investment decisions, including the suitability of such decisions, based solely on its own judgment and advice from its advisors, and not in reliance on information or opinion from the other Party or the other Party's advisors.

(I) It has not received from the other Party any assurances or promises regarding financial results or benefits from this Agreement.

5.2 **Representations and Warranties of PWCC.** Unless otherwise agreed upon and as expressly limited in the attached Service Schedule, PWCC further represents and warrants, as of the date of delivery of Energy Products as provided in this Agreement, that:

(A) PWCC is the owner of and has good title to the Energy Products;

(B) the Energy Products are transferred to APS free and clear of all liens, taxes, claims, security interests and other encumbrances; and

(C) the Energy Products are transferred to APS free of any right or interest in or to the Energy Products by any other person or entity.

5.3 **LIMITATION OF WARRANTIES.** ALL OTHER WARRANTIES, WHETHER WRITTEN OR ORAL, EXPRESS OR IMPLIED, INCLUDING BUT NOT LIMITED TO ANY WARRANTY OF MERCHANTABILITY OR WARRANTY OF FITNESS FOR ANY PARTICULAR PURPOSE, ARE DISCLAIMED.

5.4 **Survival.** This Article 5 survives the termination of this Agreement.

Article 6
<u>Assurances</u>

6.1 **Adequate Assurances.** If a material change occurs such that a Party can reasonably call the continued performance of this Agreement by the Affected Party into question, then:

(A) A Party may request in writing that the Affected Party provide Credit Support, in a commercially reasonable amount and in a form acceptable to the requesting Party.

(B) Upon receipt of the request described in Section 6.1(A), the Affected Party shall provide Credit Support within five Business Days.

(C) If the Affected Party fails to comply with Section 6.1(B), then an Event of Default shall occur.

(D) If the Affected Party complies with Section 6.1(B), then no Event of Default shall have occurred as a result of the Affected Party incurring a material change.

Article 7
<u>Default and Remedies</u>

7.1 **Default.**

(A) **Events of Default.** Events of Default are as follows:

(1) **Failure to Deliver or Receive Energy Products.** A Party defaults if it fails to deliver or receive all or a substantial portion of the required Energy Product for a period of 5 calendar days or more after receiving written notice of the failure from the other Party.

(2) **Failure to Pay.** A Party defaults if it or its Credit Support Provider fails within 5 Business Days after receiving written notice from the other Party to make any payment when due, whether under this Agreement or under the Credit Support.

(3) **Failure to Deliver Assurances.** A Party defaults if it or its Credit Support Provider fails, within 5 Business Days after receiving written notice from the other Party, to provide adequate assurances pursuant to Section 6.1.

(4) **Failure to Perform Agreement.** A Party defaults if it fails, within 5 Business Days after receiving written notice from the other Party, to comply with or perform any material term of this Agreement.

(5) **Failure to Maintain Credit Support.** A Party defaults if:

(a) it fails to maintain Credit Support in full force and effect pursuant to the terms of and during the duration specified in this Agreement, unless the other Party agrees to the failure in writing or unless the Credit Support terminates according to its terms; or

(b) the Credit Support Provider disaffirms, repudiates, rejects, or challenges the validity of the Credit Support, whether in whole or in part.

(6) **Failure to Remain Solvent.** A Party defaults if it or its Credit Support Provider:

(a) is dissolved other than pursuant to a merger;

(b) becomes insolvent, or is unable to pay its debts, or fails or admits in writing its inability generally to pay its debts as they become due;

(c) makes a general assignment, arrangement or composition with or for the benefit of its creditors;

(d) institutes or has instituted against it a proceeding seeking a judgment of insolvency or bankruptcy or any other relief under any bankruptcy or insolvency law or other similar law affecting creditors' rights;

(e) has a resolution passed for its winding-up, official management or liquidation, other than pursuant to a merger;

(f) seeks or becomes subject to the appointment of an administrator, provisional liquidation, conservator, receiver, trustee, custodian or other similar official for all or substantially all of its assets;

(g) has a secured party take possession of all or substantially all of its assets;

(h) has a distress, execution, attachment, sequestration or other legal process levied, enforced or sued on against all or substantially all its assets and within 30 calendar days from the initiation of such process:

(i) the secured party maintains possession of the assets; or

(ii) the legal process is not dismissed, discharged, or stayed;

(i) causes or is subject to any event with respect to it which has an analogous effect to any of the events listed in Section 7.1(A)(6)(a) – (h); or

(j) takes any action in furtherance of, or indicating its consent to, approval of, or acquiescence in, any of the events listed in Section 7.1(A)(6)(a) - (i).

(7) **Failure Following Merger or Transfer.** A Party defaults if it or its Credit Support Provider:

(a) merges with or into, or transfers all or substantially all its assets to, another entity and at that time:

(i) the resulting, surviving, or transferee entity fails to assume all the obligations of the Party or Credit Support Provider under this Agreement or any required Credit Support; or

(ii) the benefits of any Credit Support fail to extend, without consent of the other Party, to the performance of the resulting, surviving or transferee entity; or

(b) merges with or into, or transfers all or substantially all its assets to, another entity, and:

(i) the merger or transfer is not itself an Event of Default;

(ii) the creditworthiness of the successor is materially weaker than the creditworthiness of the assignor before the merger or transfer, taking into account Credit Support; and

(iii) the transferee fails to make collateral arrangements with and provide collateral to the other Party or provide adequate assurances pursuant to Section 6.1.

(B) **Notices of Default.** Each Party shall notify the other Party promptly of any event that, with the giving of notice or the passage of time or both, would constitute an Event of Default with respect to the other Party.

(C) **Remedies Upon Event of Default.** If an Event of Default is continuing and not cured for a period of 3 Business Days after the Defaulting Party receives written notice of the Event of Default, the Performing Party may, at its sole option, do one or more of the following:

(1) Withhold or suspend all or part of the payments to the Defaulting Party required under this Agreement until the default is cured.

(2) Withhold or suspend all or part of the deliveries of Energy Products to the Defaulting Party required under this Agreement until the default is cured.

(3) Designate an Early Termination Date by providing written notice to the Defaulting Party. The Early Termination Date shall be no earlier than 2 Business Days following the date written notice is received by the Defaulting Party.

(D) **Liquidation on Early Termination.**

(1) On the Early Termination Date, the Parties shall liquidate all transactions, including any portion of transactions not yet fully delivered, that are then outstanding.

(2) Liquidation shall occur by canceling each transaction being liquidated and calculating a Net Settlement Amount pursuant to Section 7.1(E).

(3) To the extent that, in the reasonable opinion of the Performing Party, a transaction is commercially or legally impracticable to terminate and liquidate on the Early Termination Date, then that transaction shall be terminated and liquidated as soon thereafter as is reasonably practicable, but the determination of the liquidated amount for that transaction shall not delay the payment or calculation of the Net Settlement Amount.

(4) Except for the payment of the Net Settlement Amount, no further planned payments or deliveries under this Agreement shall be required after the Early Termination Date.

(5) The Performing Party shall notify the Defaulting Party in writing of the amount and basis for calculation of the Net Settlement Amount.

(6) The Net Settlement Amount shall be paid as follows:

(a) If the Net Settlement Amount is a positive number, the Defaulting Party shall, within 5 Business Days of receipt of such notice, pay to the Performing Party an amount equal to the Net Settlement Amount plus Interest.

(b) If the Net Settlement Amount is a negative number, the Performing Party shall pay to the Defaulting Party an amount equal to the Net Settlement Amount within 5 Business Days of determining the Net Settlement Amount.

(E) Calculation of Net Settlement Amount.

(1) Net Settlement Amount. The Net Settlement Amount is calculated for each transaction as follows:

(a) If a Market Quotation can be determined:

(i) the Market Quotation, determined in accordance with Section 7.1(E)(2), for the transactions, whether positive or negative; plus

(ii) Unpaid Amounts, determined in accordance with Section 7.1(E)(3), owed by the Defaulting Party to the Performing Party; less

(iii) Unpaid Amounts, determined in accordance with Section 7.1(E)(3), owed by the Performing Party to the Defaulting Party.

(b) If a Market Quotation cannot be determined, or in the reasonable belief of the Performing Party would not produce a commercially reasonable result:

(i) the amount the Performing Party reasonably and in good faith determines to be its aggregate losses and costs (net of gains) associated with this Agreement, including but not limited to brokerage fees and commissions, loss of bargain damages, and cost of funds; or

(ii) at the election of the Performing Party, all losses and costs (net of gains) incurred to terminate, liquidate, obtain, or reestablish hedges and related trading positions.

(2) Market Quotation. The Market Quotation is an amount that would be paid by Reference Market Makers to enter into a transaction that would preserve for the Performing Party the economic benefits of this Agreement after the Early Termination Date. The Market Quotation shall be determined as follows:

(a) The Performing Party shall request quotations from at least 3 Reference Market Makers on a date and time selected in good faith by the Performing Party.

(b) The quotations from Reference Market Makers shall consider existing Credit Support and would be subject to such documentation to which the Performing Party and Reference Market Maker agree in good faith.

(c) The quotations from Reference Market Makers shall exclude Unpaid Amounts, but shall include any payment or delivery that would have been required after the Early Termination Date assuming the satisfaction of all conditions precedent.

(d) A quotation to be paid by the Performing Party shall be expressed as a positive number and a quotation to be paid to the Performing Party shall be expressed as a negative number.

(e) Each Reference Market Maker shall provide its quotation as of the same date and local time as the Early Termination Date to the extent reasonably practicable, or otherwise as soon as practicable after the Early Termination Date.

(f) The Market Quotation shall be the arithmetic mean of all quotations after disregarding the highest and lowest quotation. If more than one quotation has the same highest or lowest value, then only one such quotation shall be disregarded.

(g) If less than 3 quotations are provided by Reference Market Makers, then the Market Quotation cannot be determined and the Net Settlement Amount shall be determined under Section 7.1(E)(1)(b).

(3) **Unpaid Amounts.** Unpaid Amounts are determined as follows:

(a) The amount for all terminated transactions that became or would have become payable on or prior to the Early Termination Date and which remain unpaid as of the Early Termination Date; plus

(b) The fair market value, as reasonably determined by the Performing Party as of the delivery date, of Energy Products that were required to be delivered on or prior to the Early Termination Date and which have not been settled as of the Early Termination Date; plus

(c) All non-duplicative Direct Actual Damages incurred prior to the Early Termination Date; plus

(d) Interest on all such amounts to the extent permitted by law.

(4) **Disputes Regarding Net Settlement Amount.** If the Defaulting Party disputes the calculation of the Net Settlement Amount by the Performing Party, then:

(a) the dispute shall be resolved as provided in Article 12;

(b) pending resolution of the dispute, the Defaulting Party shall pay the full amount of the Net Settlement Amount as provided in Section 7.1(D)(6); and

(c) if the dispute results in a refund of any portion of the Net Settlement Amount, the Performing Party shall make the refund within 3 Business Days of such determination plus Interest.

7.2 Remedies Upon Breach of Agreement.

(A) If there is no express remedy or measure of damages for breach of the Agreement, then the breaching Party shall be liable for Direct Actual Damages for any breach of this Agreement determined as follows:

(1) If APS is the breaching Party and the amount of Energy Products it received is less than the amount provided for in this Agreement, then the damages APS will owe to PWCC are:

(a) the Contract Price minus the Sales Price, multiplied by the amount of Energy Products due under the Agreement minus the actual amount received by APS;[1] plus

(b) transmission charges for firm transmission service upstream of the Delivery Point incurred to achieve the Sales Price, less the reduction in transmission charges achieved as a result of the reduction in APS' receipt of Energy Products based on PWCC's reasonable efforts to achieve the reduction; unless

(c) the total amount calculated is negative, in which case there are no Direct Actual Damages.

(2) If PWCC is the breaching Party and the amount of Energy Products it delivered is less than the amount provided for in this Agreement, then the damages PWCC will owe to APS are:

(a) the Substitute Price minus the Contract Price, multiplied by the amount of Energy Products due under the Agreement minus the actual amount delivered to APS;[2] plus

(b) transmission charges for firm transmission service upstream of the Delivery Point that APS incurred to achieve the Substitute Price, less the reduction in transmission charges achieved as a result of the reduction in PWCC's delivery of Energy Products based on APS' reasonable efforts to achieve the reduction; unless

---

1 [Contract Price – Sales Price] × [quantity due – quantity received]

2 [Substitute Price – Contract Price] × [quantity due – quantity received]

(c) the total amount calculated using the foregoing formula is negative, in which case there are no Direct Actual Damages.

7.3 **Forward Contracts.** The Parties agree that transactions for the forward sale and purchase of Energy Products entered into under this Agreement are "forward contracts" and the Parties are "forward contract merchants" within the meaning of the United States Bankruptcy Code.

7.4 **Enforcement of Remedies.**

(A) Except as otherwise provided in this Agreement, the rights, powers, remedies and privileges provided in this Agreement are cumulative and not exclusive of any rights, powers, remedies and privileges provided by law.

(B) A single or partial exercise of any right, power or privilege will not be presumed to preclude any subsequent or further exercise of that right, power or privilege or the exercise of any other right, power or privilege.

7.5 **Duty to Mitigate.**

(A) Except as provided in Section 7.5(B), each Party has a duty to mitigate damages in good faith and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of an Event of Default.

(B) Neither Party is required to utilize or change the utilization of its owned or controlled assets, including contractual assets, or its market positions, or to curtail load, to minimize the other Party's liability for damages.

7.6 **Set-Off.**

(A) At the option of the Performing Party and without prior notice to the Defaulting Party or breaching Party, any amounts payable to one Party by the other Party may be set-off against any amounts payable, whether at that time or in the future or upon the occurrence of a contingency and irrespective of the currency, place of payment or booking office of the obligation, under any other agreements or obligations between the Parties.

(B) If the Performing Party exercises a set-off under Section 7.6(A), it shall give notice to the Defaulting Party or breaching Party of the set-off.

(C) If an obligation used for a set-off under Section 7.6(A) is unascertained, the Performing Party may in good faith estimate that obligation and set-off in respect of that estimate, but the Performing Party shall account to the Defaulting Party or breaching Party when the obligation is ascertained.

7.7 LIMITATIONS OF LIABILITY.

(A) THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES OF THIS AGREEMENT.

(B) FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES IS THE SOLE AND EXCLUSIVE REMEDY FOR SUCH BREACH.

(C) IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED FOR, LIABILITY IS LIMITED TO DIRECT ACTUAL DAMAGES AND SUCH DIRECT ACTUAL DAMAGES IS THE SOLE AND EXCLUSIVE REMEDY.

(D) EXCEPT WHERE SPECIFICALLY SET FORTH IN THIS AGREEMENT, NEITHER PARTY SHALL BE REQUIRED TO PAY OR BE LIABLE FOR SPECIAL, CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, INCLUDING BUT NOT LIMITED TO LOST PROFITS OR BUSINESS INTERRUPTION DAMAGES AND WHETHER BY STATUTE, IN TORT, IN CONTRACT, OR OTHERWISE.

(E) THE PARTIES INTEND THAT THE LIMITATIONS OF LIABILITY IMPOSED IN THIS AGREEMENT ARE WITHOUT REGARD TO THE CAUSE OR CAUSES, INCLUDING BUT NOT LIMITED TO THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE IS SOLE, JOINT, CONCURRENT, ACTIVE OR PASSIVE, OR OTHERWISE.

(F) IF ANY DAMAGES UNDER THIS AGREEMENT ARE DEEMED LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT SUCH DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, THAT OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT, AND THAT THE LIQUIDATED DAMAGES CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

7.8 Survival. This Article 7 survives the termination of this Agreement.

Article 8
Force Majeure

8.1 Suspension of Obligations.

(A) Except with regard to any obligation to pay money under the Agreement, if either Party cannot, in whole or in part, carry out its obligations under this Agreement as a result of Force Majeure, then

(1) The Party claiming Force Majeure shall give the other Party written notice and full particulars of the Force Majeure as soon as reasonably possible after the occurrence of the cause relied upon.

(2) Only to the extent affected by the Force Majeure, the obligations of the affected Party are suspended.

(3) During the pendency of the Force Majeure, the affected Party is not liable to the other Party for:

(a) any claims relating directly or indirectly to the failure of the affected Party to perform under this Agreement as a result of the Force Majeure; and

(b) any loss, damage, injury or expense resulting from, or arising out of, the Force Majeure.

(B) If an event of Force Majeure excuses PWCC from delivering any of the Energy Products, PWCC shall make best efforts to secure on APS' behalf Replacement Energy Products for the Energy Products that PWCC is excused from delivering if:

(1) APS requests such efforts; and

(2) APS assumes responsibility for all resulting costs.

(C) PWCC shall use reasonable efforts to minimize the costs to APS of Replacement Energy Products obtained under Section 8.1(B).

8.2 Due Diligence.

(A) A Party claiming Force Majeure shall use due diligence to fulfill its obligations under this Agreement and to remove any disability caused by such event at the earliest practicable time.

(B) Nothing in this Article 8 shall require a Party to settle any strike or labor dispute.

(C) A Party claiming Force Majeure shall continue to perform immediately after the Force Majeure has been removed.

Article 9
Taxes and Other Charges

9.1 Responsibility for Taxes and Other Charges.

(A) Except as otherwise provided in this Section 9.1, PWCC is responsible for all Taxes on or with respect to the Energy Products incurred prior to delivery to APS up to and at the Delivery Points.

(B) APS is responsible for all Taxes on or with respect to the Energy Products incurred from the Delivery Points except for ad valorem or income taxes, which relate to the wholesale of the Energy Products and which are the responsibility of PWCC.

(C) If during the term of this Agreement, any material increased costs are associated with the Dedicated Units as a result of any Governmental Authority or any judicial order, APS shall be responsible for all such increased costs through an annualized charge.

(D) If PWCC is required by law or regulation to remit or pay Taxes that are APS' responsibility under Section 9.1(B), APS shall promptly reimburse PWCC for such Taxes.

(E) If APS is required by law or regulation to remit or pay Taxes that are PWCC's responsibility under Section 9.1(A), APS may deduct the amount of any such Taxes from the sums due to PWCC under this Agreement.

(F) Nothing in this Agreement obligates a Party to be responsible for any taxes for which it is exempt by law.

(G) Each Party shall indemnify, defend and hold the other Party harmless for, from and against all liability for Taxes for which the indemnifying Party is responsible.

Article 10
Notices and Other Communications

10.1 Methods of Providing Notice. All invoices, payments, statements, notices, and communications made under this Agreement shall be in writing as follows:

(A) By registered or certified or express mail, with a return receipt requested, postage prepaid, or by comparable delivery service, or by hand with a receipt, or by facsimile with the original sent by first class mail, to the individuals listed on Exhibit B.

(B) Either Party may modify any information specified in Exhibit B by giving written notice to the other Party.

10.2 Receipt of Notice. All written communications made as provided in Section 10.1 are deemed given upon receipt by the addressee. In the case of facsimiles, receipt occurs on the date that the facsimile is received by the addressee in legible form.

Article 11
<u>Effective Date and Term</u>

11.1 Effective Date. This Agreement shall become effective upon the completion of all the following:

(A) The grant of a variance to APS of Arizona Administrative Code Rule R14-2-1606(B) by the Arizona Corporation Commission consistent with Section 3.1 of the attached Service Schedule.

(B) The transfer of the non-nuclear generation assets to Pinnacle West Energy Corporation.

(C) The acceptance of both this Agreement and the Pinnacle West Energy Contract by FERC without modification or condition, except that if FERC or any court imposes any condition, limitation, or qualification, then:

(1) each Party shall determine whether the condition, limitation or qualification individually, or in the aggregate, has a material adverse effect on the Party with respect to this Agreement;

(2) a Party determining an adverse effect under Section 11.1(C)(1) shall as soon as practicable, but in no case after more than 30 calendar days of the FERC or court action, notify the other Party;

(3) after notification, the Parties shall cooperate on a commercially reasonable basis to renegotiate the terms of this Agreement to preserve the original economic relationship of the Parties with respect to this Agreement; and

(4) if the parties fail to renegotiate the terms of this Agreement, the Agreement is null and void and have no further force and effect.

(D) Approval of this Agreement by the Arizona Corporation Commission.

11.2 Termination Date.

(A) Unless earlier terminated pursuant to the terms of this Agreement or extended pursuant to Section 11.2(B), this Agreement shall terminate at midnight on December 31, 2015.

(B) This Agreement shall automatically be renewed for up to three additional 5-year terms unless either Party provides to the other Party a notice of termination at least 12 months prior to the scheduled termination of this Agreement.

11.3 Partial Termination.

(A) The obligations of the Parties with respect to the Dedicated Units Energy Products shall terminate upon the termination or material change of the Pinnacle West Energy Contract, if the termination or material change of the Pinnacle West Energy Contract is outside of the control of PWCC and Pinnacle West Energy Corporation and regardless of whether such termination or material change occurs during a renewal period pursuant to Section 11.2(B).

(B) If this Agreement is partially terminated under Section 11.3(A), the Parties shall engage in good faith negotiations for a subsequent agreement regarding the provision of Energy Products in lieu of the Dedicated Units Energy Products.

11.4 Regulatory Approvals. Each Party shall use commercially reasonable efforts to obtain the necessary regulatory approvals so that this Agreement shall become effective on the earliest practicable date.

Article 12
Dispute Resolution

12.1 Alternative Dispute Resolution. Except as provided in Section 12.4, all claims or disputes, whether sounding in tort or contract or otherwise, between the Parties, including their agents and representatives, arising under or relating to this Agreement are subject to alternative dispute resolution as provided in this Article 12.

12.2 Mediation. Any dispute between the Parties shall first be submitted to non-binding mediation using the following procedures:

(A) A Party shall provide a written request for mediation to the other Party.

(B) The mediation shall commence within 60 calendar days from receipt of the request in Section 12.2(A).

(C) A mediator shall be chosen by mutual agreement of the Parties within 15 calendar days of receipt of the request in Section 12.2(A).

(D) All discussions or materials presented during or for purposes of the mediation shall be considered Confidential Information and subject to Rule 408 of the federal and state rules of evidence and any similar regulatory rules.

12.3 Arbitration. If a dispute cannot be resolved after mediation under Section 12.2 and except as provided in Section 12.4, the dispute shall be submitted to binding arbitration as follows:

(A) The arbitration shall be conducted in Phoenix, Arizona in accordance with the Federal Arbitration Act and by the then-prevailing Commercial Arbitration Rules of the American Arbitration Association. The arbitration proceedings, decision and award under this Section 12.3 shall be governed by the Federal Arbitration Act.

(B) The validity, construction, and interpretation of this Article 12 and all procedural aspects of the arbitration shall be governed by the Federal Arbitration Act and shall be decided by the arbitrators.

(C) Submission to arbitration shall be made upon the request of either Party.

(D) There shall be 3 arbitrators. Each Party shall appoint a single arbitrator within 20 calendar days after service of the notice of arbitration. The 2 arbitrators so appointed shall select the third arbitrator, who shall be the chairperson of the tribunal, within 20 calendar days after the both arbitrators are appointed. The chairperson shall have over 8 years of experience in energy-related transactions.

(E) None of the arbitrators shall be employees or former employees of either Party or have any direct interest in either Party or the subject matter of the arbitration, unless the conflict is expressly acknowledged and waived in writing by both Parties.

(F) The chairperson shall schedule and hear the dispute within 6 months after appointment and shall render the panel's decision within 30 calendar days after the hearing concludes.

(G) The arbitrators shall have no authority to award consequential, treble, exemplary, or punitive damages of any type or kind regardless of whether such damages may be available under any law or right. The Parties waive their rights, if any, to recover or claim such damages.

(H) All discussions or materials presented during or for purposes of the arbitration shall be considered Confidential Information.

(I) All costs and expenses of the arbitrators shall be borne equally by the Parties. The arbitration shall take place in Phoenix, Arizona.

(J) The arbitration award shall be final and binding on the Parties and may be entered in any court of competent jurisdiction. If required by applicable law, the arbitration award shall be filed with FERC and subject to FERC approval.

12.4 Equitable Relief. Either Party may petition a court of appropriate and proper jurisdiction, as described in Section 13.6, for non-monetary relief relating to any claim of breach of this Agreement to prevent undue hardship relating to the claimed breach pending the completion of mediation or arbitration under Sections 12.2 and 12.3.

Article 13
General Provisions

13.1 Entire Agreement; Amendments and Counterparts.

(A) Except as provided in Section 1.3, the terms of this Agreement constitute the entire agreement between the Parties with respect to its subject matter.

(B) The terms of this Agreement may be changed only by mutual written agreement executed by both Parties after the date of this Agreement.

(C) This Agreement may be executed in counterparts.

13.2 No Waiver.

(A) No waiver of a default constitutes a waiver of any other default or defaults whether of a like kind or different nature.

(B) Any delay in asserting or enforcing any right under this Agreement does not waive such right, unless barred by an applicable statute of limitation.

13.3 Headings. Headings and titles are for convenience only and do not affect the meaning or interpretation of any provision of this Agreement.

13.4 Confidentiality.

(A) Each Party and their agents shall maintain all Confidential Information in confidence and shall use such information solely in connection with this Agreement.

(B) Neither Party may disclose Confidential Information to third parties without the prior written consent of the other Party, except to the extent necessary to effectuate the transfer of Energy Products after providing the other Party with prompt written notice of the intent to disclose to the third party.

(C) This Section 13.4 shall survive the termination of this Agreement for a period of one year.

13.5 Governing Law.

(A) This Agreement shall be governed by, construed and enforced in accordance with the laws of Arizona, without regard to principles of conflict of laws.

(B) The Parties agree that for purposes of this Agreement the products sold herein are not "goods" within the meaning of any Uniform Commercial Code.

13.6 Jurisdiction and Costs.

(A) Subject to Article 12 and Section 13.6(B), any judicial action relating in any way to this Agreement shall be brought only in a state or federal court located in Phoenix, Arizona.

(B) An action to enforce an arbitration award may be brought in any jurisdiction.

(C) The Parties waive any right to trial by jury in an action relating to this Agreement.

(D) The prevailing Party in any judicial action is entitled to recover its costs, litigation and other expenses, and reasonable attorneys' fees incurred in connection with such proceedings.

13.7 No Third-Party Beneficiaries.

(A) There are no third-party beneficiaries to this Agreement.

(B) This Agreement does not create, nor shall it be construed to create, any standard of care, duty or liability to any third party.

13.8 Binding Effect. This Agreement is binding on and inures to the benefit of the Parties and their respective successors and permitted assigns.

13.9 Recording.

(A) Either Party may record telephone conversations and other discussions regarding matters arising under this Agreement.

(B) Each Party agrees to obtain the consent of its employees and agents to such recording to the extent required by applicable law.

(C) All recordings of telephone conversations and other discussions are deemed Confidential Information.

13.10 Regulatory Jurisdiction. This Agreement and any actions under this Agreement shall be subject to applicable regulatory jurisdiction and approvals, but this Agreement shall not be construed as subjecting either Party to the jurisdiction of any regulatory agency that would not otherwise have jurisdiction over such Party.

13.11 Assignment.

(A) Neither Party may transfer or assign any of its rights, title, interests or obligations in or under this Agreement, including assignments of the Dedicated Contracts from PWCC, without the prior written consent of the other Party, except for:

(1) an assignment, including but not limited to a transfer or pledge, made as security for any financing if:

(a) the assigning Party provides prompt notice to the other Party of the assignment, including the effective date; and

(b) the assignment does not release the assigning Party from any obligations or liabilities under this Agreement prior to the effective date of the assignment; or

(2) an assignment, including but not limited to a transfer or delegation, to an Affiliate if:

(a) the assigning Party provides prompt notice to the other Party of the assignment, including the effective date;

(b) the assignee Affiliate agrees to be fully bound by the Agreement;

(c) the assignee Affiliate meets the Credit Support requirements of the non-assigning Party; and

(d) the assignment does not release the assigning Party from any obligations or liabilities under this Agreement prior to the effective date of the assignment.

(B) Any transfer that does not comply with Section 3.11(A) is null and void.

13.12 Records.

(A) Each Party shall maintain records of all transactions under this Agreement for a minimum of 3 years from the billing date of the transaction.

(B) Each Party may require the other Party to produce the other Party's records to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Agreement.

(C) If the records produced under Section 13.12(B) reveal any inaccuracy in any invoice or similar statement, a refund shall issue to the Party owed money plus Interest, except that if the invoice or statement resulting in the refund is over 12 months old, no refund shall issue.

13.13 Negotiated Agreement. The Parties agree that they have had meaningful discussions and negotiations over the provisions of this Agreement and therefore no provision is to be construed against the Party who drafted and prepared this Agreement.

13.14 Severability. If any provision of this Agreement is determined to be unenforceable, illegal or otherwise invalid, then that provision shall be severed and the remainder of the Agreement shall remain in full force and effect if:

(A) the Parties can legally, practically, and commercially continue without the severed provision; and

(B) the severance does not defeat the purpose or relative economic position of either or both Parties in entering into this Agreement.

13.15 Time of the Essence. Time is of the essence of this Agreement.

Signed:

PINNACLE WEST CAPITAL CORPORATION	ARIZONA PUBLIC SERVICE COMPANY
By:______________________	By:______________________
Name:____________________	Name:____________________
Title:_____________________	Title:_____________________
Date:_____________________	Date:_____________________

EXHIBIT A

Definitions

When initially capitalized, the following terms used in the Agreement, including the Service Schedule and exhibits, have the meanings set forth below:

"Affected Party" means a Party affected by a material change under Section 6.1.

"Affiliate" means: (a) an entity directly or indirectly controlling the other entity; (b) an entity directly or indirectly controlled by the other entity; or (c) an entity commonly controlled directly or indirectly with the other entity.

"Ancillary Services" means the services specified in Schedules 1 through 6 of APS' Open Access Transmission Tariff.

"APS" means Arizona Public Service Company.

"APS' Full Load Requirements" means APS' full Energy Product requirements needed to serve APS' present and future Standard Offer retail customers. APS' Full Load Requirements excludes the amount of APS' retail load served by the following resources: (1) the SRP Power Coordination Agreement of September 15, 1955 and Territorial Agreement of August 31, 1955 to the extent such agreement is not a Dedicated Contract; (2) deliveries of capacity and energy under the September 21, 1990 Asset Purchase and Power Exchange Agreement, Sections 3 and 4, between APS and PacificCorp to the extent such agreement is not a Dedicated Contract; (3) the Arizona Corporation Commission's environmental portfolio standard in effect on the date of this Agreement; (4) APS' purchase power contracts with Qualifying Facilities and customer-owned generation in effect on the date of this Agreement or as subsequently authorized by law; (5) the output of APS' Palo Verde Nuclear Generation Station assets until they are transferred to Pinnacle West Energy Corporation; and (6) other generating assets retained by APS pursuant to an order of the Arizona Corporation Commission.

"Base Rate" means the lesser of (a) the annual interest rate published as the "Prime Rate" in the *Wall Street Journal*'s "Money Rates" section, unless the *Wall Street Journal* no longer publishes the "Prime Rate," in which case a comparable rate agreed to by the Parties, plus 2 percent; or (b) the maximum interest rate allowed by law.

"Business Day" means a weekday during which United States banks are open for general commercial business and ending at 5:00 p.m. Phoenix time.

"Capacity" means electric generating capability, expressed in kilowatts (kW) or megawatts (MW).

"Competitive Bidding Process" means the bidding process through which PWCC or its assignee or agent shall contract for the portion of the Energy Products described in the Service Schedule as Competitively-Bid Energy Products.

"Competitively-Bid Energy Products" means Energy Products obtained through the Competitive Bidding Process described in Section 3.1 of the Service Schedule.

"Confidential Information" means any information relating to or provided under this Agreement that is designated by a Party as confidential, except (a) information in a Party's possession prior to its receipt from the other Party; (b) information obtained from a third person who, as far as the obtaining Party is aware, was not prohibited by a contractual, legal or fiduciary obligation from transmitting the information; (c) information that has become publicly available through no fault of the obtaining Party; and (d) information that a Party is required by law, regulation, or administrative or judicial order to disclose, including information related to satisfying regulatory requirements, if the Party disclosing such information has provided prompt notice of the requirement and allowed a reasonable period of time for the other Party to seek to restrain such disclosure.

"Contract Price" means the price specified in the attached Service Schedule for each Contract Year including adjustments.

"Contract Term" or **"Term"** means the period beginning on the Effective Date and ending on the termination date specified in Section 11.2.

"Contract Year" means (a) for the initial contract year, 12:01 A.M. on the date delivery of Energy Products commences pursuant to Section 1 of the attached Service Schedule, and ending 12:00 Midnight, December 31 of the same calendar year; and (b) for each subsequent calendar year, the period of time between 12:01 A.M., January 1 and ending 12:00 Midnight, December 31.

"Credit Support" means: (a) a Letter of Credit, (b) a Guaranty, or (c) such other form of commercially-reasonable security acceptable to the secured Party.

"Credit Support Provider" means: (a) a Guarantor, (b) an Issuer, or (c) a provider of another form of Credit Support who is acceptable to the secured Party.

"Dedicated Contracts Energy Products" means Energy and Capacity sold to APS from the Dedicated Contracts.

"Dedicated Contracts" means energy and capacity procured pursuant to the: (a) SRP Power Coordination Agreement and Territorial Agreement, and (b) Sections 3 and 4 of the Asset Purchase and Power Exchange Agreement between APS and Pacificorp dated September 21, 1990; but (c) only to the extent that such contracts are transferred to or assumed by Pinnacle West Capital Corporation.

"Dedicated Energy Products" means Energy and Capacity sold to APS from the Dedicated Units and Dedicated Contracts.

"Dedicated Units" means Palo Verde Units 1-3, West Phoenix Units 1-5, Steam Units 4 & 6 and CT1-2, Saguaro Steam Units 1&2 and CTs 1-3, Navajo Units 1-3, Four Corners Units 1-5, Yucca CTs 1-4, Douglas CT, Cholla Units 1-3, Ocotillo Units 1-2 and CT1-2 and Redhawk Units 1-2, from commissioning until such units are retired, as applicable.

"Dedicated Units Billing Energy" means the quantity of Energy billed to APS by PWCC each calendar month under Section 3.2 of the Service Schedule. Unless revised as a result of an applicable RTO requirement, Dedicated Units Billing Energy shall equal: (a) the sum of net tie metering for all interconnections between APS' control area and other control areas as measured through telemetered data and adjusted for end-of-month system revenue metering as agreed between the Parties, plus (b) all net metered generation interconnected with APS' control area as measured through telemetered data and adjusted for end-of-month system revenue metering as agreed between the Parties, plus (c) losses on third parties' transmission systems associated with transmission used by APS to serve APS' Full Load Requirements, less (d) retail and wholesale loads served by other providers or supplied by PWCC to APS under separate contract within APS' control area, less (e) Supplemental Energy Products, less (f) Replacement Energy Products, less (g) Competitively-Bid Energy Products, less (h) Dedicated Contracts Energy Products, less (i) those resources specifically excluded in the definition of APS' Full Load Requirements.

"Dedicated Units Energy Products" means Energy and Capacity sold the APS from the Dedicated Units.

"Defaulting Party" means a Party who itself or through its Credit Support Provider is subject to an Event of Default.

"Delivery Point" means a location or locations, as agreed-upon from time to time, at which PWCC's resources used to provide Energy Products to APS interconnect with: (a) APS' transmission or distribution system; (b) the system of a future RTO in which APS' retail load is located; or (c) points of interconnection between such systems and adjoining systems.

"Demand" means the rate at which Energy is delivered.

"Direct Actual Damages" means the damages calculated under Section 7.2.

"Early Termination Date" means a date on which the Agreement is terminated that is earlier than the date specified in Section 11.2 of the Agreement.

"**Energy**" means three-phase, sixty-hertz electric energy delivered at the nominal voltage of the Delivery Point expressed in megawatt hours (MWh) or kilowatt hours (kWh).

"Energy Products" means Energy and Capacity.

"**Event of Default**" means an event of default described in Section 7.1.

"**FERC**" means the Federal Energy Regulatory Commission or its successor.

"**Force Majeure**" means an event that: (a) is not anticipated on the date the Agreement is signed; (b) is not within the reasonable control of the Party claiming Force Majeure; (c) could not, in the exercise of reasonable diligence and Good Utility Practice by the Party claiming Force Majeure, have been prevented or avoided; and (d) renders the Party claiming Force Majeure unable to carry out, wholly or in part, its obligations under this Agreement. Subject to the foregoing, Force Majeure includes, but is not limited to, the following events: (1) act of God; (2) act of public enemy, war, terrorism, blockade, insurrection, civil disturbance, disobedience or riot; (3) strike, lockout, material shortage or other industrial disturbance; (4) epidemic, landslide, earthquake, fire, storm, lightning, flood or other natural catastrophe; (5) failure of the transmission or distribution grid, including third parties' transmission facilities, to transmit or distribute Energy; (6) reductions or interruptions in services which may be required by the control area operator or regional transmission organization; (7) material failure of performance by any PWCC supplier, including failures as a result of Force Majeure, which results in a shutdown or material reduction of any of the generation capacity or output owned or controlled by PWCC or a PWCC Affiliate; (8) shutdown or reduction by the Nuclear Regulatory Commission of a material portion of the generation capacity or output which is owned or controlled by PWCC or a PWCC Affiliate; (9) act, omission, failure to act, or order of a civil, judicial, regulatory or government authority, if the Party claiming Force Majeure has acted to the fullest extent reasonable to prevent or correct the act, omission, failure to act or order; and (10) any other act or omission similar to the foregoing examples which by the exercise of a Party's reasonable diligence cannot be overcome. Force Majeure specifically excludes PWCC's ability to sell Dedicated Energy Products at a more advantageous price.

"**Good Utility Practice**" means (a) any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period; and (b) any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice does not necessarily require the optimum practice, method, or act to the exclusion of all others but does include a requirement that PWCC provide installed or purchased generating reserves reasonably needed to supply firm Dedicated Energy Products to APS as required under this Agreement.

"**Governmental Authority**" means (a) a city, municipality, county, state or other governmental board or authority; (b) a regulatory or public power board or authority; (c) a public utility or public power district; (d) a joint action agency; (e) a federally recognized tribal board, authority or agency; or (e) other similar political subdivisions or public entities of the United States, or any state or a territory, acting individually or in combination.

"Guarantor" means an entity or entities executing a Guaranty of the obligation of one Party to the other Party. A Guarantor must be reasonably acceptable to the Party receiving the Guaranty.

"Guaranty" means a guaranty, hypothecation agreement, security agreement, or any other document containing an obligation of a Guarantor in favor of, and supporting obligations of, one Party to the other Party. The Guaranty must be in a form and substance reasonably acceptable to the Party receiving the Guaranty.

"Interest" means interest accruing at the Base Rate, compounded daily based on a 360-day year, from and including the due date to and including the payment date or, if applicable, interest as ordered by FERC.

"Issuer" means a person executing and delivering to a Party a Letter of Credit or another form of Credit Support document that is not a Guaranty. An Issuer must be reasonably acceptable to the receiving Party.

"Letter of Credit" means an instrument or agreement, revocable or irrevocable, entered into by a bank or other financial institution providing that the issuer will honor drafts or other demands for payment upon compliance with the conditions specified in the credit.

"Market Quotation" means a quotation determined under Section 7.1(E)(2).

"NERC" means the North American Electric Reliability Council and any successor.

"Net Settlement Amount" means the amount calculated under Section 7.1(E)(1).

"Off-Systems Sales Margin" means the revenue received from energy sales to anyone other than APS from the Dedicated Units less: (a) the costs of associated fuel, transmission and Ancillary Services if applicable, and (b) any other out-of-pocket costs associated with the sale.

"Parties" means both APS and PWCC.

"Party" means either APS or PWCC.

"Performing Party" means the non-defaulting Party upon an Event of Default or the non-breaching Party in the case of a breach.

"Pinnacle West Energy Contract" means the contract between PWCC and Pinnacle West Energy Corporation referred to in Section 2.1(C) of the Agreement.

"Purchase Price" means the price in United States dollars, unless otherwise agreed, to be paid by APS to PWCC in exchange for the Energy Products. The Purchase Price may be stated in a per unit price for a specific Energy Product or Products or as a total price for all Energy Products.

"PWCC" means Pinnacle West Capital Corporation.

"Reference Market Makers" means four leading dealers in the relevant market selected by either Party determining a Market Quotation in good faith from among dealers of the highest credit standing which satisfy all the criteria that a Party applies generally at the time of deciding whether to enter into similar transactions

"Replacement Energy Products" means Energy Products provided by PWCC under Section 3.1.4 or Section 3.4 of the Service Schedule.

"RTO" means a FERC-approved regional transmission organization, including but not limited to a transco, gridco or the WestConnect RTO.

"Sales Price" means (a) the price at which the Performing Party, acting in a commercially reasonable manner, effects a resale of undelivered Energy Products; or, (b) the market price for the quantity of Energy Products at the Delivery Points agreed upon by the Parties; less (c) costs reasonably incurred by the Performing party in reselling Energy Products, additional transmission charges incurred by the Performing Party in delivering Energy Product to third-party buyers and penalties, ratcheted demands or similar charges.

"SRP" means the Salt River Project Agricultural Improvement and Power District.

"Substitute Price" means the price at which APS acting in a commercially reasonable manner purchases at the Delivery Points a replacement for Energy Products not delivered by PWCC, plus costs reasonably incurred by APS in purchasing the substitute product; plus additional transmission charges reasonably incurred by APS in purchasing the substitute product.

"Supplemental Energy Products" means Energy Products provided by PWCC under Section 3.3 of the Service Schedule.

"Tariff" means PWCC's Market-Based Rate Tariff on file and approved by FERC, as amended from time to time.

"Taxes" means all taxes, fees, levies, penalties, licenses or charges imposed by any Governmental Authority.

"Transmission Provider" means an entity or entities transmitting or transporting the Energy Product on PWCC's or APS' behalf to or from the Delivery Points.

"Unpaid Amounts" means the amounts determined under Section 7.1(E)(3).

"WSCC" means the Western Systems Coordinating Council.

EXHIBIT B

Notification and Points of Contact

For PWCC: Contract Administration to:

PINNACLE WEST CAPITAL CORPORATION
400 N. 5th Street, Station 9842
Phoenix, AZ 85004
ATTN: Dennis Beals

PHONE: (602) 250-3101
FAX: (602) 250-3719

Payments to:

PINNACLE WEST CAPITAL CORPORATION
Bank Name: Bank One of Arizona
Acct No.: 2270-3938
ABA No.: 122100024

For APS: ARIZONA PUBLIC SERVICE COMPANY
400 N. 5^{th} Street, Station 8632
Phoenix, AZ 85004
ATTN: Keith Van Ausdal

PHONE: (602) 250-2951
FAX: (602) 250-213

SERVICE SCHEDULE

This Service Schedule further defines the obligations of the Parties with respect to the Agreement.

1. Effective Date.

1.1 This Service Schedule is for the sale and purchase of APS' Full Load Requirements, beginning on the Effective Date of the Agreement and continuing through December 31, 2015, unless otherwise terminated or extended pursuant to this Agreement.

2. Forecast.

2.1 APS shall provide a five-year forecast of the APS' Full Load Requirements on an hourly basis 60 days prior to each calendar year. The first five-year forecast shall be provided within 30 days of the execution of this Agreement. APS shall also update the forecast during each calendar year for known or anticipated changes in load.

2.2 Scheduling/Forecast. APS shall use its best efforts to submit accurate and timely forecasts and to facilitate PWCC's submittal of an accurate schedule for receipt of APS' Full Load Requirements. PWCC may schedule the delivery of Energy Products to APS in any combination of MW amounts and at any combination of Delivery Points as necessary to satisfy the total Energy Products supply requirements.

3. Providing APS' Full Load Requirements. PWCC shall provide APS' Full Load Requirements and APS shall pay all costs associated with such service as follows:

3.1 Competitively-Bid Energy Products.

3.1.1 Commencing on January 1, 2003, PWCC shall secure and provide Energy Products to APS through a competitive bidding process in the initial amount of 270 MWs at an overall 51% load factor. Energy Products acquired through a competitive bidding process shall include transmission to the Delivery Points. PWCC may charge APS for Ancillary Services or other delivery costs if not included in the Competitively-Bid Energy Products.

3.1.2 Energy Products acquired through a competitive bidding process shall be increased by an additional 270 MWs at an overall 51% load factor each Contract Year thereafter through 2008 so that by the end of 2008, 1620

MW will be supplied—an amount which APS estimates to be approximately 23% of 2008 peak load.

3.1.3 PWCC shall, directly or through an assignee or agent, conduct the Competitive Bidding Process for the benefit of APS. The specific details of the Competitive Bidding Process shall be determined by PWCC in consultation with APS, provided that the selection of the winning bidders, as well as contract provisions, specifications and creditworthiness shall be expressly approved by APS.

3.1.4 APS shall be responsible for any and all costs and expenses incurred in the acquisition of any Energy Products supplied through the Competitive Bidding Process, including PWCC's administrative expenses associated with bid development and evaluation, and procurement. In the event of non-performance by parties that are under contractual commitments as a result of the Competitive Bidding Process, PWCC will use commercially reasonable efforts to obtain Replacement Energy Products for the benefit of APS. APS shall be responsible for all costs incurred for the Replacement Energy Products. In consultation with APS, PWCC shall pursue all commercially legal remedies for defaults under contracts entered into as a result of the Competitive Bidding Process. APS shall be responsible for all costs and fees associated with the pursuit of such remedies, and APS shall receive all monies awarded as a remedy.

3.1.5 Should PWCC wish to participate in the Competitive Bidding Process as a seller, PWCC shall engage an independent third party to perform the necessary functions of the Competitive Bidding Process on behalf of PWCC. APS shall approve such independent third party. If PWCC is selected in the Competitive Bidding Process, then a separate agreement between APS and PWCC will be executed for such Competitively Bid Energy Products.

3.2 Dedicated Energy Products. Subject to the Agreement and this Service Schedule, PWCC shall provide Dedicated Energy Products from the Dedicated Units and the Dedicated Contracts to serve APS' Full Load Requirements.

3.2.1 Dedicated Units Energy Products. Dedicated Units Energy Products shall be priced at the actual prices charged to PWCC in the Pinnacle West Energy Contract. The Parties recognize that the prices in the Pinnacle West Energy Contract include:

- a Facilities Charge that includes a return of and on the fixed capital assets of the Dedicated Units and their associated operation and maintenance costs excluding fuel, as set forth in Attachment 1 to this Service Schedule;

- a Base Fuel Charge ("BFC") for fuel and related costs associated with the Dedicated Units Energy Products, as set forth in Attachment 2 to this Service Schedule;
- a Fuel and Purchased Power Adjustment ("FPPA") for variable costs, as set forth in Attachment 2 to this Service Schedule; and
- transmission, losses, and Ancillary Services costs to the Delivery Points as a pass-through charge to APS.

The Fuel and Purchased Power Adjustment can be positive or negative.

3.2.2 Pricing of Dedicated Units Energy Products.

3.2.2.1 Based on Section 3.2.1 above and Attachment 1 to this Service Schedule, the initial Facilities Charges for Dedicated Units Energy Products in the Pinnacle West Energy Contract shall be:

Year	Facilities Charge ($000/Month)	
2002	$ 31,230	(excludes Palo Verde)
2003	$ 63,600	
2004	$ 67,120	

3.2.2.2 For Contract Years following 2004, the Facilities Charge in the Pinnacle West Energy Contract shall be calculated as provided in Attachment 1 to this Service Schedule.

3.2.2.3 The Base Fuel Charge in the Pinnacle West Energy Contract shall be $0.0210 per kWh for 2002 and $0.0174 per kWh for 2003 and thereafter for the remaining term of this Agreement, as provided in Attachment 2 to this Service Schedule.

3.2.2.4 Beginning March 1, 2003, a Fuel and Purchased Power Adjustment to the Base Fuel Charge will be applied each month to the billing for Dedicated Units Energy Products. The Fuel and Purchased Power Adjustment in the Pinnacle West Energy Contract shall be calculated annually prior to March of each calendar year as provided in Attachment 2 to this Service Schedule.

3.2.2.5 For billing purposes, the Base Fuel Charge and the Fuel and Purchased Power Adjustment shall be applied to the Dedicated Units Billing Energy.

3.2.3 Minimum Availability of Dedicated Units.

3.2.3.1 Capacity. At a minimum, PWCC shall make Capacity from the Dedicated Units available as follows: (a) for 2002, prior to the transfer of Palo Verde Nuclear Generating Station Assets, the lesser of 3440 MW at system peak or actual load at system peak; and (b) for 2003 and later, after the transfer of Palo Verde Nuclear Generating Station Assets, the lesser of 4720 MW at system peak or actual load at system peak, subject to adjustment as Dedicated Units are retired.

3.2.3.2 Energy. At a minimum, PWCC shall have available Energy from the Dedicated Units in the amount of: (a) for 2002, prior to the transfer of Palo Verde Nuclear Generating Station Assets, 15,370 GWh annually; and (b) for 2003 and later, after the transfer of Palo Verde Nuclear Generating Station Assets, 21,090 GWh annually, subject to adjustment as Dedicated Units are retired.

3.2.4 Dedicated Contracts Energy Products. Dedicated Contracts Energy Products shall be priced at the actual cost incurred by PWCC under the provisions of those contracts, including transmission, losses, and Ancillary Services to the Delivery Point. In the event of a default on a Dedicated Contract, PWCC shall obtain Replacement Energy Products pursuant to Section 3.4 of this Service Schedule.

3.3 Supplemental Energy Products. If APS' Full Load Requirements exceeds the Energy Products provided under Sections 3.1 and 3.2, or if there are insufficient qualified bidders to supply the required level of Competitively-Bid Energy Products under Section 3.1 of this Service Schedule, then PWCC shall use commercially-reasonable efforts to obtain the additional energy requirements in the market. APS shall be responsible for any and all costs and expenses incurred in the acquisition of any Supplemental Energy Requirements supplied including PWCC's administrative expenses incurred for procurement.

3.4 Replacement Energy Products. In the event of non-performance by parties that are under contractual commitments, PWCC shall use commercially-reasonable efforts to obtain Replacement Energy Products for the benefit of APS. PWCC shall also obtain Replacement Energy Products when requested under Section 8.1(B) of the Agreement. APS shall be responsible for any and all costs incurred for the acquisition of Replacement Energy Products including PWCC's administrative expenses incurred for procurement. In consultation with APS, PWCC shall pursue all commercially legal remedies for defaults under contracts entered into to acquire Supplemental Energy Products. APS shall be responsible for all costs and fees associated with the pursuit of such remedies, and APS shall receive all monies awarded as a remedy.

Calculation of the Facilities Charge in the Pinnacle West Energy Contract

1. **Facilities Charge (FC).**
The FC for 2002-04 as specified in Section 3.2.2.1 of the Service Schedule was derived using the method below. Effective January 1, 2005 and every three years thereafter the FC shall include the reasonable costs of owning and operating the Dedicated Units as recalculated below:

FC \$/Month = [[(ROR %) X (Net Dedicated Units Assets \$)] + (Dedicated Units Operating Annual Expenses \$) – Annual Ancillary Service Revenues[1]] / 12 Months

Where:

Rate of Return (ROR) is 9.38% which is the cost of capital assuming a 50/50 debt-equity capital structure, at a 7.5% cost of debt and a 11.25% return on equity.

Net Dedicated Units Assets[2] = Original Plant-in-Service Cost[3] – Accumulated Depreciation – Accumulated Deferred Income Taxes + Material & Supplies + Prepayments + Working Cash + Miscellaneous Deferred Credits

Dedicated Units Operating Expenses[4] = Operation & Maintenance Expenses[5] + Administrative & General Expenses + Depreciation & Amortization Expenses[6] + Ad Valorem Taxes[7] +Income Tax Expense[8] + Other Taxes or Assessments[9]

---

[1] Includes revenues paid to PWCC by APS for ancillary services pursuant to the terms of a separate contract.
[2] Projected three year average of year end balances. Each component shall be defined pursuant to the FERC system of accounts or if no applicable FERC system of accounts exists, then on General Accepted Accounting Principles (GAAP). All A&G related expenses, not directly charged, shall be allocated on wages and salaries for the Dedicated Units as a percent of total Pinnacle West Energy wages and salaries.
[3] Original Plant-in-Service Costs will include all capitalized costs of the Dedicated Units plus improvements including common and intangible.
[4] Projected three year average. Each component shall be defined pursuant to the FERC system of accounts or if no applicable FERC system of accounts exists, then on General Accepted Accounting Principles (GAAP). All A&G related expenses, not directly charged, shall be allocated on wages and salaries for the Dedicated Units as a percent of total Pinnacle West Energy wages and salaries.
[5] Costs and expenses associated with the Dedicated Units excluding fuel and purchased power.
[6] Costs and expenses associated with the Dedicated Units, including related common facilities.
[7] Costs and expenses associated with the Dedicated Units, including related common facilities.
[8] Based on the statutory tax rate, both state and federal, for PWEC on stand alone basis.
[9] Taxes and assessments based on generation or gross revenue.

Calculation of the BFC and FPPA in the Pinnacle West Energy Contract

1. **Base Fuel Charge (BFC).**
The BFC shall be set at $0.021/kWh for the calendar year 2002, and at $0.0174 /kWh effective January 1, 2003 for the remainder of the Agreement, and is the Projected Average Fuel Costs associated with the Dedicated Units (AFCDU) for 2002-2004.

Where:

AFCDU $/kWh = (Total fuels cost of Dedicated Units[1] $)/(Total generation of the Dedicated Units MWh)

2. **Fuel & Purchased Power Adjustment (FPPA).**
Beginning March 1, 2003 a FPPA to the BFC will be applicable each month to the billing for Dedicated Units Energy Products. The FPPA shall be calculated annually prior to March of each calendar year as follows:

$$\text{FPPA \$/kWh} = [(\text{Projected AFCDU}^{2}\text{-BFC})\ \text{\$/kWh}] + \frac{[((\text{Actual AFCDU}^{3}\text{-Projected AFCDU}^{4}\ \text{\$/kWh})\ \text{X Actual kWh}) - \text{Off-System Sales Margin \$}]}{\text{Projected kWh}}$$

Where:

"Actual kWh" is the actual Dedicated Units Energy Products purchased by APS on a kWh basis for the prior contract year.

"Projected kWh" is the kWh projected by APS pursuant to Section 2 of this Service Schedule, less the Energy Products acquired under Section 3.1, Section 3.2.4, Section 3.3, and Section 3.4 of this Service Schedule, for the period March 1 of the current Contract Year through the last day of February of the next Contract Year.

$$\text{Off-System Sales Margin}^{5} = [(\text{Off-System MWh X (Price}^{6}\ \text{\$/MWh} - \text{AFCDU}^{7}\ \text{\$/MWh})) - \text{Other Costs}^{8}] \text{ X .25}$$

---

[1] Total fuels costs of Dedicated Units shall include all coal, gas including transportation, oil, nuclear fuel expenses, costs and benefits of fuel-related financial instruments, nuclear spent fuel costs, any applicable surcharges, purchased power costs associated with economic dispatch of the Dedicated Units, nuclear decommissioning expense to the extent it is not recovered from the System Benefits charge authorized by the Arizona Corporation Commission, and any other fuel related expenses, including but not limited to costs associated with emissions allowances.
[2] For current Contract Year.
[3] For prior Contract Year.
[4] For prior Contract Year.
[5] For prior Contract Year for Energy Products delivered and sold into the wholesale market for third-party purchases.
[6] The Price will be based upon the Dow Jones Palo Verde Daily On and Off-Peak Index as applicable to the specific sales. In the event this index ceases to exist or a more representative index is developed for Arizona or the southwest portion of the U.S.A. then the index will be replaced.
[7] For prior Contract Year.
[8] Includes transmission costs and losses, and Ancillary Services, if applicable, and other out-of-pocket costs associated with the sales.

SCHEDULE JED-1

DAILEY POWER PRICES

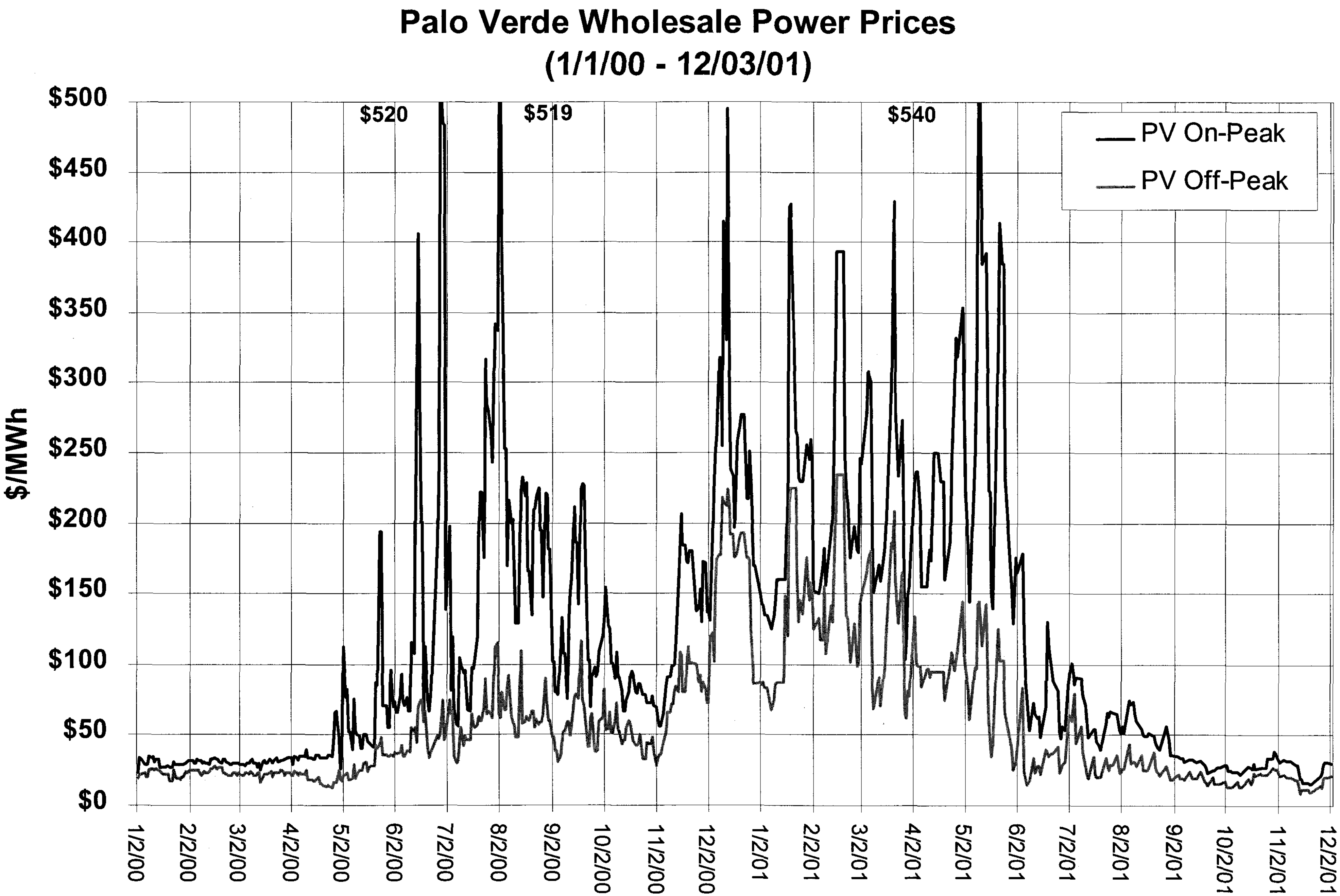

Palo Verde Wholesale Power Prices
(1/1/00 - 12/03/01)
$/MWh
$500
$450
$400
$350
$300
$250
$200
$150
$100
$50
$0
$520
$519
$540
PV On-Peak
PV Off-Peak
1/2/00
2/2/00
3/2/00
4/2/00
5/2/00
6/2/00
7/2/00
8/2/00
9/2/00
10/2/00
11/2/00
12/2/00
1/2/01
2/2/01
3/2/01
4/2/01
5/2/01
6/2/01
7/2/01
8/2/01
9/2/01
10/2/01
11/2/01
12/2/01

Figure 3

SCHEDULE JED-2

DAILEY NATURAL GAS PRICES

SCHEDULE JED-2

Henry Hub vs. Topock
Natural Gas Wholesale Prices
(1/1/00 - 12/04/01)

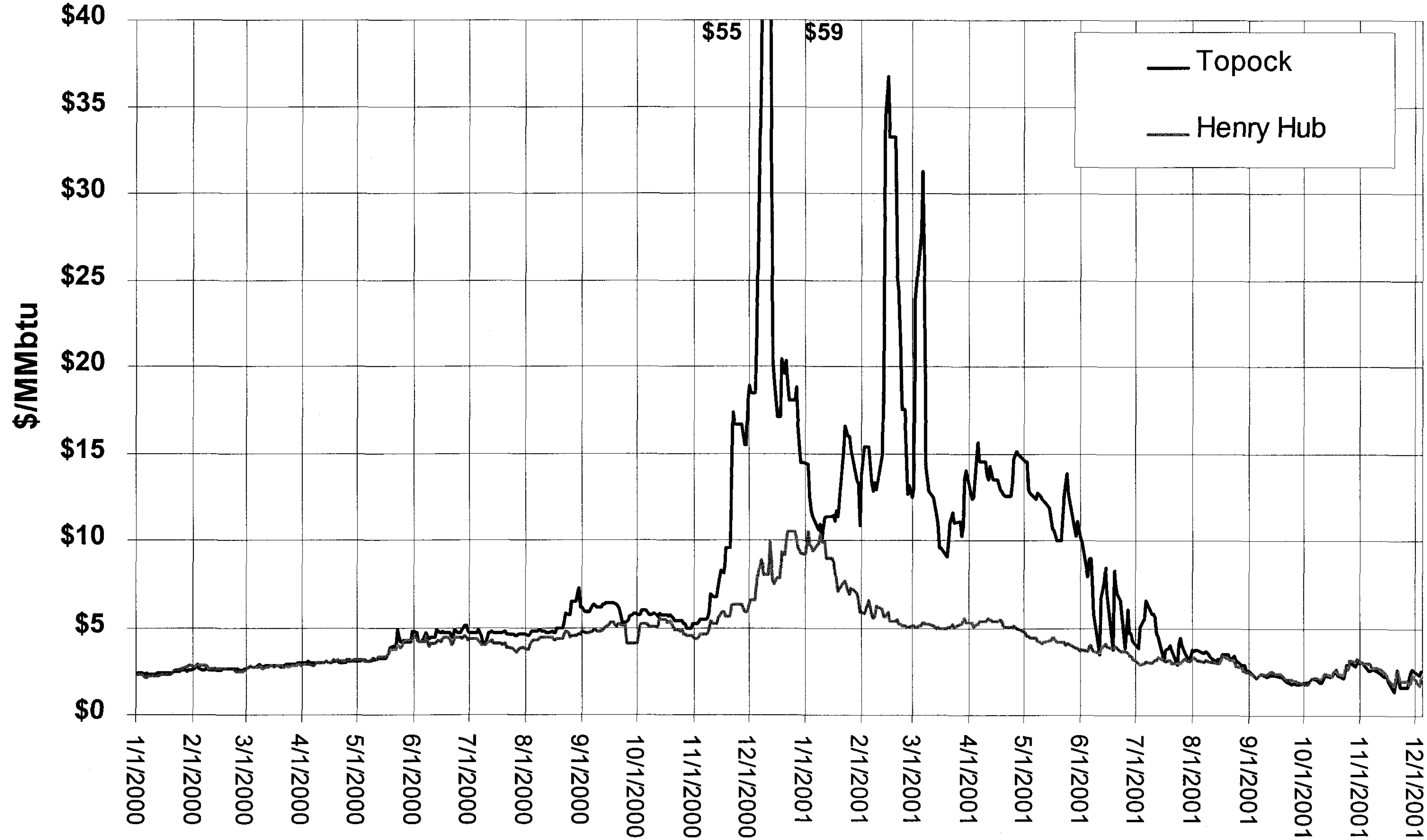


Figure 4

SCHEDULE JED-3

ESTIMATED CUMULATIVE

CUSTOMER SAVINGS

APS Power Procurement
PPA Cumulative Cost Savings Vs. LRMC
(Figure 5)

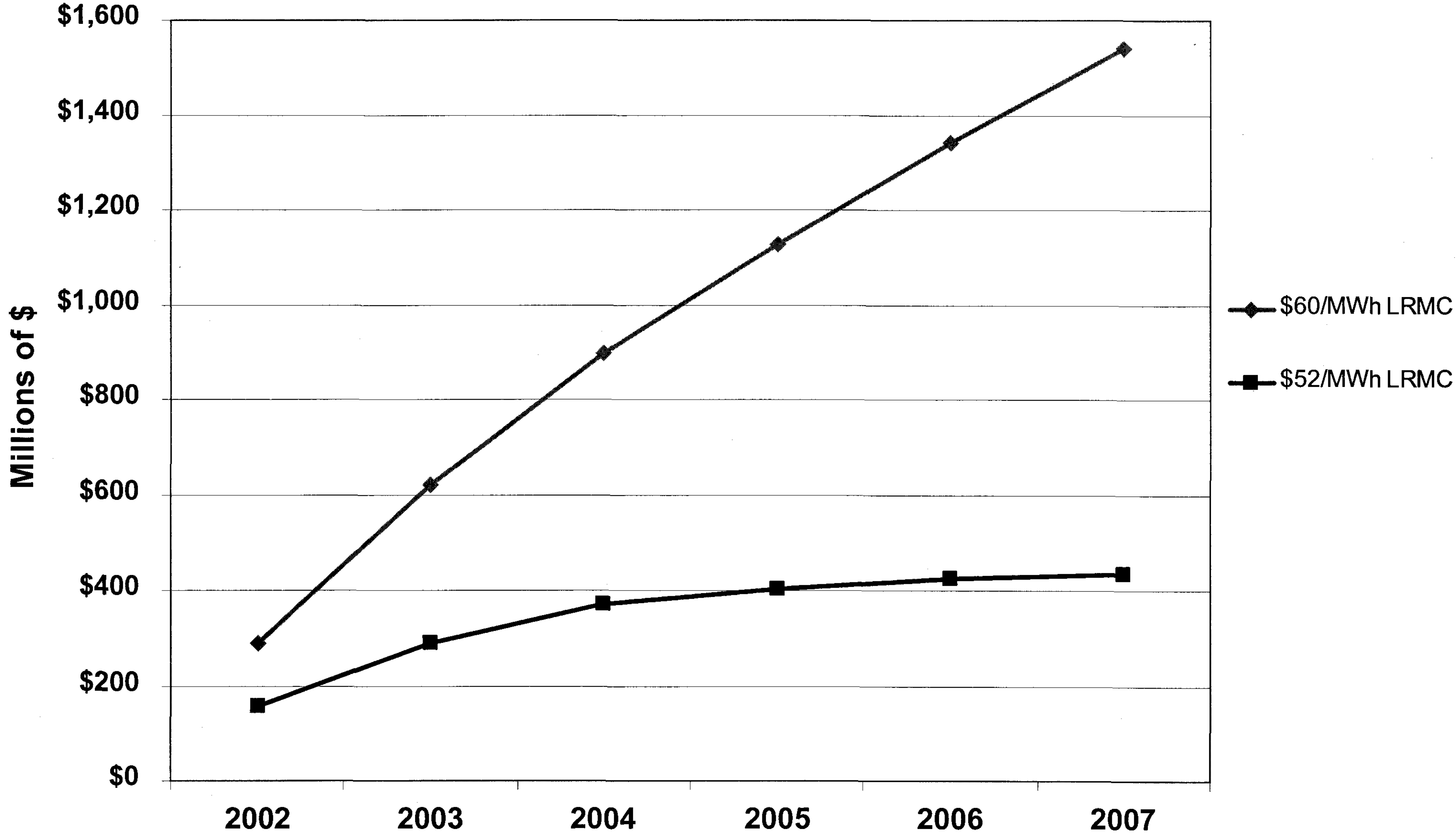


Figure 5

DR. JOHN H. LANDON

TESTIMONY OF JOHN H. LANDON

ON BEHALF OF

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-01-0822

PRINCIPAL AND DIRECTOR,

ENERGY AND TELECOMMUNICATIONS PRACTICE,

ANALYSIS GROUP/ECONOMICS

December 12, 2001

TABLE OF CONTENTS

DIRECT TESTIMONY OF JOHN H. LANDON

(DOCKET NO. E-01345A-01-0822)

I. INTRODUCTION & QUALIFICATIONS

Q. Please state your name and business address.

A. My name is John H. Landon, and my business address is Two Embarcadero Center, Suite 1750, San Francisco, California, 94111.

Q. What is your current position?

A. I am a Principal and Director of the Energy and Telecommunications practice of Analysis Group/Economics, an economic consulting firm. My resume is attached to this testimony as Exhibit___(JHL-1).

A. Background

Q. Please outline your educational background.

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

Q. Where were you employed after leaving Cornell University?

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

Q. What subjects did you teach during this period?

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

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

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

Q. When did you join Analysis Group/Economics?

A. I joined Analysis Group/Economics in March of 1997.

Q. What has been the nature of your assignments at NERA and Analysis Group/Economics?

A. Much of my work over the last twenty-four years has been on issues relating to the application of economic principles to the electric utility industry. I have participated in numerous projects addressing economic and related antitrust issues before the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), the Securities and Exchange Commission (SEC), state regulatory commissions, and federal and state courts.

B. Electric Industry Qualifications

Q. Please briefly outline your electric utility related background.

A. I studied regulatory economics both as an undergraduate (Michigan State with Professor Joel Dirlam) and as a graduate student (Cornell University with Professor Alfred Kahn). I was one of the graduate assistants who provided research assistance for Professor Kahn as he wrote his *Economics of Regulation*.

As a faculty member at Case Western Reserve University and the University of Delaware, I taught regulatory economics and authored or co-authored several articles and book chapters focused on economic aspects of the electric utility industry. In my more than 24 years of practice as an economic consultant, I have spent the majority of my time on issues involving electric utilities.

C. Testimony before Regulatory Authorities

Q. Have you previously testified?

A. Yes. I have testified on many occasions before state and federal courts and regulatory agencies on a variety of matters. These matters include: deregulation, affiliate relations, competition and market power, rate making, performance-based regulation, transmission governance, demand-side management, cost allocation and pricing.

Q. Before which state regulatory commissions have you testified?

A. I have provided testimony before the regulatory commissions of Arkansas, Arizona, California, Delaware, Florida, Illinois, Iowa, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Jersey, New Mexico, New York, Ohio, Pennsylvania, Texas, Vermont and West Virginia.

II. PURPOSE OF TESTIMONY

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

A. I have been asked by Arizona Public Service Company (APS) to discuss certain aspects of the Request of Arizona Public Service Company for a Partial Variance of A.A.C. R14-2-1606(B) (Variance Request) and for approval of a Purchase Power Agreement (PPA) with Pinnacle West.

Q. Please summarize your testimony.

A. My testimony focuses on two effects of these proposals: 1) their likely effects on APS' retail customers, and 2) their likely effects on the development of competitive markets.

Q. Please summarize your conclusions.

A. I conclude that:

1) The Variance Request and the proposed PPA will provide Standard Offer customers rate stability relative to other options available to APS to serve Standard Offer customers. Furthermore, the proposed PPA offers important security and reliability advantages over short-term market prices and separate long-term contract alternatives.

2) The development of competitive wholesale and retail markets is not compromised by the Variance Request or by the proposed PPA. More specifically, I explain how, under the circumstances, relaxing the requirement for market bids covering 50 percent of power to serve Standard Offer customers provides a sustainable path to developing competitive markets in Arizona, preserves the competitive wholesale market's demand and supply balance, improves the prospects for effective competition in the near term, and does not harm independent power producers (IPPs) over the long term.

III. OVERVIEW OF APS PROPOSALS

Q. What are the predominant features of the proposed PPA?

A. The PPA consists of an obligation from Pinnacle West to APS to provide energy and capacity in return for a payment that is comprised of a fixed facilities charge and an energy charge. Service under the PPA is backed by a portfolio of dedicated plants whose costs are reflected in the facilities and energy charges. These charges are subject to adjustment over the term of the contract depending on costs incurred; the facilities charges may be adjusted every three years whereas the energy charges are adjusted annually. In addition, the PPA provides for Pinnacle West to obtain "Competitively-Bid Energy Products" on behalf of APS commencing with 270 megawatts on January 1, 2003 and increasing by 270 megawatts annually, up to 1620 megawatts in 2008. Pinnacle West will obtain additional energy from competitive markets on behalf of APS as needed either to cover APS requirements beyond those specified in the proposed PPA, or to replace power in the event of default by a supplier of Competitively-Bid Energy Products. The initial term of this agreement is through 2015 with provisions for three five-year extensions thereafter.

It is my view that based on the proposed terms, the PPA offers the following advantages to APS and its Standard Offer customers: 1) Prices that are stable relative to likely market prices; and 2) A reliable source of power compared with other options available to APS to serve Standard Offer customers.

For these reasons it is my view that the proposed PPA represents a prudent resource acquisition for APS.

In addition, I have reviewed the likely effects of these proposals on the development of competitive markets and find that they will not retard the transition to competitive markets for the following reasons: 1) Wholesale markets are regional, the amount of power provided under the PPA is small in the context of regional markets, and therefore unlikely to affect their development, 2) Changing the 50 percent rule for APS does not adversely affect Arizona independent power producers because the overall supply/demand balance is unchanged, and Pinnacle West will still be willing to purchase attractively priced energy from them. The load that will be served under the PPA is matched to existing generation resources that would be part of the market supply in any event. Furthermore, retail customers of APS will still have the opportunity to shop should competitively attractive alternatives arise in the marketplace.

IV. EFFECTS ON STANDARD OFFER CUSTOMERS

A. Overview of Effects of Proposed PPA on Standard Offer Customers

Q. Please discuss how the proposed PPA will affect Standard Offer customers.

A. The proposed PPA will give APS a means to create a supply option for Standard Offer customers that combines long-term price stability with reliable service backed by a diversified portfolio of plants. While prices under the PPA are subject to adjustment, they will be more stable than prices in competitive spot markets or prices based on short-term contracts. The portfolio-backed obligation to APS from Pinnacle West also offers an attractive level of reliability relative to other sources of supply.

B. Price Volatility and Increased Stability Under the Proposed PPA

Q. Please discuss the increased exposure to price volatility that consumers face in the evolving environment.

A. Electricity prices in competitive markets can be very volatile. While long-run average prices may be lower under competition, during short-term periods of high demand relative to resource availability, prices can and do move to very high levels. Exhibit__(JHL-2) shows wholesale electricity prices for peak power at Palo Verde over the past year, prices have ranged from around $20 per megawatt-hour to well over $500. Similarly, Exhibit__(JHL-3) displays gas prices over the past year at the Permian Basin. Gas prices have ranged from around $2.00 to around $10.00, a five-fold difference. Please note that this price volatility is upstream of the El Paso Gas Pipeline and therefore unrelated to that pipeline's supply disruptions commencing in 2000.

Q. Is such price volatility likely to affect prices to Standard Offer customers?

A. Yes. While Standard Offer customers may not pay spot market prices directly, these prices when rolled into costs of service can still have profound effects on price levels. The experience of regulated utilities in the Pacific Northwest over the past year offers a sobering example. Faced with a drought that affected hydroelectric power availability Pacific Northwest utilities were forced to buy power in the competitive market. The effects of the drought together with the effects of the California meltdown led to extraordinarily high local prices, in many instances well above the wholesale prices in California. To maintain their financial stability, some of these utilities have had to raise rates to retail customers by 40 to 50 percent to cover purchased power costs.

C. Price Stability for Standard Offer Customers

Q. Is long-term price stability a reasonable goal for the Arizona Commission and consumers?

A. Yes. Electricity and gas prices in the competitive (spot) market are likely to be volatile, and can fluctuate wildly over very short periods of time. This volatility can be very unsettling to consumers and yet shielding them from market costs that the provider incurs to serve them, for example through a retail rate freeze without corresponding assurances of compensation for electric supply costs, would place the provider at financial risk. Therefore, it is desirable to offer customers a means of achieving relative price stability that also protects the provider's financial integrity.

Q. Does the proposed PPA offer a means to reduce the price volatility illustrated above to customers?

A. Yes. Dedicating a diverse portfolio of generating units at cost-based prices under a long term contract offers an excellent way to avoid exposure to market volatility. Stable prices under firm, asset-backed requirements contracts can insulate customers from wide swings up and down in market energy or capacity prices while ensuring that sufficient revenues are generated to cover the resources used to meet demand.

Q. Does this benefit Standard Offer customers?

A. Yes, residential and small commercial customers are likely to be adverse to the risks of price volatility, and to lack the time, skills or tools to hedge their risk exposure. In addition, because they are small customers, the time and transaction costs of hedging their risks would be very high relative to the likely benefit that they would receive.

Q. Please discuss the benefits of utilizing the portfolio approach to create an asset-backed PPA.

A. The proposed PPA ensures that dedicated assets are used to benefit customers. By using the costs of these assets to establish the prices paid by Standard Offer customers under the PPA, customers are assured of being able to secure much of their electric needs on a reasonable basis. In addition, customers will still have the opportunity to acquire retail service from alternative suppliers at competitive rates should they find more attractive prices or service options in the marketplace than those offered by APS.

Q. Please comment on the term of the PPA.

A. Because the proposed PPA is based predominantly on the capital costs of existing units, and because market prices likely will rise over time to reflect the costs of new generation, which are likely to escalate, the final years of the agreement are probably the most valuable to rate payers. In addition, a long term provides adequate time for institutions and regulations to be developed and entry of new firms to occur so that the energy market is geographically diverse and rich in alternative sources. This means that the public interest is likely to be enhanced by the relatively long length of the contract whose initial term runs to 2015.

Q. What might be the effects of high prices in the market on APS' Standard Offer customers without the Variance and proposed PPA?

A. Under the Settlement Agreement, retail prices for Standard Offer service in APS' territory cannot be increased through July 2004. Thus, consumers would be insulated from any high market prices until then. However, APS would necessarily bear the brunt of financial exposure to the gap between the price it is allowed to charge consumers and the price it must pay. Following July 2004, under the Settlement Agreement, consumers are scheduled to pay bid or market prices. If market prices are higher, they will be reflected in higher rates for Standard Offer service.

D. The proposed PPA offers an attractive level of reliability relative to other, current sources of supply

Q. How does the proposed PPA provide enhanced reliability relative to other sources of supply?

A The proposed PPA incorporates directly a diverse portfolio of generating plants with diverse fuel requirements. In contrast, once it becomes available, virtually all competitively-supplied generation in Arizona will be from new, gas-fired plants and, therefore, exposed to volatility in gas prices or to disruption of gas supplies. Since natural gas plants often will be on the margin, these units will drive the electricity spot market prices. Hence, volatility in the gas supply market (see Exhibit___(JHL-3)) largely will translate to wildly fluctuating electricity prices. Relying on a diverse portfolio of nuclear, coal and gas resources to back up the requirements of Standard Offer customers means that their source of supply is physically and financially more secure than may be possible in competitive markets.

In addition, the form of the PPA incorporates security of supply not limited to specific agreements to purchase from individual generation units. Resource diversity is created by the system sale under which Pinnacle West must supply regardless of whether specific units are available. This means that while the contract is backed up and prices based on a diverse group of specific units, there is an obligation to meet contract requirements from other sources if required. In a substantial sense, this means that reserves are being provided to the benefit of Standard Offer customers.

Q. Please discuss how the portfolio of plants backing the proposed PPA enhances reliability of supply for Standard Offer customers over the alternative of requiring that 50 percent of power to serve them comes from the competitive market.

A. The portfolio of plants that will be dedicated to serving Standard Offer customers under the terms of the proposed PPA has been planned by the utility and reviewed by the Commission to balance cost risks such as fuel price risk and risks associated with relying primarily on new and less well tested technology. While the PPA portfolio will include some new plants incorporating new technologies, these are balanced by a predominance of plants utilizing well established coal-fired and nuclear technologies as well as by existing gas plants utilizing established technologies. In addition, the dedicated plants are strategically located to ensure access to the APS customer base in a relatively reliable and efficient manner.

In contrast, the predominant type of generation plant under construction by power marketers is gas-fired combined cycle units. This is a relatively new and evolving technology with multiple efficiency enhancements still in development. Many newly constructed combined cycle units have performed less well than expected, at least initially, and, as a consequence, have had lower than initially expected availability. The proposed PPA offers APS and its customers a reliable source of power with an established track record.

Q. Are there other reliability concerns with relying on newly constructed plants in developing competitive markets to supply a large proportion of the needs of Standard Offer customers?

A. Yes. We are in the midst of a transition from transmission systems designed to support vertically-integrated and locally-dispatched utility operations to disaggregated regional markets that will fully support the competitive processes. That transition is not complete and will take some time to accomplish. At a minimum, the amount of time that will be required is a function of that required to design and implement institutional structures to support a more broadly administered system, create appropriate incentives for proper expansion of the transmission system, identify needed transmission investments, obtain financing, permitting and finally to construct the necessary improvements. In the meantime, lack of geographic diversity of generation locations and limitations on local market breadth and depth will reduce the extent to which competitive markets may be relied upon to serve large portions of the needs of Standard Offer customers.

V. EFFECT OF VARIANCE REQUEST AND PPA ON COMPETITIVE MARKETS

A. Development of competitive markets is not compromised by the proposed PPA.

Q. Does the PPA retard the development of competitive markets relevant to Arizona?

A. No. In my opinion, it ensures that there will be effective competition in both the short and long term. It must be recognized that there are at least two separate competitive markets to consider. First, the relevant wholesale market includes the entire Western States Interconnection. This market is broadly competitive with or without APS purchases to serve Standard Offer customers. Once the institutional infrastructure that is under development is in place, this will be even more true. This PPA–indeed, the Arizona market taken as a whole–is small relative to the total market. Arizona, New Mexico and Southern Nevada region accounted for only 16.6 percent of loads and 15.9 percent of resources in the WSCC during 2000. Furthermore, past price relationships between Arizona and other areas in the West suggest that destinations outside of Arizona for Arizona-based generation may be more attractive to competitive generators than those inside the state. In addition, the PPA does not foreclose the IPPs' access to the part of the market that is covered by the PPA. Pinnacle West will, itself, purchase from others to supply APS customers when it is less expensive than running its own generation. Moreover, if Pinnacle West assets are devoted to the needs of APS customers they will not compete with IPPs elsewhere. It is important to remember that the PPA does not alter the demand/supply balance. Thus, the PPA does not tie up a large segment of the wholesale market, but rather removes an equal amount of supply and demand from one segment under some circumstances.

In addition to the Western States market, it is relevant to consider the current state of the retail market in Arizona. Over time, more suppliers will be added, transmission will be expanded and institutions such as regional transmission organizations (RTOs) will develop to support greater reliance on competition to serve the needs of area customers. At this point it is not clear that relying on competitive bids for substantial blocks of power would result in Standard Offer prices to customers that would be stable at competitive levels. Under the proposed PPA, there will be a stable cost-based alternative and customers would still be able to choose competitive retail suppliers if they are able to offer better terms or specialized choices. APS retail customers will still be able to shop, and to purchase from alternative sources if their prices and/or product offerings are attractive relative to those offered by APS.

Q. Are there pro-competitive aspects to the proposed PPA?

A. Yes. As I discuss below, the PPA establishes a benchmark price for Arizona retail customers that is attractive compared with market prices. If APS were required to utilize competitive bids for 50 percent of Standard Offer load, there is a significant danger that a bidder or bidders could bid above long-term market price.

Following July 2004, when these competitive bids are reflected in Standard Offer prices to customers, customers would be at risk. Furthermore, the PPA is a cost-based system commitment backed by a diverse portfolio of assets that enhances security relative to individual unit or non-asset based contracts and internalizes a hedging function and costs. This offers customers a secure alternative at stable prices for comparison with competitive alternatives.

B. Changing 50 percent rule for APS does not adversely affect Arizona independent power producers

Q. In your opinion, will a change in the requirement that APS purchase 50 percent of the power to serve Standard Offer customers from competitive suppliers adversely affect IPPs in Arizona?

A. No, as I discussed above, it is likely that independent generation plants will primarily serve regional as opposed to Arizona-specific load. As highlighted in press releases and analysts reports regarding proposed new plants, the plants are strategically located near both natural gas pipelines and transmission lines that link to the Southwestern markets and those in California. APS witness Jack Davis points out that it is not possible to obtain even 50 percent of APS' requirements from the Palo Verde Hub to the company's primary and secondary load centers: "...yet it is precisely in the Palo Verde area that most of the [merchants] have elected to either build their plants or to interconnect with the Arizona grid." Furthermore, Arizona is a low price area relative to other important load centers in the WSCC, thus IPPs will be inclined to seek to sell their production outside of the state. While transmission links to reach other, higher price load centers are presently in place, planned new transmission investments will further improve access to other load centers. In addition, if FERC RTO and transmission planning and pricing issues are adequately resolved, transmission investment is likely to accelerate.

Q. **Are there other locations in the country where IPPs are being built to serve other than local retail loads?**

A. Yes. Any assertion that generation under construction in one state is predominantly built to serve local load is demonstrably contrary to investors' announcements and to what is happening across the country. Elsewhere, large amounts of competitive generation are being built in states that have no plans for retail open access, i.e., where retail loads are supplied by vertically integrated utilities under embedded cost of service pricing. For example, in Mississippi which has not committed to restructuring electricity at the retail level in any manner, merchant generators have indicated that they will build around 15,000 MW of new plant, about 5,600 MW of this is already operating or well under construction. This compares with 1999 utility-owned capacity of about 6,800 MW. Similar trends are evident in other southern states such as Kentucky, South Carolina and Tennessee.

Q. **Do you have any other observations regarding the likely effect of deviating from the 50 percent rule for competitive bidding?**

A. Yes. The competitive electric generation business, like many other capital intensive industries, is likely to be subject to boom and bust cycles. Any glut of generation due to economic factors and attendant depressed price levels is likely to be short-term until demand once again catches up to supply. At that point, market prices would rise to above the long-run competitive level. Once prices are sufficiently attractive, new investment may once again lead to over supply and to lower prices. The proposed contract, however, is long-term and intended to shield Standard Offer customers from the effects of these cycles. The Commission needs to weigh any trade-off between consumer benefits from stable prices under the proposed contract with short-term benefits to the owners of generation that might arise from the 50 percent requirement.

VI. CONCLUSIONS

Q. Please discuss your conclusions regarding the Variance Request and the proposed PPA.

A. It is my view that based on the proposed terms, the PPA offers the following two principle advantages to APS and its Standard Offer customers: First, it provides prices that are stable relative to likely market prices. Second, it is a reliable source of power compared with other options before APS to serve Standard Offer customers. For these reasons it is my view that the proposed PPA represents a prudent acquisition for APS and its customers.

In addition, I have reviewed the likely effects of these proposals on the development of competitive markets and find that they will not retard the transition to competitive markets for the following two principal reasons: First, wholesale markets are regional, this PPA is small in the context of regional markets, and therefore unlikely to affect their development. Second, changing the

50 percent rule does not adversely affect Arizona IPPs because Pinnacle West will still be willing to purchase attractively priced power from them and because the load that will be served under the PPA is matched to existing generation resources. Furthermore, retail customers of APS will still have the opportunity to shop should competitively attractive alternatives arise in the marketplace. These proposals support and extend the Commission's prior actions in establishing the transition period and rate freeze and encourage progress toward competitive markets.

If the Variance Request is not granted and competitive bids and/or market forces cause prices for Standard Offer customers to be high and/or volatile, I fear that it will be politically difficult to sustain the desirable movement toward competitive markets and the long-term benefits they will bring. The Variance Request and PPA offer a sustainable and low risk path to the benefits of competition.

Q. Does this conclude your direct testimony?

A. Yes, it does.

JOHN H. LANDON
Principal & Director, Energy Practice

Phone: (415) 263-2224
Fax: (415) 391-8505
jlandon@analysisgroup.com

Two Embarcadero Center
Suite 1750
San Francisco, CA 94111

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

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

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

PROFESSIONAL ACTIVITIES

Member of the Governor of Delaware's Economic Advisory Committee

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

A Director of the Delaware Econometric Model Group

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

Member of the American Economic Association

Associate Member of the American Bar Association

TESTIMONY PROVIDED FOR THE FOLLOWING CLIENTS:

- **Oklahoma Gas and Electric Company**
  Before the Arkansas Public Service Commission, Docket No. 00-190-U, September 29, 2000. (Direct Testimony) October 24, 2000 (Rebuttal).

- **Public Service Company of New Mexico**
  Before the New Mexico Public Regulation Commission, Case No. 3137, May 31, 2000.

- **Eastern Edison Company**
  Before the Superior Court, Commonwealth of Massachusetts, Boston, Massachusetts, on behalf of Eastern Edison Company, March 29, 2000.

- **Florida Power & Light Company**
  Before the Florida Public Service Commission, Docket No. 991462-EU, Petition for determination of need for electrical power plant in Okeechobee County by Okeechobee Company, L.L.C., February 18, 2000. (Direct and Supplemental Testimonies)

- **Sierra Pacific Power Company/Nevada Power Company (Nevada Power)**
  Comments on proposed Code of Conduct rules filed with the State of Nevada Public Utilities Commission, PUCN Docket No. 97-8001 (Provider of Last Resort), January 26, 2000.

- **Ohio Power Company and Columbus Southern Power Company**
  Before the Public Utilities Commission of Ohio, Case Nos. 99-1729-EL-ETP, 99-1730-EL-ETP, December 30, 1999 (Direct Testimony); April 18, 2000 (Supplemental Direct Testimony).

- **Christian Hellwig vs. Autodesk, Inc.**
  Before the Superior Court of the State of California for the County of Marin, Case No. 174842, December 14, 1999.

- **Public Service Company of New Mexico**
  Comments on proposed Code of Conduct rules filed with the New Mexico Public Regulation Commission, NMPRC Case No. 3106, September 27, 1999.

- **Arizona Public Service Company**
  Before the Arizona Corporation Commission, Docket Nos. E-01345A-98-0473, E-01345A-97-0773, and RE-00000C-94-0165, July 21, 1999. (Direct, Rebuttal and Surrebuttal Testimonies)

- **Appalachian Power Company**
  Before West Virginia Public Service Commission in West Virginia PSC Case No. 98-0452-E-GI, July 7, 1999. (Direct and Rebuttal Testimonies)

- **Ameren Corporation and Union Electric Company**
  Comments on behalf of Ameren Corporation and Union Electric Company filed with the State of Missouri Public Service Commission concerning proposed affiliate transactions rules for electric, gas, and steamheating utilities (Proposed Rule 4 CSR 240-20.015) and marketing affiliate rules for gas utilities (Proposed Rule 4 CSR 240-20.016). (Direct Comments filed June 30, 1999 and Reply Comments filed July 30, 1999)

- **GTE Corporation and Bell Atlantic Corporation Merger**
  Before the Public Utilities Commission of the State of California, Application 98-12-005, June 21, 1999. (Report and Rebuttal Testimony)

- **Kathleen Betts v. United Airlines, Inc.**
  Before the United States District Court, Northern District of California, Case No. C97-4329 CW, March 25, 1999.

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

- **The McGraw-Hill Companies**
  Before the United States District Court for the District of Colorado, Civil Action No. 96-Z-1087, October 1998.

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

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

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

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

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

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

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

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

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

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

- **Commonwealth Edison Company**

Before the Illinois Commerce Commission, Docket No. 98-0013, March, 1998. (Direct, Rebuttal and Surrebuttal Testimonies)

- **Arizona Public Service Corporation**
  Before the Arizona Corporation Commission, Docket No. U-0000-94-165, February 4, 1998.

- **Silvaco Data Systems**
  Before the Superior Court for the State of California, November 7, 1997.

- **Entergy Gulf States, Inc.**
  Public Utility Commission of Texas, April 4, 1997 and October 24, 1997.

- **Delmarva Power & Light Company**
  Before the Maryland Public Service Commission, Delaware Docket No. 79-229, August 19, 1997.

- **The McGraw-Hill Companies, Inc.**
  Before the United States District Court for the District of Colorado, Civil Action No. 94-WM-1697, July 17, 1997.

- **Donaldson, Lufkin & Jenrette**
  In the matter of the arbitration between Donaldson, Lufkin & Jenrette Securities Corporation and Lori Zager, NYSE No. 1996-005868, April 11, 1997.

- **Louisiana Pacific**
  Superior Court of the State of California, County of Humbolt, Case No. 94DRO166, February 10, 1997.

- **Hoffmann-La Roche, Inc.**
  Superior Court of the State of California, County of Santa Clara, Case No. CV 746366, February 4, 1997.

- **Arizona Public Service Company**
  Arizona Corporation Commission, Docket No. R-0000-94-165, November 27, 1996.

- **MidAmerican Energy Company**
  Iowa State Utilities Board, Docket No. APP-96-1 and RPU-96-8 (Consolidated), October 30, 1996.

- **California Tennis Club**
  Superior Court of the State of California, County of San Francisco, Case No. 972651, September 27, 1996.

- **El Paso Electric Company**
  United States District Court, District of New Mexico, Civil Action No. 95-485-LCS, July 2 and 3, 1996.

- **Nevada Power Company**
  American Arbitration Association in the matter Saguaro Power Company, Inc. v. Nevada Power Company, AAA Case No. 79 Y 199 0054 95, May 29, 1996.

- **Arizona Public Service Company**

Arizona Corporation Commission, Docket No. U-1345-95-491, March 1 and April 4, 1996.

- **Fireman's Insurance Companies**
  Insurance Commissioner of the State of California, Case No. RB-94-002-00, February 9, 1996.

- **Nevada Power Company**
  American Arbitration Association in the matter Nevada Cogeneration Associates #1 and Nevada Cogeneration Associates #2 v. Nevada Power Company, AAA Case No. 79 Y 199 0064 95, December 6 and 7, 1995.

- **Beverly Enterprises-California, Inc.**
  Superior Court of the State of California, County of San Francisco, Case No. 962589, November 6 and 7, 1995.

- **PECO Energy Company**
  Pennsylvania Public Utility Commission, Docket No. I-940032, November 6, 1995.

- **Southern California Gas Company**
  Private arbitration panel in the matter Marathon Oil Company v. Southern California Gas Company, May 18, 1995.

- **Southern Company Services, Inc.**
  Federal Energy Regulatory Commission, Docket Nos. ER94-1348-000 and EL94-85-000, November 7, 1994.

- **American Electric Power Service Corporation**
  Federal Energy Regulatory Commission, Docket No. ER93-540-001, August 26, 1994 and January 18, 1995.

- **Florida Power & Light Company**
  Florida Public Service Commission, Docket No. 930548-EG, May 19, May 25 and June 6, 1994.

- **PECO Energy Company and Susquehanna Electric Company**
  Federal Energy Regulatory Commission, Docket No. ER94-8-000, January 21, 1994.

- **El Paso Electric Company and Central & South West Services, Inc.**
  Federal Energy Regulatory Commission, Docket No. EC94-7-000, January 10 and December 12, 1994.

- **Benziger Family Ranch Associates, dba Glen Ellen Winery, et al.**
  Superior Court of California, Sonoma County, Case No. 187834, June 23, 1993.

- **The Montana Power Company**
  Montana Public Service Commission, Docket No. 93.6.24, June 21, 1993 and October 15, 1993.

- **Consumers Power Company**
  Michigan Public Service Commission, Case No. U-10335, May 10, 1993.

- **Detroit Edison Company**
  Michigan Public Service Commission, Case Nos. U-10143 and U-10176, March 1, 1993 and May 17, 1993.

- **Florida Power & Light Company**
  Florida Public Service Commission, Docket No. 920606-EG, December 15, 1992 and January 20, 1993.

- **Intermedics, Inc.**
  United States District Court, Northern District of California, Civil Action No. 90-20233 JW (WDB), December 2, 1992.

- **Eaton Corporation, et al.**
  Superior Court of California, Sonoma County, Case No. 179105, August 24, 1992.

- **Florida Power & Light Company**
  Florida Public Service Commission, Docket No. 920520-EQ, August 5, 1992.

- **Florida Power & Light Company**
  Florida Public Service Commission, Docket No. 891324-EU, March 12, 1991.

- **Iowa Public Service Company**
  Iowa State Utilities Board, Docket No. SPU-88-7, February 28, 1989 and September 1, 1989.

- **Arizona Public Service Company**
  Arizona Corporation Commission, Docket No. U-1345-88-180, November 7, 1988 and January 17, 1989.

- **Delmarva Power and Light Company**
  Delaware Public Service Commission, Docket No. 88-16, June 3, 1988, February 10, 1989 and April 24, 1989.

- **Florida Power Corporation**
  Florida Public Service Commission, Docket No. 860001-EI-G, Investigation Into Affiliated Cost-Plus Fuel Supply Relationships of Florida Power Corporation, May 2, 1988.

- **Cambridge Electric Light Company and Commonwealth Electric Company**
  Massachusetts Department of Public Utilities, Docket Nos. DPU87-2C and DPU87-3C, January 29, 1988.

- **Gulf States Utilities Company**
  Nineteenth Judicial District Court, State of Louisiana, Case No. 324,224, Division "I", January 28, 1988.

- **Utah Power and Light Company, PacifiCorp, PC/UP&L Merging Corporation**
  Federal Energy Regulatory Commission, Docket No. EC88-2-000, January 8, 1988 and February 24, 1988.

- **Illinois Power Company**
  Illinois Commerce Commission, Docket No. 87-0695, November 19, 1987, June 10, 1988 and July 22, 1988.

- **Canal Electric Company**
  Federal Energy Regulatory Commission, Docket No. ER86-704-001, October 15, 1987.

- **Minnesota Power and Light Company**
  Minnesota Public Utilities Commission, Docket No. E-015/GR-87-223, September 16, 1987.

- **Gulf States Utilities Company**
  Texas Public Utility Commission, Docket Nos. 6755 and 7195, *April 13, 1987.*

- **Gulf States Utilities Company**
  Louisiana Public Service Commission, Docket No. U-17282, March 23, 1987 and May 26, 1987.

- **Arizona Public Service Company**
  Arizona Corporation Commission, Docket No. U-1345-85-367, February 13, 1987 and March 16, 1987.

- **Delmarva Power and Light Company**
  Delaware Public Service Commission, PSC Regulation Docket No. 14 (Concerning Gas and Electric Fuel Adjustment Clauses), December 1, 1986 and December 21, 1987.

- **Southern California Edison Company**
  United States District Court, Central District of California, Civil Action No. 78-0810-MRP, August 26-28, 1986.

- **Florida Power and Light Company**
  Florida Public Service Commission, Docket No. 860786-EI, August 15, 1986 and September 5, 1986.

- **Jersey Central Power and Light Company**
  New Jersey Board of Public Utilities, BPU Docket No. 8511-1116, August 7, 1986.

- **Florida Power and Light Company**
  Florida Public Service Commission, Docket No. 850673-EU, Generic Investigation of Standby Rates, July 16, 1986 and July 30, 1986.

- **Commonwealth Edison Company**
  Federal Energy Regulatory Commission, Docket Nos. ER86-76-001 and ER86-230-001, June 23, 1986.

- **Gulf States Utilities Company**
  Federal Energy Regulatory Commission, Docket No. ER85-538-001, January 6, 1986 and April 25, 1986.

- **Arizona Public Service Company**
  Arizona Corporation Commission, Docket No. U-1345-85-156, November 15, 1985, February 3, 1986 and February 18, 1986.

- **Eastern Utility Associates Power Corporation**
  Federal Energy Regulatory Commission, Docket No. EL85-46-000, September 20, 1985.

- **Southern California Edison Company**
  Federal Energy Regulatory Commission, Docket No. ER79-150-000 (Phase II) Price Squeeze, August 20, 1985.

- **Baltimore Gas and Electric Company**
  Maryland Public Service Commission, Case No. 7871, August 1, 1985 and December 16, 1985.

- **Central Vermont Public Service Corporation**
  Vermont Public Service Board, Docket No. 5030, July 12, 1985.

- **Delmarva Power and Light Company**
  Maryland Public Service Commission, Case No. 7871, June 28, 1985 and December 16, 1985.

- **Florida Power and Light Company**
  Florida Public Service Commission, Docket No. 840399-EU, April 19, 1985 and May 1, 1985.

- **Central and South West Services, Inc.**
  Federal Energy Regulatory Commission, Docket No. ER82-545, et al., April 11, 1985.

- **Gulf States Utilities Company**
  Louisiana Public Service Commission, Docket No. U-16338, April 9, 1985.

- **Gulf States Utilities Company**
  Federal Energy Regulatory Commission, Docket No. ER84-568-000, February 22, 1985.

- **Gulf States Utilities Company**
  Texas Public Utility Commission, Docket No. 5820, October 15, 1984.

- **Central and South West Services, Inc.**
  Federal Energy Regulatory Commission, Docket No. ER84-31-000, August 6, 1984.

- **Delmarva Power and Light Company**
  Delaware Public Service Commission, Docket No. 84-21, July 3, 1984 and July 10, 1985.

- **Houston Lighting and Power Company**
  Texas Public Utility Commission, Docket No. 5779, June 7, 1984.

- **Gulf States Utilities Company**
  Louisiana Public Service Commission, Docket No. V-16038, June 7, 1984.

- **Gulf States Utilities Company**
  Texas Public Utility Commission, Docket No. 5560, April 23, 1984.

- **Pennsylvania Power Company**
  Federal Energy Regulatory Commission, Docket No. ER81-779, December 1, 1983.

- **American Electric Power System Companies**
  Federal Energy Regulatory Commission, Docket No. E-9206, November 21, 1983 and November 5, 1984.

- **Appalachian Power Company**
  Public Service Commission of West Virginia, Case No. 83-384-E-GI, November 2, 1983.

- **Investor-Owned Electric and Gas Utilities of Iowa**
  Iowa State Commerce Commission, Docket No. RMU-83-17, October 27, 1983.

- **Appalachian Power Company**
  Federal Energy Regulatory Commission, Docket Nos. ER82-853 and ER82-854, October 31, 1983.

- **Ohio Edison Company**
  Federal Energy Regulatory Commission, Docket No. ER82-79 (Phase II), April 15, 1983.

- **Ohio Power Company**
  Federal Energy Regulatory Commission, Docket Nos. ER82-553 and ER82-554, March 25, 1983, May 20, 1983 and June 27, 1983.

- **Pennsylvania Power Company**
  Pennsylvania Public Utility Commission, Docket No. R-821918C002, January 21, 1983.

- **Indiana and Michigan Electric Company**
  United States District Court, Northern District of Indiana, Civil Action No. F78-148, March 1982.

- **Louisiana Power and Light Company**
  Federal Energy Regulatory Commission, Docket Nos. EL81-13 and ER81-457, September 4, 1981 and September 13, 1981.

- **Philadelphia Electric Company**
  United States District Court, Eastern District of Pennsylvania, Civil Action No. 78-2533, July 7-9, 1981.

- **Appalachian Power Company**
  Federal Energy Regulatory Commission, Docket No. EL78-13, March 1981 and January 1982.

- **Arkansas Power and Light Company**
  Arkansas Public Service Commission, Docket No. F-007, November 1980.

- **Central Vermont Public Service Corporation**
  State of Vermont Public Service Board, PSB Docket No. 4299, November 30, 1979.

- **Union Electric Company**
  Federal Energy Regulatory Commission, Docket No. ER77-614, February 9, 1979.

- **Wisconsin Power and Light Company**
  Federal Energy Regulatory Commission, Docket No. ER77-347, May 31, 1978 and March 7, 1979.

- **Empire State Power Resources, Inc.**
  New York State Public Service Commission, Case No. 26798, October 11, 1977.

- **Staff of the Securities and Exchange Commission**
  Securities and Exchange Commission, In the Matter of Delmarva Power and Light Company, File No. 59-144, April 30, 1973.

EXPERT REPORTS AND AFFIDAVITS

"Affidavit of John H. Landon on behalf of American Electric Power Marketing, Inc., et al. before the Federal Energy Regulatory Commission, Docket No. ER96-2495 et al., August 7, 2000.

"Rebuttal Report of John Landon," in response to the Expert Report of William H. Kaempfer, Ph.D. in the matter of David Minshall v. The McGraw-Hill Companies and MHGH-TV before the United States District Court for the District of Colorado, Case No.. C 98-M-2694, July 19, 2000.

"Declaration of Dr. John H. Landon" in the matter of Tennessee Valley Authority v. United States Environmental Protection Agency, and John H. Hankinson Jr., Regional Administrator, United States Environmental Protection Agency, Region IV at the United States Court of Appeals for the Eleventh Circuit, Docket Nos. 00-12310-E and 00-12459-E (Consolidated under Docket No 12310-E), July 12, 2000.

"Expert Report of John H. Landon," related to calculation of damages in the matter of David Minshall v. The McGraw-Hill Companies and KMGH-TV, before the United States District Court for the District of Colorado, Case No. C98-M-2694, June 19, 2000.

"An Economic Assessment of the Benefits of Repealing PUHCA," an independent analysis of the costs and benefits of the Public Utility Holding Company Act of 1935 (PUHCA) commissioned by Mid-American Energy Holdings Company, April 2000.

"Expert Report of John H. Landon," related to calculation of damages in the matter of Sarah Stevens vs. UCSF-Stanford Health Care, et al., before the United States District Court for the Northern District of California, Case No. C99-0575, March 7, 2000.

"Expert Report of John H. Landon," related to calculation of damages in the matter of Donald H. Kelley vs. Shepard's/McGraw-Hill, Inc., before the District Court of El Paso County, State of Colorado, Case No. 98-CV-3850, Division 6, March 1, 2000.

"Expert Report of John H. Landon," related to economic damages allegedly attributable to Airworthiness Directive 96-01-03 in the matter of Evergreen Airlines v. Hayes Pemco, before the United States District Court for the Northern District of California, Case No. C-96-2494-WHO, December 23, 1999.

"Expert Report of John H. Landon," related to calculation of lost income in the matter of Christian Hellwig v. Autodesk, Inc., before the Superior Court of the State of California for the County of Marin, Case No. 174842, November 8, 1999.

"Expert Report of John H. Landon," related to calculation of lost income in the matter of William H. Coleman III v. 24 Hour Fitness Inc., et al. before the United States District Court District of Colorado, Case No. 99-WM-483, December 1, 1999.

"Affidavit of John H. Landon on Behalf of American Electric Power Company," prepared on behalf of American Electric Power Company before the Federal Energy Regulatory Commission, Case No. 98-0452-E-GI, September 21, 1999.

"Affidavit of John H. Landon," prepared on behalf of American Electric Power Company before the Federal Energy Regulatory Commission, Docket No. ER96-2495-12, September 16, 1999.

"Expert Report of John H. Landon," related to calculation of damages in the matter of Willis William Ritter, III v. Cooper Industries, Inc., before the United States District Court, Northern District of California, Case No. C 96-2838 TEH, September 10, 1999.

"Expert Report of John H. Landon," in compliance with Rule 26(a) in the matter of Kathleen Betts v. United Airlines, Inc., before the United States District Court, Court of California, Case No. C97-4329 CW, December 8, 1998.

"Expert Report of John H. Landon," in compliance with Rule 26(a) in the matter of Thomas L. Kerstein v. The McGraw-Hill Companies, Docket No. 96-Z-1087, February 2, 1998.

"Expert Report of John H. Landon," in compliance with Rule 26(a) in the matter of Trigen-Oklahoma City Energy Corporation v. Oklahoma Gas & Electric Company, before the United States District Court, Western District of Oklahoma, Case No. CIV-96-1595-L, October 9, 1998.

"Expert Report of John H. Landon, " in compliance with Rule 26(a) in the matter of Donald H. Kelley v. Shepard's/McGraw-Hill, Inc., before the District Court, El Paso County, Colorado, Case No. 96-CV-2449, August 10, 1997.

"Expert Report of John H. Landon," in compliance with Rule 26(a) in the matter of Augusta Software Design, Inc. v. Shepard's/McGraw-Hill, Inc., before the District Court, City and County of Denver, Colorado, Case No. 96-CV-6977, April 13, 1997.

"Expert Report of John H. Landon," in compliance with Rule 26(a) in the matter of Konrad Schmidt, III v. Shepard's/McGraw-Hill, Inc., before the District Court, El Paso County, Colorado, Case No. 96-CV-1731, April 9, 1997.

"Expert Report of John H. Landon," in compliance with Rule 26(a) in the matter of Dennis Brierton et al. v. Emery Worldwide, et al., Docket No. CV 75 3391, August 8, 1997.

"Expert Report of John H. Landon," in compliance with Rule 26(a) in the matter of Arthur W. Manning v. McGraw-Hill, Inc., Docket No. 94-13-1697, July 10, 1997.

"Affidavit of John H. Landon," on behalf of American Electric Power Service Corporation before the Federal Energy Regulatory Commission, Docket No. ER93-540-001, July 18, 1996.

"Rebuttal to Expert Report of Phillip Allman," expert rebuttal report of John H. Landon prepared on behalf of Family Health Foundation, Inc. in the United States District Court, Northern District of California, Case No. C95-2013, September 9, 1996.

"Rebuttal to Expert Report of Ona Schissel," expert rebuttal report of John H. Landon prepared on behalf of Family Health Foundation, Inc. in the United States District Court, Northern District of California, Case No. C95-2013, August 23, 1996.

"Expert Report of John H. Landon," prepared on behalf of Family Health Foundation, Inc. in the United States District Court, Northern District of California, Case No. C95-2013, July 16, 1996.

"Expert Report of John H. Landon on behalf of Nevada Power Company," in a private arbitration before the American Arbitration Association in the matter *Saguaro Power Company, Inc. v. Nevada Power Company*, AAA Case No. 79 Y 199 0054 95, April 4, 1996.

"An Overview of the Electric Utility Industry," expert report of John H. Landon prepared on behalf of El Paso Electric Company before the United States District Court, District of New Mexico, Civil Action No. 95-485-LCS, March 1, 1996.

"Adverse Consequences and Material Impairment Resulting from the Las Cruces Condemnation," expert report of John H. Landon prepared on behalf of El Paso Electric Company before the United States District Court, District of New Mexico, Civil Action No. 95-485-LCS, March 1, 1996.

"Statement of John H. Landon," on behalf of PECO Energy Company regarding Investigation into Electric Power Competition, before the Pennsylvania Public Utility Commission, Docket No. I-940032, January 6, 1996.

"Expert Report of John H. Landon on behalf of Nevada Power Company," in a private arbitration before the American Arbitration Association in the matter *Nevada Cogeneration Associates #1 and Nevada Cogeneration Associates #2 v. Nevada Power Company*, AAA Case No. 79 Y 199 0064 95, November 14, 1995.

"Rebuttal Expert Report of John H. Landon," prepared on behalf of Southern California Gas Company before a private arbitration panel in the matter *Marathon Oil Company v. Southern California Gas Company*, April 21, 1995.

"Expert Report of John H. Landon," prepared on behalf of Southern California Gas Company before a private arbitration panel in the matter *Marathon Oil Company v. Southern California Gas Company*, April 7, 1995.

"Initial Comments of National Economic Research Associates, Inc. on Florida DSM Employment Impacts," prepared for Florida Power & Light Company, January 1994, with Mark P. Berkman and Peter H. Griffes.

"Answers to Questions Concerning the Treatment of Distribution Companies," prepared for the Chilean National Energy Commission, October 25, 1993.

"Final Report on Transmission Pricing in Chile to the Chilean National Energy Commission," prepared for the Chilean National Energy Commission, October 25, 1993.

"A Proposal for Backstop Regulation for Cable Television Prices," prepared on behalf of Time Warner Entertainment Company, L.P. before the Federal Communications Commission, August 25, 1993, with Lewis Perl, Paul Brandon and Anna Della Valle.

"Affidavit of John H. Landon on Behalf of Northeast Utilities Service Company," prepared on behalf of Northeast Utilities Service Company before the Federal Energy Regulatory Commission, Docket Nos. EC90-10-007, et al., April 27, 1993.

"Incentive Regulation in the Electric Utility Industry," a survey of state regulation programs throughout the United States, January 1993.

"Affidavit of John H. Landon in Support of Motion for Summary Judgment," prepared on behalf of Portland General Electric Company before the United States District Court, District of Oregon, Civil Action Nos. 90-524 FR and 90-592 FR, December 9, 1992.

"Affidavit of John H. Landon on Behalf of Northeast Utilities Service Company," prepared in support of Request for Rehearing of Northeast Utilities Service Company before the Federal Energy Regulatory Commission, Docket No. ER92-766-000, November 2, 1992.

"Declaration of John Landon in Support of Plaintiff's Motion for Summary Judgment or Alternatively for Summary Adjudication," prepared on behalf of Benziger Family Ranch Associates d/b/a/ Glen Ellen Winery before the Superior Court of California, Sonoma County, Case No. 187834, October 9, 1992.

"Supplemental Expert Report of John H. Landon in Response to the Expert Report of Gordon T.C. Taylor," prepared on behalf of Portland General Electric Company before the United States District Court, District of Oregon, Civil Action Nos. 90-524 FR and 90-592 FR, August 28, 1992.

"Expert Report of John H. Landon," prepared on behalf of Portland General Electric Company before the United States District Court, District of Oregon, Civil Action Nos. 90-524 FR and 90-592 FR, July 3, 1992.

"Declaration of John Landon in Opposition to Plaintiff's Motion for Permanent Injunction," an affidavit prepared on behalf of Sega of America, Inc. before the United States District Court, Central District of California, Civil Action No. CV-90 2323 RJK, April 23, 1992.

"Preliminary Report for the Colombian National Planning Department," presented to the Colombian National Planning Department, Bogotá, Colombia, November 7, 1991.

"The United States Electric Utility Industry," presented at the Seminar on Restructuring the Electric Power Subsector in Colombia, Paipa, Colombia, sponsored by The World Bank, May 31-June 1, 1991.

"Affidavit of John H. Landon," prepared on behalf J. F. Shea Company, Coast Cable Partners, *et al.* before the United States District Court, Northern District of California, San Jose Division, Civil Action No. C-90-20073 WAI, October 3, 1990.

"Incentive Regulation in the Electric Utility Industry," a survey of state regulation programs throughout the United States, July 1990.

"An Estimate of the Economic Loss Sustained by Brian Nelson as a Result of His Job Loss," an Expert Report prepared on behalf of Pacific Gas and Electric Company before the Superior Court of the State of California, City and County of San Francisco, Case No. 864961, June 20, 1990.

"Affidavit of John H. Landon on Behalf of Florida Power & Light Company," prepared on behalf of Florida Power & Light Company before the United States District Court, Middle District of Florida, Tampa Division, Civil Action No. 88-1622-CIV-T-13C, March 30, 1990.

"Declaration of John H. Landon in Support of Defendant's Motion to Exclude Plaintiff's Expert Witness on Damages or, Alternatively, to Bifurcate Trial on Liability and Damages Issues," an affidavit prepared on behalf of Clyde Robin Seed Company, Inc. before the United States District Court, Northern District of California, Civil Action No. C 88-4540 SC, February 23, 1990.

"Expert Report of John H. Landon," prepared on behalf of Florida Power and Light Company, FPL Group, Inc. and FPL Energy Service, Inc. before the United States District Court, Southern District of Florida, Civil Action No. 88-2145, December 8, 1989.

"An Evaluation of the OCC's Performance Incentive Proposal and Suggestions for a New Performance Incentive Program," a report prepared on behalf of the Ohio Electric Utility Institute, September 23, 1988, with Stephen M. St. Marie.

"Comments Responding to BPU Staff's Assessment of Cogeneration and Small Power Production," prepared on behalf of Public Service Electric and Gas Company before the New Jersey Board of Public Utilities, Docket No. 8010-687B, August 31, 1987, with Joe D. Pace.

"Incentive Regulation in the Electric Utility Industry," a survey of state regulation programs throughout the United States, July 1987.

"Comments (Initial and Reply) of National Economic Research Associates, Inc.," prepared on behalf of Illinois Power Company before the Illinois Commerce Commission, No. 86-NOI-1, Excess Capacity, December 15, 1986 and January 20, 1987.
"Incentive Regulation in the Electric Utility Industry," a survey of state regulation programs throughout the United States, October 1985.

"Utility Performance Evaluation," prepared for the Rate Research Committee of the Edison Electric Institute, September 18, 1984, with David A. Huettner.

"Comments on the Proposed Standard for Utility Construction Decision Making," prepared on behalf of the Ohio Electric Utility Institute before the Public Utilities Commission of Ohio, Case No. 84-61-AU-ORD, April 28, 1984.

"Expert Report of John H. Landon," prepared on behalf of Pennsylvania Power Company before the United States District Court, Western District of Pennsylvania, Civil Action No. 77-1145, March 1, 1984.

"Additional Comments," prepared on behalf of the Investor-Owned Electric and Gas Utilities of Iowa before the Iowa State Commerce Commission, Docket No. RMU-83-17, October 1983.

"Recommendations of the Investor-Owned Electric and Gas Utilities of Iowa in Response to the Iowa State Commerce Commission Request for Comments in Docket No. RMU-83-17," prepared in conjunction with Iowa investor-owned utilities, October 1983.

"Report to the Iowa State Commerce Commission on Measuring Productivity of Electric Utilities," prepared on behalf of Investor-Owned Electric and Gas Utilities of Iowa before the Iowa State Commerce Commission, Docket No. RMU-83-17, October 1983.

"Analysis of the Operations Review Division Proposal," prepared on behalf of the Investor-Owned Electric and Gas Utilities of Iowa before the Iowa State Commerce Commission, Docket No. RMU-83-17, October 21, 1983.

"Comment on 'Incentive Regulation in the Electric Utility Industry'," prepared on behalf of a consortium of electric utilities and submitted to the Federal Energy Regulatory Commission, March 1983.

"Expert Report on Competition and Relevant Markets," prepared on behalf of Delmarva Power and Light Company before the United States District Court, District of Delaware, Civil Action Nos. 77-254 and 77-296, December 15, 1982.

"Measuring Productivity of Electric Utilities," a report prepared for Wisconsin Electric Power Company, May 1982.

"Analysis of Chapter 14 'Competition' of the National Power Grid Study," prepared by NERA for the Edison Electric Institute, December 20, 1979.

"Short Term Economic Forecasting Techniques for Selected Atlantic Fisheries," prepared for U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service, Office of Fisheries Development, Economic Analysis Group, April 1978, with Lee G. Anderson.

"Economic Impact of Alternative Crude Oil Transfer Techniques in the Lower Delaware Region: A Report on a Proposed Analytic Design," prepared for the Center for the Study of Marine Policy, College of Marine Studies, University of Delaware, September 30, 1974, with William R. Latham and Mark G. Brown.

PUBLICATIONS

"Retail Access Pilot Programs: Where's the Beef?," *The Electricity Journal*, Vol. 9, No. 10, December 1996, pp. 19-25, with Edward P. Kahn.

"Wine Wars: An Economic Analysis of Winery/Distributor Litigation," *Practical Winery & Vineyard*, January/February 1994, pp. 40-41, with Kara T. Boatman.

"Use and Abuse of Economic Experts in Winning a Business Jury Trial," American Bar Association, National Institute, November 1990, with Lewis J. Perl. (Reprinted in *How to Win a Business Jury Trial*, copyright 1990, 1991 and 1992, American Bar Association.)

"Opportunity Costs as a Legitimate Component of the Cost of Transmission Service," *Public Utilities Fortnightly*, December 7, 1989, with Joe D. Pace and Paul L. Joskow.

"Theories of Vertical Integration and Their Application to the Electric Utility Industry," *The Antitrust Bulletin*, Spring 1983.

"Measuring Electric Utility Efficiency," *Proceedings of the Fall Industrial Engineering Conference*, American Institute of Industrial Engineers, Cincinnati, Ohio, November 14-17, 1982.

"Introducing Competition into the Electric Utility Industry: An Economic Appraisal," *Energy Law Journal*, Vol. 3, No. 1, May 1982, pp. 1-65, with Joe D. Pace.

"Regional Econometric Models: Specification and Simulation of a Quarterly Alternative for Small Regions," *Journal of Regional Science*, Vol. 19, No. 1, 1979, pp. 1-13, with William R. Latham and Kenneth A. Lewis.

"Electric Utilities: Economies and Diseconomies of Scale," *Southern Economic Journal*, Vol. 44, No. 4, April 1978, pp. 883-912, with David A. Huettner.

"Restructuring the Electric Utility Industry: A Modest Proposal," *Electric Power Reform: The Alternatives for Michigan*, William H. Shaker, Wilbert Steffy, eds. (Ann Arbor, Mich.: Institute of Science and Technology, The University of Michigan, 1976), pp. 217-229, with David A. Huettner.

"Market Structure, Nonpecuniary Factors, and Professional Salaries: Registered Nurses," *Journal of Economics and Business*, Vol. 28, 1975-1976, pp. 151-155, with Charles R. Link.

"Richard Hellman, Government Competition in the Electric Utility Industry: A Theoretical and Empirical Study," The Antitrust Bulletin, Vol. XX, No. 3, Fall 1975, pp. 681-684. [Book Review.]

"Changing Technology and Optimal Industrial Structure," *Technological Change: Economics, Management and Environment*, Bela Gold, ed. (New York, N.Y.: Pergamon Press, 1975), Chapter 4, pp. 107-127.

"Monopsony and Teachers' Salaries: Some Contrary Evidence ¾ Comment," *Industrial and Labor Relations Review*, Vol. 28, No. 4, July 1975, pp. 574-577.

"Monopsony and Union Power in the Market for Nurses," *Southern Economic Journal*, Vol. 41, No. 4, April 1975, pp. 649-659, with Charles R. Link.

"Pricing in Combined Gas and Electric Utilities: A Second Look," *The Antitrust Bulletin*, Vol. XVIII, No. 1, Spring 1973, pp. 83-98.

"Political Fragmentation, Income Distribution, and the Demand for Government Services," *Nebraska Journal of Economics and Business*, Autumn 1972, pp. 171-184, with Robert N. Baird.

"Electric and Gas Combination and Economic Performance," *Journal of Economics and Business*, Fall 1972, Vol. 25, pp. 1-13.

"Discrimination, Monopsony, and Union Power in the Building Trades: A Cross-Sectional Analysis," *Monthly Labor Review*, April 1972, pp. 24-26, with William Pierce.

"The Effects of Collective Bargaining on Public School Teachers' Salaries ¾ Comment," *Industrial and Labor Relations Review*, Vol. 25, No. 3, April 1972, pp. 410-423, with Robert N. Baird.

"An Economic Analysis of Combination Utilities," *The Antitrust Bulletin*, Vol. XVII, No. 1, Spring 1972, pp. 237-268, with John W. Wilson.

"Teacher Salaries and School Decentralization," *Education and Urban Society*, February 1972, pp. 197-210, with Robert N. Baird.

"Monopsony in the Market for Public School Teachers," *The American Economic Review*, Vol. LXI, No. 5, December 1971, pp. 965-971, with Robert N. Baird.

"The Relation of Market Concentration to Advertising Rates: The Newspaper Industry," *The Antitrust Bulletin*, Vol. XVI, No. 1, Spring 1971, pp. 53-100.

"The Effect of Product Market Concentration on Wage Levels: An Intra-Industry Approach," *Industrial and Labor Relations Review*, Vol. 23, No. 2, January 1970, pp. 237-247.

Exhibit JHL-2

Palo Verde Day-Ahead Peak Spot Prices: November 2000 - November 2001

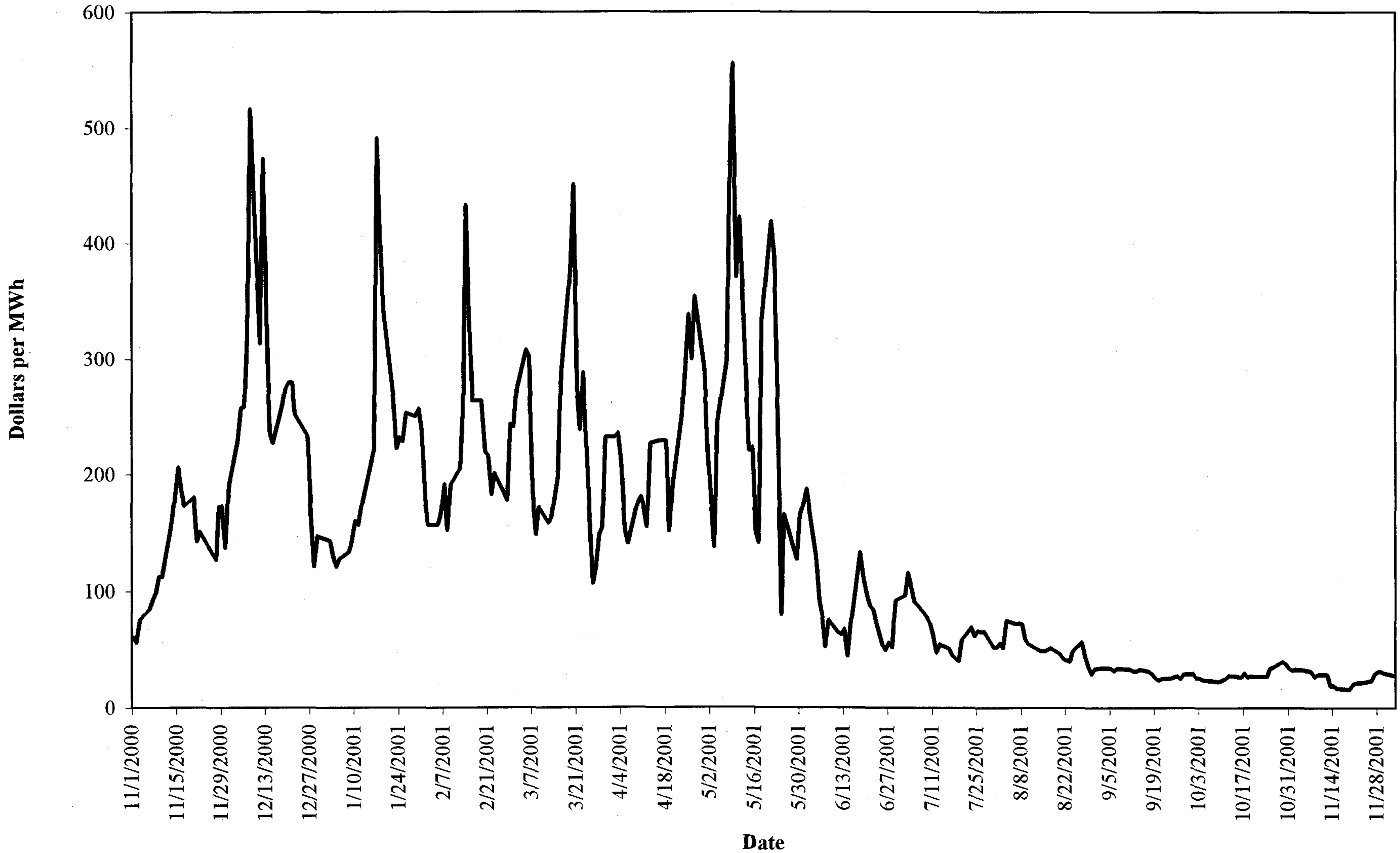
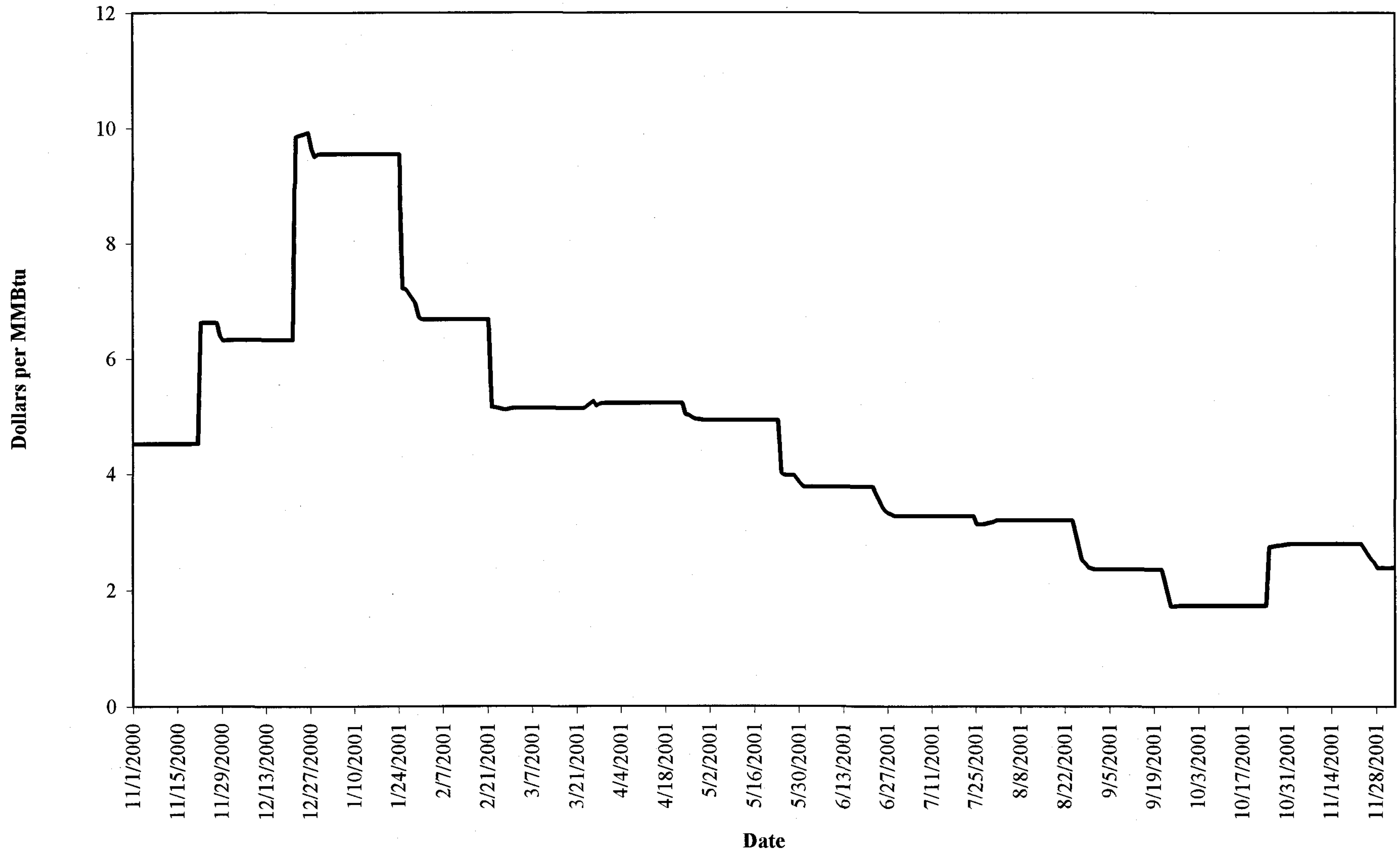


Exhibit JHL-3

El Paso Permian Basin Natural Gas Spot Prices: November 2000 - November 2001



DR. WILLIAM H. HIERONYMUS

BEFORE THE
ARIZONA CORPORATION COMMISSION

Docket No. E-01345A-01-0822

DIRECT TESTIMONY OF WILLIAM H. HIERONYMUS
ON BEHALF OF
ARIZONA PUBLIC SERVICE COMPANY

DECEMBER 12, 2001

TABLE OF CONTENTS

BEFORE THE
ARIZONA CORPORATION COMMISSION

Docket No. E-01345A-01-0822

DIRECT TESTIMONY OF WILLIAM H. HIERONYMUS

INTRODUCTION

Q. Please state your name and business address.

A. My name is William H. Hieronymus. I am a Vice President of Charles River Associates, Inc. My address is 200 Clarendon Street, T-33, Boston MA 02116.

Q. What is your educational and professional background?

A. I have a bachelors degree from the University of Iowa and masters and doctoral degrees in economics from the University of Michigan. Following service in the U.S. military, I began my consulting career in 1973, when I joined Charles River Associates Incorporated (CRA), initially as a specialist in antitrust. By 1975, primarily as a result of market changes stemming from the OPEC oil embargo, I began to focus on the economics of energy and especially electricity and gas utilities. I left CRA in late 1978 and joined Putnam, Hayes & Bartlett (PHB). I remained with PHB and successor firms until June 2001, when I rejoined CRA. Over the past 27 years, I have worked on most aspects of the economics of electric and gas utilities including load forecasting, rate design, system planning, regulatory policy and market design. Beginning in 1988, I have focused on issues arising from industry restructuring. I spent five years in London, working initially on the restructuring of the U.K. electricity sector and subsequently on restructuring continental and Pacific rim electricity systems and regulatory regimes. In 1993, I returned to the U.S. Subsequently I have worked on regulatory reforms, industry restructuring and market design, and mergers and acquisitions in connection with U.S. industry restructuring. In these connections, I have testified well in excess of 100 times before federal and state regulatory commissions, legislatures and courts.

Q. Are you familiar with power markets in the western U.S. and in Arizona?

A. Yes. I have consulted to Arizona Public Service Company (APS or Company) and other western utilities for nearly two decades on a variety of issues. In this context, I have testified on several occasions before the Arizona Corporation Commission (Commission), most recently in Docket No. E-01345A-98-0473. My more general familiarity with power markets in the West arises from work with clients including arbitration proceedings concerning asset valuation and changed regulatory circumstances, assistance in valuing assets available for sale, work on the market rules and market power issues in California, analysis and testimony concerning numerous mergers and acquisitions in the WSCC, and work on the PG&E bankruptcy reorganization.

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

A. APS has requested a partial variance to one of the Commission's Retail Electric Competition Rules, A.A.C. R14-2-1601, *et seq.*, proposing to reduce the competitive bid requirement in R14-2-1606(B) of those rules [Rule 1606(B)]. It has proposed instead that APS enter into a long-term, full requirements purchase power agreement (PPA) with Pinnacle West Capital Corporation (PWCC) with an escalating competitive bid component. Counsel for the Company has asked me to comment on two aspects of its proposal: 1) whether accepting the PPA being offered is in the best interests of consumers in APS's service area, and 2) the effect on competition of substituting the full requirements contract for Rule 1606(B).

SUMMARY OF CONCLUSIONS

Q. Do you believe that the proposed PPA is in the best interests of APS' customers?

A. Yes, for several reasons. First, it is far from certain that the competition to serve approximately 3,000 MW of APS load beginning in January 2003 would lead to reasonable prices. Other than Pinnacle West Energy Corporation (PWEC), APS's generating affiliate, there will be only one material source of peaking capacity, the Sundance station, that is scheduled for partial completion in 2002. Setting aside capacity already contracted to SRP, the only non-PWEC competing capacity in Arizona that is scheduled to be on line by the beginning of 2003 are the South Point units (roughly 325 MW of uncontracted capacity), Duke Energy's Arlington Valley 1 (580 MW of capacity) and Griffith (650MW of capacity, owned by the same firm that owns Sundance). Two of these plants are located in Mohave County, at some distance from APS's loads. Thus, there are only three competing firms, only one of which is designed to supply peaking energy. Moreover, the aggregate capacity available from these facilities, even assuming they could deliver to APS loads, is less than half of the PWEC load that would be put out for bid. Of course, PWEC or PWCC could bid, but would do so with the knowledge that it faced limited competition and that some of its capacity likely would be needed.

Although some might suggest simply delaying the competitive bidding requirement by a few years, this would not cure another main limitation of the competition—that the only merchant generation being constructed in Arizona is gas-fired. The extreme volatility of gas prices has been demonstrated graphically over the past two years. At least as importantly, gas is likely to increase in price substantially more rapidly that the fuels mix of the Dedicated Units in the proposed PPA.

The official U.S. government (Energy Information Administration) forecast is that gas prices will not return to the low levels of the late 1990s. Gas delivered to utilities in APS's region, which cost about $2.50/Mmbtu in 1999, is forecasted to fall from the very high 2000-2001 levels only to $3.20/Mmbtu (in 1999 constant dollars) and then rise to $3.63 by 2015, again in 1999 constant dollar prices. By comparison, coal, which comprises the largest share of the Dedicated Units under the PPA, starts from a lower base and is subject to declining rather than increasing constant dollar prices. The same forecast cited above shows constant dollar coal prices declining from $1.04/Mmbtu in 1999 to $0.74/Mmbtu in 2015.[1] Thus, over this 16-year period, the price advantage of coal rises from a ratio of less than 2.5:1 to 4.9:1. Even taking into account the superior heat rate of new combined cycle units in comparison to coal steam units, the fuel cost advantage of the coal units trends to about 3.5:1 (i.e., fuel cost per

[1] The regional coal price is below the price in Arizona since it is weighted heavily by delivered costs to minemouth plants in the Powder River Basin. However, the escalation forecast should be similar.

kWh will be three-and-one-half times greater for the combined cycle unit). Nuclear fuel has historically also declined in cost on a current dollar basis and starts from a much lower per-kWh value. The remaining component of the Dedicated Units will be gas, and will likely escalate at a comparable value as similar competing units. However, gas will account for only about 30 percent of the energy from the Dedicated Units.

Another check on the value of the contract to customers is to compare it to other long-term contracts that generators have been willing to sign. The only substantial body of such contracts for which terms are available are the California Department of Water Resources (DWR) contracts. I note that some critics have alleged that at least some of the DWR contracts are over-priced. However the concerns that DWR have stated relate primarily to the short term contracts signed for 2001-2003, not to the long-term, and later starting contracts for which there was much more vigorous competition.

DWR characterizes its contracts as costing $138/MWh in 2001, $106/MWh in 2002 $89/MWh in 2003, $75/MWh in 2004 and $64/MWh in 2005. Thereafter, costs are essentially flat at around $60/MWh. While not stated in the DWR report, I believe that these are constant dollar prices. This is about one-third higher (and at least 20 percent higher if the DWR costs are in nominal dollars) that the cost of power from the Dedicated Units.

The most thorough analysis of the DWR contracts of which I am aware was submitted to the FERC by Eugene Meehan of NERA on behalf of Pacific Gas & Electric on November 30, 2001 in Docket No. ER02-456-000. He concluded that the most representative group of DWR contracts for comparison to a long-term purchased power agreement (that was similar in most respects to the proposed PPA) has a levelized nominal price of $57/MWh for baseload capacity and $79/MWh for peaking capacity. I have calculated the cost of power from the Dedicated Units included in the proposed PPA on a similar basis and conclude that their cost (which, were it comparable in cost the DWR contracts would be between the baseload and peaking prices) is approximately $50.5/MWh. Again, this demonstrates that the proposed contract is cheaper than the most similar group of contracts to which it can be compared.

Q. Please summarize your conclusions concerning the effect on competition of the partial variance to the Commission's rules that APS is proposing.

A. My primary conclusion is that there will be no adverse effect on competition. Whether the APS load is met wholly from PWCC resources and purchases or by APS purchasing energy and capacity from other suppliers will not change the overall supply of and demand for electric energy. Any capacity that can compete to meet load in 2003 already is completed or sufficiently far advanced in construction that the requested change in the Commission's market rules will not affect supply. In my opinion, most of the capacity that has not begun construction will not be built, at least not on a timetable relevant to the bidding for load at or near a 2003 schedule. Regardless of the PPA, there simply is not a sufficient market, either in the Desert Southwest or in California, to warrant building material amounts of capacity beyond that which already is under construction.

From this, it follows that the market price for merchant energy and capacity will not be affected by the proposed PPA. There are second order possibilities relating to market structure and the possible exercise of market power. While I believe that the Arizona market is structurally competitive, based on analyses that I conducted in Docket No. E-01345A-09-0473 and on subsequent merchant capacity development which has further reduced market concentration, I do note that PWEC will be the largest generator in Arizona in 2003. Substituting merchant capacity being built by others for PWEC's capacity in a contract to meet APS load would increase market concentration for uncommitted capacity available to the wholesale market.

Q. When you state that there is no adverse effect on competition, does this mean that there is no effect on competitors?

A. Not necessarily. No one likes to lose the possibility of gaining a sale, at least not until all of their capacity is sold out. However, I believe that the bulk of the merchant capacity that is being built in Arizona was intended for the California market. Of course, the APS proposal does not wholly freeze competitors out from contracts. With a minimum of 270 MW per year available for contract in each year beginning in 2003, APS would absorb the equivalent of a major combined cycle unit on a biennial basis. Moreover, any retail direct access load also could be served by other wholesale energy suppliers.

THE BENEFITS OF THE PROPOSED CONTRACT TO APS' CUSTOMERS

Q. What features of the proposed contract do you regard as most significant?

A. There are several features that might be worthy of discussion. However, I will focus on the three that I regard as most significant. First, this is a requirements contract. It provides for sufficient reserves to meet APS's load reliably. It also meets the APS load shape, rather than being shaped, for example, to meet the output profile of a single unit. Second, it is based on a diverse set of resources and, in particular, is not wholly or even primarily based on gas. Third, and relatedly, it virtually assures that the cost of electricity from the Dedicated Units will decline in real terms over the life of the contract.

Q. Why is it important that this is a requirements contract?

A. I focus on this aspect of the contract because it affects how the proposed PPA can be compared to other contracts that might be used as a benchmark.. There are several reasons why a requirements contract differs from, and is superior to, other common forms of contract. First, it includes reserves and ancillary services. A typical energy contract does not, though a firm power contract may provide the equivalent of reserves. Pure reserve costs, which must be added to the cost of a unit-contingent purchase, are in the range of at least $5 per MWh for APS's load shape.[2]

A second reason why the requirements feature of the contract is important is that an equivalent contract must also be shaped to meet APS's load. APS has a relatively low load factor, approximately 51 percent, due to extreme temperatures and the lack of a substantial industrial process baseload. On-peak power is more valuable, and costly, than off-peak power.

---

2 The long run marginal cost of "pure peaking" capacity for reserve service is considerably higher, in the range of at least $50 per kW-year, or more than $10 per MWh based on APS's load shape.

A numeric example makes it clear why this is the case. Consider a new combined cycle plant with a fixed cost of $120 per kW-year and a fuel and variable O&M cost of $0.025 per kWh.[3] At a 90 percent load factor, power from the plant costs 4.04 cents per kWh (2.5+$120/8760*.9). At a load factor of 70 percent, the cost is 4.46 cents, at a load factor of 50 percent it is 5.24 cents and at a load factor of 30 percent it is 7.07 cents. A peaker with an annual cost of $60 per kW-year, a fuel cost of $0.035 per kWh and a load factor of 10 percent costs 10.3 cents per kWh and at a load factor of 5 percent costs 17.2 cents per kWh. Even this is not the limit of costs. A plant that runs only in APS's peak 1 percent of hours costs over 70 cents per kWh. Notably, these representative values do not include either reserve or ancillary services costs.

Meeting APS's load shape with the types of new merchant units that are available potentially to compete with the contract would require a mixture of such resources – combined cycle units running at between about 30 and 90 percent load factors and simple cycle peakers running at between about 1 percent and 30 percent load factors.

Q. How does the need to meet APS's load shape affect comparisons between the proposed PPA and other contracts that have been offered or signed in the region?

A. The only large body of comparable contracts is the contracts signed by the California DWR. Some of those contracts are "must-take", around the clock

[3] The costs of the combined cycle and peaking units in these examples are illustrative but are broadly representative of equipment market conditions in the past year. Fuels prices are consistent with a price of $3.50/ MMBtu. For simplicity, O&M and environmental costs are treated as fixed. Values are rounded to avoid a false sense of precision.

contracts. Others are dispatchable; still others are for peaking power only. The must-take contracts are the cheapest, with prices as low as about $55 per MWh.[4] However, these cannot validly be compared to the APS contract which meets a 51 percent load factor demand.

Q. You also stated that a key feature of the contract is its fuel diversity and lack of dependence on gas. Why is this important?

A. Gas prices have proven to be very volatile. This is particularly true of the past two years; however, longer periods have shown both substantial short term volatility and longer term cycles of high and low prices. One lesson of the past year is that prices in the West can be particularly volatile, in part because variability in rainfall and hydroelectric output translate directly into variability in the demand for gas.

Conversely, coal prices and nuclear fuel are not nearly so volatile. Both tend to be bought under long-term contracts that do not vary with temporary market conditions. The Dedicated Units are primarily (around 73 percent of energy) coal and nuclear and hence far less volatile than gas-fired generation costs. While it is possible (for a price) to hedge gas acquisition costs forward, even long-term gas contracts generally are for shorter periods than coal contracts.

Q. You also mentioned long-term escalation in the context of the fuels mix. Why is this relevant?

---

[4] Prices are higher than in my representative calculations in part because the prices I refer to in the DWR contracts are levelized nominal prices and, hence, reflect escalation in contract terms (in many cases, capacity and O&M costs are inflation indexed) and fuels prices. The representative prices that I cited are levelized real prices (i.e. not taking into account the effects of inflation),

A. As I stated in my summary, gas is expected to escalate over time as a result of reserve depletion and consequently higher production costs. While forecasts vary, there is no disagreement of which I am aware with the central expectation that costs will increase in the long run at rates greater than inflation. Conversely, coal, which will provide approximately half of the output from the Dedicated Units, has a long history of declining real prices. Energy forecasters expect that this will continue.

Exhibit WHH-2 shows the 2001 U.S. Energy Information Agency's forecast of long term fuels prices for fuel delivered to power plants in the mountain region, the EIA region that contains the Desert Southwest. Between 1999 (the last year before the gas price spike of 2000) and 2015, the price of coal is expected to decline by 29 percent in real terms while the price of gas is expected to increase by 45 percent in real terms. Equivalently, the cost per MMBtu for gas will increase from 2.4 to 4.9 times the cost of coal, a more than doubling of the relative price. Moreover, the EIA forecast is not based on speculation about time-distant events. The gas price that it forecasts for 2015 is actually lower in real terms than the price experienced in 2000.

Based on this forecast, the fuel component of the cost of power from the Dedicated Units could be expected to decline in real terms over the life of the contract relative to 1999 base prices, whereas the fuels cost of replacement power from gas-fired merchant units could be expected to increase at about 2.35 percent per year relative to inflation.

Q. Wouldn't it be possible to reproduce the fuels mix of the contract based on other resources?

A. No. PWCC has tried to purchase the shares of coal and nuclear plants in the Desert Southwest that are controlled by others. However, now that California has required that Southern California Edison retain its desert generation to serve its native load, there are no entitlements for coal and nuclear available for long term purchase. Even if a small amount were to come available, it could not even approach the amount necessary to supply the approximately 73 percent of APS's load (or even half of it) that is met by the coal and nuclear Dedicated Units under the contract.

With the increases in the price of gas that have been seen recently, there is a renewed interest in building new coal and nuclear plants. However, none are planned for the area near APS in a timeframe that would be available to compete in an auction to meet APS load in or even near a 2003 timeframe.

Q. Are there any other features of the contract that are important in evaluating its long term price performance?

A. Yes. The cost of the contract for the Dedicated Units can be thought of as having three components: recovery of fixed capital costs, O&M, and fuel. Operation and maintenance costs likely will go up with inflation. Based on the foregoing discussion, fuel cost should go up at less than inflation. With respect to the Dedicated Units, capital-related costs will increase to the extent that new capital additions have to be recovered and decrease as a result of depreciation. Based on my experience in the industry, I conclude that the nominal capital-related component of rates may decrease on a per-kW and per-kWh basis; it certainly will decline in real terms. Since capital cost recovery is the largest part of contract cost, and fuel is the second largest, this means that the cost of power from the Dedicated Units will decline in real terms over the life of the contract.

The treatment of capital-related costs in the contract also bears on the comparison to other contracts. Many contracts to which this contract might be compared have capacity-related cost provisions that cause demand charges to automatically increase at the rate of inflation.

Q. In discussing this proposed PPA you have referred repeatedly to the cost of power from the Dedicated Units. Are you aware that the contract provides also for purchasing capacity and energy from the market?

A. Yes, but that aspect of the contract is irrelevant for purposes of cost comparison. Future market purchases to cover load growth will be at market prices. This is true whether this contract is entered into or not. Hence, the cost of this additional power is essentially irrelevant to evaluating the contract. The differences between the contract and any alternative relate only to the prices paid for the Dedicated Units.

Q. Have you compared the contract to any comparable contracts?

A. Yes.

Q. What are the characteristics of comparable contracts?

A. The appraisal process and policies of FERC that I am familiar with, establish that the contracts used for benchmarking purposes should be executed in the same geographic area in the same timeframe. Both price and non-price terms should be considered and the benchmarking contracts should be for a comparable product and time period, or adjusted so that they are comparable.

Q. What contracts are comparable to the proposed PPA between PWCC and APS?

Q. The only body of contracts that were negotiated at approximately the same time as the proposed PPA, in the same power region and that cover a similar period of time are the contracts signed by DWR. DWR signed contracts with merchant generators and power marketers for about 12,000 MW of power between February and August 2001. Many of these are long term contracts of ten years or more. The contracts cover a variety of energy products: unit power, 7X24 must-take power, fully or partially dispatchable cycling power and peaking power.

Some of the contracts clearly are not comparable to the proposed PPA. The most expensive contracts are short term contracts for power in 2001 and 2002. Because of the very high prices in the short term power markets when the contracts were signed, the opportunity cost of both the sellers and DWR (whose alternative was to buy in spot markets) was very high.

A number of the later long-term contracts are much more comparable. Some do not start until 2003. They are backed by capacity that was not then yet built or even, in some cases, under construction. In bargaining with sellers of power from such plants, DWR had a much wider set of possible suppliers who competed to make sales to DWR.

However, none of the contracts are fully comparable to the proposed PPA. DWR was assembling a portfolio of contracts to allow it to meet the power needs of Southern California Edison and Pacific Gas and Electric that were not met by those utilities retained resources. In essence, DWR was preparing to offer partial requirements service from a portfolio of contracts. No single contract needed to be, and none was, sculpted to meet the California utilities' loads. Nonetheless, by looking at the range of contracts signed by DWR, it is possible to determine, at least broadly, whether the proposed PPA is more or less expensive.

Q. Is it not true that some of the DWR contracts are regarded as uneconomic and that there is pressure to renegotiate them?

A. Because power prices fell back to much more competitive levels much faster than had been anticipated, beginning in the summer of 2001, the <u>short-term</u> contracts that it signed are not economic. However, I have <u>excluded</u> these contracts as not comparable. It also is the case that, in view of the amount of conservation caused by a four cent per kWh price increase and the recession, and the amount of load that elected retail access just before access was suspended, DWR has too much must-take power. Discussions about renegotiation have focused on these short-term and must-run contracts.

There also are a few fixed-price contracts that locked in the high gas prices of the spring of 2001.[5] These contracts also are not comparable.

The long-term contracts signed later in the spring and in the summer that are indexed to gas prices rather than locking in gas prices are, however, comparable. While some have asserted that all of the contracts are impacted by market power on the part of sellers, DWR had a wide selection of potential sellers

[5] Between February and September, from the beginning to the end of the period over which DWR signed contracts, Henry Hub gas prices fell by about $1 per MMBtu.

to bargain with. One need look no further than the substantial amount of capacity under construction or planned for near term construction in Arizona that is not contracted to DWR or anyone else to see that DWR was facing a competitive market. Indeed, DWR was in the enviable position of being the "only game in town." Since PG&E and Edison were not creditworthy, DWR was the sole buyer of contracts to meet their load and by far the dominant buyer in the region.

Q. How does the proposed PPA compare to the DWR contracts?

A. The DWR reported in June 2001 that its contract costs were expected to by $138/MWh in the remainder of 2001, $106/MWh in 2002, $89/MWh in 2003, $75/MWh in 2004 and $64/MWh in 2005. From 2006 onward, it forecasted costs of $60/MWh. It is clear from reviewing its contracts, which escalate costs with inflation and/or specific costs such as fuels, that these forecasts are constant dollar prices, not escalated for inflation. In comparison, my analysis indicates that the cost under the contract is $49/MWh in 2004. For reasons that I have described, this cost will increase at less than inflation. Thus, a simple comparison shows that the APS contract is considerably cheaper.

Q. Have you reviewed the individual DWR contracts?

A. Yes. DWR has made the contracts available to the public. This is quite atypical; finding benchmark contracts has become generally very difficult since the price terms of contracts filed with FERC almost always are redacted. I reviewed these contracts in preparing my testimony in Docket No. ER02-456-000, the Section 203 filing at FERC relating to PG&E's reorganization into separate companies.

Q. Can you compare the DWR contracts to the proposed PPA?

A. Yes, but not readily. Contracts differ in terms of the power product that is offered (e.g. must-take baseload or dispatchable or peaking), their length of term, their escalation provisions, their firmness, and so forth. Even with simplifying assumptions, a precise calculation of cost is not possible. Additionally, as I discussed earlier, no single contract matches or was designed to match the load of a utility such as APS. Rather, DWR's intent was to assemble a portfolio of contracts that, together with the retained generation of PG&E and Edison, would meet the utility loads of the two non-credit worthy companies.

Still, one can get reasonably accurate measure of the cost of power from the different contracts for comparison with the proposed PPA. A high level of precision in the comparison is not really necessary since the DWR contracts tend to have both higher fuel and higher capacity-related costs, less attractive (to the customer) escalation provisions and no better, or materially worse dispatchability than the proposed PPA. I could demonstrate this on a contract-by-contract basis, but the essence of the comparison is that PWCC stands ready to provide power to meet the load shape of APS on terms similar to those that providers of 7X24 must- take power, a much less valuable product, require, and much cheaper than contracts offering more similar load shaping and dispatchability.

Q. Do you know of any systematic attempt to compare the costs of the DWR contracts with other contracts similar in concept to the proposed PPA?

A. Yes. A recent study sought to comprehensively calculate the costs of the DWR contracts on an "apples to apples" basis. Because the study was intended for filing at the FERC, it followed the rules laid down by FERC precedent, which require that the comparison be based on levelized nominal costs.

The study was submitted in the Federal Power Act Section 203 filing at the FERC, in which the approval of the transfer of generating and related transmission facilities to a related entity was sought. Eugene Meehan, a NERA consultant retained by PG&E, assessed the DWR contracts on the specific basis required by FERC precedent. I have reviewed his analysis in some considerable detail and believe that it was conducted accurately. Mr. Meehan culled through the 55 DWR contracts to find those that were least affected by the chaos in power markets in the spring of 2001 and most readily compared to a contract negotiated later in the year. He did not attempt to match individual contracts to the partial requirements contracting that he was evaluating. Rather, his intent was to find the best contracts to put into a portfolio for such evaluation.

Q. How do the DRW contracts compare to the proposed PPA?

A. I have calculated the cost of the proposed PPA in order to compare it to the DRW contracts selected by Mr. Meehan. I have used the same methodology and assumptions (e.g. regarding fuels costs[6]) that he used to calculated their costs. I find that the levelized nominal cost of power from the Dedicated Units is approximately $50.5 per MWh on a levelized nominal basis (Exhibit WWH-3).[7]

---

6 Fuel costs are taken from the same EIA forecast that I have used. Because the comparison group consisted primarily of California units, he used primarily Pacific delivery prices, whereas I have used prices delivered in the mountain region. Notably, I use mountain region prices solely to determine the rate of escalation appropriate to the fuels mix for the Dedicated Units. The starting price to which that escalation is applied is the $17.4 per MWh specified in the contract. Because coal delivered in Arizona is more expensive than coal in the mountain region more generally, this is a higher price than I would have calculated based on the 2003 prices in the EIA forecast.

7 The costs that I used were the 2003 and 2004 facilities charges specified in the contract, assumed to escalate at inflation less 1.5 percent; the starting fuel cost specified in the contract (1.74 cents per kWh in

Exhibit WWH-4 shows comparable data from Mr. Meehan's study. It is clear that the only contracts that are even remotely as attractive in price are the "must-take" baseload contracts. However, 24-hour must take power is a very inferior product, as it requires that the buyer resell power at a loss during off-peak hours. These are precisely the types of contracts that DWR is seeking to re-negotiate. In comparison to the entire span of contracts in Mr. Meehan's comparison group, i.e. a mixture of baseload, cycling and peaking contracts appropriate for comparison, it is clear that the proposed PPA is substantially cheaper than the equivalent that might be assembled from these contracts. [8]

Q. **Are there characteristics of the capacity dedicated to this contract that uniquely are suited to serving the APS load?**

A. Yes. Because the existing APS capacity was built to serve that load, it is sited to allow APS to meet load reliably. A second characteristic of the APS capacity that I have discussed above is that it provides fuel diversity and a mix of peaking, cycling and baseload capacity reasonably matched to the characteristics of the APS load. Essentially all of the potentially competing capacity being built in or near Arizona is combined cycle gas capacity that is best used as mid-merit capacity in the Desert Southwest or as more baseloaded capacity in the California market. Moreover, since this alternative capacity is entirely gas-fired, it is

---

2003); escalating at the real rates in the EIA gas and coal forecasts (with nuclear fuel increasing at the rate of inflation) and a quantity of 25,531 gWh per year. Consistent with Mr. Meehan's study, a discount rate of 9 percent was used for levelizing costs.

[8] The contract between PG&E and the proposed generating company that would own the hydroelectric and nuclear facilities to be dedicated under a twelve year contract was found by Mr. Meehan to be cheaper than the comparable contracts. He reports a levelized cost for the PG&E contract of $52 per MWh, slightly higher than the $50.5 per MWh that I calculate for the Dedicated Units.

uniformly exposed (and would expose customers) to gas market volatility and escalation.

Q. What do you conclude from your review of comparable contracts and your analyses more generally?

A. The contract being offered to APS by its affiliate, PWCC, is quite attractive. In my opinion, APS could not assemble a set of market contracts with unaffiliated entities that would be nearly as attractive.

EFFECT OF THE PROPOSED PARTIAL VARIANCE ON COMPETITION

Q. What will be the effects of granting the partial variance and approving the PPA on competition in wholesale markets?

A. The essence of the transaction is that it neither creates nor eliminates supply in the market. Nor does it create or eliminate demand. Hence, the supply and demand for capacity and energy is identical to what it would be in the absence of the transaction. It follows that the market price that competitors (both buyers and sellers) in the market will face as a result of the transaction is also unchanged.

The competitive effects of a transaction such as this generally are reviewed in terms of their effects on the structure of the market. More concentrated markets are less conducive to competitive pricing than less concentrated markets. For example, a single firm that has all of the capacity that can serve a market is, by definition, a monopolist. At least in the short run, a monopolist can charge well above a competitive price and earn higher profits by doing so.[9] A less-than-monopolistic market structure that is highly concentrated (an oligopoly) is also considered likely to result in higher-than-competitive prices.

Because the transaction neither increases nor decreases supply and demand in the overall power market, nor changes the control of generation from one party to another, it has no impact on the overall structure of the wholesale market. The number of suppliers of electricity, what they have available to supply, and their market shares are wholly unaffected.

Q. You have noted that the overall supply and demand balance is not affected by this proposed PPA. However, is it not the case that this transaction effectively removes a large share of PWEC's capacity from being offered to third parties in the wholesale market?

A. Yes. However, it also removes a similar amount of demand from the market, since APS's retail load that is covered by this contract is functionally the same in magnitude. If the amount that suppliers will offer at a price of, say, $50 per MWh is 10,000 MW and the amount that consumers will purchase is also 10,000 MW, supply and demand are in balance and the market price will be $50. If I now assume that 5,000 MW of demand are "removed" from the market as a result of a long term contract with one or more generators, and an equivalent amount of capacity, having now been contracted long term, is also removed from the market,

---

9 There are some circumstances where even a monopolist cannot earn higher profits by charging super-competitive prices. The minimal condition for this to be true is that the elasticity of demand (the percentage change in the quantity demanded by customers divided by the percentage change in prices) is less than one. The substantial literature on the demand for electricity indicates that the short run elasticity is well less than one.

the supply-demand balance is not changed. Hence, the competitive price also will be unchanged.

Q. If, hypothetically, APS load was "removed" from the wholesale market by reason of a long-term contract with someone other than PWCC, would the competitive market price also be unaffected?

A. Yes. For identical contractual terms (e.g., in terms of amounts under contract), the results will be identical. An alternative contract of the same magnitude would have different effects only if portions of the contract require uneconomic dispatch of energy. One can conceive of other contract terms (for example, must-take contracts for resources that sometimes were uneconomic), but in general, rational contracts will have identical results whether the counter-party is PWCC or some other generator(s).

Q. You said that there could be second order effects on the market. What could these effects, if any, be?

A. One such effect would be if a contract caused capacity to be constructed that otherwise would not be built. This would increase supply into the market. This might – or might not – be a good thing. The new capacity would be, by hypothesis, capacity that would not have been built as merchant capacity in response to anticipated market prices. Such a result, while perhaps good for consumers (at least in the short run), would result in uneconomic excess capacity.

Q. How might this occur?

A. There is a queue of projects in Arizona and nearby areas at various stages of development. In totality, this queue exceeds any rational forecast of the amount that will or should actually be built.[10] Generally, one would expect that the projects that have expended substantial resources in reaching their current state of completion would be the least likely to be cancelled. Suppose, for example, that I am building two huts on an island to store the coconut crop. I discover that only one is needed. I would consider which of the two requires the least effort to complete it; this would be completed and the other abandoned. Markets mimic this individual choice. If, in the prospect of an excess supply, it becomes clear that too much capacity is in the queue, some of it surely will be cancelled. Usually, there will be a certain amount of bluffing and posturing, but the end result is that the capacity with the lowest cost-to-complete will go forward at the expense of capacity that is not yet under construction or, in extreme cases, is under construction but less advanced. In economists jargon, decisions are made on the basis of potential revenues relative to "to go" costs – costs that can be avoided, in this case, by ceasing construction. Costs already expended, termed "sunk costs", simply are irrelevant. Thus, if I have a $250 million dollar project upon which I have spent $25 million on development, my sunk cost is $25 million and my "to go" cost is $225 million. Under most circumstances, this project will

[10] The California Energy Commission database of WSCC generating projects lists 8,062 MW of "Category 1" projects, in Arizona, 2,640 MW of "Category 2" and 8,520 MW of "Category 3". Category 1 projects are projects that are under construction or recently completed. Category 2 projects have essentially all regulatory approvals. Category 3 projects are in the regulatory approval queue. There also are categories 4 and 5, which are less definite. Overall in the WSCC there are more than 30,000 MW of Category 1 projects, 11,000 MW of Category 2 and 38,000 MW of Category 3.

not proceed in preference to an otherwise identical project upon which, say, $100 million has been spent, and the "to go" cost is $150 million.

Q. How does this example relate to the Dedicated Units?

A. The bulk of the dedicated capacity is fully complete and in service. The rest consists primarily of units that are well advanced in construction and due on line in approximately six months. These are not candidates for cancellation.

CONCLUSION

Q. What do you conclude concerning the proposed contract?

A. My primary conclusion is that the contract should be approved by the Commission as being in the best interests of APS's power supply customers. This is primarily for two reasons.

The first is that sufficient competitive alternatives simply are not available. And the alternatives that are available, or could become available in the near future, lack the desirable fuels diversity, price stability and price escalation provisions of the contract.

Second, I conclude that substituting the contract for bidding out half of APS's load will not adversely affect competition in wholesale markets. The APS resources, were they not dedicated to the contract, will not go away. They still would be in the market. The same is true of other resources that are sufficiently advanced that they could have participated in a competitive bid process. Hence, the supply-demand balance, and market prices for desert generation, will not be changed. Moreover, APS is a small part of the market for which merchant generators have built and are building capacity. Their options are not materially altered by the contract, particularly in view of the set-aside of future requirements for competitive procurement and the existence of retail access. Finally, the structural competitiveness of the Arizona/desert southwest market is, if anything, enhanced by the contract.

Q. Does this complete your testimony?

A. Yes.

WILLIAM H. HIERONYMUS — Vice President

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

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

ELECTRICITY SECTOR STRUCTURE, REGULATION, AND RELATED MANAGEMENT AND PLANNING ISSUES

U.S. Market Restructuring Assignments

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

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

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

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

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

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

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

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

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

Valuation of Utility Assets in North America

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

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

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

Other U.S. Utility Engagements

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

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

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

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

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

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

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

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

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

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

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

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

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

U.K. Assignments

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

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

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

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

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

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

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

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

- For the European Bank for Reconstruction and Development, he performed analyses of least-cost power options and evaluated the return on a major investment that the Bank was considering for a partially completed nuclear plant in Slovakia. Part of this assignment involved developing a forecast of electricity prices, both in Eastern Europe and for potential exports to the West.

- For the OECD he performed a study of energy subsidies worldwide and the impact of subsidy elimination on the environment, particularly on greenhouse gases.

- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, Dr. Hieronymus developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command-and-control system to a decentralized, corporatized system.

- For Iberdrola, the largest investor-owned Spanish electricity company, he assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution companies, its regulation, and the phasing out of subsidies. He also has assisted the company in evaluating generation expansion options and in valuing offers for imported power.

- Dr. Hieronymus contributed extensively to a project for the Ukrainian Electricity Ministry, the goal of which was to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. The proposed reorganization is based on regional electric power companies, linked by a unified central market, with market-based prices for electricity.

- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior managers for the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, Dr. Hieronymus continued to advise both the Russian energy and power ministry and the government-owned generation and transmission company on restructuring and market development issues.

- On behalf of a large continental electricity company, Dr. Hieronymus analyzed the proposed directives from the European Commission on gas and electricity transit (open access regimes) and on the internal market for electricity. The purpose of this assignment was to forecast likely developments in the structure and regulation of the electricity sector in the common market and to assist the client in understanding their implications.

- For the electric utility company of the Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.

- For a task force representing the Treasury, electricity generating, and electricity distribution industries in New Zealand, Dr. Hieronymus undertook an analysis of industry structure and regulatory alternatives for achieving the economically efficient generation of electricity. The analysis explored how the industry likely would operate under alternative regimes and their implications for asset valuation, electricity pricing, competition, and regulatory requirements.

TARIFF DESIGN METHODOLOGIES AND POLICY ISSUES

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

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

- For EPRI, Dr. Hieronymus directed a study that examined the effects of time-of-day rates on the level and pattern of residential electricity consumption.
- For the EPRI-NARUC Rate Design Study, he developed a methodology for designing optimum cost-tracking block rate structures.
- On behalf of a group of cogenerators, Dr. Hieronymus filed testimony before the Energy Select Committee of the UK Parliament on the effects of prices on cogeneration development.
- For the Edison Electric Institute (EEI), he prepared a statement of the industry's position on proposed federal guidelines regarding fuel adjustment clauses. He also assisted EEI in responding to the U.S. Department of Energy (DOE) guidelines on cost-of-service standards.
- For private utility clients, Dr. Hieronymus assisted in the preparation both of their comments on draft FERC regulations and of their compliance plans for PURPA Section 133.
- For the EEI Utility Regulatory Analysis Program, he co-authored an analysis of the DOE position on the purposes of the Public Utilities Regulatory Policies Act (PURPA) of 1978. The report focused on the relationship between those purposes and cost-of-service and ratemaking positions under consideration in the generic hearings required by PURPA.
- For a state utilities commission, Dr. Hieronymus assessed its utilities' existing automatic adjustment clauses to determine their compliance with PURPA and recommended modifications.
- For DOE, he developed an analysis of automatic adjustment clauses currently employed by electric utilities. The focus of this analysis was on efficiency incentive effects.
- For the commissioners of a public utility commission, Dr. Hieronymus assisted in preparation of briefing papers, lines of questioning, and proposed findings of fact in a generic rate design proceeding.

SALES FORECASTING METHODOLOGIES FOR GAS AND ELECTRIC UTILITIES

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

- For a large eastern utility, Dr. Hieronymus developed a load forecasting model designed to interface with the utility's revenue forecasting system-planning functions. The model forecasts detailed monthly sales and seasonal peaks for a 10-year period.
- For DOE, he directed development of an independent needs assessment model for use by state public utility commissions. This major study developed the capabilities required for independent forecasting by state commissions and provided a forecasting model for their interim use.
- For several state regulatory commissions, Dr. Hieronymus has consulted in the development of service area-level forecasting models of electric utility companies.
- For EPRI, he authored a study of electricity demand and load forecasting models. The study surveyed state-of-the-art models of electricity demand and subjected the most promising models to empirical testing to determine their potential for use in long-term forecasting.
- For a Midwestern electric utility, he provided consulting assistance in improving the client's load forecast, and testified in defense of the revised forecasting models.
- For an East Coast gas utility, Dr. Hieronymus testified with respect to sales forecasts and provided consulting assistance in improving the models used to forecast residential and commercial sales.

OTHER STUDIES PERTAINING TO REGULATED AND ENERGY COMPANIES

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These cases have included Sherman Act Section 1 and 2 allegations, contract negotiations, generic rate hearings, ITC hearings, and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. For a major electrical equipment vendor, Dr. Hieronymus testified on damages with respect to alleged defects and associated fraud and warranty claims. In connection with mergers for which he is the market power expert, Dr. Hieronymus is assisting clients in responding to the Hart-Scott-Rodino requests issued by the Antitrust Division of the U.S. Department of Justice. In an arbitration case, he testified as to changed circumstances affecting the equitable nature of a contract. In a municipalization case, he testified concerning the reasonable expectation period for the supplier of power and transmission services to a municipality.
- For a private client, Dr. Hieronymus headed a project that examined the feasibility and value of a major synthetic natural gas project. The study analyzed both the future supply costs of alternative natural gas sources and the effects of potential changes in FPC rate regulations on project viability. The analysis was used in preparing contract negotiation strategies.

- For an industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, Dr. Hieronymus developed an estimate of the potential market for the system by geographic area.
- For the U.S. Environmental Protection Agency (EPA), he was the principal investigator in a series of studies that forecasted future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

Dr. Hieronymus has addressed a number of conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervenor strategies in utility regulatory proceedings, utility deregulation, and utility-related opportunities for investment bankers. Prior to rejoining CRA in June 2001, Dr. Hieronymus was a Member of the Management Group at PA Consulting, which acquired Hagler Bailly, Inc. in October 2000. He was a Senior Vice President of Hagler Bailly. In 1998, Hagler Bailly acquired Dr. Hieronymus's former employer, Putnam, Hayes & Bartlett, Inc. He was a Managing Director at PHB. He joined PHB in 1978. From 1973 to 1978 he was a Senior Research Associate at CRA. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving as a Captain in the U.S. Army

WILLIAM H. HIERONYMUS — Vice President

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

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

ELECTRICITY SECTOR STRUCTURE, REGULATION, AND RELATED MANAGEMENT AND PLANNING ISSUES

U.S. Market Restructuring Assignments

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

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

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

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

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

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

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

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

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

Valuation of Utility Assets in North America

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

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

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

Other U.S. Utility Engagements

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

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

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

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

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

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

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

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

- For a major Midwestern utility, Dr. Hieronymus headed a team that assisted senior management in devising its strategic plans, including examination of such issues as plant refurbishment/life extension strategies, impacts of increased competition, and available diversification opportunities.
- On behalf of two West Coast utilities, Dr. Hieronymus testified in a needs certification hearing for a major coal-fired generation complex concerning the economics of the facility relative to competing sources of power, particularly unconventional sources and demand reductions.
- For a large western combination utility, he participated in a major 18-month effort to provide the client with an integrated planning and rate case management system. His specific responsibilities included assisting in the design and integration of electric and gas energy demand forecasts, peak load and load shape forecasts, and forecasts of the impacts of conservation and load management programs.
- For two Midwestern utilities, Dr. Hieronymus prepared an analysis of intervenor-proposed modifications to the utilities' resource plans. He then testified on their behalf before a legislative committee.
- For a major combination electric and gas utility, he directed the adaptation of a financial simulation model for use in resource planning and evaluation of conservation programs.

U.K. Assignments

- Following promulgation of the white paper that established the general framework for privatization of the electricity industry in the United Kingdom, Dr. Hieronymus participated extensively in the task forces charged with developing the new market system and regulatory regime. His work on behalf of the Electricity Council and the twelve regional councils focused on the proposed regulatory regime, including the price cap and regulatory formulas, and distribution and transmission use of system tariffs. He was an active participant in industry-government task forces charged with creating the legislation, regulatory framework, initial contracts, and rules of the pooling and settlements system. He also assisted the regional companies in the valuation of initial contract offers from the generators, including supporting their successful refusal to contract for the proposed nuclear power plants that subsequently were canceled as being non-commercial.
- During the preparation for privatization, Dr. Hieronymus assisted several individual U.K. electricity companies in understanding the evolving system, in developing use of system tariffs, and in enhancing technical capabilities in power purchasing and contracting. He continued to advise a number of clients, including regional companies, power developers, large industrial customers, and financial institutions on the U.K. power system for a number of years after privatization.

- Dr. Hieronymus assisted four of the regional electricity companies in negotiating equity ownership positions and developing the power purchase contracts for a 1,825 megawatt combined cycle gas station. He also assisted clients in evaluating other potential generating investments including cogeneration and non-conventional resources.
- Dr. Hieronymus also has consulted on the separate reorganization and privatization of the Scottish electricity sector. Part of his role in that privatization included advising the larger of the two Scottish companies and, through it, the Secretary of State on all phases of the restructuring and privatization, including the drafting of regulations, asset valuation, and company strategy.
- He assisted one of the Regional Electricity Companies in England and Wales in the 1993 through 1995 regulatory proceedings that reset the price caps for its retailing and distribution businesses. Included in this assignment was consideration of such policy issues as incentives for the economic purchasing of power, the scope of price control, and the use of comparisons among companies as a basis for price regulation. Dr. Hieronymus's model for determining network refurbishment needs was used by the regulator in determining revenue allowances for capital investments.
- He assisted this same utility in its defense against a hostile takeover, including preparation of its submission to the Cabinet Minister who had the responsibility for determining whether the merger should be referred to the competition authority.

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

- Dr. Hieronymus assisted a large state-owned European electricity company in evaluating the impacts of the 1997 EU directive on electricity that *inter alia* requires retail access and competitive markets for generation. The assignment included advice on the organizational solution to elements of the directive requiring a separate transmission system operator and the business need to create a competitive marketing function.
- For the European Bank for Reconstruction and Development, he performed analyses of least-cost power options and evaluated the return on a major investment that the Bank was considering for a partially completed nuclear plant in Slovakia. Part of this assignment involved developing a forecast of electricity prices, both in Eastern Europe and for potential exports to the West.
- For the OECD he performed a study of energy subsidies worldwide and the impact of subsidy elimination on the environment, particularly on greenhouse gases.
- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, Dr. Hieronymus developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command-and-control system to a decentralized, corporatized system.
- For Iberdrola, the largest investor-owned Spanish electricity company, he assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution companies, its regulation, and

the phasing out of subsidies. He also has assisted the company in evaluating generation expansion options and in valuing offers for imported power.

- Dr. Hieronymus contributed extensively to a project for the Ukrainian Electricity Ministry, the goal of which was to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. The proposed reorganization is based on regional electric power companies, linked by a unified central market, with market-based prices for electricity.

- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior managers for the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, Dr. Hieronymus continued to advise both the Russian energy and power ministry and the government-owned generation and transmission company on restructuring and market development issues.

- On behalf of a large continental electricity company, Dr. Hieronymus analyzed the proposed directives from the European Commission on gas and electricity transit (open access regimes) and on the internal market for electricity. The purpose of this assignment was to forecast likely developments in the structure and regulation of the electricity sector in the common market and to assist the client in understanding their implications.

- For the electric utility company of the Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.

- For a task force representing the Treasury, electricity generating, and electricity distribution industries in New Zealand, Dr. Hieronymus undertook an analysis of industry structure and regulatory alternatives for achieving the economically efficient generation of electricity. The analysis explored how the industry likely would operate under alternative regimes and their implications for asset valuation, electricity pricing, competition, and regulatory requirements.

TARIFF DESIGN METHODOLOGIES AND POLICY ISSUES

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

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

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

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

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

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

- For private utility clients, Dr. Hieronymus assisted in the preparation both of their comments on draft FERC regulations and of their compliance plans for PURPA Section 133.

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

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

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

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

SALES FORECASTING METHODOLOGIES FOR GAS AND ELECTRIC UTILITIES

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

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

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

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

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

- For a Midwestern electric utility, he provided consulting assistance in improving the client's load forecast, and testified in defense of the revised forecasting models.

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

OTHER STUDIES PERTAINING TO REGULATED AND ENERGY COMPANIES

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These cases have included Sherman Act Section 1 and 2 allegations, contract negotiations, generic rate hearings, ITC hearings, and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. For a major electrical equipment vendor, Dr. Hieronymus testified on damages with respect to alleged defects and associated fraud and warranty claims. In connection with mergers for which he is the market power expert, Dr. Hieronymus is assisting clients in responding to the Hart-Scott-Rodino requests issued by the Antitrust Division of the U.S. Department of Justice. In an arbitration case, he testified as to changed circumstances affecting the equitable nature of a contract. In a municipalization case, he testified concerning the reasonable expectation period for the supplier of power and transmission services to a municipality.

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

- For an industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, Dr. Hieronymus developed an estimate of the potential market for the system by geographic area.
- For the U.S. Environmental Protection Agency (EPA), he was the principal investigator in a series of studies that forecasted future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

Dr. Hieronymus has addressed a number of conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervenor strategies in utility regulatory proceedings, utility deregulation, and utility-related opportunities for investment bankers.
Prior to rejoining CRA in June 2001, Dr. Hieronymus was a Member of the Management Group at PA Consulting, which acquired Hagler Bailly, Inc. in October 2000. He was a Senior Vice President of Hagler Bailly. In 1998, Hagler Bailly acquired Dr. Hieronymus's former employer, Putnam, Hayes & Bartlett, Inc. He was a Managing Director at PHB. He joined PHB in 1978. From 1973 to 1978 he was a Senior Research Associate at CRA. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving as a Captain in the U.S. Army

2001 EIA Base Case Fuel Forecasts:
Delivered to Power Plants in Mountain States
($/MMBtu, $1999)

Year	Natural Gas	Steam Coal
1999	2.50	1.04
2000	3.85	1.02
2001	3.84	1.00
2002	3.39	0.99
2003	3.20	0.97
2004	3.24	0.95
2005	3.34	0.93
2006	3.43	0.92
2007	3.44	0.86
2008	3.44	0.83
2009	3.47	0.80
2010	3.50	0.78
2011	3.54	0.77
2012	3.58	0.76
2013	3.61	0.75
2014	3.62	0.75
2015	3.63	0.74

Exhibit WHH-3

LEVELIZED COST OF THE DEDICATED UNITS

Year	Fuel	Capital	Total	Nominal Cost/MWh	Real ost/MWH	Inflation	Total Fuel	Gas	Real Fuel Coal	Nuclear
2003	444239400	763200000	1207439400	47.3	47.3	1.016	1.088	3.2	0.97	0.6
2004	449623261	805440000	1255063261	49.2	48.0	1.018	1.084	3.24	0.95	0.6
2005	459346485	807856320	1267202805	49.6	47.2	1.020	1.088	3.34	0.93	0.6
2006	471666522	811895602	1283562123	50.3	46.7	1.022	1.095	3.43	0.92	0.6
2007	470085517	817578871	1287664387	50.4	45.7	1.024	1.068	3.44	0.86	0.6
2008	474944130	824937081	1299881211	50.9	45.0	1.026	1.054	3.44	0.83	0.6
2009	482555879	834011389	1316567268	51.6	44.5	1.028	1.043	3.47	0.8	0.6
2010	493456342	844853537	1338309879	52.4	44.1	1.031	1.038	3.5	0.78	0.6
2011	509044653	858371193	1367415846	53.6	44.0	1.031	1.038	3.54	0.77	0.6
2012	525125228	872105132	1397230360	54.7	43.8	1.031	1.039	3.58	0.76	0.6
2013	541017500	886058814	1427076315	55.9	43.7	1.031	1.038	3.61	0.75	0.6
2014	558506728	900235755	1458742484	57.1	43.5	1.031	1.040	3.62	0.75	0.6
2015	573929618	914639527	1488569145	58.3	43.4	1.031	1.036	3.63	0.74	0.6
		NPV		$324.14	$315.18					
		Lev. Nom.		$50.51	$49.11					

Comparison of PWCC Contract Dedicated Units to DWR Contracts
(Levelized Nominal Cost per MWh)

SELLER	PRODUCT	COST
PWCC	Portfolio output	$50.51
PacifiCorp	Unit firm baseload power	$54.23
Sempra Baseload	Unit firm baseload power	$55.49
Sempra Peak	Unit firm peak power	$69.49
Clearwood Electric	Unit firm baseload power	$69.90
Coral Peak	Unit firm peak power	$76.71
Coral Baseload	Unit firm baseload power	$76.71
Wellhead (Gates)	4,000 hour dispatchable peak power	$79.06
Fresno	4,000 hour dispatchable peak power	$91.43
CalPeak (Midway)	2,500 hour dispatchable power (1,200 in summer peak	$94.52
GWF	4,000 hour dispatchable peak power	$95.87
Alliance Colton	Dispatchable peak and unrestricted power	$119.96

Sources: Exhibits GEN-2-7 and GEN-2-9, Direct Testimony and Exhibits of Eugene T. Meehan, FERC Docket No. ER02-345-000 and Exhibit WHH-3

ARIZONA PUBLIC SERVICE COMPANY

RE: DOCKET NO. E-01345A-01-0822

DIRECT TESTIMONY OF:

JACK E. DAVIS

JOHN H. LANDON, Ph.D.

DR. WILLIAM H. HIERONYMUS

DECEMBER 12, 2001