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Transcript Exhibit(s)

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Commonwealth7,

BEFORE THE

ARIZONA CORPORATION COMMISSION

TESTIMONY OF JOHN H. LANDON

On Behalf of

Arizona Public Service Company

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

June 4, 1999

EXHIBIT
Admitted
APS-3

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I. QUALIFICATIONS

Q. Please state your name and business address.

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

Q. What is your current position?

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

Q. Please outline your educational background.

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

Q. Where were you employed after leaving Cornell University?

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

Q. Which subjects did you teach during this period?

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

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

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

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

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

Q. When did you join Analysis Group/Economics?

A. I joined in March of 1997.

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

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

Q. Have you previously testified?

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

Q. Have you testified before the Arizona Corporation before?

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

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

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

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

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

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

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

III. EXECUTIVE SUMMARY AND ORGANIZATION OF TESTIMONY

Q. Please summarize your testimony.

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

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

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

Q. How is your testimony organized?

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

IV. OVERVIEW OF THE AGREEMENT

Q. Please summarize the major provisions of the Agreement.

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

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

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

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

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

V. ESTABLISHMENT OF RETAIL COMPETITION

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

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

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

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

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

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

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

VI. RATE REDUCTIONS

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

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

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

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

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

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

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

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

VII. MARKET POWER ISSUES

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

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

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

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

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

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

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

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

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

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

VIII. REGULATORY ASSETS AND STRANDED COSTS

A. Specifics of the Agreement

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

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

Q. How much will APS collect through the CTC?

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

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

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

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

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

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

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

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

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

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

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

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

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

B. APS Estimates

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

A. Yes, I have.

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

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

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

A. Yes.

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

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

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

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

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

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

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

Table 1: Historic capacity factors for APS plants

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

Table 2: Capacity factors used in stranded cost calculations

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

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

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

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

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

C. Mitigation of Stranded Costs

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

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

Q. Does APS's proposal include mitigation efforts?

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

IX. ADDITIONAL ITEMS

Q. Who has endorsed the Settlement Agreement?

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

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

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

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

X. CONCLUSIONS

Q. Please summarize your conclusions.

A. My conclusions are as follows:

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

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

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit 1

Curriculum Vitae of JOHN H. LANDON

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

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

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

PROFESSIONAL ACTIVITIES

Member of the Governor of Delaware's Economic Advisory Committee

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

A Director of the Delaware Econometric Model Group

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

Member of the American Economic Association

Associate Member of the American Bar Association

TESTIMONY PROVIDED FOR THE FOLLOWING CLIENTS:

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

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

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

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

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

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

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

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

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

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

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

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.

McGraw-Hill, 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
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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
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BEFORE THE

ARIZONA CORPORATION COMMISSION

TESTIMONY OF JOHN H. LANDON

On Behalf of

Arizona Public Service Company

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

June 4, 1999

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I. QUALIFICATIONS

Q. Please state your name and business address.

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

Q. What is your current position?

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

Q. Please outline your educational background.

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

Q. Where were you employed after leaving Cornell University?

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

Q. Which subjects did you teach during this period?

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

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

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

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

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

Q. When did you join Analysis Group/Economics?

A. I joined in March of 1997.

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

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

Q. Have you previously testified?

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

Q. Have you testified before the Arizona Corporation before?

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

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

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

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

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

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

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

III. EXECUTIVE SUMMARY AND ORGANIZATION OF TESTIMONY

Q. Please summarize your testimony.

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

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

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

Q. How is your testimony organized?

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

IV. OVERVIEW OF THE AGREEMENT

Q. Please summarize the major provisions of the Agreement.

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

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

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

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

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

V. ESTABLISHMENT OF RETAIL COMPETITION

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

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

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

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

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

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

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

VI. RATE REDUCTIONS

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

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

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

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

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

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

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

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

VII. MARKET POWER ISSUES

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

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

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

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

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

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

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

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

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

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

VIII. REGULATORY ASSETS AND STRANDED COSTS

A. Specifics of the Agreement

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

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

Q. How much will APS collect through the CTC?

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

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

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

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

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

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

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

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

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

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

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

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

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

B. APS Estimates

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

A. Yes, I have.

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

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

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

A. Yes.

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

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

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

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

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

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

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

Table 1: Historic capacity factors for APS plants

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

Table 2: Capacity factors used in stranded cost calculations

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

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

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

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

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

C. Mitigation of Stranded Costs

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

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

Q. Does APS's proposal include mitigation efforts?

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

IX. ADDITIONAL ITEMS

Q. Who has endorsed the Settlement Agreement?

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

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

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

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

X. CONCLUSIONS

Q. Please summarize your conclusions.

A. My conclusions are as follows:

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

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

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit 1

Curriculum Vitae of
JOHN H. LANDON

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

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

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

PROFESSIONAL ACTIVITIES

Member of the Governor of Delaware's Economic Advisory Committee

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

A Director of the Delaware Econometric Model Group

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

Member of the American Economic Association

Associate Member of the American Bar Association

TESTIMONY PROVIDED FOR THE FOLLOWING CLIENTS:

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Delmarva Power & Light Company
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The McGraw-Hill Companies, Inc.
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Arizona Public Service Corporation
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"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.

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"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.

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"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.

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"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.

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"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.

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"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.

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"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 1

Curriculum Vitae of
JOHN H. LANDON

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

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

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

PROFESSIONAL ACTIVITIES

Member of the Governor of Delaware's Economic Advisory Committee

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

A Director of the Delaware Econometric Model Group

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

Member of the American Economic Association

Associate Member of the American Bar Association

TESTIMONY PROVIDED FOR THE FOLLOWING CLIENTS:

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

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

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

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

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

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

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

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

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

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

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

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.

McGraw-Hill, 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.

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.

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

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

Southern California Edison Company
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Baltimore Gas and Electric Company
Maryland Public Service Commission, Case No. 7871, August 1, 1985 and December 16, 1985.

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Central Vermont Public Service Corporation
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Wisconsin Power and Light Company
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"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.

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"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.

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"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.

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"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.

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"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.

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"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.

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BEFORE THE

ARIZONA CORPORATION COMMISSION

DOCKET NO. U-0000-94-165

TESTIMONY OF DOUGLAS A. OGLESBY
Vice President and General Counsel

On Behalf of

PG&E ENERGY SERVICES CORPORATION

January 21, 1998

EXHIBIT
PG&E 1
Admitted

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TESTIMONY OF DOUGLAS A. OGLESBY

(Docket No. U-0000-94-165)

I. INTRODUCTION

Q. Please state your name, address, professional background and experience, and whom you are representing?

A. My name is Douglas A. Oglesby, 345 California Street, Suite 3200, San Francisco, California. I am Vice President and General Counsel for PG&E Energy Services Corporation ("Energy Services") and am representing it in the proceeding. My background and experience are set forth in Attachment DAO-1.

Q. Do you have previous experience relative to restructuring of the electric utility industry and to proposals relating to the recovery of "stranded costs"?

A. Yes. I have been actively involved for many years in a wide range of electric industry restructuring activities at both the Federal and state levels, including extensive participation in the California restructuring proceedings. Much of this activity has involved stranded cost issues. This activity includes my advocacy of stranded costs policies before legislative committees of two states and before the Federal Energy Regulatory Commission, on behalf of the Edison Electric Institute, the trade association for investor-owned utilities. I am quite familiar with stranded cost recovery policies, and in particular am very familiar with California's stranded cost provisions and processes to date. I also am familiar with the stranded costs implications of several recent sales of generation assets by utilities, in particular the recent sale by the New England Electric System ("NEES") of its non-nuclear generation assets to Energy Services' affiliate US Generating Company ("US Gen"), and the sale by Energy Services' utility affiliate Pacific Gas and Electric Company ("PG&E") of several large fossil generation plants. I am also either personally active in or direct the efforts of Energy Services staff on electric restructuring analysis and advocacy in many states having high commercial priority for Energy Services, including Arizona, Oregon, New Mexico, Utah, Nevada, Washington, Illinois, Texas, and Pennsylvania.

Q. Please summarize your testimony.

A. This testimony advances a proposal for stranded costs determination and recovery for the Arizona utilities which is both fair to Arizona electric customers and to the utilities and their shareholders, and which will encourage the development of competitive electric markets. This proposal is predicated on the divestiture of the generation assets of the Arizona utilities. Recent utility generation asset sales have resulted in sale prices well in excess of the depreciated book value of the assets. These sales have therefore not only established a market valuation for the assets' value, but have also permitted the utilities to credit to their ratepayers the premium over book, enabling them to "buy down" their stranded costs. In all cases of which I am aware, the sale proceeds exceeded the utilities' expected revenues.

A stranded costs valuation and recovery program must (1) afford the utilities a reasonable opportunity to recover all legitimate, verifiable and non-mitigatable stranded costs in a (2) competitively neutral manner over (3) a relatively short transition period. These three criteria are essential in order to encourage a competitive market in electricity to develop and to enable Arizona consumers to achieve substantial reductions in the delivered cost of electricity as soon as reasonably practicable. Our proposal satisfies these three criteria. It is premised on the Arizona utilities' voluntary divestiture of their generation assets, both nuclear and non-nuclear. Sales of non-nuclear generation are very likely to result in sale prices well in excess of the assets' depreciated book value. Therefore, if a utility elects to keep its generation on a regulated basis rather than to sell it, that asset's market value would be deemed to be its depreciated book value, resulting in no stranded cost attributable to the retained generation. Sale proceeds in excess of book would be credited against other potential stranded costs, such as regulatory assets and nuclear decommissioning costs.

Nuclear assets would be treated somewhat differently because of the greater uncertainty that their offer for sale would generate above-book bids. If no viable bid is made, or if the highest bid is nonetheless below book, the difference between market and book value would be the nuclear component of stranded costs.

All stranded costs would be recovered through a non-bypassable Competition Transition Charge (CTC) over a period of four years. At the end of this four-year period, the CTC would be eliminated, and all cost recovery by the utilities would be on a market basis.

Each utility would develop for Commission review and approval a standard offer tariff for the provision of delivery and supply services to their customers who are not eligible for or do not choose an alternative supplier during the phase-in period before all customers are eligible for direct access. This tariff would include charges for regulated transmission, distribution, public benefits charges, the CTC, and energy. The price for the energy component of this standard offer tariff would be the market cost of the utility's power purchased to meet this supply obligation. The difference between this purchased power cost and the Commission-approved nuclear revenue requirement on a kilowatt-hour basis would be the nuclear component of the CTC. In effect, then, this difference is the difference between market value and book value of the nuclear investment.

II. GENERAL CONSIDERATIONS AND A PROPOSED SOLUTION

Q. Who is Energy Services and what are the nature of its business activities?

A. Energy Services is an unregulated subsidiary of the diversified energy holding company, PG&E Corporation, headquartered in San Francisco. Energy Services sells gas and electric commodities and a wide range of other energy-related products and services nationwide, including Arizona, where it has had an active sales office for about two years. Energy Services' activities are **not** regulated by the California Public Utilities Commission ("CPUC") or any other state commission, and it is structurally, organizationally, functionally, operationally, and financially fully separate from its utility affiliate Pacific Gas & Electric Company ("PG&E").

Q. Has Energy Services previously participated in proceedings before the Commission involving restructuring of the electric utility industry in Arizona?

A. Yes. Energy Services has actively participated in this Commission's retail competition proceedings since it issued its proposed rules in mid-1996, and has attended and submitted comments in several of the Commission-established working groups, including the three subcommittees on stranded costs.

Q. Has Energy Services also been active as a party in the litigation in Maricopa County Superior Court involving the Commission's Decision No. 59943 and the Electric Competition Rules?

A. Yes. In that case we have actively supported this Commission's authority to issue its retail competition rules and to restructure the Arizona electric industry.

Q. Why is PG&E Energy Services interested in the outcome of stranded cost issues in Arizona?

A. Arizona is an important market for Energy Services. Energy Services has very ambitious business objectives and Arizona's attractive customer markets, and its close geographic proximity to California make Arizona a very attractive location for us to do business.

However, the methods adopted by this Commission for stranded cost calculation and recovery and related incentives will dramatically impact the ability of my company to compete successfully in Arizona. Throughout 1997, we have repeatedly advocated in Arizona regulatory and legislative forums four basic themes regarding stranded cost recovery: First, as a condition to being permitted the opportunity to recover stranded costs, an Affected Utility must enable those customers eligible for direct access the opportunity to purchase competitive electric supply at prices lower than those of the Affected Utilities. Second, stranded cost recovery must be a competitively beneficial or , at a minimum, a **neutral** factor in an eligible customer's decision to select an alternative competitive supplier or remain on "standard offer" tariffs. Third, Affected Utilities must not have the opportunity to recover more than 100% of stranded costs, but neither should they be arbitrarily limited to recovery of some lesser percentage of legitimate, verifiable and non-mitigable stranded costs. The utilities should be provided a reasonable opportunity to recover their stranded costs over a limited transition period of 3-5 years by way of a non-bypassable competition transition charge ("CTC"). CTC exemptions should be limited to those the Commission has already adopted for self-generation and demand-side management and those that qualify for an exemption under the Commission's rule permitting exceptions based on the public interest.

We offer here a proposal which satisfies each of these criteria.

Q. Please describe your proposal and discuss the reasons why Energy Services believes it is responsive to the indicated criteria.

A. An essential premise of our proposal is this Commission's continued steadfast commitment to permitting Arizonans to choose their electricity supplier. To summarize, under our proposal a utility would be permitted an opportunity to recover its generation-related stranded costs during the transition period only if it divests its generation assets (including a good faith effort to sell its nuclear generation). More specifically, our proposal calls for:

1. All non-nuclear generation would be sold (to private entities only, or, if publicly owned, through use of non-tax exempt debt) through a Commission supervised auction. If a utility chooses not to sell all its generation by a specified date, the generation's market value would be presumed to be its depreciated book value and, therefore, not to have any stranded costs. If for any reason beyond the utility's reasonable control, a sale cannot take place, then the generation would be valued on the basis of the highest bid (if at least three bids) or through an independent appraisal.
2. Proceeds from generation asset sales in **excess** of embedded balance sheet cost will be applied to recovery of approved nuclear and non-generation-related stranded costs, such as prudently incurred nuclear decommissioning, regulatory assets, and one-time generation employee severance costs (union and clerical only). Any remaining nuclear and non-generation-related stranded costs would be subject to the prospect of recovery during the transition period through the nonbypassable CTC. While the Commission has authority to approve accelerated recovery of decommissioning and regulatory assets, such acceleration is not necessary under this proposal, especially if reductions in standard offer prices are sought. Recovery of these remaining costs occurs largely through cost of service assignment to distribution even

with recovery over normal amortization schedules. No other costs of service would be eligible for stranded cost recovery. In the unlikely event that the sale proceeds fail to recover the depreciated book value of the assets, the utility would be permitted to recover the shortfall through the non-bypassable CTC.

3. As previously mentioned, nuclear generation must also be offered for sale. However, in the event that such an offer does not result in any viable bids, recovery of the above-market investment will be permitted in the CTC. During the transition period, the nuclear component of CTC's would be calculated as the difference between the standard offer price of electricity and the net book value calculated on a per kilowatt/hour basis. If the nuclear asset is sold, but at a price that does not fully recover depreciated book, the unrecovered amount of the investment would be accorded stranded cost recovery calculated as described above. Revenues from the sale in excess of depreciated book would be treated the same as excess revenues from the sale of non-nuclear generation. Duke Energy has just announced its interest in the nuclear units of Ontario Hydro, so I would expect that an offer of the Arizona utilities' interests in nuclear units would result in viable bids.

It is certainly possible that the nuclear utilities may not be able to recover 100% of their stranded costs during the transition period, due to the magnitude of their nuclear investment. It is also quite possible they will be able to do so.

In any event, the utilities will be permitted to recover as much of their approved stranded costs as they can during the transition period. The California investor owned utilities were faced with much the same prospect, and they responded by restructuring their nuclear assets through such techniques as accelerated depreciation and, in the case of Diablo Canyon, PG&E's nuclear plant, foregoing authorized price increases in that plant's performance-based settlement agreement. The result was that PG&E is voluntarily foregoing billions of dollars on a net present value basis of its nuclear generation profits. Arizona utilities should be expected to do likewise in order to provide a fair opportunity for Arizonans to enjoy the benefits of competition and to be permitted to recover the great bulk, if not 100%, of their non-nuclear stranded costs without the operating risk to which they would otherwise be exposed under a traditional regulatory regime which requires that the assets must be used and useful to warrant recovery of their costs in base rates.

4. As a method of increasing bids for power plants, the Commission could establish non-bypassable property tax adjustment clauses for actual property taxes due on the (presently) Arizona utilities' owned portions of Palo Verde, Coronado, Springerville and Cholla power plants. The property tax clauses would collect actual property taxes due (subject to capping at present dollar amounts) from each utility's existing retail customers in regulated distribution charges for the remaining life of each identified plant based on applicable state tax law regardless of who is the owner. Future capital additions would be excluded from recovery in these clauses. Thus, the new plant owners would not be burdened by Arizona's property taxes and bids would accordingly be much higher. As a result, proceeds to Arizona's utilities from asset sales would be greater and their remaining stranded costs much lower. Such clauses will not only improve the competitiveness of each of these plants but also address alleged rural Arizona property tax losses resulting from electricity competition.

5. The financial responsibility for nuclear decommissioning would remain with the existing customers of nuclear utilities. This should result in higher bids for nuclear assets.

Q. In item 3 above, did you indirectly say that under a net revenues lost method PG&E did not receive 100% stranded cost recovery?

A. Yes. PG&E has an opportunity to recovery nearly 100% of its stranded costs based on market methods, but this is much less than 100% based on a net lost revenue method. This is a direct result of the reductions PG&E made in the prices authorized in its Diablo Canyon performance-based agreement, the CPUC's reducing the allowed return on generation equity to 90% of the embedded cost of debt to reflect reduced risk associated with stranded cost recovery, and the relatively short 4-year recovery period, which puts the utility at substantial market risk that stranded costs might not be fully recovered prior to expiration of the transition period.

Q. How would your recommendation impact the state's major regulated utilities?

A. TEP has no nuclear, and therefore no nuclear decommissioning costs, and I am informed relatively low regulatory assets. Hence, it would retain its surpluses from asset sales and, thus, stands to do relatively well under this proposal. APS would be allowed to continue to collect its substantial regulatory assets, although not necessarily on an accelerated basis, and its nuclear decommissioning costs and could receive tax clauses on both Palo Verde and Cholla power plants with the resulting economic benefits previously mentioned.

As a result of property tax clauses on recent vintage power plants and the relief from nuclear decommissioning financial responsibilities, Arizona's utilities that believe they have stranded costs will have strong incentives to sell under a timely deadline.

In summary, with the exception of nuclear, if a utility is not willing to voluntarily sell its generation assets within established deadlines, then it would receive no additional stranded cost recovery and no property tax clause. This program could begin immediately and be largely completed in 1998, although nuclear sales may take somewhat longer. The major impact of asset sales on unbundled tariffs could be determined in late 1998, just prior to the start of competition. Hence, the basic design of unbundled tariffs can continue on a separate parallel course.

Q. Why does Energy Services strongly prefer an asset sale over other market based methods?

A. It is by far the fairest method to recover stranded costs from Arizona retail customers and yet allow for stranded cost recovery. Retail customers pay stranded costs (decommissioning, regulatory assets, and severance) only after the utility applies the proceeds from the highest bid to its stranded costs. Other methods, which rely on forecasts or assumptions of market price are based on averages. I don't know of anyone that would sell a home, car or business based on an average of offers they receive. Rather, people sell to the highest bidder. This creates the most value. Everyone's expectation of future price is always different. Why would the Commission want to use an average expectation and risk making retail customers pay more than what's actually stranded?

Q. In the case of the NEES sale, some losing bidders are saying that US Gen paid too much. Are NEES' retail customers saying that?

A. No. NEES's customers should be delighted with the sale, since the price US Gen paid was about 140% of the depreciated book value of the assets sold. NEES's retail customers will pay less in stranded cost as a result. The market price for electricity is independent of NEES's sale price.

Q. What do you mean by "creating" market value?

A. In New England, for instance, the winning bid exceeded expectations. This occurred, in part, because the US Gen's winning bid included an incentive payment of $225 million to NEES if they open their markets to retail competition no later than January 1, 1999. Payments decline substantially for dates thereafter. It is only through asset sales that value can be created.

It is apparent to outside observers that Palo Verde nuclear station is Arizona's primary stranded cost problem. Regulatory assets and decommissioning are largely nuclear related. Property taxes are also significant for nuclear plants. Energy Services' proposal specifically allows recovery for identifiable components of nuclear costs and creates an opportunity for Arizona's utilities to sell their nuclear generation assets at prices above net book values.

Q. Do existing stranded cost recovery programs in Arizona cause you concern?

A. Yes. APS, for example, in its Rate Reduction Agreement, is currently recovering $110 million annually in stranded costs relating to regulatory assets prior to the onset of retail competition. Yet this Rate Reduction program neither requires APS to undertake any real steps to prepare for competition nor even to provide genuine assurances of that eventuality. Rather, APS now has strong incentives to delay the onset of competition in Arizona and, in our opinion, that is exactly what it and the state's other major utilities are doing.

Q. Do you think that the Arizona utilities will cooperate to foster retail competition if the Commission first allows them to recover their stranded costs?

A. No. The existence of stranded costs is a double edged sword. On the one hand, recovery is a major issue to solve. On the other hand, recovery can provide incentives to cooperate. Several utilities across the nation with little or no stranded costs are stalling competition in their own territories. Take Utah for example. PacifiCorp's unit Utah Power and Light is stalling competition in that state despite having generation costs of only 2.5 cents per kilowatt hour. Utah is thus struggling with finding the means to motivate PacifiCorp to cooperate. PacifiCorp has also sought to avoid application of the California restructuring orders to its California customers. PacifiCorp, however, is actively participating in advancing Nevada's restructuring process. We see this time and again: In fact, TEP's chairman Charles Bayless is a staunch advocate of retail competition outside Arizona, but resists it mightily in his backyard. APS is actively marketing at retail in California, having opened an office in the Los Angeles area and successfully obtaining electric service provider status in the Sacramento Municipal Utility District's retail program. There is a very real effort by many utilities, including Arizona's, to stall competition on the home front while aggressively seeking to advance and reap its benefits elsewhere.

In California, there is a tremendous momentum behind competition despite the delay in direct access from January 1, 1998, to March 31, 1998. Considering all that has occurred in California the past 18 months, it is remarkable that the California ISO / PX will only miss the start date by 3 months. Despite the delays caused by the unnecessarily complex ISO/PX systems, the fact that California is continuing to move forward on retail competition with the cooperation of the state's major utilities can only be attributed in large part to California's explicit linking of stranded cost recovery to the timely onset of competition and asset sales. Many other aspects of California's restructuring are on schedule including fossil asset divestiture and residential rate reductions (10%). Our asset sale proposal assures Arizona there will be competition following stranded cost recovery.

III. ISSUES OF PARTICULAR IMPORTANCE TO ENERGY SERVICES OR THE ARIZONA SCHOOL BOARDS ASSOCIATION

Q. Which of the issues identified in the Initial Procedural Order are most important to Energy Services?

A. All of the issues are important, but Issues 3 (calculation method), 8 (price caps), 9 (mitigation), and their impact on 1 (rules) in that order are the most important to us.

Q. With regard to Issue #3, what costs should be included as part of "stranded costs"?

A. Only legitimate, verifiable and non-mitigatable costs imposed by the onset of competition should be eligible for the prospect of stranded cost recovery. For instance, unamortized regulatory assets and nuclear decommissioning costs would be eligible for recovery but only under an asset sale scenario. As previously discussed, property taxes could likewise have an adjustment clause in order to increase bids and further the public interest.

However, an avoidable cost that is simply unaffordable at competitive prices should not be allowed recovery. For instance, marketing and sales expenses, corporate overheads and all other avoidable or semi-avoidable costs allocated to competitive services should not be allowed recovery as stranded costs. Competitive services in this case also includes the standard offer sale of energy. This is because it is the energy component of the standard offer tariff that will be the competitive product. Energy service providers, such as Energy Services, will have to compete with the standard offer energy price in order to market successfully in Arizona. Some one-time employee severance costs may be an appropriate exception, depending on the circumstances. California's legislation permitted recovery as stranded cost only severances for union and clerical employees. The job market for professionals is very strong today.

In addition, the Commission must be sure to include all prior amounts of stranded cost recovered by the affected utilities in their determination of the total amount of recoverable stranded costs. In this regard, APS' accelerated recovery of regulatory must be accounted for in determining the total amount of stranded costs APS will be permitted to endeavor to recover during the transition period.

Q. With further reference to Issue #3, how should those costs be calculated?

A. Net revenues lost methods should not be used. Net revenues lost is an arbitrary method which inevitably leads to a reduction in incentive to mitigate and a reliance on assumptions and computer models, not market realities. Periodic true-ups do not solve the problems inherent in a net revenues lost method. A revenue lost approach also carries a very high risk that costs will be recovered which should not be accorded stranded cost treatment, such as marketing and sales costs.

Net revenues lost can also mislead customers about eventual rate decreases upon expiration of stranded cost recovery. In other words, a subsequent increase in regulated distribution rates can lead to less of a rate reduction upon expiration of stranded cost recovery. A utility can make such an increase in distribution rates more palatable (hidden) under a net lost revenues recovery mechanism because the increase will have the appearance of stranded costs.

Q. What approach does Energy Services recommend?

A. As previously discussed, we recommend the Commission use asset valuation as the method for determining the amount of stranded costs eligible for recovery. Specifically a method based on the highest bid for generation offered for sale. We also believe that the utilities should not be permitted to include as recoverable stranded costs any above-market costs incurred after December 26, 1996, the effective date of Decision 59943. Certainly with the issuance of the retail competition rules on that date, the utilities were then on notice that any new investment must survive a market test. For previously stated reasons, voluntary asset sales are emerging in the U.S. as the preferred calculation method. Proceeds from sales can credit existing debt and common equity in their current capital structure percentages, unless the Commission wants to modify existing financial leverage. Retail customers only pay stranded costs remaining after netting surpluses from proceeds in excess of embedded balance sheet amounts.

Arizona has no PURPA contracts and fortunately does not face above market purchased power contracts, which is a large component of stranded costs in California. Under our "solution," purchased power contracts should be included for sale in the "all other" generation category.

Q. **With reference to Issue #8, should there be price caps or a rate freeze imposed as part of the development of a stranded cost recovery program; and, if so, how should they be calculated?**

A. The Commission should establish a price ceiling in the form of standard offer tariffs. Standard offer tariffs should be available to all retail customers. Such standard offer tariffs should be predicated on voluntary generation asset sales and thus would recover only essential distribution, transmission, the CTC (which recovers Commission-authorized stranded costs comprised of regulatory assets, nuclear investment and decommissioning costs, property tax adjustment clause(s), sales taxes, and regulatory assets), and other system benefits charges only after crediting surplus proceeds from asset sales. Of course, standard offer must include a generation component.

Q. How would the generation component price be established?

A. After generation sales, all generation (with the exception of nuclear if not sold) will have been marked to market. If not sold, the nuclear plants should be deemed to be dispatched first. Since nuclear will be insufficient to meet the nuclear utilities' standard offer loads, they will be required to make up the difference with purchased power. The (market-based) purchased power will be deemed the standard offer generation price (with appropriate load factor adjustments). During the four year transition period, the difference on a kilowatt per hour basis between the market purchased power cost and the nuclear revenue requirement will be the nuclear component of the CTC. The incumbent utilities can then offer market based (purchased power) generation prices in standard offer. Purchases will, for a while, largely come from market priced purchases from the new owners of recently sold power plants. We recommend the Commission prohibit a utility from constructing or owning power plants on a regulated basis following voluntary asset sales. Such a ban, of course, would not apply to any unregulated and separate affiliates of the utility.

We observe that nuclear may very well be quite competitive under Energy Services proposal. The purchaser of the nuclear interests of the affected utilities will not be burdened with the costs of regulatory assets, nuclear decommissioning or property taxes. Nuclear, will, however, in all other regards be exposed to market forces. Inefficient management of Palo Verde could (and should) result in poor financial performance for its new owners. We also note that if the nuclear assets do not sell, with only a 4 year period to recover their stranded costs, the utilities will have ample incentive also to manage their nuclear assets efficiently.

Q. What else should be considered in connection with use of the standard offer as a price ceiling?

A. Clearly, an important consideration under this approach is the quality of the unbundled tariffs for Arizona's affected utilities. A mis-assignment of competitive (generation) costs to regulated services will reduce competition because the generation component of the standard offer will be too low and stifle competition. For example, certain costs, such as sales, customer service and marketing, should be assigned to the generation function because a competing electric service provider must recover those costs in its commodity price, and does not have the option of loading those costs on to other, regulated functions (such as transmission and distribution) because it does not have such functions. In other words, the only way new entrants such as Energy Services can beat a standard offer price is if that price reflects the true costs to the utility to provide that service in the competitive market.

We do not have a strong preference for how metering and billing costs are treated under standard offer, except that they should be fair and properly assigned to the appropriate function. While a complete exit from the merchant function by the utility is inevitable, these services could be included in standard offer for some period of time under our proposal.

In Energy Services' opinion, our solution offers a real opportunity for Arizona. The California option of establishing an overall rate freeze and crediting back on customers' bills the power exchange price, metering and billing is not available (nor really desirable) in Arizona. First, Arizona has not established a power exchange. Second, the commitment behind Desert Star is still not 100%, plus Arizona has a vision of a less complicated market structure. Indeed, the California structure is unnecessarily complex and is not essential to the creation of a true competitive market. It should not be replicated in Arizona.

It is likely the Arizona utilities would want a set expiration date for standard offer under this proposal. This is because standard offer is a fixed price offering and the utilities will want to align their resource purchases to an established time frame. Eventually, standard offer must expire. Once all retail customers are eligible for retail access, standard offer can phase out and be replaced by competitive bidding for default service.

Q. With regard to Issue #9, what factors should be considered in the "mitigation" of stranded costs?

A. Ultimately, all stranded costs must be mitigated because electric rates should not be allowed to increase as a result of stranded cost recovery. Under Energy Services' proposal standard offer prices would likely decrease on January 1, 1999 (or earlier) because the proposal (i) uses the highest, not average, value of assets and captures surpluses to pay remaining stranded costs; (ii) does not require acceleration of stranded cost components to remain in good standing with the accounting community; and (iii) encourages mitigation through unbundling and direct competition inasmuch as no other regulatory crutches are provided to the utilities. An additional feature of our proposal is that the Commission needs to consider mitigation factors only in determining regulated tariffs. These factors are:

1. **Proper allocation of costs as between regulated competitive services**: Costs must be properly assigned and avoidable costs in competitive services must not be afforded stranded cost recovery. Rather, they should be funded by market revenues.
2. **Service territory economic growth**: Arizona is growing at a rate which consistently places it at or near the top of the 50 states year after year. Since there appears to be no support for excluding new customers from paying stranded costs, we suggest new growth is a very significant source for paying

stranded costs and / or for funding infrastructure required by competition (e.g., ISO). Because wholesale costs are much less than embedded revenues, new customers are contributing marginal revenues far in excess of marginal costs.

3. **The return on equity for generation assets**: Stranded cost recovery provides a level of assurance of recovery that exceeds that of traditional regulation. Generation equity returns, as a result, can be re-aligned with risk. Equity returns on regulatory assets eligible for stranded cost recovery should be reduced. In California, equity returns on all generation rate base were reduced to 90% of the level of the cost of debt for purposes of stranded cost recovery.

4. **The costs of competitive infrastructure**: These must be explicitly addressed or the utilities may claim that their revenues are inadequate to fund such infrastructure as an ISO, billing interface systems, and customer education. Although APS is presently collecting an additional $110 million in regulatory assets, it has publicly indicated it lacks funding for at least some programs. In other words, if not explicitly addressed, the utilities might claim every extra dollar goes for stranded cost recovery unless it suits their purposes (e.g., marketing efforts in California).

5. **Affiliate separation**: Complete separation between a utility's regulated, monopoly services and any competitive services is essential to the development of a competitive market. This separation requires that any competitive services must be offered, if at all, only through a separate,

unregulated affiliated entity (which must be a separate corporation). With proper accounting separation and transfer pricing rules, requiring that competitive activities be conducted through a separate entity, which permits more effective monitoring and oversight, the chances for cross subsidization of competitive services by regulated revenues are substantially reduced. Internal accounting controls are ineffective in ensuring that regulated services do not subsidize competitive services. Such subsidization will impose increased costs on ratepayers and damage competition. First, ratepayers would bear a portion of the utility's costs of providing the competitive service, and second, the ability of the utility to offer competitive services at lower prices (because a portion of its costs will be recovered in rates from ratepayers) will squelch competition from alternative providers who must recover all their costs of service in the prices of competitive services. It is simply impossible to police the utilities effectively to ensure there is no cross-subsidization of unregulated utility activities. For instance, the Arizona utilities keep insisting their California efforts are a result of this Commission's request to mitigate stranded costs. However, there is presently almost no profit potential in these efforts, only losses associated with starting up in new markets. We cannot help but wonder whether any margin the Arizona utilities are making on their California sales would be less than what would be eliminated from regulated rates if the total costs of their marketing efforts in California were known.

Q. With reference to Issue #1, Should the Electric Competition Rules be modified regarding stranded costs; and, if so, how?

A. Energy Services has no proposed modifications at this time. After reviewing the testimony and exhibits submitted in this proceeding, and considering the record as a whole, we may conclude some modifications are in order. In such event, we will communicate our views to the Commission and the parties.

IV. MISCELLANEOUS POINTS

Q. Do you have additional points to communicate?

A. Yes. I have some additional observations from Energy Services' experience in other states and comments about what has gone well in California.

Q. Is there anything of relevance in recent asset sales under California's mandatory voluntary fossil asset sale?

A. Yes. The California generation asset sales factor into "CTC" at their sales prices. Both Southern California Edison and PG&E have accepted very attractive bids for their fossil generation assets, Edison's at about 2.5 times book value, and PG&E's

at about a 1.3 multiple. In fact, at we know that at least one Arizona utility bid on at least one of PG&E's plants. Of course, there are fact differences between California, New England and Arizona, but the winning bids are so much higher than anyone contemplated a year ago in stranded cost discussions. I know of no reason why the result should be any different in Arizona.

Q. Does this conclude your testimony?

A. Yes.

98-04/Oglesby ACC Stranded Cost Testimony.doc/1-19-98

DOUGLAS A. OGLESBY
Vice President and General Counsel
PG&E Energy Services

Mr. Oglesby is responsible for all legal matters, including customer agreements, vendor contracts, energy transactions and regulatory representation. He is also responsible for energy policy issues, particularly legislative and regulatory policies concerning industry restructuring.

Mr. Oglesby has 20 years of legal experience in energy law and the utility industry. Mr. Oglesby came to PG&E Energy Services from a major international law firm where he was a partner in the firm's energy practice group. As a member of the firm, he represented large energy consumers, domestic and international independent power developers, power marketers and utilities on a wide range of energy issues.

Prior to private practice, Mr. Oglesby was an attorney in the law department of Pacific Gas and Electric Company, where for many years he served as Chief Counsel of PG&E's Electric Supply Business Unit. As Chief Counsel he was the principal legal advisor to the Business Unit's general manager and to PG&E's senior management on electric supply matters, and was responsible for all legal services required by the Business Unit, principally relating to electric resource planning, industry structure and restructuring, power plant fuel supply, bulk power, utility interchange, transmission and non-utility power transactions and associated pricing and rate issues.

Mr. Oglesby's practice has focused primarily on energy transactional matters, including power purchase contracts and transmission arrangements, and on issues related to electric industry restructuring. He has practiced extensively before the Federal Energy Regulatory Commission, the California Public Utilities Commission, the California Energy Commission, and other state and federal agencies on a wide range of energy-related issues, including utility rates. He has counseled extensively on transmission access and on removing barriers to transactions between energy consumers and suppliers. For the last several years he has been actively involved in industry structure legislative and regulatory policy issues including advocacy at both the state and federal levels on important energy services restructuring and competitive energy market issues. Among other accomplishments, Mr. Oglesby personally participated in the development of the 1992 National Energy Policy Act and helped shape that Act's provisions relating to independent power development and electric transmission. He has participated in numerous conferences and seminars as a speaker and panelist on energy policy issues.

Mr. Oglesby obtained his law degree from Boalt Hall School of Law, University of California, Berkeley and graduated from Oregon State University, Corvallis, Oregon, with a B.S. in General Science. He is also a graduate of the Harvard Business School Program for Management Development.

APS - 4

Pacific Gas and Electric Company
San Francisco, California

	Original	*Cal. P.U.C. Sheet No.*	16156-E
Cancelling		*Cal. P.U.C. Sheet No.*	

SCHEDULE E - CREDIT – REVENUE CYCLE SERVICES CREDITS

APPLICABILITY: This schedule applies to Customers that receive certain services from energy service providers (ESPs). Customers for whom PG&E provides consolidated billing or dual billing will receive checks quarterly from PG&E equal to the sum of the credits, beginning in January 1999. For customers whose ESP provides consolidated billing, PG&E will send to the ESP a check equal to the sum of the credits monthly. No later than January 1, 2000, PG&E will apply the credits directly to customer bills. (N)

TERRITORY: The entire PG&E service territory.

CREDITS: 1. METER OWNERSHIP CREDITS

If an ESP owns a Direct Access Customer's meter or a Customer owns its own meter, one of the following credits will apply, respective of the PG&E rate schedule on which the Customer is served.

Rate Schedule	Per Meter Per Month
E-1/EL-1	$0.09
EM/EML	$0.09
ES/ESL	$0.09
ESR/ESRL	$0.09
ET/ETL	$0.61
E-7/EL-7	$0.57
E-A7/EL-A7	$0.57
E-8/EL-8	$0.09
E-9	$0.57
E-SEG	$0.09
A-1 Singlephase	$0.09
A-1 Polyphase	$0.61
A-6 Singlephase	$0.57
A-6 Polyphase	$1.33
A-10, all voltages	$1.42
E-19V Secondary	$1.42
E-19V Primary	$1.42
E-19V Transmission	$1.42
E-19 Secondary	$1.42
E-19 Primary	$1.42
E-19 Transmission	$1.42
E-19 Nonfirm Secondary	$4.57
E-19 Nonfirm Primary	$4.57
E-19 Nonfirm Transmission	$4.57
E-20 Secondary	$1.42
E-20 Primary	$1.42
E-20 Transmission	$1.42
E-20 Nonfirm Secondary	$4.57
E-20 Nonfirm Primary	$4.57
E-20 Nonfirm Transmission	$4.57
LS-1	n/a
LS-2	n/a
LS-3	$0.09
OL-1	n/a
TC-1	$0.09

(N)

EXHIBIT
A84
admitted

(Continued)

SCHEDULE E - CREDIT – REVENUE CYCLE SERVICES CREDITS
(Continued)

CREDITS: (Cont'd.)

1. METER OWNERSHIP CREDITS (Cont'd.) (N)

Rate Schedule	Per Meter Per Month
AG-1A	$0.61
AG-1B	$1.42
AG-RA	$1.33
AG-RB	$1.42
AG-VA	$1.33
AG-VB	$1.42
AG-4A	$1.42
AG-4B	$1.42
AG-4C	$1.42
AG-5A	$1.42
AG-5B	$1.42
AG-5C	$1.42
SNONT	$0.09

(N)

(Continued)

SCHEDULE E - CREDIT – REVENUE CYCLE SERVICES CREDITS
(Continued)

CREDITS: (Cont'd.)

2. METER SERVICES CREDITS (N)

If an ESP provides meter services one of the following credits will apply, respective of the PG&E rate schedule on which the Customer is served.

Rate Schedule	Per Meter Per Month
E-1/EL-1	$0.16
EM/EML	$0.16
ES/ESL	$0.16
ESR/ESRL	$0.16
ET/ETL	$0.39
E-7/EL-7	$1.71
E-A7/EL-A7	$1.71
E-8/EL-8	$0.16
E-9	$1.71
E-SEG	$0.16
A-1 Singlephase	$0.10
A-1 Polyphase	$0.10
A-6 Singlephase	$1.66
A-6 Polyphase	$1.66
A-10, all voltages	$0.90
E-19V Secondary	$0.90
E-19V Primary	$0.90
E-19V Transmission	$0.90
E-19 Secondary	$0.90
E-19 Primary	$0.90
E-19 Transmission	$0.90
E-19 Nonfirm Secondary	$11.18
E-19 Nonfirm Primary	$11.18
E-19 Nonfirm Transmission	$11.18
E-20 Secondary	$0.90
E-20 Primary	$0.90
E-20 Transmission	$0.90
E-20 Nonfirm Secondary	$11.12
E-20 Nonfirm Primary	$11.12
E-20 Nonfirm Transmission	$11.12
LS-1	n/a
LS-2	n/a
LS-3	$0.10
OL-1	n/a
TC-1	$0.10

(N)

(Continued)

SCHEDULE E - CREDIT – REVENUE CYCLE SERVICES CREDITS
(Continued)

CREDITS: (Cont'd.)

2. METER SERVICES CREDITS (Cont'd.) (N)

Rate Schedule	Per Meter Per Month
AG-1A	$0.06
AG-1B	$0.86
AG-RA	$1.62
AG-RB	$0.86
AG-VA	$1.62
AG-VB	$0.86
AG-4A	$0.86
AG-4B	$0.86
AG-4C	$0.86
AG-5A	$0.86
AG-5B	$0.86
AG-5C	$0.86
SNONT	$0.34

(N)

(Continued)

SCHEDULE E - CREDIT – REVENUE CYCLE SERVICES CREDITS
(Continued)

CREDITS: (Cont'd.)

3. METER READING CREDITS (N)

If an ESP provides meter reading services for its Customer, one of the following credits will apply, respective of the PG&E rate schedule on which the Customer is served, whether or not the Customer takes both gas and electric service from PG&E, and the method the ESP uses to read the meter.

Rate Schedule	Per Meter Per Month		
	Dual Commodity Site, Electric Meter Only	Electric Only Site	Telephone/ Modem Reads
E-1/EL-1	$0.21	$0.71	n/a
EM/EML	$0.21	$0.71	n/a
ES/ESL	$0.21	$0.71	n/a
ESR/ESRL	$0.21	$0.71	n/a
ET/ETL	$0.21	$0.71	n/a
E-7/EL-7	$0.21	$0.71	n/a
E-A7/EL-A7	$0.21	$0.71	n/a
E-8/EL-8	$0.21	$0.71	n/a
E-9	$0.21	$0.71	n/a
E-SEG	$0.21	$0.71	n/a
A-1 Singlephase	$0.22	$0.72	n/a
A-1 Polyphase	$0.22	$0.72	n/a
A-6 Singlephase	$0.22	$0.72	n/a
A-6 Polyphase	$0.22	$0.72	n/a
A-10, all voltages	$0.22	$0.72	n/a
E-19V Secondary	n/a	$2.64	n/a
E-19V Primary	n/a	$2.64	n/a
E-19V Transmission	n/a	$2.64	n/a
E-19 Secondary	n/a	$2.64	n/a
E-19 Primary	n/a	$2.64	n/a
E-19 Transmission	n/a	$2.64	n/a
E-19 Nonfirm Secondary	n/a	n/a	$35.95
E-19 Nonfirm Primary	n/a	n/a	$35.95
E-19 Nonfirm Transmission	n/a	n/a	$35.95
E-20 Secondary	n/a	$2.64	n/a
E-20 Primary	n/a	$2.64	n/a
E-20 Transmission	n/a	$2.64	n/a
E-20 Nonfirm Secondary	n/a	n/a	$35.95
E-20 Nonfirm Primary	n/a	n/a	$35.95
E-20 Nonfirm Transmission	n/a	n/a	$35.95
LS-1	n/a	n/a	n/a
LS-2	n/a	n/a	n/a
LS-3	$0.21	$0.67	n/a
OL-1	n/a	n/a	n/a
TC-1	$0.21	$0.67	n/a (N)

(Continued)

SCHEDULE E - CREDIT – REVENUE CYCLE SERVICES CREDITS
(Continued)

RATES: (Cont'd.) 3. METER READING CREDITS (Cont'd.) (N)

Rate Schedule	Per Meter Per Month		
	Dual Commodity Site, Electric Meter Only	Electric Only Site	Telephone/ Modem Reads
AG-1A	n/a	$1.85	n/a
AG-1B	n/a	$1.85	n/a
AG-RA	n/a	$1.85	n/a
AG-RB	n/a	$1.85	n/a
AG-VA	n/a	$1.85	n/a
AG-VB	n/a	$1.85	n/a
AG-4A	n/a	$1.85	n/a
AG-4B	n/a	$1.85	n/a
AG-4C	n/a	$1.85	n/a
AG-5A	n/a	$3.66	n/a
AG-5B	n/a	$3.66	n/a
AG-5C	n/a	$3.66	n/a
SNONT	$0.22	$0.72	n/a

(N)

(Continued)

SCHEDULE E - CREDIT – REVENUE CYCLE SERVICES CREDITS
(Continued)

CREDITS: (Cont'd.)

4. BILLING CREDITS (N)

If an ESP provides consolidated billing services for its Customer, one of the following credits will apply, respective of the PG&E rate schedule on which the Customer is served, and whether the ESP is providing full or partial consolidated billing services (defined in Rule 22).

Rate Schedule	Per Account Per Month			
	Partial ESP Consolidated Billing - Dual Commodity	Partial ESP Consolidated Billing - Electric Only	Full ESP Consolidated Billing - Dual Commodity	Full ESP Consolidated Billing - Electric Only Commodity
E-1/EL-1	$0.05	$0.83	$0.05	$0.83
EM/EML	$0.05	$0.83	$0.05	$0.83
ES/ESL	$0.05	$0.83	$0.05	$0.83
ESR/ESRL	$0.05	$0.83	$0.05	$0.83
ET/ETL	$0.05	$0.83	$0.05	$0.83
E-7/EL-7	$0.08	$0.86	$0.08	$0.86
E-A7/EL-A7	$0.08	$0.86	$0.08	$0.86
E-8/EL-8	$0.13	$0.92	$0.13	$0.92
E-9	$0.08	$0.86	$0.08	$0.86
E-SEG	$0.05	$0.83	$0.05	$0.83
A-1 Singlephase	$0.14	$1.23	$0.14	$1.23
A-1 Polyphase	$0.14	$1.23	$0.14	$1.23
A-6 Singlephase	$0.25	$1.34	$0.25	$1.34
A-6 Polyphase	$0.25	$1.34	$0.25	$1.34
A-10, all voltages	$2.05	$3.12	$2.05	$3.12
E-19V Secondary	$9.35	$10.42	$9.35	$10.42
E-19V Primary	$9.35	$10.42	$9.35	$10.42
E-19V Transmission	$9.35	$10.42	$9.35	$10.42
E-19 Secondary	$9.35	$10.42	$9.35	$10.42
E-19 Primary	$9.35	$10.42	$9.35	$10.42
E-19 Transmission	$9.35	$10.42	$9.35	$10.42
E-19 Nonfirm Secondary	$12.47	$13.53	$12.47	$13.53
E-19 Nonfirm Primary	$12.47	$13.53	$12.47	$13.53
E-19 Nonfirm Transmission	$12.47	$13.53	$12.47	$13.53
E-20 Secondary	$26.51	$27.57	$26.51	$27.57
E-20 Primary	$26.51	$27.57	$26.51	$27.57
E-20 Transmission	$26.51	$27.57	$26.51	$27.57
E-20 Nonfirm Secondary	$37.53	$38.60	$37.53	$38.60
E-20 Nonfirm Primary	$37.53	$38.60	$37.53	$38.60
E-20 Nonfirm Transmission	$37.53	$38.60	$37.53	$38.60
LS-1	$0.12	$1.19	$0.12	$1.19
LS-2	$0.12	$1.19	$0.12	$1.19
LS-3	$0.12	$1.19	$0.12	$1.19
OL-1	$0.12	$1.19	$0.12	$1.19
TC-1	$0.12	$1.19	$0.12	$1.19

(N)

(Continued)

SCHEDULE E - CREDIT – REVENUE CYCLE SERVICES CREDITS
(Continued)

CREDITS: (Cont'd.)

4. BILLING CREDITS (Cont'd.) (N)

Rate Schedule	Per Account Per Month			
	Partial ESP Consolidated Billing - Dual Commodity	Partial ESP Consolidated Billing - Electric Only	Full ESP Consolidated Billing - Dual Commodity	Full ESP Consolidated Billing - Electric Only Commodity
AG-1A	$0.11	$1.17	$0.11	$1.17
AG-1B	$0.43	$1.50	$0.43	$1.50
AG-RA	$0.13	$1.20	$0.13	$1.20
AG-RB	$0.32	$1.39	$0.32	$1.39
AG-VA	$0.14	$1.21	$0.14	$1.21
AG-VB	$0.34	$1.41	$0.34	$1.41
AG-4A	$0.14	$1.21	$0.14	$1.21
AG-4B	$0.14	$1.21	$0.14	$1.21
AG-4C	$0.14	$1.21	$0.14	$1.21
AG-5A	$0.24	$1.31	$0.24	$1.31
AG-5B	$0.24	$1.31	$0.24	$1.31
AG-5C	$0.24	$1.31	$0.24	$1.31
SNONT	$36.54	$37.63	$36.54	$37.63

(N)

BEFORE THE ARIZONA CORPORATION COMMISSION

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CHAIRMAN
JIM IRVIN
COMMISSIONER
TONY WEST
COMMISSIONER

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

IN THE MATTER OF THE FILING OF ARIZONA PUBLIC SERVICE COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1061 ET. SEQ.) DOCKET NO. E-01345A-97-0773

IN THE MATTER OF COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.) DOCKET NO. RE-00000C-94-0165

NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the testimony of Greg Patterson on the Proposed Settlement, in the above-referenced dockets.

RESPECTFULLY SUBMITTED this 4th day of June, 1999.

Karen E. Nally

Scott S. Wakefield, Chief Counsel
Karen E. Nally, Counsel

AN ORIGINAL AND TEN COPIES
of the foregoing filed this 4th day
of June, 1999 with:

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

EXHIBIT
Admitted
RUCO-1

COPIES of the foregoing hand delivered this 4th day of June, 1999 to:

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COPIES of the foregoing mailed to
All Parties in Docket No. RE-00000C-94-0165

By Cheryl Fraulob
Cheryl Fraulob
Legal Secretary II

BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
CHAIRMAN
JIM IRVIN
COMMISSIONER
TONY WEST
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS PLAN FOR STRANDED COST RECOVERY.	DOCKET NO. E-01345A-98-0473
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IN THE MATTER OF COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. RE-00000C-94-0165

DIRECT TESTIMONY

OF

GREG PATTERSON

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 4, 1999

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

A. My name is Greg Patterson. I am the Director of the Residential Utility Consumer Office ("RUCO") located at 2828 North Central Avenue, Suite 1200, Phoenix, Arizona 85004.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix A, which is attached to this testimony, describes my educational background and qualifications.

Q. What is your position on the Arizona Public Service ("APS") settlement?

A. The APS settlement is good for residential consumers and I support it.

Q. How will the settlement benefit residential customers?

A. The settlement provides a series of 1.5% rate decreases over each of the next 5 years. This will allow all residential consumers, including those who remain on standard offer service, to benefit from competition.

The settlement assures continuation of the Community Action Partnership – which includes weatherization, facility repair and replacement, bill assistance, health and safety programs and energy education. This will allow the Commission to protect consumers through programs that have an assured funding mechanism and a proven track record.

The settlement caps APS's stranded investment at $350 million while disallowing $183 million (net present value) of costs. APS also agrees to withdraw its various court appeals.

Q. Could litigating these issues have led to a reduction of standard offer rates?

A. No. Standard offer rates can only be lowered through a general rate proceeding. In practice this is difficult to arrange.

Q. Why?

A. If we assume a company is over earning, they are obviously not going to voluntarily file a rate case. The ACC has to issue an Order to Show Cause ("OSC") and then prove that rates are too high. This is an expensive, risky and politically-charged process. The ACC might initiate this process once and maybe even twice over this five-year period, but they certainly wouldn't issue an OSC every year.

Furthermore, a company facing annual rate proceedings has no incentive to lower costs. The annual 1.5% rate decreases would never materialize because the underlying costs would never decrease.

Q. Could litigating these issues have delayed competition?

A. Certainly. While we don't know if APS's legal challenges would have ultimately prevailed. I believe the company could have substantially delayed competition.

Q. Is competition good for residential consumers?

A. It is in theory. Competition should make energy providers more efficient and more responsive to consumer needs. Competition gives consumers choices and empowers them to shop for services that meet their needs. Companies that respond well to those needs will make a lot of money and those who don't respond well won't survive. If a company builds an inefficient power plant or enters into an expensive coal contract it will not be able to pass those high costs on to consumers.

Q. Will consumers benefit by this agreement even if they don't have access to competition?

A. Yes. The standard offer rate decreases, disallowance of certain costs, and continuation of low-income programs benefit consumers. Additionally, the benefits of a highly competitive market – efficient production, better service and lower prices – affect consumers whether they choose to change suppliers or not.

Q. What was RUCO's position on the previous APS settlement?

A. RUCO opposed the previous settlement.

Q. Why?

A. The previous agreements were negotiated without significant input from consumer interests. The rate decreases from these agreements were too small. The stranded asset recovery was too big. The proposed sale of generating assets to APS from TEP could have led to the ability of APS to exercise additional horizontal market power. The proposal that TEP become the owner of the high voltage transmission within Arizona did not seem workable.

Q. How does this settlement differ from the last one?

A. Consumers were invited to participate this time. The rate decreases are larger. The stranded investment recovery is smaller. The proposed sale of generating assets to

APS from TEP has been eliminated. The proposal that TEP become the owner of the high voltage transmission has also been eliminated.

Q. How much stranded investment would APS have collected under the order issued by the Commission?

A. That's actually subject to some debate. Jack Davis testified to an estimate of $533 million. However, he was careful to say that this amount was only valid under certain assumptions. That number was reiterated in the August 21, 1998 filing, but the company was clear that this was a "mitigated number." We don't know how much APS would have asked for in a stranded cost proceeding.

Q. How much of their regulatory assets does APS collect under this agreement?

A. All of them.

Q. Why?

A. The regulatory assets were established by the ACC in 1985 and reaffirmed by the ACC in Decision number 59601 in 1996. That collection is again reaffirmed in 1999's Decision number 61677.

Q. Does this conclude your testimony?

A. Yes.

APPENDIX A

GREG PATTERSON

Education:	University of Arizona BSBA Accounting With Distinction 1985
Certification:	Certified Public Accountant
Experience:	Residential Utility Consumer Office (RUCO) 1995 - present

- Director
- Represent residential consumer interests in electric, gas, telecommunications and water rate cases.

RESIDENTIAL UTILITY CONSUMER OFFICE

2828 NORTH CENTRAL AVENUE • SUITE 1200 • PHOENIX, ARIZONA 85004 • (602) 279-5659 • FAX: (602) 285-0350

Jane Dee Hull
Governor

Greg Patterson
Director

RECEIVED
JUL 01 1999

June 29, 1999

Douglas C. Nelson, Esq.
Douglas C. Nelson, P.C.
7000 North 16th Street, Suite 120
PMB 307
Phoenix, Arizona 85020

VIA FACSIMILE
ORIGINAL MAILED

Re: Arizona Public Service Company Settlement
ACC Docket No. E-01345A-98-0473 et al.

Dear Mr. Nelson:

Enclosed are RUCO's Responses to Commonwealth Energy Corporation's First Set of Data Requests, in the above-referenced matter.

If you have any questions, please feel free to contact me at 279-5659 ext. 349.

Sincerely,

Scott S. Wakefield
Chief Counsel

Enclosures

EXHIBIT
Commonwealth
6
Admitted

RESPONSE TO COMMONWEALTH ENERGY'S DISCOVERY REQUEST

1. Promotion of Competition

   a. Please furnish any study performed on the Settlement's ability to promote electric competition.

   b. Please provide any study that illustrates the expected generation shopping credit that are imputed within the Direct Access tariffs.

   c. Please provide any study that forecasts the expected numbers of customers (by class with their respective loads) that are likely to seek competitive electric services if the Settlement is approved.

   d. Please provide any study that assures the public of no cost shifting associated with the same service that a customer receives under the Standard Offer or from an ESP.

   e. Please provide any study on the electric cost savings associated with the Settlement.

RESPONSE:

1.a. RUCO has not performed any formal study on the Settlement's ability to promote electric competition.

1.b. RUCO has not performed or reviewed any study illustrating the expected generation shopping credits.

1.c. RUCO has not performed or reviewed any such study.

1.d. RUCO has not performed or reviewed any such study.

1.e. RUCO has not performed or reviewed any such study beyond the terms of the Settlement Agreement itself. The Settlement Agreement provides for a total of 7.5% in rate reductions for residential standard offer customers, implemented as 1.5% reductions each year from July 1, 1999 through July 1, 2003. In addition, the Settlement provides for decreases in the CTC and distribution charges for Direct Access customers as set forth in Exhibit A, Schedules A and B to the Settlement Agreement.

2. Stranded Costs

a. Please explain why regulatory assets are now to be recovered under the Distribution charge rather than the CTC.

b. Please provide any study performed on APS's stranded costs (and/or regulatory assets).

c. RUCO's consultant, Dr. Richard A. Rosen, calculated the estimated unbundled generation, transmission, distribution and customer revenue results for APS in 1998, as follows:

Generation	5.02 cents per kWh
Transmission	0.59 cents per kWh
Distribution	2.06 cents per kWh
Customer-related expense	0.38 cents per kWh

Direct Testimony of Dr. Richard Rosen, dated January 21, 1997 (sic - 1998), at 40 & Exh. RAR-12, *Arizona Commission, Docket No. U-0000-94-065.*

Please explain the discrepancy, if any, in these unbundled revenue results and the expected revenue for the above components under the Settlement for residential customers.

d. Please explain whether or not residential customers will receive a generation shopping credit of over 5 cents under the Settlement.

e. Dr. Rosen included regulatory assets as a part of stranded costs and he determined that APS would have negative stranded costs under various scenarios. *Id.* at 61 and RAR-2. Please explain the discrepancy in Dr. Rosen's estimated APS stranded costs and the stranded cost figure in the Settlement.

RESPONSE:

2.a. RUCO disagrees with the question's premise that regulatory assets were previously recoverable through the CTC. Current rates are bundled, such that regulatory assets are not recovered via any particular billing element. RUCO has not been a party to any previous settlement that may have classified regulatory assets as part of the CTC.

2.b RUCO performed a study on APS's stranded cost, which was included in the direct testimony of Dr. Richard Rosen dated January 21, 1998 in Arizona Corporation Commission Docket No. U-0000-94-165. As Commonwealth refers to that testimony in the subsequent question, it appears that Commonwealth already has a copy of the testimony and the study in its possession. RUCO has not performed or reviewed any other such studies.

2.c The unbundled rates in the Settlement are a result of negotiations between the parties in which all parties compromised on a variety of issues. While the Settlement does not reflect unbundled element pricing as previously suggested by Dr. Rosen, it does reflect standard offer price decreases that will accrue to all standard offer residential customers. In addition, the Settlement provides for a decreasing CTC each year through 2004.

2.d. RUCO has not determined the generation shopping credit which residential customers will receive under the terms of the Settlement. RUCO believes that the shopping credit will vary depending upon which standard offer residential tariff a customer is currently receiving service.

2.e. The stranded cost figure in the Settlement is a result of negotiations between the parties in which all parties compromised on a variety of issues. While the Settlement does not reflect stranded costs as previously suggested by Dr. Rosen, it does reflect standard offer price decreases that will accrue to all standard offer residential customers. In addition, the Settlement provides for a decreasing CTC each year through 2004.

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF)
COMPETITION IN THE)
PROVISION OF ELECTRIC)
SERVICES THROUGHOUT)
THE STATE OF ARIZONA)

DOCKET NO. U-0000-94-165

DIRECT TESTIMONY OF

DR. RICHARD A. ROSEN

Submitted on Behalf of
The Residential Utility Consumer Office

January 21, 1997

EXHIBIT
Commonwealth
7
Admitted

D. Unbundling Results for APS, SRP and TEP

Q. DID YOU USE THE TELLUS UNBUNDLIGN METHODOLOGY TO DEVELOP ESTIMATES OF THE UNBUNDLED REVENUES FOR APS, TEP, AND SRP?

A. Yes, I did.

Q. WHAT WERE THE UNBUNDLED GENERATION, TRANSMISSION, DISTRIBUTION AND CUSTOMER REVENUE RESULTS FOR APS?

A. The unit unbundled revenues for APS were as follows:

- Generation - 5.02 cents per kWh
- Transmission - 0.59 cents per kWh
- Distribution - 2.06 cents per kWh
- Customer - 0.38 cents per kWh.

The total average retail rate was 8.05 cents per kWh.

Q. WHAT WERE THE UNBUNDLED GENERATION, TRANSMISSION, DISTRIBUTION AND CUSTOMER REVENUE RESULTS FOR TEP?

A. The unit unbundled revenues for TEP were as follows:

- Generation - 6.12 cents per kWh
- Transmission - 0.83 cents per kWh
- Distribution - 1.32 cents per kWh
- Customer - 0.29 cents per kWh.

The total average retail rate was 8.55 cents per kWh.

Summary of Stranded Costs Estimates

Net Present Value of Stranded Costs (1996-2010)
(million 1998$)

Scenario	Company		
	APS*	TEP	SRP
Base Case	836	1198	42
High Market Price	411	1051	-440
Low Market Price	1211	1345	526

*Note: Stranded Costs for APS accounts for generation-related assets not in rates ($110.3 million).

Net Present Value of Stranded Costs (1998-2012)
(million 1998$)

Scenario	Company		
	APS*	TEP	SRP
Base Case	102	779	-834
High Market Price	-417	599	-1433
Low Market Price	559	959	-233

*Note: Stranded Costs for APS accounts for generation-related assets not in rates ($110.3 million).

Net Present Value of Stranded Costs (1998-2020)
(million 1998$)

Scenario	Company		
	APS*	TEP	SRP
Base Case	-838	513	-3009
High Market Price	-1578	257	-3927
Low Market Price	-186	770	-2090

*Note: Stranded Costs for APS accounts for generation-related assets not in rates ($110.3 million).

Table 3b: Projecting Future Costs for
Arizona Public Service Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.[1] (GWh)	Stranded Costs ($ million)
1996	1.63	1.63	18,428	299.9
1997	1.37	1.37	18,753	256.0
1998	1.08	1.08	19,255	208.6
1999	0.78	0.78	19,523	152.1
2000	0.45	0.45	19,979	90.3
2001	0.32	0.32	19,968	63.3
2002	0.18	0.18	20,269	36.2
2003	0.04	0.04	20,911	7.5
2004	(0.11)	(0.11)	21,517	(23.9)
2005	(0.21)	(0.21)	22,110	(46.9)
2006	(0.32)	(0.32)	22,563	(71.5)
2007	(0.43)	(0.43)	23,024	(98.1)
2008	(0.54)	(0.54)	23,495	(126.7)
2009	(0.66)	(0.66)	23,975	(157.5)
2010	(0.78)	(0.78)	24,466	(190.6)
2011	(0.91)	(0.91)	24,966	(226.1)
2012	(1.04)	(1.04)	25,476	(264.2)
2013	(1.17)	(1.17)	25,997	(305.1)
2014	(1.31)	(1.31)	26,529	(348.8)
2015	(1.46)	(1.46)	27,072	(395.7)
2016	(1.61)	(1.61)	27,625	(445.8)
2017	(1.77)	(1.77)	28,190	(499.4)
2018	(1.93)	(1.93)	28,767	(556.6)
2019	(2.10)	(2.10)	29,355	(617.7)
2020	(2.28)	(2.28)	29,955	(682.9)

Net Present Value of Stranded Costs (1996-2010):		$726.0
Generation-Related Assets Not in Rates:	$	110.3
Total NPV of Stranded Costs (1996-2010) (1998$):		$836.3
Net Present Value of Stranded Costs (1998-2012):		($8.1)
Generation-Related Assets Not in Rates:	$	110.3
Total NPV of Stranded Costs (1998-2012) (1998$):		$102.2
Net Present Value of Stranded Costs (1998-2020):		($947.9)
Generation-Related Assets Not in Rates:	$	110.3
Total NPV of Stranded Costs (1998-2020) (1998$):		($837.6)
Assumed utility nominal discount rate		7.75%

[1] System generation, excluding purchased power. Assumed escalation rate: 2.0%

Table 3a: Projections of Stranded Costs[1]
Arizona Public Service Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:	User Exogenous Input in Base Year, CC/CT Mix Method in Year Excess Capacity Ends
Escalation Rates:	See Table 4: Scenario Assumptions
O&M Costs	3.0%
Year when excess capacity ends:	2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	3.39	5.02	0.00
1997	3.66	5.02	0.00
1998	3.94	5.02	0.00
1999	4.24	5.02	0.00
2000	4.57	5.02	0.00
2001	4.70	5.02	0.00
2002	4.84	5.02	0.00
2003	4.99	5.02	0.00
2004	5.13	5.02	0.00
2005	5.28	5.07	0.00
2006	5.44	5.12	0.00
2007	5.60	5.17	0.00
2008	5.77	5.23	0.00
2009	5.93	5.28	0.00
2010	6.11	5.33	0.00
2011	6.29	5.38	0.00
2012	6.48	5.44	0.00
2013	6.67	5.49	0.00
2014	6.86	5.55	0.00
2015	7.06	5.60	0.00
2016	7.27	5.66	0.00
2017	7.49	5.72	0.00
2018	7.71	5.77	0.00
2019	7.93	5.83	0.00
2020	8.17	5.89	0.00

[1] All costs are in nominal dollars.

Table 2: Unbundling Analysis of Historical Costs - 1996
Arizona Public Service Company
(thousand dollars)

Category	Total Cost	Cost Components			
		Generation	Transmission	Distribution	Customer
O&M Expenses:					
Production	$508,476	$508,476			
O&M Minus Fuel	$416.344	$297,256			
Fuel	$211,220	$211,220			
Transmission	$14,067		$14,067		
Distribution	$50,207			$50.207	
Customer/Sales	$54,814				$54,814
Subtotal	$627,564	$508,476	$14,067	$50,207	$54,814
A&G[1]	$133,222	$ 95,116	$ 4,501	$ 16,065	$ 17,539
Total	$760,786	$603,592	$18,568	$66,272	$72,353
Plant Related Costs:					
Depreciation and Amort.	$237,555	$130,281	$29,423	$77,852	$0
Net Interest	$1,077	$551	$126	$401	$0
Net Income	$364,223	$186,122	$42,446	$135,656	$0
Income Taxes[2]	$178,514	$91,222	$20,804	$66,488	$0
Other Taxes[3]	$68,023	$34,761	$7,927	$25,335	$0
Residual[4]	$55,014	$28,113	$6,411	$20,490	$0
Total	$904,406	$471,049	$107,136	$326,221	$0
Total Operating Revenues[5]	$1,665,192	$1,074,641	$125,704	$392,493	$72,353
less Wholesale Revenues	($133,416)	($119,445)	($13,972)	$0	$0
Total Retail Revenues	$1,531,775	$955,196	$111,732	$392,493	$72,353
Total Retail Sales (MWH)	19,020,696				
Average Retail Rate (cents/kWh)	**8.05**	**5.02**	**0.59**	**2.06**	**0.38**

Footnotes:

[1] A&G Costs are allocated to Generation, Transmission, Distribution, and Customer cost components based on the following percentages: 71.4%, 3.4%, 12.1%, and 13.2%.

[2] Income Taxes include Federal Income Taxes, Other Incomes Taxes, Provision for Deferred Income Taxes (incl. credits).

[3] Other Taxes are those classified by DOE/EIA as "taxes other than income taxes." For purposes of this analysis, state sales taxes, if applicable, are deducted from Other taxes since these taxes will be levied regardless of industry structure.

[4] Residual is set so that total O&M Expenses plus Plant Related Costs equal Total Operating Revenues (net of sales taxes).

[5] Total Operating Revenues do not include revenues collected from state sales taxes.

Table 1: Market Price Calculation for Arizona Public Service Company
Scenario: Base year wholesale price based on average price of purchased power

(1) Using Least Cost Mix of Combined Cycle and Combustion Turbine:

Real Levelized Fixed Charge Factor: 10.88%

Combined Cycle:	Total Costs:	1996 Real Levelized Costs
Capital Costs	383.0 S/kW	0.84 c/kWh
Fixed O&M	11.7 S/kW-yr	0.24 c/kWh
Variable O&M	0.20 mills/kWh	0.02 c/kWh
Fuel	1.97 c/kWh	1.72 c/kWh
	Sum of Levelized Costs:	*2.82 c/kWh*
	Levelized Capacity Costs:	*53.4 S/kW-yr*

Combustion Turbine:	Total Costs:	1996 Real Levelized Costs
Capital Costs	275.0 S/kW	7.04 c/kWh
Fixed O&M	9.4 S/kW-yr	2.21 ¢/kWh
Variable O&M	0.10 mills/kWh	0.01 ¢/kWh
Fuel	3.61 ¢/kWh	3.16 c/kWh
	Sum of Levelized Costs:	*12.42 c/kWh*
	Levelized Capacity Costs:	*39.3 S/kW-yr*

Capacity Factor Crossover for CC/CT		11%
Percent of CC energy in Market Price		98.1%
Percent of CT energy in Market Price		1.9%
Average Price of CC/CT mix		**3.00 ¢/kWh**
T&D Line Loss Adjustment	7%	0.21 ¢/kWh
Order 888 Ancillary Services		0.10 c/kWh
Retailing A&G Adjustment		0.50 ¢/kWh
Other Retailing Costs Adjustment		0.27 ¢/kWh
Adjusted Retail Market Price based on CC/CT mix		**4.08 ¢/kWh**
Year Excess Capacity Ends		**2000**

(2) Using Capacity Charge and Energy Charge:

Capacity Charge ($/kW-yr):	**NA**	
Energy Charge (¢/kWh):	**NA**	
Average Market Price for Electricity:		**none ¢/kWh**

(3) Using an Exogenous Value:

User-Input Wholesale Market Price for Electricity		**2.36 ¢/kWh**
T&D Line Loss Adjustment	7%	**0.16 ¢/kWh**
Order 888 Ancillary Services		**0.10 ¢/kWh**
Retailing A&G Adjustment		**0.50 ¢/kWh**
Other Retailing Costs Adjustment		**0.27 ¢/kWh**
User-Input Retail Market Price for Electricity		**3.39 ¢/kWh**

Table 4
Assumptions Used in Estimating Stranded Costs for Arizona Public Service Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

I. Inputs for the RGS Market Price Calculation Based on CC/CT Optimal Mix:

Financial Assumptions:	
Real Discount Rate =	7.28%
Inflation Rate =	3.00%
Private Nom. Disc. Rate =	10.50%
Real Levelized FCF =	10.88%
Reserve Margin =	15%

Fuel Price Forecast (1996$/MMBtu):	*User-input*				
1996	$3.03	2004	$2.68	2012	$2.75
1997	$2.11	2005	$2.72	2013	$2.71
1998	$2.27	2006	$2.73	2014	$2.73
1999	$2.32	2007	$2.73	2015	$2.75
2000	$2.36	2008	$2.73	2016	$2.80
2001	$2.39	2009	$2.71	2017	$2.85
2002	$2.48	2010	$2.71	2018	$2.90
2003	$2.59	2011	$2.72	2019	$2.95
				2020	$3.00

Source: Exhibit_(RAR-6)

Combined Cycle:		
Capital Cost	383.0	1996$/kW
Fixed O&M	11.7	1996$/kW/yr
Var O&M	0.200	1996mills/kW
Heat Rate	6,500	Btu/kWh

Schnitzer, in Docket No. 16705, Texas Direct Testimony and EIA Annual Energy Outlook 1997

Combustion Turbine:		
Capital Cost	275.0	1996$/kW
Fixed O&M	9.4	1996$/kW/yr
Var O&M	0.100	1996mills/kW
Heat Rate	11,900	Btu/kWh

Tellus Institute. Energy Innovations- A Prosperous Path to a Clean Environment (June 1997)

Cross-Over Calculation:

LOAD FACTOR	54%
Max. Annual Load (MW)	4616
Min. Monthly Peak (MW)	2484
Load Factor for Min. Monthly Load	0.81
Effective Min. Annual Load	2023
Max. Load + Reserve Margin (MW)	5308
Cut-off point:	11.0%
Load at above Cut-off (MW)	4331
Total Energy under Load Curve (MWh)	21,865,083
Energy Supplied by CTs (MWh)	415,437
Energy Supplied by CCs (MWh)	21,449,646
Percentage of Energy Supplied by CTs	1.9%
Percentage of Energy Supplied by CCs	98.1%

Month-1996	Total Monthly Energy (MWh)	Monthly Non-Req. Sales for Resale & Losses (MWh)	Net Energy (MWh)	Monthly Peak (MW)
Jan	1,755,196	121,658	1,633,538	3,134
Feb	1,538,583	93,484	1,445,099	3,027
Mar	1,578,178	81,408	1,496,770	2,703
Apr	1,606,380	70,048	1,536,332	3,223
May	1,888,666	52,951	1,835,715	3,576
Jun	2,176,835	72,505	2,104,330	4,113
Jul	2,546,161	61,708	2,484,453	4,616
Aug	2,492,746	32,371	2,460,375	4,491
Sep	2,070,813	150,700	1,920,113	3,953
Oct	2,062,028	284,609	1,777,419	3,662
Nov	1,901,166	424,258	1,476,908	2,484
Dec	2,147,940	453,909	1,694,031	3,354
TOTAL	23,764,692	1,899,609	21,865,083	4,616

Utility FERC Form 1 Data

Average Wholesale Market Price of Electricity Based	30.04	$/MWh
on CC/CT Method	3.00	c/kWh
T&D Line Loss Adjustment	0.21	c/kWh
Order 888 Ancillary Services	0.10	c/kWh
Retailing A&G Adjustment	0.50	c/kWh
Other Retailing Costs Adjstmt	0.27	c/kWh

II. Other Market Price Options:

Capacity/Energy Charge:		
Capacity Charge	NA	$/MW
Energy Charge	NA	c/kWh
User-Input Retail Market Price:	3.39	c/kWh

CC-CT Market Price Worksheet for: Arizona Public Service Company

Utility Load Data:

For each utility, a load profile for one year must be entered below. This data can be found in the utility's FERC Form 1, pg. 401. The areas in BLUE are the values which must be entered by the user

Month	Total Monthly Energy (MWh) USER-INPUT	Monthly Non-Requirements Sales for Resale & Associated Losses (MWh) USER-INPUT	Net Energy (MWh)	Monthly Peak (MW) USER-INPUT	Min. Monthly Load (MW)	Load Factor for Min. Monthly Load	Effective Min. Monthly Load (MW)
Jan	1,755,196	121,658	1,633,538	3,134			
Feb	1,538,583	93,484	1,445,099	3,027			
Mar	1,578,178	81,408	1,496,770	2,703			
Apr	1,606,380	70,048	1,536,332	3,223			
May	1,888,666	52,951	1,835,715	3,576			
Jun	2,176,835	72,505	2,104,330	4,113			
Jul	2,546,161	61,708	2,484,453	4,616			
Aug	2,492,746	32,371	2,460,375	4,491			
Sep	2,070,813	150,700	1,920,113	3,953			
Oct	2,062,028	284,609	1,777,419	3,662			
Nov	1,901,166	424,258	1,476,908	2,484	2484	81%	2,023
Dec	2,147,940	453,909	1,694,031	3,354			
TOTAL	23,764,692	1,899,609	21,865,083	4,616	2,484	0.81	2,023

LOAD FACTOR	54%
Max. Annual Load (MW)	4,616
Min. Monthly Peak (MW)	2,484
Load Factor for Min. Monthly Load	0.81
Effective Min. Annual Load	2,023
Max. Load + Reserve Margin (MW)	5,308
Cut-off point:	11%
Load at above Cut-off (MW)	4,331

ratio between total energy under load curve and total monthly energy: 0.92

Total Energy under Load Curve (MWh)	21,865,083		
Energy Supplied by CTs (MWh)	415,437	Ratio of energy supplied by CTs	1.9%
Energy Supplied by CCs (MWh)	21,449,646	Ratio of energy supplied by CCs	98.1%
check	0		

CC

$ 28.21 MWh

Capital Cost	41.67	$/kW times	4,331	MW	equals	180,465,659	dollars
Fixed O&M	11.70	$/kW times	4,331	MW	equals	50,670,217	dollars
Var O&M	0.20	mills/kWh times	21,449,646	MWh	equals	4,289,929	dollars
Fuel	1.72	cents/kWh times	21,449,646	MWh	equals	369,748,232	dollars

CT

$ 124.19 MWh

Capital Cost	29.92	$/kW times	978	MW	equals	29,250,158	dollars
Fixed O&M	9.40	$/kW times	978	MW	equals	9,189,555	dollars
Var O&M	0.10	mills/kWh times	415,437	MWh	equals	41,544	dollars
Fuel	3.16	cents/kWh times	415,437	MWh	equals	13,110,652	dollars

TOTAL 656,765,946 dollars

Tot Energy in real LDC 21,865,083 MWh

OUTPUT

Average Market Price of Electricity - 1996

30.04	$/MWh
3.00	c/kWh

Table 3b: Projecting Future Costs for
Arizona Public Service Company
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.[1] (GWh)	Stranded Costs ($ million)
1996	1.63	1.63	18,428	299.9
1997	1.32	1.32	18,753	247.1
1998	0.98	0.98	19,255	188.6
1999	0.61	0.61	19,523	119.2
2000	0.21	0.21	19,979	41.5
2001	0.07	0.07	19,968	13.2
2002	(0.08)	(0.08)	20,269	(16.2)
2003	(0.23)	(0.23)	20,911	(48.2)
2004	(0.39)	(0.39)	21,517	(82.9)
2005	(0.49)	(0.49)	22,110	(109.3)
2006	(0.61)	(0.61)	22,563	(137.1)
2007	(0.73)	(0.73)	23,024	(166.9)
2008	(0.85)	(0.85)	23,495	(199.0)
2009	(0.97)	(0.97)	23,975	(233.5)
2010	(1.11)	(1.11)	24,466	(270.4)
2011	(1.24)	(1.24)	24,966	(309.9)
2012	(1.38)	(1.38)	25,476	(352.3)
2013	(1.53)	(1.53)	25,997	(397.6)
2014	(1.68)	(1.68)	26,529	(446.0)
2015	(1.84)	(1.84)	27,072	(497.8)
2016	(2.00)	(2.00)	27,625	(553.1)
2017	(2.17)	(2.17)	28,190	(612.1)
2018	(2.35)	(2.35)	28,767	(675.0)
2019	(2.53)	(2.53)	29,355	(742.1)
2020	(2.72)	(2.72)	29,955	(813.6)

Net Present Value of Stranded Costs (1996-2010):		**$300.3**
Generation-Related Assets Not in Rates:	**$**	**110.3**
Total NPV of Stranded Costs (1996-2010) (1998$):		**$410.6**
Net Present Value of Stranded Costs (1998-2012):		**($527.1)**
Generation-Related Assets Not in Rates:	**$**	**110.3**
Total NPV of Stranded Costs (1998-2012) (1998$):		**($416.7)**
Net Present Value of Stranded Costs (1998-2020):		**($1,688.4)**
Generation-Related Assets Not in Rates:	**$**	**110.3**
Total NPV of Stranded Costs (1998-2020) (1998$):		**($1,578.0)**
Assumed utility nominal discount rate		**7.75%**

[1] System generation, excluding purchased power. Assumed escalation rate: 2.0%

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Table 3a: Projections of Stranded Costs[1]
Arizona Public Service Company
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:	User Exogenous Input in Base Year, CC/CT Mix Method in Year Excess Capacity Ends
Escalation Rates:	See Table 4: Scenario Assumptions
O&M Costs	3.0%
Year when excess capacity ends:	2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	3.39	5.02	0.00
1997	3.70	5.02	0.00
1998	4.04	5.02	0.00
1999	4.41	5.02	0.00
2000	4.81	5.02	0.00
2001	4.96	5.02	0.00
2002	5.10	5.02	0.00
2003	5.25	5.02	0.00
2004	5.41	5.02	0.00
2005	5.57	5.07	0.00
2006	5.73	5.12	0.00
2007	5.90	5.17	0.00
2008	6.07	5.23	0.00
2009	6.25	5.28	0.00
2010	6.44	5.33	0.00
2011	6.63	5.38	0.00
2012	6.82	5.44	0.00
2013	7.02	5.49	0.00
2014	7.23	5.55	0.00
2015	7.44	5.60	0.00
2016	7.66	5.66	0.00
2017	7.89	5.72	0.00
2018	8.12	5.77	0.00
2019	8.36	5.83	0.00
2020	8.60	5.89	0.00

[1] All costs are in nominal dollars.

Table 3b: Projecting Future Costs for
Arizona Public Service Company
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.[1] (GWh)	Stranded Costs ($ million)
1996	1.63	1.63	18,428	299.9
1997	1.41	1.41	18,753	264.2
1998	1.18	1.18	19,255	226.6
1999	0.93	0.93	19,523	181.4
2000	0.67	0.67	19,979	133.1
2001	0.54	0.54	19,968	107.4
2002	0.41	0.41	20,269	82.3
2003	0.27	0.27	20,911	56.4
2004	0.13	0.13	21,517	27.9
2005	0.04	0.04	22,110	7.9
2006	(0.06)	(0.06)	22,563	(13.9)
2007	(0.16)	(0.16)	23,024	(37.6)
2008	(0.27)	(0.27)	23,495	(63.1)
2009	(0.38)	(0.38)	23,975	(90.7)
2010	(0.49)	(0.49)	24,466	(120.4)
2011	(0.61)	(0.61)	24,966	(152.4)
2012	(0.73)	(0.73)	25,476	(186.8)
2013	(0.86)	(0.86)	25,997	(223.8)
2014	(0.99)	(0.99)	26,529	(263.4)
2015	(1.13)	(1.13)	27,072	(305.9)
2016	(1.27)	(1.27)	27,625	(351.5)
2017	(1.42)	(1.42)	28,190	(400.3)
2018	(1.57)	(1.57)	28,767	(452.6)
2019	(1.73)	(1.73)	29,355	(508.4)
2020	(1.90)	(1.90)	29,955	(568.1)

Net Present Value of Stranded Costs (1996-2010):		**$1,101.0**
Generation-Related Assets Not in Rates:	**$**	**110.3**
Total NPV of Stranded Costs (1996-2010) (1998$):		**$1,211.3**
Net Present Value of Stranded Costs (1998-2012):		**$448.6**
Generation-Related Assets Not in Rates:	**$**	**110.3**
Total NPV of Stranded Costs (1998-2012) (1998$):		**$558.9**
Net Present Value of Stranded Costs (1998-2020):		**($296.6)**
Generation-Related Assets Not in Rates:	**$**	**110.3**
Total NPV of Stranded Costs (1998-2020) (1998$):		**($186.3)**
Assumed utility nominal discount rate		**7.75%**

[1] System generation, excluding purchased power. Assumed escalation rate: 2.0%

Table 3a: Projections of Stranded Costs[1]
Arizona Public Service Company
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:	User Exogenous Input in Base Year, CC/CT Mix Method in Year Excess Capacity Ends
Escalation Rates:	See Table 4: Scenario Assumptions
O&M Costs	3.0%
Year when excess capacity ends:	2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	3.39	5.02	0.00
1997	3.61	5.02	0.00
1998	3.85	5.02	0.00
1999	4.09	5.02	0.00
2000	4.36	5.02	0.00
2001	4.48	5.02	0.00
2002	4.62	5.02	0.00
2003	4.75	5.02	0.00
2004	4.89	5.02	0.00
2005	5.04	5.07	0.00
2006	5.18	5.12	0.00
2007	5.34	5.17	0.00
2008	5.49	5.23	0.00
2009	5.66	5.28	0.00
2010	5.82	5.33	0.00
2011	5.99	5.38	0.00
2012	6.17	5.44	0.00
2013	6.35	5.49	0.00
2014	6.54	5.55	0.00
2015	6.73	5.60	0.00
2016	6.93	5.66	0.00
2017	7.14	5.72	0.00
2018	7.35	5.77	0.00
2019	7.56	5.83	0.00
2020	7.78	5.89	0.00

[1] All costs are in nominal dollars.

Tellus Institute
Strandable Costs Calculation Model

1. Introduction

This document serves as a guide to the Tellus Institute approach to calculating strandable costs for an electric utility. It provides an overview of the methodology, inputs, and scenario development used in calculating utility-specific strandable costs. To facilitate the strandable costs calculation, a simple model was developed consisting of four interdependent analyses: an unbundling analysis, a market price analysis, a financial evaluation of strandable costs in a single year, and a projection of strandable costs over a specified period of analysis. Since each utility faces a unique set of circumstances entering into the competitive generation market, the Tellus Strandable Costs Model (SCM) is designed to provide an analysis of the specific financial conditions for each utility.

It is important to recognize that any estimates of strandable costs will include many uncertainties, and will be subject to debate by many parties. Therefore, estimates of strandable costs should be as simple and as clear as possible. This information guide is intended to explain Tellus' SCM modeling assumptions and should assist readers in following the logic of the calculations in the model. In addition, Tellus recommends that SCM estimates should be prepared for a variety of scenarios and sensitivities to indicate how the stranded costs might change with different input assumptions.

2. Methodology

Strandable costs can generally be defined as the difference between the competitive market value and the regulated book value (or embedded cost value) of a utility's generation assets. Therefore, the general approach to estimating strandable costs is to calculate the difference between (a) the utility's embedded generation cost value over a specified period of time, and (b) the market price for power in the region over the same period of time. The SCM follows from this basic equation. As such, the SCM calculates a utility's *potentially strandable* costs, as opposed to costs that would actually be stranded (e.g., as a result of customers actually leaving the utility's system for an alternative supplier). Strandable costs represents the maximum amount of costs that may become stranded in a retail competitive generation market.

The SCM includes four main components: a market price calculation; an unbundling calculation of the utility's average retail generation price; a calculation of strandable costs in the base year; and a projection of strandable costs over a user specified period of analysis.

Market Price Calculation

The user can choose from three different methods to determine the average generation market price value for the first year of analysis, based on: 1) a least cost mix of new natural gas combined cycle and combustion turbine generating units; 2) user-specified capacity and energy charges; or 3) an exogenous user-input value. In all cases, the estimate of market price is based on the assumption that competitive generation companies in the utility's region provide energy sufficient to meet the utility's entire load. In other words, the market price represents the average cost of power in the region, as opposed to the marginal cost.

The first option derives a competitive market price based on the cost of an optimal combination of new natural gas combined cycle and combustion turbine units. This method requires the user to make assumptions about current and future fuel (gas) prices, a discount rate, and fixed charge factor. A real levelized average market price based on this CC/CT mix represents the market price for the first year of analysis.

For the second option, the competitive market price is based on user-specified energy and capacity charges. Specific energy and capacity price information could be based on existing state or regional market price proxy values, such as competitive wholesale prices, avoided cost values, etc.

Finally, the user has the option of simply entering an exogenous, average market price value.

Unbundled Generation Costs

The user enters utility-specific costs and revenues for a historical year using information provided by utilities to FERC. Unbundled costs are calculated by allocating the data into generation, transmission, distribution, and customer related expenses, according to FERC accounting categories. After the expenses and revenues are spread among these categories, further adjustments are made regarding wholesale transactions to produce a final estimate of embedded costs per category. An average unbundled rate (in cents/kWh) for each component is then computed by dividing embedded costs by ultimate sales to customers.

Strandable Costs - Base Year

Strandable costs for the first year of analysis are calculated based on a comparison of the utility's unbundled generation rate and the assumed market price. The user has the option of assuming a transition charge, which allows the utility to recover from customers a portion of stranded costs. The "net" revenue reduction represents the strandable costs, less any revenues recovered through the transition charge. The utility's net revenue reduction is then compared to how it will impact the utility's shareholders, as well as its average retail customer.

Strandable Cost - Projections

Finally, the SCM allows the user to develop scenario projections based on a fixed time horizon (not to exceed 10 years). The method for determining the market price over the projected time period will depend on whether or not the utility has excess capacity, and if that excess capacity is anticipated to end during the period of the analysis. If the utility does have excess capacity which is expected to end within the period of analysis, then regardless of what method is used to calculate market price in the base year, the model will automatically switch to the CC/CT Mix market price in the year that excess capacity ends, since this price will best represent the marginal cost of generation in the future. In that year, the CC/CT Mix market price will reflect a price that is escalated from the base year CC/CT Mix price according to user's assumed escalation rates for fuel, energy and fixed cost components.

Regardless of which market price methodology is used, the user can make assumptions about escalation rates for the various market price components (e.g., energy and demand charges). The user may also choose to enter an escalation rate for the utility's average unbundled generation price projection. And finally, the user may estimate the utility's future electricity sales either by entering a forecast of sales over the projection period or by escalating the base year sales at a specified rate.

The computation and inputs for the SCM are discussed in greater detail below.

3. Inputs and Computational Analysis

The inputs necessary to calculate strandable costs will come from a number of utility-specific and industry-specific sources. Examples of such sources are: the utility's FERC FORM 1, current utility Integrated Resource Plans and Annual Reports, and various fuel cost forecasts, and supply and demand forecasts for the region.

Unbundling Generation Costs

The first step in the valuation of a utility's existing generation assets is to isolate those costs and revenues which are associated with generation-related assets. To do this, the models' unbundling input spreadsheet requires that information from the utility's Operating Income (FERC FORM 1 pp. 114-119), Electric Operation and Maintenance Expenses (FERC FORM 1 pp. 320-323), Customer Sales and Operating Revenues (FERC FORM 1 pp. 300-304), and Electric Utility Plant (FERC FORM 1 pp. 220-221) be entered as inputs.

The model uses a simple method to unbundle these costs and revenues by allocating the Operation & Maintenance Expenses, Plant Related Expenses, and Operating Revenues in rate base into generation-related, transmission-related, distribution-related and customer-related costs and revenues, according to each category's contribution to net plant (or gross plant in the case of depreciation). In the case of Administrative and General Expenses, the user has the option to directly allocate these costs to any of the four cost components.

Total Operating Revenues represent the value of assets in rate base, for both wholesale and retail operations. In order to obtain the utility's total *retail* revenues, a wholesale revenue adjustment must be made to Total Operating Revenues. The Adjusted Retail Revenues are then converted to an average retail rate (cents/kWh) per cost component by dividing the totals by total retail sales. The final result is an estimate of unbundled generation, distribution, transmission, and customer costs for the utility's retail operations.

Market Price

Estimating a competitive market price for a specific state or region is likely to be highly uncertain. In order to accommodate different levels of information about the market price for power, the model allows for three market price options to be pursued and examined in separate scenarios.

As discussed earlier, the first option utilizes cost information for a newly built Combustion Turbine (CT) and a newly built Combined Cycle (CC) plant to determine a market price based on the optimal mix of CTs and CCs to serve the utility's load profile. This estimation of market price is likely to represent a "high" market price value. The model offers the user the option to input plant-related cost information for a new CC or CT, or to simply use the default values provided from the *EPRI Technical Assessment Guide*. In addition, financial assumptions such as the fixed charge factor, and fuel cost escalation and inflation rates may be input or default values may be used.

To determine the likely future mix of CCs and CTs for a utility's system, the SCM conducts a crossover calculation, based on a comparison of fixed and variable costs, to determine the capacity factor below which CTs will operate and above which CCs will operate. The outcome of the crossover calculations provides the combination of CCs and CTs which would serve this utility's system at the lowest cost, optimal or least cost system. In order to correctly compare the unbundled generation rate to the CC/CT market price in the strandable costs comparison, it is necessary to adjust the CC/CT market price to reflect the generation-related A&G costs the utility would likely incur in providing this electricity, just as they are reflected in the unbundled generation rate. The amount of the CC/CT market price A&G adjustment is based on the historical cost of generation related A&G, as reflected in the unbundling spreadsheet.

The second market price option allows for the choice of representative energy and demand charges to be input. Using these charges, along with the utility's load data, the model calculates the average market generation price in costs/kWh. Using this method, the user can create a range of high, medium, and low market prices assumptions that are derived from a range of user input energy and demand charges.

The third market price option simply allows the user to directly input a market generation price (in cents/kWh). Again, with this straightforward method, the user can create a range of market price assumptions.

Strandable Costs - Base Year

Once the unbundled generation costs for the utility have been estimated by the model, and a market price has been estimated, strandable costs for the base year can be calculated as the difference between the two. The model presents the output for a one year strandable cost calculation. The model calculates the net reduction in generation costs (in ¢/kWh) as the difference between the average utility generation cost and the competitive market price. If a transition charge is assumed, then the net reduction in generation costs will be reduced accordingly. Finally, retail sales are used to determine the strandable costs (i.e., revenue reduction) in this one year.

In turn, the model examines the impact on the shareholders by examining the Revenue Reductions due to competition as a percentage of the following costs:

- Net Income plus Income Taxes (or Gross Income)
- Gross Income plus Depreciation
- Gross Income plus Depreciation and Net Interest.

The first comparison is likely the most important, since the financial viability of a utility is typically measured in terms of its ability to pay its shareholders and its income taxes. A scenario in which there would be a sharing of stranded costs (e.g., using a transition charge) would clearly alleviate the impact on shareholders, yet not provide as a large reduction in the average generation rate to ratepayers.

4. Strandable Costs - Projections

The SCM allows for scenarios that calculate potential strandable costs over a multiple year period. The importance of analyzing this information is that while the first year may reveal significant initial strandable costs for a utility, the utility's strandable costs over a longer period of analysis may provide an entirely different picture. For example, a utility with stranded costs in the base year may, within a few years, face no strandable costs, and may even receive profits as a result of its embedded generation costs falling below expected future market prices.

In this multi-year period analysis, the user first selects the time period for the projection, and identifies the year that excess capacity, if it exists, is anticipated to end. If excess capacity is exhausted within the projection period, the CC/CT market price takes effect in at that point in time. If no new capacity is needed within the projection period, then the market price assumed in the base year is simply escalated over the period of analysis based on a user specified escalation rate.

Depending on the market price methodology, selected escalation rates must be entered:

- CC/CT mixed price: escalation rates for Fuel Costs, Capital Costs, and O&M costs.
- Energy and Capacity Charges: escalation rates for the energy and capacity charges.
- Exogenous market price: Escalation rate for the exogenous ¢/kWh market price.

In addition to market price escalation data, escalation rates can be applied to the utility's average retail generation price and its retail sales in the base year.

Once the model calculates the projection of strandable costs, the sum of the strandable costs stream is converted to net present value. In a final important step, an adjustment is made to reflect the net present value of the generation-related regulatory assets not yet in ratebase. The sum of the stream of strandable costs and the potentially strandable regulatory assets, both in terms of net-present value, is the total potential strandable costs.

Based on a series of assumptions about the future costs of fuel, the increase in the market price over time, and the option to consider a transition charge, a full range of strandable cost sensitivities may be examined.