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**BEFORE THE ARIZONA CORPORATION COMMISSION**

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WILLIAM A. MUNDELL
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Commissioner

IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC DIVISION OF CITIZENS COMMUNICATIONS COMPANY TO CHANGE THE CURRENT PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE RATE, TO ESTABLISH A NEW PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE BANK, AND TO REQUEST APPROVE GUIDELINES FOR THE RECOVERY OF COSTS INCURRED IN CONNECTION WITH ENERGY RISK MANAGEMENT INITIATIVES.

Docket No. E-01032C-00-0751

**STAFF'S NOTICE OF FILING DIRECT TESTIMONY**

In accordance with the January 11, 2002 Procedural Order, the Staff hereby files the direct testimony and exhibits of Lee Smith and Douglas C. Smith.

DATED this 8th day of February, 2002.

ARIZONA CORPORATION COMMISSION

By Christopher C. Kempley
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Arizona Corporation Commission
DOCKETED

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**BEFORE THE ARIZONA CORPORATION COMMISSION**

WILLIAM A. MUNDELL
Chairman
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DIRECT

TESTIMONY

OF

DOUGLAS SMITH

ON BEHALF OF

ARIZONA CORPORATION COMMISSION STAFF

FEBRUARY 8, 2002

# Testimony of Douglas C. Smith

**Q. What is your name and business address?**

A. My name is Douglas C. Smith. I am the Technical Director for La Capra Associates, 333 Washington Street, Boston, Massachusetts.

LaCapra Associates ("La Capra") is a consulting firm specializing in electric industry restructuring, energy planning, market analysis, and regulatory policy in the electricity and natural gas industries. For twenty years, we have served a broad range of organizations involved with energy markets -- public and private utilities, energy producers and traders, financial institutions and investors, consumers, regulatory agencies, and public policy and research organizations. A copy of my resume is included as Attachment S-1.

**Q. On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of the Arizona Corporation Commission ("Commission" or ACC") Staff.

**Q. What is your involvement in this case?**

A. My testimony encompasses the issues associated with power markets, regional demand and supply conditions, and risk management opportunities. This testimony is contained within the prefiled testimony of Ms. Lee Smith, primarily, but not entirely, within Section VII. I assisted Ms. Smith, but was not primarily responsible for, Sections VIII and IX. See page 1 of Ms. Smith's testimony for reference to my work. The pages of Lee Smith's testimony to which I contributed are attached and incorporated as my testimony as Attachment S-2.

**Q. Please describe your background and experience.**

A. I am an electric power industry planning specialist with 15 years of experience in areas including power systems planning and analysis, wholesale and retail power transactions, and electric utility rates. I have participated in restructuring-related activities in Pennsylvania, Massachusetts, Vermont, New Jersey and Ohio. I have participated in numerous generation asset valuation and competitive market assessment projects on behalf of merchant generating companies, electric utilities, state regulatory and consumer agencies, and end-users. During the past year I have assisted the California Office of Ratepayer Advocate in its review of power transactions conducted by San Diego Gas & Electric, and the California Bureau of State Audits in its review of power transactions conducted by the California Department of Water Resources.

I have managed the electric power supplies of several electric utilities, and have developed wholesale electricity price forecasts for use by market participants. I presently assist several retail electricity customers, including the National Railroad Passenger Corporation ("Amtrak"), in the procurement of retail generation service from competitive suppliers. I have testified before state regulatory authorities in Pennsylvania, Massachusetts, New Hampshire, New Jersey, Vermont, and Puerto Rico.

**Q. Does this conclude your testimony?**

A. Yes, it does.

**DOUGLAS C. SMITH**
**LA CAPRA ASSOCIATES**
Technical Director

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Douglas Smith, Technical Director, has over 15 years of experience in the electric power industry. He is experienced and skilled in the areas of electricity markets, transactions and competitive procurement, resource planning, system simulation, and project feasibility analysis. While at La Capra Associates, Mr. Smith has assisted utilities, generators, and regulatory agencies in the analysis of issues related to electric system planning, price forecasting, and risk management and power transactions. Mr. Smith has significant experience as an expert witness, on behalf of private and public sector clients. While employed as Electrical Planning Engineer and Power Cost Analyst for the Vermont Department of Public Service, he was responsible for the review of generation facilities and wholesale power transactions proposed by electric utilities, and for reviewing all power supply costs in the context of electric utility retail rate proceedings.

## ACCOMPLISHMENTS

- Managed and conducted power transactions of several New England electric utilities, from 1991 to present. Responsibilities include risk management strategy and analysis, simulations of alternative procurement strategies, negotiation with potential trading partners, and development of contract terms. Presently responsible for managing the power supply portfolio of the Washington (VT) Electric Cooperative, Inc.

- Assisted the California Office of the Ratepayer Advocate in assessing the reasonableness of San Diego Gas & Electric's procurement practices. Mr. Smith analyzed historical spot market prices, forward market conditions and the utility's net short position to assess whether the company should have utilized Block Forward contracts to mitigate customers' exposure to spot market prices. Mr. Smith's findings were presented in written testimony before the California Public Utility Commission.

- Led the procurement of competitive retail generation service contracts for Amtrak (the National Railroad Passenger Corporation). Responsibilities included analysis of utility "shopping credits," solicitation of competitive supplies, evaluation of proposals, and competitive negotiations with suppliers. This effort produced successful supply contracts with several suppliers, resulting in several million dollars of customer savings.

- On behalf of the California Bureau of State Audits, reviewed the short- and long-term power transactions conducted by the California Department of Water Resources during 2001. This effort addressed the Department's long term portfolio strategy and execution, along with its short term power transaction activities.

- Led a detailed analysis of future wholesale electricity market prices in the PJM Interconnection, and presented the analysis in expert testimony before the Pennsylvania Public Utilities Commission. This market price forecast was adopted by the Commission as the basis for determining the stranded generation costs of Pennsylvania utilities.

- Assisted generator clients in assessing the future economic competitiveness and appropriate purchase price of existing generating assets in New England, New York, and California.

- Led detailed dispatch simulations of electric utility systems -- including the NEPOOL, PJM and ECAR regions of the U.S., the state of Maharashtra (India), and numerous individual U.S. utilities -- to identify the implications of alternative resource choices and planning assumptions on market prices and revenues.

- Determined the amount of additional generating capacity required by the Puerto Rico Electric Power Authority to maintain its system reliability objectives, and identified the sensitivity of those needs to alternative outcomes for key parameters. Successfully presented the results in testimony before the Planning Board of Puerto Rico.

- On behalf of the World Bank, assisted in La Capra Associates' review of technical and policy issues related to the acquisition of non-utility power in India.

- On behalf of U.S. state regulatory agencies, performed comprehensive analyses of numerous wholesale electric power transactions, including domestic and international transactions of up to 20 years in duration, based on analysis of the expected costs and the role of the transaction in each purchaser's supply portfolio.

## EXPERIENCE

**La Capra Associates** — Boston, MA
*Technical Director* — December 1990 to Present

**Vermont Department of Public Service** — Montpelier, VT
*Electrical Planning Engineer* — October 1988 to December 1990

## EDUCATION

**B.S., Brown University, 1986**
Mechanical Engineering with Energy Conversion emphasis

**EPRI Seminars on Utility Planning and Production Costing Techniques**

**Users' group and training seminars associated with the UPLAN and ENPRO production costing models**

**VII. CITIZENS SHOULD HAVE BEEN AWARE, PRIOR TO THE JULY 2000 BILLINGS, THAT IT COULD HAVE A PROBLEM WITH BILLS IN THE SUMMER OF 2000**

**Q. Should Citizens have been aware, before the summer of 2000, that its summer power costs could be higher than normal?**

A. Yes, it should have been aware that its summer power costs could be higher than normal. Since its power bills depended on a number of elements that were outside of its control and not perfectly predictable, Citizens could not have known for certain that its power costs would be significantly higher than normal, which proved to be the case. However, it should have expected that its bills would be higher than the previous year and, by early spring of 2000, it should have known that there was a reasonable possibility that power costs would be much higher than historic costs. In any event, once Citizens learned that APS's SIC implementation tied to market purchases, they should have realized they were substantially exposed to market price risk that was outside of its control and not perfectly predictable.

**Q. Was Citizens aware ahead of time that APS would need to purchase power to meet load in the summer of 2000?**

A. Yes. The billing dispute that began in the summer of 1999 was triggered because APS purchased power to meet Citizens' load for some months in 1998. There were a number of months in 1999 when APS had to purchase power to meet Citizens load, and charged a minimum bill based on the disputed SIC. In response to a discovery response about its expectations for the summer of 2000, Staff Data Request 7.13, Citizens indicated that it "...was aware that APS/PWEC did not have adequate system generation to meet its native load plus Citizens load."

**Q. What was the trend in market prices during late 1999 and early 2000?**

A. As I will describe below, several key drivers of electricity market prices appeared worse in late 1999 and early 2000 than in previous years. As a result, forward market prices for energy deliveries in summer 2000 were increasing, and were significantly above historical levels.

**Q. What kind of information on the electricity market is available to a small company such as Citizens?**

A. Citizens personnel regularly viewed market prices and read industry publications, according to the response to Staff Data Request 5.36. There are a number of publications available that provide valuable market intelligence. *Power Markets Week*, for example, is a weekly publication that provides information on prices and other market price drivers. The Western Systems

Coordinating Council ("WSCC") releases a number of public reports on loads, generation, and other factors specific to the western market. Specific public sources for information about supply/demand conditions in the western market include:

- WSCC's report entitled "Existing Generation and Significant Additions and Changes to System Facilities, 1999 – 2008" (issued April 1999);
- The California Energy Commission Staff's report entitled "High Temperatures & Electricity Demand, An Assessment of Supply Adequacy in California" (issued July 1999);
- WSCC's report entitled "Summary of Estimated Loads and Resources" (issued October 1999).

Citizens could have accessed all of these information sources with relative ease. Citizens could also have availed itself of additional market intelligence, proprietary analyses, and trading expertise by retaining consultants.

**Q. What information would be the basis for expecting that power costs might be higher than the previous year?**

A. The most basic information would be supply and demand conditions in the market. If an examination of the growth in supply and demand revealed that demand was growing faster than supply, one would expect that higher prices were likely. The forward market, which prices future contracts, provides a measure of what other market participants expect future prices to be. Conditions in fuel markets and in hydro supplies also would provide clues. Rising fuel prices would suggest higher electric prices; lower hydro supplies would suggest the same.

**Q. What was the demand growth situation for Arizona and the region?**

A. WSCC had been experiencing steady electricity demand growth, which was forecast to continue. For the period 1995 to 1998, energy consumption in WSCC grew at an average annual rate of 2.5% and peak demand grew at an average rate of about 4.0%. Energy consumption for WSCC for the period 1999 through 2005 was forecast[2] to grow at an average annual rate of about 1.6% with peak demand growing at about 1.7% average annual rate. The forecast of energy consumption and peak demand for the desert southwest showed even more robust growth. Energy consumption was forecast to grow by about 2.7% and peak demand by about 2.9% annually, over the 1999 to 2005 period.

**Q. Had generating capacity additions in Arizona and neighboring states kept pace with demand?**

A. No. For the region encompassing California, Arizona, and New Mexico, generation increased by only 210 MW from January 1997 to January 1999 (WSCC Existing Generation and Significant Additions-Changes to System Facilities, January 1, 1999). This is out of a total generation base of over 75,000 MW, or an increase of less than one percent. Furthermore, available generation actually declined in the Arizona – New Mexico sub region from January 1998 to January 1999. This information was readily available from the WSCC.

**Q. What was the forecast for generation additions for Arizona / New Mexico in 2000?**

A. The WSCC, in 1999, forecast generation additions in 2000 for the Arizona, New Mexico region of 7 megawatts, out of a total installed capacity of around 19,000 MW. For the combined region of California, Arizona, and New Mexico total generation additions of 824 MW, or 1% of the total generation base, were forecast to come online in 2000. Given the long construction time for new generating units, the likelihood of large unanticipated amounts of new capacity entering the market quickly tends to be small.

**Q. What was the supply and demand situation for the region in recent years?**

A. The West in general and Arizona more specifically faced a situation where demand was beginning to outstrip supply. Attachment S-4 presents the WSCC's

[2] "Summary of Estimated Loads and Resources," (WSCC Technical Staff, May 2000)

summary (published in October 1999) of actual loads and resources during 1998. Page 1 of the exhibit summarizes the Arizona-New Mexico-Nevada area; page 2 presents the same information for the California – Mexico area.

The WSCC documents show that in Summer 1998, the actual margin of reserves over firm load for Arizona/ New Mexico dropped to 5.1% (1,033 MW) in August. For four summer months the reserve margin was at or below 10.4%. Actual reserve margins in the California-Mexico area dropped to 7.7 and 8.2 percent in August and September 1998, respectively.

**Q. Did these capacity margins in 1998 reflect an unusually unfavorable combination of circumstances?**

A. No. If anything, the 1998 results reflected a combination of favorable outcomes with respect to generator outages and electricity demand.

Attachment S-4 shows that total unavailable capability in the Arizona-New Mexico-Nevada area was between 196 and 424 MW during the four summer months of 1998. Unavailable capability in the California-Mexico area was less than 650 MW, out of more than 54,000 MW of installed capacity. Attachment S-5 shows historical unavailable generation for these areas during peak demand conditions, as reported by the California Energy Commission in a July 1999 report.[3] This exhibit shows that actual average outages experienced in each area from 1988 to 1997 were much higher than the actual 1998 results, and that actual outages in some years were thousands of MW higher. All else equal, more normal outage patterns would produce significantly lower reserve margins and a tighter energy market.

With respect to electricity demand, it is well known that air conditioning is an important end use and that high temperatures can drive up demand substantially.

[3] "High Temperatures & Electricity Demand, An Assessment of Supply Adequacy in California" (CEC Staff, July 1999).

Attachment S-6, taken directly from National Climatic Data Center[4], illustrates average summer temperatures from 1990 through 2001, and ranks them over that period and over all years since 1895. Pages 1 and 2 of the exhibit present this information for Arizona and California, respectively, with higher rank values representing higher temperatures. The low rankings for the past few summers (i.e., 1998 and 1999) indicate that average temperatures in each area were moderately cool from an historical perspective. While average temperature is not a perfect indicator of air conditioning load, it is clear that temperatures and electricity demand could easily turn out higher than they had in 1998 and 1999.

**Q. Looking forward to 2000 from 1999, what was the supply/demand outlook?**

A. Attachment S-7 (2 pages) presents the WSCC's summary of monthly supply and demand in the Arizona-New Mexico-Nevada area for 1999 and 2000. The document shows nominal summer reserve margins (the bottom row of numbers) of 13.4 to 18.8 percent in 1999, and 17.7 to 21.0 percent in 2000. The key points about it are:

- Summer peak demand (including interruptible) was projected at 21,070 MW, an increase of 641 MW from actual 1998;
- Total generating capacity in the region was projected at 19,317 MW, an increase of 485 MW from 1998;
- Total generator availability was assumed to be essentially zero; compared to typical historical outages of over 1,000 MW;
- Firm/joint imports were projected at about 3,700 MW, an increase of about 1,300 MW from 1998;
- In addition to the increase in firm imports, the category "Planned Purchases and Sales" was assumed at over 3,000 MW (amounting to over 14 percent of the regional peak demand) during July and August 2000. This category represents assumed purchases that had not yet been contracted. The WSCC presentation was showing that the Arizona-New Mexico-Nevada area would be relying on a large

[4] Website of the National Oceanic & Atmospheric Administration: http://www.NOAA.gov/climate.html

increase in purchases from neighboring regions which were themselves experiencing declining reserves and were exposed to weather and generator outage risks.

The WSCC document showed more than adequate capacity reserves for Summer 2000, due primarily to its optimistic assumptions regarding generator unavailability and purchases from outside the area. As shown in Attachment S-8, the CEC confirmed in a 1999 report[5] that from 1988 through 1997, actual reserves in the WSCC have consistently turned out much lower than indicated by WSCC projections.

The WSCC summary does, however, show the sensitivity of the supply/demand outlook to alternative outcomes. For example, Attachment S-9 assumes a typical historical outage level of 1,100 MW (with no other adjustments) and obtains reserve margins of 8 to 13 percent for Summer 1999. It was apparent that if demand or generator outages turned out significantly higher than normal, or if import purchases did not materialize as assumed, reserve margins for the area could easily fall below five percent.

**Q. What does the supply/demand situation mean for potential price levels?**

A. This situation indicated a tightening supply situation. As had been experienced in the summers of 1998 and 1999, which received extensive press coverage, tight supply can lead to very large market price increases. Prices increase for two related reasons: because higher cost units are utilized, and, as demand approaches the level of available supply, because of tight supplies (or, in the extreme, shortages). The combination can lead to prices that are greatly in excess of the variable production cost of the most expensive unit being utilized (sometimes called the marginal unit).

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[5] "High Temperatures & Electricity Demand, An Assessment of Supply Adequacy in California" (CEC Staff, July 1999)

Prior to Summer 2000, spot market prices in most eastern electricity markets had already exhibited large spikes during tight supply conditions. For example, Attachment S-10 illustrates that spot market energy prices in the PJM Interconnection jumped to a monthly average of about $162/MWh in July 1999, despite never having averaged more than $51/MWh in any month since the market's inception. Energy price spikes in PJM were limited to some extent by a $1,000/MWh energy price cap; other eastern markets had shown even greater price spikes. During several days in June and July 1998, prices for on-peak energy trades at the Cinergy hub exceeded $1,500/MWh. Due largely to the effects of such high-price days, average daily prices at Cinergy for these months averaged about $263/MWh and $149/MWh, respectively. These prices compare to typical monthly on-peak average prices of $20 to $40/MWh. While the specific circumstances in these markets differed in some respects, the point here is that well before 2000, eastern U.S. electricity markets had shown that tight supply conditions can translate to very large price increases.

**Q. What other observable factors could affect the supply / demand situation?**

A. Weather and the availability of hydroelectric generation also influence the supply / demand balance. Weather is probably the biggest influence on electricity demand. A California Energy Commission study[6] showed that on the peak electricity demand day in California, an increase in the temperature of five degrees translates to an increase in peak demand for California of 8.5%. The study also showed that with temperatures that occur in one out of every 5 years, Arizona would have only a 1% reserve margin, and with temperatures that occur in one out of every 40 years, the reserve margin would turn negative. This suggests that if summer weather has been lower than normal, demand will go up as temperatures climb to or above normal.

**Q. What is the role of hydroelectric generation in the western market?**

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[6] Ibid.

A. Both California and the Pacific Northwest are heavily dependent on hydroelectric generation, which can vary significantly from year to year. In years where hydro production is reduced due to limited water, the Pacific Northwest has less energy to export and California must look elsewhere to replace the diminished hydroelectric generation. In years of low hydro production in the Pacific Northwest and, especially, California, added demand is placed on electricity generated in Arizona. Furthermore, hydroelectric generation operating costs are very low, so when it is not available the power is replaced from thermal units which are more expensive on an operating cost basis, sometimes by a significant degree.

**Q. What was known in the spring of 2000 about potential hydro production in the upcoming summer?**

A. The Northwest River Forecast Center, a department within the National Oceanic and Atmospheric Administration, releases periodic forecasts of the water available for hydro production. As early as the middle of February, the Northwest River Forecast Center was warning of below normal water flows, and therefore hydro production, for the summer. This forecast was reported in the February 21, 2000 issue of *Power Markets Week*.

**Q. What other factors are indicators of the direction of electric prices?**

A. Fuel prices are a major component of electric prices, so that as fuel prices increase, electric prices can also be expected to increase. This is particularly true of the price of natural gas, since this fuel is used to produce output on the margin (and therefore affect market clearing prices) much of the time, and particularly during summer peak hours. For example, for a gas-fired unit with a heatrate of 10,000 BTU/kWh, a gas price increase of $1.00/mmBTU would translate to an increase of $10/MWh.

**Q. What could be observed regarding gas prices?**

A. Attachment S-11 illustrates daily spot gas prices at Henry Hub (Louisiana) from January 1998 through April 2000. The exhibit shows that natural gas prices drifted significantly upward during late 1999 and early 2000. For example, prices from September 1999 through April 2000 averaged over \$2.50/mmBTU, compared to prices under \$2.00/mmBTU during late 1998 and early 1999. By March, prices had increased by about \$1/mmBTU compared to early 1999 values. Attachment S-12 illustrates monthly average spot gas prices in the first three months of 1998 through 2000.

**Q. Were there any explicit warnings in the trade press indicating the possibility for high market prices in summer of 2000?**

A. Yes. For instance, ICF/Kaiser Consulting Group, in announcing the publication of its 1999 Bulk Power Outlook, warned that surplus hydro conditions in the past few years had masked the tightening supply / demand balance in the west. The announcement went on to report[7]:

- "The West stands at least a one-in-three chance of experiencing price spikes similar to those seen in the Midwest during the summer of 1998."
- "Price spikes were more likely to occur in summer of 2000 than summer 1999 due to expected favorable hydro and weather conditions in 1999."
- "Despite above average hydro supplies, western market prices had been increasing."
- In the event of above-normal summer temperatures, supplies could be very tight. "Pre-conditions are there for a very precarious situation…"

**Q. How did forward prices in the Southwest behave prior to summer 2000?**

A. Forward prices represent prices at which buyers and sellers agree to exchange power during a future delivery period. Forward prices for deliveries in the summer months of 2000 showed a noticeable increase over previous years. The average price of a third quarter 2000 forward contract at Palo Verde, an active

[7] As reported in *Power Markets Week* June 7, 1999.

trading hub, was \$63.46/MWh[8]. This compares to an average life-of-contract price of \$51.00/MWh for third quarter 1999 contracts and \$40.22/MWh for third quarter 1998 contracts. Summer 2000 forwards were also significantly above actual 1999 spot prices.

For deliveries in the four summer months June through September 2000, the monthly average of forward prices from July 1999 through April 2000 were at \$40.08, \$56.43, \$72.33, and \$58.62, respectively. Spot prices in the summer of 1999 for on peak power for June through September were \$32.68, \$41.49, \$42.71, and \$33.40, respectively. Attachment S-13 shows the monthly averages for these forward prices and historical spot prices. Attachment S-14 shows that from December 1999 through April 2000, forward prices for Summer 2000 deliveries at Palo Verde gradually increased from about \$55/MWh to \$70/MWh.

The forward and spot price data show that market expectations over the 9 months preceding May of 2000 were that prices in the summer of 2000 would be at least 20% higher (and over 70% higher in some months) than the actual monthly average spot price for the same month in the summer of 1999. It appears that market participants saw the potential for significant spot price increases, likely based on the supply/demand and fuel price considerations that are discussed in the past several pages.

**Q. Do forward prices indicate the maximum prices that may occur in the future period?**

A. No, forwards represent fixed prices at which willing sellers and buyers commit at a particular time for deliveries in some future period. Forward prices for a given delivery period thus represent the middle range of expectations about future spot prices for that period. Hotter weather than expected, higher fuel prices, the

[8] The average price was calculated based on transactions from July 1999 through April 2000. Reported in Power Markets Week.

failure of large generating units or transmission lines could all cause prices to climb much higher.

**Q. What does Citizens say about its expectations for power prices in 2000?**

A. Citizens stated that it "...did understand that a possibility existed of being billed subject to the ceiling or billing provisions of the contract prior to May 2000." (Response to Staff Data Request 5.17) In response to Staff Data Request 6.14, Citizens stated that it "...did not have information that led it to believe that wholesale electricity prices would increase as dramatically as experienced in the summer of 2000." In other words, it was aware that its bills might be determined by market prices (the incremental cost of APS's purchased power) and that there was potential for higher prices, but it did not anticipate the actual magnitude of extreme market prices that actually resulted.

In the same data response, Citizens stated that "the contract definition of SIC effectively shielded the Company and its customers from high wholesale prices". This was in spite of the fact that Citizens argued with APS from the summer of 1999 about this definition, and its position had not prevailed by the summer of 2000.

**Q. Knowing that its bills might depend on the System Incremental Cost, did Citizens project what SICs might be in the summer of 2000?**

A. No. Although Citizens was aware that it might have a problem, it has not indicated that it made any attempt to estimate the magnitude of the potential problem. In response to Staff Data Request 5.19, it stated that it "did not prepare estimates of SIC pricing prior to May 2000."

**Q. Even if Citizens could not know how high summer of 2000 spot market prices would turn out, should it still have been concerned?**

A. Yes. A much lower price increase than actually occurred would still have created significant problems with summer bills. Citizens' costs for Schedule A in the summer of 1999 were still based on nominal pricing, at about 3.7 cents per kWh. If Schedule A had been based on market prices, the Company's entire load would have been impacted by the market. For example, forward prices in April of 2000 for the third quarter of 2000 were 2.5 cents per kWh higher than actual spot prices in the third quarter of 1999. This would have increased their power costs by about $9 million.

Citizens was clearly aware that APS believed it could charge Citizens its market prices. It should have been aware that load in the summer of 1999 in Arizona and the Southwest region was lower than normal, since summer temperatures had been relatively low. Citizens knew that it had been subject to the minimum bills provision of the Old Contract in a low load year. It should have known that there was significant load growth in Arizona, and that APS had not built any new generation. These conditions all suggested that APS would need to purchase to supply Citizens. As long as market prices were higher than the fixed prices in the contract, much of the summer bills would have been based on the minimum bill calculation, even in normal market conditions.

**Q. Would there have been a symmetric expectation that the SIC could be much lower than historic values?**

A. There should not have been. Citizens itself argues that prices could increase more than they could decrease, in defending its negotiation of the fixed price contract. It notes, in response to RUCO Data Request 4.5, that potential price variation is asymmetrical. Prices couldn't fall below the marginal cost of production. However price increases could be much greater. Not only could the marginal cost of production increase significantly, but prices could increase well above the marginal cost of production due to shortages of supply. Further, as discussed above, WSCC had not, in recent years, experienced a combination of relatively high loads, poor availabilities and low hydro.

## VIII. WHAT CUC SHOULD HAVE DONE PRIOR TO THE SUMMER OF 2000 THAT MIGHT HAVE REDUCED ITS FUTURE BILLS

**Q. Could Citizens have taken any actions prior to the summer of 2000 that might have prevented or minimized the problems that arose during the summer?**

A. Yes. It could have: (1) attempted to renegotiate its contract as soon as it became aware of how APS was interpreting the SIC; (2) made a greater effort to settle the SIC issue; (3) sought to hedge market prices for the summer; and (4) taken actions to get more value from its Valencia units.

**Q. What might contract negotiation have accomplished?**

A. The consummation of any contract takes two willing parties But, ideally, the contract would have contained some obligation for APS to minimize costs, clearer definitions, a guarantee of Citizens' ability to audit all bills, and definitions of all minimum bills and other pricing provisions so that there was full knowledge of the basis for prices. The lack of clear definitions and protection to Citizens were particularly important as APS began to depend more on purchases, which Citizens was aware increased the impact of the SIC definition.

One cannot be certain that Citizens and APS would have consummated a mutually satisfactory contract along the foregoing lines. On the other hand, however, one can be confident that the chances of success would have been improved had there been a more timely and more extensive effort to do so.

**Q. How might Citizens have attempted to resolve the SIC issues, outside of negotiation with APS?**

A. Citizens could have gone to FERC to clarify the SIC dispute. As of April 17, 2000, it was clear that APS still interpreted the SIC as including all purchases (LS5.16). If Citizens believed this was a misinterpretation of the contract, it should have clarified this issue.

Another disputed issue involved APS including forward power purchases in its computation of the SIC. Once Citizens' consultants identified this as a problem the Phase I Audit Report, Section D, this could also have been pursued at FERC.

**Q. How and why could Citizens have hedged its potential price volatility?**

A. In the first months of 2000, signs were increasing that indicated prices could be very high in the summer. Citizens knew that the SIC issue was not resolved, so that it might be subject to market prices. Given this situation, it could have requested APS to purchase forward power for them. A forward purchase or other type of future commitment is not a guarantee of lower prices, but is a means to reduce risk. For instance, in a situation in which one believed there was an equal probability that prices could double and that they could fall by 10%, it would be worth paying something (of course, weighing the costs and benefits) for an "insurance policy" that limited the potential price increase. Citizens might have had to pay some premium to APS, but with such an agreement, there is no obvious reason why APS would not have been willing to make a forward commitment for Citizens. At the least, an analysis of the situation by Citizens and a subsequent request to APS to implement its post-analysis strategy would have been prudent.

**Q. What would the savings have been from a reasonable hedge?**

A. We have estimated that if APS had purchased a reasonable block of peak period forward power for Citizens in January, February, March or April, this would have reduced summer bills by $10 million. Specifically, if APS had purchased a block of flat power of 100 MW for Citizens for the summer peak period, which is well below the Citizens minimum load, at average forward prices, and Citizens had in addition paid a premium or adder of two mills per kWh to APS, this power could have replaced much more expensive power. Attachment S-15 illustrates the potential cost savings for the July – September period, if the hedge had been purchased in January, February, March or April.

**Q. Were there other options that could have been pursued?**

A. Yes. Citizens could have sought a financial hedge for part of load. For instance, it could have looked for a product that would have fixed the price for most of its base load, at least for the summer period.

**Q. How could greater use of the Valencia units have reduced the undercollection problem?**

A. The Valencia units are three small peaking units. They could use either oil or gas as fuel, so that, to some extent, they could switch to the lower cost fuel. Although these units had fairly expensive running costs (about $0.13/kWh) (Response to RUCO Data Request 4.16), the cost could often have been less than peak period market prices. If the units were operated at 30-40 MWs during the most expensive portion of the day, that would have meant much less power purchased at peak prices.

The units' primary purpose was to serve as backup in case of an interruption on the single transmission line serving the Nogales area. If the single transmission line to the Nogales area is incapacitated by a lightning strike, the Valencia units are necessary to restore power to the Nogales area. This requires that when storms are predicted the units are brought up to 100% of capacity but are not connected to load.

When the units are not needed because of a storm interruption, the units could be operated for economic reasons.

Citizens was concerned that more frequent running could have reduced the units reliability when they were needed for backup. However, it was possible to make investments that would increase the ability to run the Valencia units when they cost less than the cost of purchased power.

**Q. Why do you believe the units have been used to reduce Citizens' power costs even before these investments were made?**

A. Citizens had a permit to run the units for 1000 hours. Some of these hours could have been used to run the units for hours when it expected that market prices would be higher than 13 cents per kWh, and in months when Citizens anticipated that it would be charged on the basis of SIC pricing.

**Q. Citizens has made expenditures on the units since the fall of 2000. Please comment on these investments.**

A. According to the response to Staff Data Request 8.37, Citizens began making improvements to the Valencia units in the fall of 2000. If these expenditures were necessary to run the units for more hours, they have proven economic. In May and June of 2001, the units were operated for economic reasons, reducing power costs by $900,000 in May alone. The Company spent $784,000 in capital costs or in operating and maintenance costs that would be capitalized, and $241,000 in additional labor costs on the Valencia units. Except for the expenditure associated with emissions testing that may allow the units to be run for more hours, these expenditures might well be considered routine reliability expenditures. I note that in the New Contract Citizens has given up the right to operate the units for economics, so future benefits will accrue to APS.

**Q. Do we know whether Citizens could have made these investments prior to the summer of 2000?**

A. This would depend on the start date, but the record does not make this clear. Evidently Citizens did make these investments in about six months. Possibly they could have been completed in less time than was actually utilized. If it did require six months to complete the work, and they began the effort in January of 2000, these improvements would have been made by July 2000 and have had substantial impact on the Summer 2000 costs. If some of these expenditures were necessary to run the units for additional hours, which is not clear, they would have been a reasonable hedge against the substantial market exposure Citizens had in its Old Contract.

**Q. Have you estimated the dollar savings that could have resulted from running the Valencia units?**

A. Yes. I estimated, based on a detailed look at four days in June, that the Valencia units could have saved about $140,000 per day. This assumed that they were run for 13 peak hours a day, at the same output level that they actually produced on a typical day in May 2001. Their emissions limitation should have allowed them to be operated for at 30-40 days. This suggests that the total savings from running the Valencia units could have been $4 to $5 million. Even if this required some investment, it appears that additional use of the units during expensive hours could have saved customers about $4 million.

**Q. Could Citizens have reduced its bills by resolving, in its favor, the dispute over whether reliability purchases belong in the SIC?**

A. Yes. However, Citizens did pursue this issue with APS to no avail. It appears unlikely that if they had brought the issue to FERC in the spring of 2000, as it became evident they could not reach agreement with APS; they would have received an order by the summer of 2000. However, Citizens might have achieved a refund by pursuing the issue.

## IX. ACTIONS CITIZENS SHOULD HAVE TAKEN DURING AND AFTER THE SUMMER OF 2000 TO REDUCE FUTURE BILLS

**Q. Do you believe there were any actions that Citizens could or should have taken during and after the summer of 2000 that might have reduced future costs?**

A. Yes. Citizens could have asked FERC to clarify the definition of the SIC. A ruling in favor of Citizens' interpretation of the SIC would have resulted in APS refunding significant amounts to Citizens and changing its billing methodology so that future bills would have been lower. There are other issues raised by Citizens' audit consultant that it could have raised in front of FERC that could have resulted in a reduction to its bills.

**Q. Specifically, what other issues could have been raised by Citizens?**

A. Citizens also could request FERC action regarding APS' treatment of forward contracts in its SIC computation. Its own audit showed that APS' method of reflecting forward purchases in the SIC always resulted in higher cost to Citizens.

As noted earlier, the contract does not define the SIC clearly. According to APS' interpretation, it would include purchases. Section III of the contract, described above, suggests that purchases that were necessary to serve Citizens would be included. This is still not definitive. APS' supply is not adequate to serve its load in many hours, so that APS makes many purchases of varying types, volumes, and durations. In many hours, it would have to make purchases even if it were not serving Citizens' load. APS' obligation to serve Citizens' load would have affected APS' unit dispatch and purchasing decisions, but there is no obvious designation of any particular purchases as being associated only with Citizens' load. Given the lack of specificity in the contract, it is useful to examine the various options by which APS could have identified certain contracts as associated with Citizens, and therefore the basis for the SIC in the contract. These include the following:

- Assign to Citizens the cost of contracts that were made last in time;
- Assign to Citizens the cost of contracts that were made first;
- Assign to Citizens a set of specific purchases, including both forward and spot;
- Assign to Citizens the average price of all APS purchases in each hour.

Since utilities tend to build a portfolio with purchases assigned over time, the latter seems the closest to representing the purchases made to serve Citizens' load.

How APS actually computed Citizens' bills differs from all of the above methods. APS ranked its supply sources by ascending price, and assigned the highest-cost source to Citizens in every hour. This approach does not appear to have any logical basis in portfolio planning, and by definition produces the highest possible SIC result and in turn, the highest possible bill to Citizens. It would seem that Citizens would have reason to raise this issue in front of FERC but we have seen no indication that they have. This alternative interpretation seems more consistent with Section III of the Service Schedules than APS' definition. It also, as discussed later, had the potential to reduce bills substantially.

**Q. Is this argument consistent with findings of Citizens' audit consultant?**

A. Yes. I have not seen any evidence that the consultant offered an alternative method of SIC pricing, but the consultant raised this issue as a problem with the bills, describing this treatment of forward purchases as the heads APS wins, tails Citizens loses approach.

ORIGINAL

# BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC DIVISION OF CITIZENS COMMUNICATIONS COMPANY TO CHANGE THE CURRENT PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE RATE, TO ESTABLISH A NEW PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE BANK, AND TO REQUEST APPROVED GUIDELINES FOR THE RECOVERY OF COSTS INCURRED IN CONNECTION WITH ENERGY RISK MANAGEMENT INITIATIVES.

DOCKET NO. E-01032C-00-0751

DIRECT

TESTIMONY

OF

LEE SMITH

ON BEHALF OF

ARIZONA CORPORATION COMMISSION STAFF

FEBRUARY 8, 2002

## I. INTRODUCTION

**Q. What is your name and business address?**

A. My name is Lee Smith, and I work for La Capra Associates, 333 Washington Street, Boston, Massachusetts.

LaCapra Associates ("La Capra") is a consulting firm specializing in electric industry restructuring, energy planning, market analysis, and regulatory policy in the electricity and natural gas industries. For twenty years, we have served a broad range of organizations involved with energy markets -- public and private utilities, energy producers and traders, financial institutions and investors, consumers, regulatory agencies, and public policy and research organizations.

**Q. On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of the Arizona Corporation Commission ("Commission" or "ACC") Staff.

**Q. Please describe your background and experience.**

A. I am a Managing Consultant and Senior Economist at La Capra Associates. I have been with this energy planning and regulatory economics firm for 18 years. Prior to my employment at La Capra Associates, I was Director of Rates and Research, in charge of gas, electric, and water rates, at the Massachusetts Department of Public Utilities. Prior to that period, I taught economics at the college level. My resume is attached as Attachment S-1.

**Q. What is the purpose of your testimony?**

A. My testimony presents the Staff's assessment of the Arizona Electric Division of Citizens Communications Company ("Citizens") application for changes to its Purchased Power Fuel Adjustment ("PPFAC") and recommendations for Commission action on that application.

**Q. How was your testimony prepared?**

A. The testimony was prepared in conjunction with Mr. Douglas C. Smith, who is La Capra Associates' Technical Director. Mr. Smith had primary responsibility for the issues associated with power markets, regional demand and supply conditions (Section VII), and he assisted me with the contract and risk mitigation issues addressed in Sections VIII and IX. The testimony was prepared as a single piece to facilitate the presentation and discussion of the issues, which are inter-related.

**Q. Would you please summarize briefly your major findings and describe your recommendations?**

A. From my review of Citizens' application, I conclude that the Company's purchased power costs were higher than necessary due to inadequate management of the power supply contract and lack of actions to mitigate the price risks inherent in the contract. Specifically, I found that:

1. there was a significant lack of clarity in key floor pricing provisions in the power purchase contract with Arizona Public Service ("APS") that was in effect from 1995 through 2001 (the "Old Contract"), which Citizens did not readily recognize and, when recognized, did not take proper steps to mitigate reasonably foreseeable price risks and increases; and
2. Citizens continues to fail to address potential overbilling related to bills from May 2000 to May 2001 under the Old Contract

Based on these findings, I recommend the following:

1. a reduction of $7 million in the $87 million underrecovered power costs;
2. that Citizens not be allowed to collect $49 million until it has pursued overbilling issues;
3. that Citizens be allowed to collect the remaining $31 million;
4. that Citizens be allowed to collect additional underrecovery under the New Contract, subject to review;
5. that such collection be allowed over 6 years with no carrying charges.

Lastly, I recommend that the Commission approve an increase in the PPFAC to reflect higher costs in the New Contract (effective, June 2001) and higher transmission costs, subject to future review, on the basis of a formula that will reflect actual incurred costs, as the current formula does.

## II. BACKGROUND AND MORE DETAILED SUMMARY

**Q. What is Citizens requesting in this proceeding?**

A. Citizens is requesting several changes to its Purchased Power Fuel Adjustment. These include:

1. a factor that would collect $87 million of underrecovered fuel costs (resulting from its Old Contract) plus additional underrecoveries from June 2001 over 7 years with a carrying charge of 6%,
2. an increase in the basic factor to reflect the fixed pricing in the New Contract with APS, and
3. a small increase in the basic factor to reflect increased transmission costs;

**Q. What caused the large undercollection?**

A. The pricing provisions of the Old Contract with APS included floor price provisions which became the operative pricing provision beginning in 1998 and caused the contract prices to increase dramatically, particularly in 2000 and 2001. Beginning in May of 2000, these price increases caused Citizens' bills under the Old Contract to increase dramatically, such that Citizens' power purchase costs were greater than the total amount of revenues Citizens was receiving from the PPFAC, including power costs recovered in base rates. The Old Contract, which accounts for the $87 million at issue in this proceeding, was in place between 1995 and June 2001. In June 2001, Citizens and APS entered a New Contract, replacing the Old Contract. This New Contract, while addressing some of the concerns with the Old Contract, also results in costs above that which care being recovered within current PPFAC rates. The underrecoveries since June 2001 under the New Contract are not included in the $87 million request in this proceeding, but will add substantial amounts to the underrecoveries total from June 2001 to current and into the future.

**Q. Please describe the Old Contract.**

A. Broadly described, the Old Contract was for all of Citizens' load, other than that which Citizens might provide from its Valencia units. As I noted earlier, the Old Contract was in place between 1995 and June 2001. The contract was structured with nominal, fixed price schedules with provisions for floor and ceiling pricing. The contract itself is in five (5) parts, four of which are dated 1995:

1. "Power Services Agreement",
2. "Service Schedule A" (baseload),
3. "Service Schedule B" (supplemental capacity),
4. "Service Schedule C" (supplemental peaking energy).

The fifth document, dated 1998, is the "Stipulation No. 3 of Charges…," which contains the prices negotiated in that year.

**Q. What caused the bills under the Old Contract to increase dramatically beginning in May 2000.**

A. As noted earlier, the price for power purchased under the Old Contract increased as the floor price provisions became operative and escalated significantly in 2000. In that period, APS's own supplies became short, causing it to require market purchases to meet its own and Citizens' load requirements. This need to go to the market coincided with the significant jump in market prices in California and throughout the West beginning in May of 2000. Citizen's cost increases were further exacerbated by ambiguities in the Old Contract language pertaining to the methods for deriving the floor prices.

**Q. How is the floor pricing linked to market prices?**

A. The floor (minimum) price in the Old Contract is based upon APS' System Incremental Cost ("SIC"). Minimum bills under Schedules A, B, and C would be predicated on the SIC computation.

When APS requires purchased power, as it did in 2000, to meet its obligations, the power is purchased in the market and market prices enter into the derivation of the floor pricing.

**Q. How did ambiguities in the Old Contract affect the prices under the contract?**

A. As I will discuss further on in my testimony [Section V], the core of the problem here is that the contracts did not provide for an unambiguous way to calculate the SIC, and thus minimum prices, at any given time. This resulted in a dispute between Citizens and APS over the application of SIC in the Old Contract, resulting in increased costs to Citizens.

**Q. How did Citizens' management of the Old Contract affect the prices under the contract?**

A. Our review of Citizens actions indicates that it was aware of the ambiguities in the Old Contract in 1999 and was unable to resolve the central problem with APS. In addition, in light of the problems with the pricing provisions, Citizens did not take reasonable steps to mitigate the impact of this problem. This matter will also be discussed later in my testimony [Section VIII].

**Q. Please describe the foreseeable price increases and the steps that Citizens might have taken to mitigate their impact (and, hence, the amount of its undercollection of power costs).**

A. It is my view that, heading into 2000, it was evident that there was a significant probability of major wholesale market price increases during at least the summer of 2000. If market prices were to spike, the floor (i.e. minimum) prices in the Old Contract would become critical.

**Q. What evidence leads you to conclude that the possibility of price rises were reasonably foreseeable by Citizens?**

A. By the summer of 1999, Citizens was aware that APS' interpretation of the contract was likely to leave them exposed to market prices in the summer of 2000. In addition, there were numerous signs in late 1999 and early 2000 that prices in the summer of 2000 were likely to be high, including rising gas prices, low hydro resources, and increasing load throughout the West. These and other factors are discussed in more detail in Section VII of my testimony.

**Q. What steps could Citizens have taken to mitigate the impact of the ambiguous pricing provisions and the potential for very high contract prices to its customers?**

A. The steps – which are not mutually exclusive – that Citizens might have taken include: a more intensive renegotiation strategy to mitigate the contractual problems regarding pricing; seeking guidance from the ACC; requesting that the Federal Energy Regulatory Commission ("FERC") assist in the resolution of the dispute; requesting that APS purchase a hedge on Citizens' behalf; additional use of the Valencia units; and perhaps other steps which, presumably, might have included civil litigation.

Citizens should have devised a strategy to manage its power contract, given the signs that prices were likely to rise. The development of the strategy would have required an assessment of the cost and benefits of, at the least, the foregoing possibilities. In my judgment, the failure to have resolved the contractual issues and, at the same time, to remain exposed to the spot market and the ambiguous contract terms when price spikes were foreseeable was not prudent behavior.

**Q. You have just described what steps Citizens could have taken. What steps did it take?**

A. Citizens devoted all of its efforts to an attempt to renegotiate its contract with APS. No other steps were taken, although we did learn – on February 6 – that Citizens did receive some information from its lawyers regarding the viability of litigation against APS. Given the lateness of the provision of that information (my testimony was due on February 8), I have not had a chance either to review it or to ask any subsequent discovery questions. I am reviewing this information and will address it in surrebuttal.

**Q. What is the problem with Citizens' strategy?**

A. The core of the problem that Citizens faced was that it was attempting to negotiate contractual terms with APS at a time when there were indications that higher prices were probable for summer 2000. It is reasonable to assume, and I think that Citizens should have so assumed, that APS might well be reluctant to negotiate terms that could have some significant cost to APS.

**Q. Given the foregoing, what should Citizens have done?**

A. In my judgment, Citizens should have undertaken an assessment of market conditions during the period – starting no later than January 2000 – during which it was negotiating with APS. Had it done so – or if it did, had it acted on the information – Citizens should have realized that finalizing an agreement with APS prior to summer 2000 would have been difficult at best.

In light of this assessment, it should not have relied solely on its renegotiation strategy. In addition to negotiating with APS, it could have (and should have) prepared the Valencia units for greater usage and examined the possibility of acquiring a financial hedge.

I recognize that, if Citizens were to continue negotiation with APS, requesting APS to purchase a physical hedge on its behalf for summer 2000 might have been problematical. However, in light of the problems that could – and evidently did – occur regarding the finalization of a revise contract, Citizens should have given some consideration to requesting that APS purchase a physical hedge, even if it would have jeopardized the negotiations.

**Q. Is it clear that Citizens had assessed market conditions at the time?**

A. No, it is not entirely clear that it did, as its response to Staff Data Request 6.14[1] is somewhat ambiguous in this regard. However, it is my opinion that a failure to examine the prospective market to inform Citizens negotiations and risk management decision making is not prudent. In addition, the prospect of higher market prices and a tightening supply situation would clearly affect APS' willingness to agree to Citizens' view of the way in which its purchases should be priced. It is particularly problematic if the negotiation is the sole component of its strategy.

**Q. Did Citizens understand what is meant by hedges or, more generally, risk mitigation?**

A. Yes. It is clear that at the time of their filing before the Commission – September 28, 2000 – they were understood. Citizens' filing (pages 33-35) requests Commission approval for it to engage in hedging activities. I would expect that these principles and concepts would have been known to Citizens in 1999 and earlier in 2000, as well.

**Q. Does Citizens need Commission approval to engage in such activities?**

A. I do not believe so. However, if Citizens believed that such approval was required, it could have and should have been requested long before September 28, 2000.

**Q. All-in-all, was Citizens prudent in its overall approach to the foregoing matters?**

A. In my view, it was not.

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1 This and other cited responses to data requests are contained in Attachment S-2.

## III. CITIZENS' PPFAC UNDERCOLLECTION AND ORIGINAL APPLICATION

**Q. What was the genesis of this proceeding?**

A. Citizens filed an Application on September 28, 2000 to increase and modify its PPFAC because of a significant increase in its power costs. Citizens had been served by a contract with Arizona Public Service that provided almost all of its power needs. This contract, here called the Old Contract, has been replaced by a New Contract (June 2001), which presently provides power to Citizens. The monthly power bills under the Old Contract increased by as much as 150% from the summer of 1999 to the summer of 2000. The pertinent details regarding the Old and New Contracts are described further on in my testimony.

**Q. Did the events of concern begin in the summer of 2000?**

A. No. The events related to the situation have occurred over a longer period. Due to the complexity of this case, I have attached a timeline as Attachment S-3.

**Q. Did Citizens explain how the costs could have increased so dramatically, given that the Old Contract had served it for since 1995?**

A. Yes. In its application, Citizens attributes the problem to a "a variety of factors, including abnormal weather conditions, increasing demand relative to its available generating capacity, and the volatility associated with deregulation."

**Q. Did Citizens indicate that it believed that its power bills were correct?**

A. No, it did not. Rather, it indicated that it was in the process of conducting an "in-depth analysis" to determine whether its charges were appropriate and if APS had used the least cost resources available to serve it. This in-depth analysis, which has also been referred to as an audit, was conducted by an outside consultant for Citizens. Because of the complexity of the contract, the audit examined other contractual matters and was not limited to a review of the bill computations. For example, the audit also examined whether APS might have increased its system incremental cost (a basis for its charges to Citizens) in a manner that might be contractually inappropriate.

**Q. What was the scope of the audit?**

A. The audit was to encompass three phases.

In Phase I, the audit analyzed the May and June 2000 data. This was completed by the time of the original Application. The Phase I analysis, according to Citizens, determined that Citizens' calculations of APS' unit costs did not differ materially from APS' calculations, and that on two high use days APS was required to purchase power to meet its load. The Application also stated that "included in the scope of the review were APS' details of the calculation of the rate, ceiling, and floor under the contracts." (Application p. 28) The Application did not describe any findings regarding these calculations.

Phase II of the audit was to examine APS' purchases and sales during the remaining summer 2000 period. And, finally, Phase III was to address Citizens' concern with "APS' due diligence in the acquisition of resources", to determine if APS' strategy "resulted in the lowest reasonable cost to Citizens" (Application p. 28).

**Q. In your opinion, what was the significance of the Phase I findings?**

A. A simple explanation is that Phase I established that the billed amounts appeared to be consistent with what was understood to be APS' interpretation of the contract. The increased contract billings were based on at least two factors, both of which required computation by APS: (1) how much power it had to purchase to serve Citizens, and (2) the incremental cost of either its own units or of the power that APS purchased. The purchases included what are referred to as reliability purchases. Reliability purchases, which were more expensive than APS' own units, were made in order to supply load as opposed to economy purchases that were made because they were less expensive than APS' own units.

**Q. Has Citizens since provided additional material regarding the results of Phases I, II and III of the audit?**

A. Some additional material has been provided. Citizens informed parties that Phase III of the audit was not pursued (Staff Data Request 4.27). In response to discovery requests, reports were provided from the earlier phases. On May 23 and June 7, 2001, Citizens submitted a report of approximately 5 pages on the Phase I audit. This report indicated that it found no specific problem with APS' purchases and sales, but that the data on which the report was based was incomplete. In the "Observations" section, it noted that the Contract did not indicate whether the floor for pricing purposes was intended to be monthly, annual, or otherwise.

It also indicated that APS' treatment of its forward purchases was not fair to Citizens. That is, when APS purchases power in advance at less than the spot price, Citizens does not get the benefit of that decision; but if, on the other hand, APS had made an advance purchase that turned out to be more expensive than the spot price, Citizens would be required to pay the cost of that purchase.

**Q. Was any other audit information provided?**

A. Yes. In addition to the foregoing, the narrative results of the Phase II audit were provided on May 2 and May 7, 2001. According to this report, the intent was to examine APS' purchases and sales practices. It found that "most all purchases" (apparently referring to the quantity purchased by APS) could be justified. A review of bill details for May and June indicated "…that APS no longer charged the highest cost purchase for all quantities, but rather charged the weighted average cost to serve the CUC load…" ("Phase II Report-Draft," p. 5, submitted in response to Staff Data Request WPD 3.22).

## IV. NEW CONTRACT AND CITIZENS' AMENDED APPLICATION

**Q. In the Amended Application filed by Citizens on September 19, 2001, did Citizens present additional information and requests to the Commission?**

A. Yes. Citizens stated that its PPFAC balance as of June 1, 2001 was $87 million. It further indicated that it had signed a New Contract with APS with fixed pricing, effective June 1, 2001. Citizens requested: (1) modification of its PPFAC to reflect the collection of the $87 million balance, the amount that the New Contract cost exceeded the amount in the current PPFAC factor; (2) a small increase in transmission costs; and (3) a mechanism that would, in the future, reconcile power costs and revenues, including additional underrecoveries from June 2001. In addition, Citizens requested that it be allowed to collect the PPFAC bank over seven years, with a carrying cost of 6%.

**Q. In the Amended Application and in its Testimony, did Citizens request collection of the entire amount of its undercollected PPFAC bank balance?**

A. Yes.

## V. OLD CONTRACT AND THE DISPUTE WITH APS

**Q. Please describe the Old Contract between Citizens and APS.**

A. As I indicated earlier, the Old Contract is the contract under which Citizens was served from 1995 until June 2001 and which gave rise to the $87 million undercollected power costs. The Old Contract was actually 5 separate documents, the first four of which were dated 1995: the "Power Service Agreement", "Service Schedule A" (baseload), "Service Schedule B" (supplemental capacity), "Service Schedule C" – (supplemental peaking energy), all dated 1995, and "Stipulation No.3 of Charges...." The fifth document contained the nominal or fixed rates negotiated in 1998. Schedules B and C could be cancelled by the end of 2003 (with notice in 2001), but cancellation of Schedule A required a 7 year notice, which could be given no earlier than June 1, 2004.

The contract is a complicated one. Charges are calculated in three different ways. In only one of those ways, "nominal pricing", is the bill determined basically by multiplying nominal (fixed) prices by demand and by energy. The other methods are based on ceiling and minimum charges. If the minimum charge is greater than the nominal but less than the ceiling, the minimum is the amount billed for that month. The ceiling charge was limited to the Palo Verde spot price in the FERC Order on Market Based pricing.

There are several terms found in the Exhibits attached to the three Service Schedules, regarding "Determination of Ceiling and Minimum Rates applicable..." In Section I of this pricing appendix, the Energy Charge is defined as "no less than 100% of APS' SIC, plus up to 10% of SIC." This is further modified so that if the System Incremental Cost ("SIC") is based on purchased power, the additional charge can be no more than one dollar per MWH. Section II states that the "minimum charge for service under Service Schedule [A, B or C] shall be the SIC." Section III of the same Service Schedule Exhibit states that "Citizens shall also be responsible for purchased power costs, and for any other costs incurred by APS in fulfilling its obligations for power and energy under this Service Schedule A which otherwise would not have been incurred."

The Contract specified that minimum bills under Schedules A, B, and C would be based on APS' SIC. The specific definition of the APS SIC, found in the Power Service Agreement Contract No. 48166, is "The higher of either the incremental fuel cost of the station or unit from which energy is obtained, estimated over the applicable range of output as dispatched; or the cost of any purchased power occurring simultaneously with sales under this Service Agreement which were made for economic purposes and would not otherwise be needed to effect transactions under this Service Agreement,..." There are subsequent terms which address transmission, taxes, and other small items which are not in dispute.

**Q. Do you have any concerns regarding the foregoing matters?**

A. Yes, I do. The lack of precision created the possibility for Citizens to be billed under different methodologies, which could cause increases in costs to Citizens. The framework of the contract did not provide Citizens with protections against price increases, disputes about pricing, or even behavior by APS that might be harmful to Citizens. A number of contract terms that would have provided protection to Citizens do not exist. For instance, there is no statement of APS' obligation to provide least cost service, or to minimize cost, or otherwise protect Citizens from APS pursuing its own interests in ways that are harmful to Citizens. The contract does not provide Citizens the ability to request all backup information necessary to audit the contract. APS billing information does not provide enough data to determine how the minimum bills were created; Citizens can only obtain this information through data requests. (Staff Data Request 5.41; Staff Data Request 5.42)

Specifically, a number of the definitions are very imprecise. For instance, the contract language does not contain a specific formula for the SIC; nor does the contract language appear to result in a definitive formula for the measurement of the SIC. An hourly SIC could have been any of the following: (1) the highest cost in an hour; (2) the average of all incremental unit costs or purchases; (3) the average of purchases needed to supply Citizens excluding APS market trading; or (4) the planned purchases made to supply Citizens load. The SIC definition appears in the main contract document and it is not specified whether incremental costs would be computed for all of Citizens load or separately for the 3 schedules.

**Q. Did Citizens indicate that it had any disagreement with its power bills?**

A. Yes. Citizens interpreted the contract term "System Incremental Cost" in a different manner than did APS. This dispute between the two parties was not a result of audit findings, but was the result, simply, of their different interpretations of the contract.

**Q. When did Citizens become aware of the difference between it and APS over this definition?**

A. In May 1999, APS sent Citizens revised bills for January through November of 1998. In the summer of 1999, on the basis of an analysis these bills, Citizens determined that APS was interpreting the SIC definition in a manner which was different from its own definition. (Response to Staff Data Request 8.02, 8.05) This dispute over interpretation of the contract was still unresolved by May 2000, and APS continued to bill on the basis of its interpretation. There was an agreement to settle the financial dispute over the bills from 1998 through April of 2000, and Citizens was refunded approximately $1.5 million of the disputed amount of $4.5 million. (Response to Staff Data Request 7.11) The financial agreement was contained in a so-called Memorandum of Understanding ("MOU"- to be discussed later in my testimony) which also included other matters.

**Q. During the course of interactions between the parties regarding the 1999 billings, did APS make any changes to its methodology?**

A. Yes. In response to Citizens complaints, APS itself redefined its SIC. According to the response to Staff Data Request 8.05, APS had defined the SIC by the most expensive unit dispatched or most expensive purchase, even if that purchase was less than Citizens entire load. Following Citizens' complaint, APS agreed to compute weighted average prices for Citizens' load, as opposed to the most expensive unit or purchase, although it still included reliability purchases which Citizens believed to be inappropriately included.

**Q. Did the MOU addressing the financial agreement over the 1999 billing resolve the SIC disagreement by the summer of 2000?**

A. No. The financial agreement does not mention any resolution of the dispute on principle; nor does it indicate that the financial settlement could serve as precedent for future disputes about the same issue. It is even possible that APS agreed to a reduction in its 1999 bills because it had subsequently redefined its SIC. Citizens admits that at the beginning of 2000 it knew that APS continued to interpret the SIC provision in a different manner from Citizens' interpretation.

**Q. Please describe in detail the basis for this dispute.**

A. As noted earlier, the definition of APS' System Incremental Cost referred to purchased power as: "…the cost of any purchased power occurring simultaneously with sales under this Service Agreement which were made for economic purposes and would not otherwise be needed to effect transactions under this Service Agreement…." According to Citizens, the SIC term should be interpreted so as to include only power purchases which were made for economic reasons: that is, purchases at lower cost that replaced production by a higher cost APS unit (Staff Data Request 4.1). APS, however, interpreted its SIC as including any purchases that were made in order to meet Citizens' load. As mentioned to earlier, Citizens refers to these as reliability purchases. It appears that Citizens is relying on the SIC definition in the contract and APS is relying on Section III of the Service Schedule Exhibits.

**Q. Was this difference in interpretation important?**

A. Yes. Under Citizens' interpretation, the SIC could not be higher than the running cost of APS' most expensive unit. The cost of purchased power would enter into the computation only if it were less expensive than APS' most expensive unit. Under APS' interpretation, however, the SIC would reflect the most expensive power purchased by APS in an hour.

**Q. Did the Amended Application or the testimony mention any other disagreements over power bills?**

A. No. The Company stated that its audit "failed to identify any significant practices that would have resulted in excessive costs for AED [Arizona Electric Division]." (p.3) I should also note that in response to Staff Data Request LS 5.05, the Company noted that the audit did not address contract interpretation.

**Q. Is there other evidence on the record that the audit uncovered additional bases for questioning the power bills?**

A. Yes. The audit indicated several other potential problems with the billing. Notes from the audit consultant indicate, in addition to the difference of interpretation of the SIC, that other problems were: (1) "Sales to third parties not assessed highest cost", (2) the SIC Floor should be one year or life of contract, (3) the "Hourly PV ceiling should be invoked", and (4) "Prudency of not hedging," and how APS treated purchases made in advance (i.e., forward purchases).

I should also add that APS's own redefinition of its SIC would seem to indicate a lack of clarity. Major bill revisions in July of 2000 indicated that APS had changed its own interpretation of the contract again.

## VI. CAUSES OF THE UNDERCOLLECTION

**Q. What were the basic causes of the increase in Citizens' average power costs during the summer of 2000?**

A. The basic cause is the fact that the Old Contract left Citizens exposed to market prices when APS needed to purchase power to meet load. Thus exposed, there were two major causes for the high costs: high loads which caused APS to become reliant on market purchases and high market prices for those purchases. These two factors are obviously interrelated; high loads cause utilities to use more expensive units and, in some circumstances may result in shortage conditions, both of which raise market prices. According to Citizens, the floor pricing provision of the Old Contract was invoked because APS purchased a large amount of expensive power. APS had to purchase power to meet Citizens' load in addition to its own, and the price at which power was purchased was much higher than the base amounts under the contract. Put another way, if APS had purchased a large amount of power, albeit at a cost similar to APS' nominal pricing, there would not have been much impact on Citizens.

**Q. Why did APS have to purchase power to meet load?**

A. There were a few reasons:

a. APS had not built capacity and was short even in the relatively cool summer of 1999;

b. APS' load in summer 2000 was higher due to hot weather and normal growth;

c. Citizens' load in summer 2000 was higher due to hot weather and normal growth.

**Q. Did the APS contract contribute to Citizens' problems?**

A. Yes, although the contract had functioned in accordance with Citizens expectations until at least some time in 1998, the ambiguities in the contract regarding minimum bills and SICs created uncertainty for Citizens. This became quite important as higher purchases and higher prices made the minimum billings applicable. For instance, APS rebilled Citizens for its May and June 2000 load based on a reinterpretation of contract terms. Its new bills increased Citizens' cost for these two months alone by $4.4 million. The letter accompanying the revisions described four changes. This was provided in response to RUCO Data Request 1.4.

## VII. CITIZENS SHOULD HAVE BEEN AWARE, PRIOR TO THE JULY 2000 BILLINGS, THAT IT COULD HAVE A PROBLEM WITH BILLS IN THE SUMMER OF 2000

**Q. Should Citizens have been aware, before the summer of 2000, that its summer power costs could be higher than normal?**

A. Yes, it should have been aware that its summer power costs could be higher than normal. Since its power bills depended on a number of elements that were outside of its control and not perfectly predictable, Citizens could not have known for certain that its power costs would be significantly higher than normal, which proved to be the case. However, it should have expected that its bills would be higher than the previous year and, by early spring of 2000, it should have known that there was a reasonable possibility that power costs would be much higher than historic costs. In any event, once Citizens learned that APS's SIC implementation tied to market purchases, they should have realized they were substantially exposed to market price risk that was outside of its control and not perfectly predictable.

**Q. Was Citizens aware ahead of time that APS would need to purchase power to meet load in the summer of 2000?**

A. Yes. The billing dispute that began in the summer of 1999 was triggered because APS purchased power to meet Citizens' load for some months in 1998. There were a number of months in 1999 when APS had to purchase power to meet Citizens load, and charged a minimum bill based on the disputed SIC. In response to a discovery response about its expectations for the summer of 2000, Staff Data Request 7.13, Citizens indicated that it "...was aware that APS/PWEC did not have adequate system generation to meet its native load plus Citizens load."

**Q. What was the trend in market prices during late 1999 and early 2000?**

A. As I will describe below, several key drivers of electricity market prices appeared worse in late 1999 and early 2000 than in previous years. As a result, forward market prices for energy deliveries in summer 2000 were increasing, and were significantly above historical levels.

**Q. What kind of information on the electricity market is available to a small company such as Citizens?**

A. Citizens personnel regularly viewed market prices and read industry publications, according to the response to Staff Data Request 5.36. There are a number of publications available that provide valuable market intelligence. *Power Markets Week*, for example, is a weekly publication that provides information on prices and other market price drivers. The Western Systems

Coordinating Council ("WSCC") releases a number of public reports on loads, generation, and other factors specific to the western market. Specific public sources for information about supply/demand conditions in the western market include:

- WSCC's report entitled "Existing Generation and Significant Additions and Changes to System Facilities, 1999 – 2008" (issued April 1999);
- The California Energy Commission Staff's report entitled "High Temperatures & Electricity Demand, An Assessment of Supply Adequacy in California" (issued July 1999);
- WSCC's report entitled "Summary of Estimated Loads and Resources" (issued October 1999).

Citizens could have accessed all of these information sources with relative ease. Citizens could also have availed itself of additional market intelligence, proprietary analyses, and trading expertise by retaining consultants.

**Q. What information would be the basis for expecting that power costs might be higher than the previous year?**

A. The most basic information would be supply and demand conditions in the market. If an examination of the growth in supply and demand revealed that demand was growing faster than supply, one would expect that higher prices were likely. The forward market, which prices future contracts, provides a measure of what other market participants expect future prices to be. Conditions in fuel markets and in hydro supplies also would provide clues. Rising fuel prices would suggest higher electric prices; lower hydro supplies would suggest the same.

**Q. What was the demand growth situation for Arizona and the region?**

A. WSCC had been experiencing steady electricity demand growth, which was forecast to continue. For the period 1995 to 1998, energy consumption in WSCC grew at an average annual rate of 2.5% and peak demand grew at an average rate of about 4.0%. Energy consumption for WSCC for the period 1999 through 2005 was forecast[2] to grow at an average annual rate of about 1.6% with peak demand growing at about 1.7% average annual rate. The forecast of energy consumption and peak demand for the desert southwest showed even more robust growth. Energy consumption was forecast to grow by about 2.7% and peak demand by about 2.9% annually, over the 1999 to 2005 period.

**Q. Had generating capacity additions in Arizona and neighboring states kept pace with demand?**

A. No. For the region encompassing California, Arizona, and New Mexico, generation increased by only 210 MW from January 1997 to January 1999 (WSCC Existing Generation and Significant Additions-Changes to System Facilities, January 1, 1999). This is out of a total generation base of over 75,000 MW, or an increase of less than one percent. Furthermore, available generation actually declined in the Arizona – New Mexico sub region from January 1998 to January 1999. This information was readily available from the WSCC.

**Q. What was the forecast for generation additions for Arizona / New Mexico in 2000?**

A. The WSCC, in 1999, forecast generation additions in 2000 for the Arizona, New Mexico region of 7 megawatts, out of a total installed capacity of around 19,000 MW. For the combined region of California, Arizona, and New Mexico total generation additions of 824 MW, or 1% of the total generation base, were forecast to come online in 2000. Given the long construction time for new generating units, the likelihood of large unanticipated amounts of new capacity entering the market quickly tends to be small.

**Q. What was the supply and demand situation for the region in recent years?**

A. The West in general and Arizona more specifically faced a situation where demand was beginning to outstrip supply. Attachment S-4 presents the WSCC's

[2] "Summary of Estimated Loads and Resources," (WSCC Technical Staff, May 2000)

summary (published in October 1999) of actual loads and resources during 1998. Page 1 of the exhibit summarizes the Arizona-New Mexico-Nevada area; page 2 presents the same information for the California – Mexico area.

The WSCC documents show that in Summer 1998, the actual margin of reserves over firm load for Arizona/ New Mexico dropped to 5.1% (1,033 MW) in August. For four summer months the reserve margin was at or below 10.4%. Actual reserve margins in the California-Mexico area dropped to 7.7 and 8.2 percent in August and September 1998, respectively.

**Q. Did these capacity margins in 1998 reflect an unusually unfavorable combination of circumstances?**

A. No. If anything, the 1998 results reflected a combination of favorable outcomes with respect to generator outages and electricity demand.

Attachment S-4 shows that total unavailable capability in the Arizona-New Mexico-Nevada area was between 196 and 424 MW during the four summer months of 1998. Unavailable capability in the California-Mexico area was less than 650 MW, out of more than 54,000 MW of installed capacity. Attachment S-5 shows historical unavailable generation for these areas during peak demand conditions, as reported by the California Energy Commission in a July 1999 report.[3] This exhibit shows that actual average outages experienced in each area from 1988 to 1997 were much higher than the actual 1998 results, and that actual outages in some years were thousands of MW higher. All else equal, more normal outage patterns would produce significantly lower reserve margins and a tighter energy market.

With respect to electricity demand, it is well known that air conditioning is an important end use and that high temperatures can drive up demand substantially.

[3] "High Temperatures & Electricity Demand, An Assessment of Supply Adequacy in California" (CEC Staff, July 1999).

Attachment S-6, taken directly from National Climatic Data Center[4], illustrates average summer temperatures from 1990 through 2001, and ranks them over that period and over all years since 1895. Pages 1 and 2 of the exhibit present this information for Arizona and California, respectively, with higher rank values representing higher temperatures. The low rankings for the past few summers (i.e., 1998 and 1999) indicate that average temperatures in each area were moderately cool from an historical perspective. While average temperature is not a perfect indicator of air conditioning load, it is clear that temperatures and electricity demand could easily turn out higher than they had in 1998 and 1999.

**Q. Looking forward to 2000 from 1999, what was the supply/demand outlook?**

A. Attachment S-7 (2 pages) presents the WSCC's summary of monthly supply and demand in the Arizona-New Mexico-Nevada area for 1999 and 2000. The document shows nominal summer reserve margins (the bottom row of numbers) of 13.4 to 18.8 percent in 1999, and 17.7 to 21.0 percent in 2000. The key points about it are:

- Summer peak demand (including interruptible) was projected at 21,070 MW, an increase of 641 MW from actual 1998;
- Total generating capacity in the region was projected at 19,317 MW, an increase of 485 MW from 1998;
- Total generator availability was assumed to be essentially zero; compared to typical historical outages of over 1,000 MW;
- Firm/joint imports were projected at about 3,700 MW, an increase of about 1,300 MW from 1998;
- In addition to the increase in firm imports, the category "Planned Purchases and Sales" was assumed at over 3,000 MW (amounting to over 14 percent of the regional peak demand) during July and August 2000. This category represents assumed purchases that had not yet been contracted. The WSCC presentation was showing that the Arizona-New Mexico-Nevada area would be relying on a large

[4] Website of the National Oceanic & Atmospheric Administration: http://www.NOAA.gov/climate.html

increase in purchases from neighboring regions which were themselves experiencing declining reserves and were exposed to weather and generator outage risks.

The WSCC document showed more than adequate capacity reserves for Summer 2000, due primarily to its optimistic assumptions regarding generator unavailability and purchases from outside the area. As shown in Attachment S-8, the CEC confirmed in a 1999 report[5] that from 1988 through 1997, actual reserves in the WSCC have consistently turned out much lower than indicated by WSCC projections.

The WSCC summary does, however, show the sensitivity of the supply/demand outlook to alternative outcomes. For example, Attachment S-9 assumes a typical historical outage level of 1,100 MW (with no other adjustments) and obtains reserve margins of 8 to 13 percent for Summer 1999. It was apparent that if demand or generator outages turned out significantly higher than normal, or if import purchases did not materialize as assumed, reserve margins for the area could easily fall below five percent.

**Q. What does the supply/demand situation mean for potential price levels?**

A. This situation indicated a tightening supply situation. As had been experienced in the summers of 1998 and 1999, which received extensive press coverage, tight supply can lead to very large market price increases. Prices increase for two related reasons: because higher cost units are utilized, and, as demand approaches the level of available supply, because of tight supplies (or, in the extreme, shortages). The combination can lead to prices that are greatly in excess of the variable production cost of the most expensive unit being utilized (sometimes called the marginal unit).

[5] "High Temperatures & Electricity Demand, An Assessment of Supply Adequacy in California" (CEC Staff, July 1999)

Prior to Summer 2000, spot market prices in most eastern electricity markets had already exhibited large spikes during tight supply conditions. For example, Attachment S-10 illustrates that spot market energy prices in the PJM Interconnection jumped to a monthly average of about $162/MWh in July 1999, despite never having averaged more than $51/MWh in any month since the market's inception. Energy price spikes in PJM were limited to some extent by a $1,000/MWh energy price cap; other eastern markets had shown even greater price spikes. During several days in June and July 1998, prices for on-peak energy trades at the Cinergy hub exceeded $1,500/MWh. Due largely to the effects of such high-price days, average daily prices at Cinergy for these months averaged about $263/MWh and $149/MWh, respectively. These prices compare to typical monthly on-peak average prices of $20 to $40/MWh. While the specific circumstances in these markets differed in some respects, the point here is that well before 2000, eastern U.S. electricity markets had shown that tight supply conditions can translate to very large price increases.

**Q. What other observable factors could affect the supply / demand situation?**

A. Weather and the availability of hydroelectric generation also influence the supply / demand balance. Weather is probably the biggest influence on electricity demand. A California Energy Commission study[6] showed that on the peak electricity demand day in California, an increase in the temperature of five degrees translates to an increase in peak demand for California of 8.5%. The study also showed that with temperatures that occur in one out of every 5 years, Arizona would have only a 1% reserve margin, and with temperatures that occur in one out of every 40 years, the reserve margin would turn negative. This suggests that if summer weather has been lower than normal, demand will go up as temperatures climb to or above normal.

**Q. What is the role of hydroelectric generation in the western market?**

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[6] Ibid.

A. Both California and the Pacific Northwest are heavily dependent on hydroelectric generation, which can vary significantly from year to year. In years where hydro production is reduced due to limited water, the Pacific Northwest has less energy to export and California must look elsewhere to replace the diminished hydroelectric generation. In years of low hydro production in the Pacific Northwest and, especially, California, added demand is placed on electricity generated in Arizona. Furthermore, hydroelectric generation operating costs are very low, so when it is not available the power is replaced from thermal units which are more expensive on an operating cost basis, sometimes by a significant degree.

**Q. What was known in the spring of 2000 about potential hydro production in the upcoming summer?**

A. The Northwest River Forecast Center, a department within the National Oceanic and Atmospheric Administration, releases periodic forecasts of the water available for hydro production. As early as the middle of February, the Northwest River Forecast Center was warning of below normal water flows, and therefore hydro production, for the summer. This forecast was reported in the February 21, 2000 issue of *Power Markets Week.*

**Q. What other factors are indicators of the direction of electric prices?**

A. Fuel prices are a major component of electric prices, so that as fuel prices increase, electric prices can also be expected to increase. This is particularly true of the price of natural gas, since this fuel is used to produce output on the margin (and therefore affect market clearing prices) much of the time, and particularly during summer peak hours. For example, for a gas-fired unit with a heatrate of 10,000 BTU/kWh, a gas price increase of $1.00/mmBTU would translate to an increase of $10/MWh.

**Q. What could be observed regarding gas prices?**

A. Attachment S-11 illustrates daily spot gas prices at Henry Hub (Louisiana) from January 1998 through April 2000. The exhibit shows that natural gas prices drifted significantly upward during late 1999 and early 2000. For example, prices from September 1999 through April 2000 averaged over \$2.50/mmBTU, compared to prices under \$2.00/mmBTU during late 1998 and early 1999. By March, prices had increased by about \$1/mmBTU compared to early 1999 values. Attachment S-12 illustrates monthly average spot gas prices in the first three months of 1998 through 2000.

**Q. Were there any explicit warnings in the trade press indicating the possibility for high market prices in summer of 2000?**

A. Yes. For instance, ICF/Kaiser Consulting Group, in announcing the publication of its 1999 Bulk Power Outlook, warned that surplus hydro conditions in the past few years had masked the tightening supply / demand balance in the west. The announcement went on to report[7]:

- "The West stands at least a one-in-three chance of experiencing price spikes similar to those seen in the Midwest during the summer of 1998."
- "Price spikes were more likely to occur in summer of 2000 than summer 1999 due to expected favorable hydro and weather conditions in 1999."
- "Despite above average hydro supplies, western market prices had been increasing."
- In the event of above-normal summer temperatures, supplies could be very tight. "Pre-conditions are there for a very precarious situation…"

**Q. How did forward prices in the Southwest behave prior to summer 2000?**

A. Forward prices represent prices at which buyers and sellers agree to exchange power during a future delivery period. Forward prices for deliveries in the summer months of 2000 showed a noticeable increase over previous years. The average price of a third quarter 2000 forward contract at Palo Verde, an active

[7] As reported in *Power Markets Week* June 7, 1999.

trading hub, was \$63.46/MWh[8]. This compares to an average life-of-contract price of \$51.00/MWh for third quarter 1999 contracts and \$40.22/MWh for third quarter 1998 contracts. Summer 2000 forwards were also significantly above actual 1999 spot prices.

For deliveries in the four summer months June through September 2000, the monthly average of forward prices from July 1999 through April 2000 were at \$40.08, \$56.43, \$72.33, and \$58.62, respectively. Spot prices in the summer of 1999 for on peak power for June through September were \$32.68, \$41.49, \$42.71, and \$33.40, respectively. Attachment S-13 shows the monthly averages for these forward prices and historical spot prices. Attachment S-14 shows that from December 1999 through April 2000, forward prices for Summer 2000 deliveries at Palo Verde gradually increased from about \$55/MWh to \$70/MWh.

The forward and spot price data show that market expectations over the 9 months preceding May of 2000 were that prices in the summer of 2000 would be at least 20% higher (and over 70% higher in some months) than the actual monthly average spot price for the same month in the summer of 1999. It appears that market participants saw the potential for significant spot price increases, likely based on the supply/demand and fuel price considerations that are discussed in the past several pages.

**Q. Do forward prices indicate the maximum prices that may occur in the future period?**

A. No, forwards represent fixed prices at which willing sellers and buyers commit at a particular time for deliveries in some future period. Forward prices for a given delivery period thus represent the middle range of expectations about future spot prices for that period. Hotter weather than expected, higher fuel prices, the

8 The average price was calculated based on transactions from July 1999 through April 2000. Reported in Power Markets Week.

failure of large generating units or transmission lines could all cause prices to climb much higher.

**Q. What does Citizens say about its expectations for power prices in 2000?**

A. Citizens stated that it "...did understand that a possibility existed of being billed subject to the ceiling or billing provisions of the contract prior to May 2000." (Response to Staff Data Request 5.17) In response to Staff Data Request 6.14, Citizens stated that it "...did not have information that led it to believe that wholesale electricity prices would increase as dramatically as experienced in the summer of 2000." In other words, it was aware that its bills might be determined by market prices (the incremental cost of APS's purchased power) and that there was potential for higher prices, but it did not anticipate the actual magnitude of extreme market prices that actually resulted.

In the same data response, Citizens stated that "the contract definition of SIC effectively shielded the Company and its customers from high wholesale prices". This was in spite of the fact that Citizens argued with APS from the summer of 1999 about this definition, and its position had not prevailed by the summer of 2000.

**Q. Knowing that its bills might depend on the System Incremental Cost, did Citizens project what SICs might be in the summer of 2000?**

A. No. Although Citizens was aware that it might have a problem, it has not indicated that it made any attempt to estimate the magnitude of the potential problem. In response to Staff Data Request 5.19, it stated that it "did not prepare estimates of SIC pricing prior to May 2000."

**Q. Even if Citizens could not know how high summer of 2000 spot market prices would turn out, should it still have been concerned?**

A. Yes. A much lower price increase than actually occurred would still have created significant problems with summer bills. Citizens' costs for Schedule A in the summer of 1999 were still based on nominal pricing, at about 3.7 cents per kWh. If Schedule A had been based on market prices, the Company's entire load would have been impacted by the market. For example, forward prices in April of 2000 for the third quarter of 2000 were 2.5 cents per kWh higher than actual spot prices in the third quarter of 1999. This would have increased their power costs by about $9 million.

Citizens was clearly aware that APS believed it could charge Citizens its market prices. It should have been aware that load in the summer of 1999 in Arizona and the Southwest region was lower than normal, since summer temperatures had been relatively low. Citizens knew that it had been subject to the minimum bills provision of the Old Contract in a low load year. It should have known that there was significant load growth in Arizona, and that APS had not built any new generation. These conditions all suggested that APS would need to purchase to supply Citizens. As long as market prices were higher than the fixed prices in the contract, much of the summer bills would have been based on the minimum bill calculation, even in normal market conditions.

**Q. Would there have been a symmetric expectation that the SIC could be much lower than historic values?**

A. There should not have been. Citizens itself argues that prices could increase more than they could decrease, in defending its negotiation of the fixed price contract. It notes, in response to RUCO Data Request 4.5, that potential price variation is asymmetrical. Prices couldn't fall below the marginal cost of production. However price increases could be much greater. Not only could the marginal cost of production increase significantly, but prices could increase well above the marginal cost of production due to shortages of supply. Further, as discussed above, WSCC had not, in recent years, experienced a combination of relatively high loads, poor availabilities and low hydro.

## VIII. WHAT CUC SHOULD HAVE DONE PRIOR TO THE SUMMER OF 2000 THAT MIGHT HAVE REDUCED ITS FUTURE BILLS

**Q. Could Citizens have taken any actions prior to the summer of 2000 that might have prevented or minimized the problems that arose during the summer?**

A. Yes. It could have: (1) attempted to renegotiate its contract as soon as it became aware of how APS was interpreting the SIC; (2) made a greater effort to settle the SIC issúe; (3) sought to hedge market prices for the summer; and (4) taken actions to get more value from its Valencia units.

**Q. What might contract negotiation have accomplished?**

A. The consummation of any contract takes two willing parties But, ideally, the contract would have contained some obligation for APS to minimize costs, clearer definitions, a guarantee of Citizens' ability to audit all bills, and definitions of all minimum bills and other pricing provisions so that there was full knowledge of the basis for prices. The lack of clear definitions and protection to Citizens were particularly important as APS began to depend more on purchases, which Citizens was aware increased the impact of the SIC definition.

One cannot be certain that Citizens and APS would have consummated a mutually satisfactory contract along the foregoing lines. On the other hand, however, one can be confident that the chances of success would have been improved had there been a more timely and more extensive effort to do so.

**Q. How might Citizens have attempted to resolve the SIC issues, outside of negotiation with APS?**

A. Citizens could have gone to FERC to clarify the SIC dispute. As of April 17, 2000, it was clear that APS still interpreted the SIC as including all purchases (LS5.16). If Citizens believed this was a misinterpretation of the contract, it should have clarified this issue.

Another disputed issue involved APS including forward power purchases in its computation of the SIC. Once Citizens' consultants identified this as a problem the Phase I Audit Report, Section D, this could also have been pursued at FERC.

**Q. How and why could Citizens have hedged its potential price volatility?**

A. In the first months of 2000, signs were increasing that indicated prices could be very high in the summer. Citizens knew that the SIC issue was not resolved, so that it might be subject to market prices. Given this situation, it could have requested APS to purchase forward power for them. A forward purchase or other type of future commitment is not a guarantee of lower prices, but is a means to reduce risk. For instance, in a situation in which one believed there was an equal probability that prices could double and that they could fall by 10%, it would be worth paying something (of course, weighing the costs and benefits) for an "insurance policy" that limited the potential price increase. Citizens might have had to pay some premium to APS, but with such an agreement, there is no obvious reason why APS would not have been willing to make a forward commitment for Citizens. At the least, an analysis of the situation by Citizens and a subsequent request to APS to implement its post-analysis strategy would have been prudent.

**Q. What would the savings have been from a reasonable hedge?**

A. We have estimated that if APS had purchased a reasonable block of peak period forward power for Citizens in January, February, March or April, this would have reduced summer bills by $10 million. Specifically, if APS had purchased a block of flat power of 100 MW for Citizens for the summer peak period, which is well below the Citizens minimum load, at average forward prices, and Citizens had in addition paid a premium or adder of two mills per kWh to APS, this power could have replaced much more expensive power. Attachment S-15 illustrates the potential cost savings for the July – September period, if the hedge had been purchased in January, February, March or April.

**Q. Were there other options that could have been pursued?**

A. Yes. Citizens could have sought a financial hedge for part of load. For instance, it could have looked for a product that would have fixed the price for most of its base load, at least for the summer period.

**Q. How could greater use of the Valencia units have reduced the undercollection problem?**

A. The Valencia units are three small peaking units. They could use either oil or gas as fuel, so that, to some extent, they could switch to the lower cost fuel. Although these units had fairly expensive running costs (about $0.13/kWh) (Response to RUCO Data Request 4.16), the cost could often have been less than peak period market prices. If the units were operated at 30-40 MWs during the most expensive portion of the day, that would have meant much less power purchased at peak prices.

The units' primary purpose was to serve as backup in case of an interruption on the single transmission line serving the Nogales area. If the single transmission line to the Nogales area is incapacitated by a lightning strike, the Valencia units are necessary to restore power to the Nogales area. This requires that when storms are predicted the units are brought up to 100% of capacity but are not connected to load.

When the units are not needed because of a storm interruption, the units could be operated for economic reasons.

Citizens was concerned that more frequent running could have reduced the units reliability when they were needed for backup. However, it was possible to make investments that would increase the ability to run the Valencia units when they cost less than the cost of purchased power.

**Q. Why do you believe the units have been used to reduce Citizens' power costs even before these investments were made?**

A. Citizens had a permit to run the units for 1000 hours. Some of these hours could have been used to run the units for hours when it expected that market prices would be higher than 13 cents per kWh, and in months when Citizens anticipated that it would be charged on the basis of SIC pricing.

**Q. Citizens has made expenditures on the units since the fall of 2000. Please comment on these investments.**

A. According to the response to Staff Data Request 8.37, Citizens began making improvements to the Valencia units in the fall of 2000. If these expenditures were necessary to run the units for more hours, they have proven economic. In May and June of 2001, the units were operated for economic reasons, reducing power costs by $900,000 in May alone. The Company spent $784,000 in capital costs or in operating and maintenance costs that would be capitalized, and $241,000 in additional labor costs on the Valencia units. Except for the expenditure associated with emissions testing that may allow the units to be run for more hours, these expenditures might well be considered routine reliability expenditures. I note that in the New Contract Citizens has given up the right to operate the units for economics, so future benefits will accrue to APS.

**Q. Do we know whether Citizens could have made these investments prior to the summer of 2000?**

A. This would depend on the start date, but the record does not make this clear. Evidently Citizens did make these investments in about six months. Possibly they could have been completed in less time than was actually utilized. If it did require six months to complete the work, and they began the effort in January of 2000, these improvements would have been made by July 2000 and have had substantial impact on the Summer 2000 costs. If some of these expenditures were necessary to run the units for additional hours, which is not clear, they would have been a reasonable hedge against the substantial market exposure Citizens had in its Old Contract.

**Q. Have you estimated the dollar savings that could have resulted from running the Valencia units?**

A. Yes. I estimated, based on a detailed look at four days in June, that the Valencia units could have saved about $140,000 per day. This assumed that they were run for 13 peak hours a day, at the same output level that they actually produced on a typical day in May 2001. Their emissions limitation should have allowed them to be operated for at 30-40 days. This suggests that the total savings from running the Valencia units could have been $4 to $5 million. Even if this required some investment, it appears that additional use of the units during expensive hours could have saved customers about $4 million.

**Q. Could Citizens have reduced its bills by resolving, in its favor, the dispute over whether reliability purchases belong in the SIC?**

A. Yes. However, Citizens did pursue this issue with APS to no avail. It appears unlikely that if they had brought the issue to FERC in the spring of 2000, as it became evident they could not reach agreement with APS; they would have received an order by the summer of 2000. However, Citizens might have achieved a refund by pursuing the issue.

## IX. ACTIONS CITIZENS SHOULD HAVE TAKEN DURING AND AFTER THE SUMMER OF 2000 TO REDUCE FUTURE BILLS

**Q. Do you believe there were any actions that Citizens could or should have taken during and after the summer of 2000 that might have reduced future costs?**

A. Yes. Citizens could have asked FERC to clarify the definition of the SIC. A ruling in favor of Citizens' interpretation of the SIC would have resulted in APS refunding significant amounts to Citizens and changing its billing methodology so that future bills would have been lower. There are other issues raised by Citizens' audit consultant that it could have raised in front of FERC that could have resulted in a reduction to its bills.

**Q. Specifically, what other issues could have been raised by Citizens?**

A. Citizens also could request FERC action regarding APS' treatment of forward contracts in its SIC computation. Its own audit showed that APS' method of reflecting forward purchases in the SIC always resulted in higher cost to Citizens.

As noted earlier, the contract does not define the SIC clearly. According to APS' interpretation, it would include purchases. Section III of the contract, described above, suggests that purchases that were necessary to serve Citizens would be included. This is still not definitive. APS' supply is not adequate to serve its load in many hours, so that APS makes many purchases of varying types, volumes, and durations. In many hours, it would have to make purchases even if it were not serving Citizens' load. APS' obligation to serve Citizens' load would have affected APS' unit dispatch and purchasing decisions, but there is no obvious designation of any particular purchases as being associated only with Citizens' load. Given the lack of specificity in the contract, it is useful to examine the various options by which APS could have identified certain contracts as associated with Citizens, and therefore the basis for the SIC in the contract. These include the following:

- Assign to Citizens the cost of contracts that were made last in time;
- Assign to Citizens the cost of contracts that were made first;
- Assign to Citizens a set of specific purchases, including both forward and spot;
- Assign to Citizens the average price of all APS purchases in each hour.

Since utilities tend to build a portfolio with purchases assigned over time, the latter seems the closest to representing the purchases made to serve Citizens' load.

How APS actually computed Citizens' bills differs from all of the above methods. APS ranked its supply sources by ascending price, and assigned the highest-cost source to Citizens in every hour. This approach does not appear to have any logical basis in portfolio planning, and by definition produces the highest possible SIC result and in turn, the highest possible bill to Citizens. It would seem that Citizens would have reason to raise this issue in front of FERC but we have seen no indication that they have. This alternative interpretation seems more consistent with Section III of the Service Schedules than APS' definition. It also, as discussed later, had the potential to reduce bills substantially.

**Q. Is this argument consistent with findings of Citizens' audit consultant?**

A. Yes. I have not seen any evidence that the consultant offered an alternative method of SIC pricing, but the consultant raised this issue as a problem with the bills, describing this treatment of forward purchases as the heads APS wins, tails Citizens loses approach.

## X. WHAT ACTIONS DID CITIZENS TAKE TO MANAGE ITS POWER COSTS?

**Q. Prior to the summer of 2000, did Citizens take any of the actions recommended above?**

A. Other than a very modest attempt to renegotiate its contract with APS, it did not take any of the recommended actions Evidently, Citizens was engaged in some exchanges of letters and discussions with APS for a change to its contract during the spring of 2000. And during the summer of 2000 there were apparently further discussions between the parties with regard to the proposed contract change.

**Q. Did Citizens take any steps regarding its power costs during 2000?**

A. Yes. After it had received the very high bills in July of 2000, Citizens conducted its in-depth analysis or audit that I have referred to earlier. Further, according to the Amended Application, it "developed a number of initiatives to reduce the amount of power needed" (Amended Application p. 3).

In addition, in late 2000 Citizens decided to run the Valencia units for economic reasons, and began the investments it believed were necessary to enable it to do so. Finally, in the summer of 2001, Citizens negotiated a new contract with APS.

**Q. Did Citizens believe that discussions in April and May of 2000 with APS about its power contract would reduce its costs?**

A. Yes. Citizens indicated that it believed that an MOU it had negotiated with APS would result in improving its situation. Citizens evidently understood that the MOU would "resolve the SIC issues". (Response to Staff Data Request 8.05) This MOU was signed by both parties on May 18, 2000.

**Q. What precisely did the MOU say about the contract?**

A. The MOU was titled "Terms of a Potential Restructuring of the Existing Power Supply Agreement Between Citizens Utilities and APS." The entire document is included in Staff Data Request 5.44. <u>*This stated the intention of APS and Citizens to develop a new contract in which would:*</u> ii. "Terminate Service Schedule A (SSA) Off-Peak, Service Schedule B, (SSB) and Service Schedule C (SSC) 12/31/03" and "Reprice SSA Off-Peak, SSB and SSC as a single block of energy" with Citizens choosing between two pricing methods.

The first method would be a fixed per MWH price determined by APS and the second would be a per MWH price. The document also specified that pricing for Schedule A (except for the off-peak power) would remain unchanged, except that Citizens could request a reduction in the contract demand as a result of verifiable load loss. There is no mention of minimum or floor pricing or the APS SIC in this document.

The second pricing method, as described, does not specify whether the base level was determined by Citizens' entire bill or by the cost of the schedules being repriced, i.e. SSA Off-Peak, SSB, and SSC. It does not specify the source of the forecasted gas price, or the source data for the actual natural gas price.

**Q. Would the MOU result in lower power costs?**

A. The MOU would not have changed any provisions regarding Schedule A, except for off-peak power. There is no guarantee as to whether the fixed pricing offered by APS each month would be higher or lower than the nominal pricing in the current contracts. The variable pricing would appear to be higher than nominal pricing unless gas prices dropped. However, the variable pricing would have been lower than market pricing (the minimum bills) at least during the summer of 2000. The key to whether the MOU described contract would have reduced power bills would be whether it eliminated the minimum bill provisions.

**Q. Did the MOU indicate that the floor pricing provision would be eliminated?**

A. No. However, since the document described termination of the SSB schedule that is the document that referred to floor pricing for B, with no provision for replacing that term of the contract, the document might be interpreted as eliminating floor pricing from SSA Off-peak and SSB.

**Q. Is there evidence as to whether APS believed that the MOU eliminated minimum pricing?**

A. By July of 2000, there is evidence that APS did not believe the contract had been altered or amended by the MOU (or in a manner consistent with the MOU) to eliminate minimum pricing. There is a footnote on the Revised July and the August bills stating that "This invoice was based on the APS/Citizens Memorandum of Understanding Dated May 18, 2000." Those bills clearly contain minimum pricing, which was in fact the basis for the charges on those bills. In other words, Citizens was charged more than the nominal pricing on the bill, in bills which were described as being based on the arrangements contained in the MOU. That is, APS' view appears to be that the MOU effectuated a change, but that the change did not eliminate minimum pricing.

**Q. Did Citizens have a different understanding regarding whether the MOU would eliminate the minimum or floor power rate?**

A. It is not clear what Citizens believed about the MOU itself. However, according to the Response to Staff Data Request 7.07, Citizens had understood that APS had made a verbal commitment to eliminate the floor pricing, but on August 29, 2000, APS withdrew that commitment. According to an attached memo prepared by Sean Breen at that time, APS personnel had indicated that "fixed" pricing, under what Citizens referred to as the "contract restructuring", would not have been subject to the floor pricing.

**Q. What is your view of the MOU?**

A. It is not entirely clear what the MOU actually was. "MOU" usually connotes something in process, or some future intent. On the other hand, the so-called MOU contains signatures and APS was evidently of the view that it effected a contractual change. Testimony by Mr. Breen filed May 22, 2000, stated that the parties had "…reached conceptual agreement to modify the existing power supply contract…" p. 7.

I do not think that the Company should have relied on this MOU and used this as a basis for not taking other actions. And it certainly should not have relied on a verbal commitment. The Company evidently was not taking any other actions partly or wholly because it believed the new contract provisions which it had been discussing would avoid the problem of power costs being based on market costs. However, a conceptual agreement is clearly not a firm commitment, nor, in the circumstances, is a purely verbal exchange. Whether the results of the discussions with APS are called a "conceptual agreement", an MOU, or Terms of Potential Restructuring, or a verbal understanding, they evidently did not commit APS to offering a new contract that made less reference to market prices. And if Citizens believed otherwise, it should have taken the proper steps to enforce its understanding of what had transpired. However one views the situation, it is evident that the negotiations and the MOU did not succeed in eliminating the disagreements between Citizens and APS.

**Q. What was Citizens' reaction to the July bill that was described as being based on the MOU?**

A. According to the response to Staff Data Request 8.09, from Citizens' perspective, "the replacement contracts envisioned in the May 18, 2000 MOU were never executed." Citizens has paid these bills under protest. Apparently, however, the bills under the Old Contract would have been the same, since the minimum billing provisions applied throughout this period.

**Q. Citizens' made an argument that it has been overbilled. Has it pursued any of the disputed interpretations of the SIC?**

A. No. The Company has stated repeatedly that it pursued the new contract instead of disputing the old contract. In response to Staff Data Request 7.01, it stated that litigation, either at the FERC or in civil court, would take several years, have an uncertain outcome, cost hundreds of thousands of dollars, and, while litigation was underway, the PPFAC bank balance would continue to grow.

**Q. Did Citizens indicate that it has given up any legal rights to pursue disputes over past billings?**

A. No, it states that it has not given up such rights. However, it also indicates that there are no outstanding billing disputes regarding the summer of 1999. (Response to Staff Data Request 7.12) This total dispute was only over $4.5 million for the period from summer of 1998 through April of 2000, and the settlement regarding this issue was for a bill reduction of $1.5million.

**Q. Did Citizens compute the effect of APS' interpretation of the SIC, or pursue this issue in any way other than in discussions with APS?**

A. Citizens estimated the impact on its undercollection of excluding reliability purchases. There is no evidence in this proceeding that it computed the effect of an alternative treatment of purchased power, although its audit found this treatment to be unfair.

**Q. Did Citizens analyze any other long-run options to the new contract?**

A. There is no evidence that it did so.

## XI. CITIZENS' MANAGEMENT OF ITS CONTRACT AND ITS POWER COSTS HAS NOT BEEN PRUDENT

**Q. Did Citizens pursue actions that could have resulted in a reduction in its power costs, either before the summer of 2000 or since that time?**

A. Citizens has not effectively managed its contract. Citizens took no actions before the summer of 2000, except for talking to APS and developing an imprecise framework for a contract that might or might not have been adopted at some point in the future. Since the summer of 2000, Citizens has not pursued either the SIC interpretation or the forward purchase treatment question through litigation. The only action taken by Citizens has been investments in Valencia that it believes allowed it to run the units more hours. Subsequently, in the new contract with APS, it allows APS to dispatch the units, so that Citizens will receive no value from this investment beyond the savings in May

**Q. Did Citizens have valid reasons not to take any actions to hedge its power costs for the summer of 2000?**

A. No. In response to Staff Data Request 6.19, Citizens indicates that information about energy hedging was generally available, but that it did not take actions in the past because: (1) it believed that its contract with APS/PWEC shielded it from high prices, and (2) it believed it needed prior approval from the Commission. However, since it knew of the dispute over the SIC calculation, it should have been aware that the existing contract might not shield it from high prices. Moreover, although I do not think there was any prohibition that would have prevented Citizens from taking these actions on its own, it could have requested ACC approval to pursue the options above. It could have presented to the Commission analyses that demonstrated that such action would reduce price volatility and could reduce costs significantly, and that without such actions, its power costs in the summer of 2000 might increase significantly.

**Q. Has Citizens indicated why it did not fully pursue the issue of the treatment of forward purchases in the SIC?**

A. Yes. Citizens did raise this issue in discussions with APS, which maintained that the contract allowed it to allocate costs in this manner. (Staff Data Request 8.22) In response to Staff Data Request 5.02, Citizens states that the new contract "was intended to resolve all contested matters." Further, Citizens indicated that rather than pursuing this and other issues at FERC through litigation, they "resolved matters by entering a new contract with APS/PWEC, which provided significant cost benefits." (Response to Staff Data Request 8.24)

**Q. If the contract terms discussed in the MOU had been finalized in a manner that eliminated the minimum billing provision from Schedule B and Schedule A off-peak, would this have resolved all contested matters?**

A. No. Even with this provision removed, Schedule A would still have been impacted by SIC pricing. Moreover, the MOU would have only changed future billings; the issue of past billings was not in any way resolved. If APS had been using an incorrect interpretation or calculation of the SIC, the amount that Citizens had been billed would not have changed and Citizens would still be asking customers to pay for that error.

**Q. Given its disagreement with APS' interpretation of the SIC, why is Citizens requesting that its customers pay the bank balance based on APS' interpretation?**

A. The explanation provided by Citizens in the Amended Application was that "it became clear that it was not possible to resolve the interpretation issues short of litigation, which is both expensive and lengthy. Further litigation would do nothing to address the continuing accumulation of unrecovered costs in the PPFAC bank." (Amended Application, p.3) Further, Citizens apparently believed that the new contract envisioned in the May 18, 2000 MOU would solve its problems (Staff Data Request 5.02; Staff Data Request 8.05).

**Q. Do the reasons why Citizens did not pursue contract interpretation issues with FERC in the past prevent it from taking these actions now?**

A. No. Since it has signed a new fixed rate contract, resolution of these issues will not change future costs. However, if it has been overbilled in the past, it should take all reasonable actions to pursue an appropriate refund.

## XII. THE ACC SHOULD ALLOW A MODIFICATION OF THE PPFAC FACTOR, BUT NOT FOR THE ENTIRE UNDERCOLLECTED AMOUNT.

**Q. Has Citizens justified collection of its entire balance?**

A. No. Citizens did not take reasonable actions that could have reduced the undercollected amount. These include having hedged a portion of its load in the spring of 2000 for the summer of 2000, operation of Valencia during high-cost hours and pursuing two disputes over contract billing at FERC or in some other venue. The latter actions, as I understand it, can still be taken. Citizens has said specifically that it did not give up the right to pursue relief on these issues.

**Q. What disallowance are you recommending?**

I have demonstrated above that reasonable actions by Citizens could have been avoided approximately $14 million in power costs. I realize that there may be some mitigating circumstances that I am not aware of, but I believe that a balancing of utility and ratepayer interests requires that Citizens bear responsibility for at least half of this amount. Specifically, I am recommending that Citizens' request for $87 million should be reduced by $7 million.

**Q. Do you recommend that Citizens be allowed to collect all of the remaining undercollected balance?**

A. I recommend that Citizens not be allowed to collect the full amount of the balance, less the disallowance, until it has pursued the SIC issues, both the question of economic versus reliability purchases, and the forward purchase issue, with all legal means available to it.

**Q. Can the potential impact on Citizens' underrecovered balance costs, if it takes the actions that you have suggested and prevail on either issue, be estimated?**

A. Yes. Citizens itself has estimated that using its definition of APS System Incremental Costs in its bill calculation would have reduced its undercollected amount by $49 million. This would require filing a Section 206 action at FERC, and achieving a favorable judgment from FERC.

With regard to whether APS had included purchased power costs in a manner that was supported by the contract, we have estimated that if the APS SIC were computed in a different and defensible manner, this would have reduced Citizens' power bills by as much as $20 million. This is discussed in detail later.

**Q. What do you propose regarding the $49 million?**

I am recommending that the $49 million of the request be deferred for future consideration. Thus, of the remaining $80 million, Citizens should only be allowed to collect $31 million ($80 million less the $49 million potential overbilling) until it has pursued the legal recourse on the disputed SIC issues.

**Q. How would you recommend that the recovery factor be developed?**

A. I recommend developing a PPFAC factor to collect the bank balance, less the disallowance, with no carrying charge. I recommend that the ACC address the remaining underrecovery after there is a final legal decision on the merits of the Citizens case on the SIC issues.

**Q. Why do you recommend that no carrying cost be allowed?**

A. Citizens' problems are partly of its own making. As discussed earlier, there are several actions that Citizens should have pursued but did not, that might have reduced the amount of the undercollection. The $7 million disallowance that I am recommending is based on only one of these factors. Not allowing a return on the amount that may be collected is an additional penalty for the Company's lack of prudency in managing its contract.

**Q. Has the ACC previously approved the prudency of the existing contract?**

A. No, it has not. However, the issue here is how Citizens has monitored and managed its power supply situation and it Old Contract. I believe that the ACC has oversight over whether Citizens has acted reasonably and prudently with regard to its management responsibilities.

**Q. Has FERC approved the existing contract?**

A. Yes, the existing contract was approved by FERC. Under those circumstances the contract would be not be ACC jurisdictional except for the fact that the contract established a series of administrative or procurement functions rather than a specific set of rates. Normally, under the filed rate doctrine, the approval by FERC would preclude the affected state jurisdiction from ruling on or altering the terms of the tariff. This principle, however, while allowing an assertion as to the validity of the contract, does not indemnify the parties against all potential outcomes in administering the contract. The imprecise terms of the contract have allowed different interpretation of the pricing terms. Moreover, as APS' and Citizens' loads have grown relative to APS' resources, the contract has left Citizens vulnerable to the types of power purchased by APS. The existence of a valid contract does not absolve Citizens from any responsibility for management, and does not preclude the ACC from any investigation into the administration of the contract and its consequent effects on retail rates. If the ACC were not to evaluate the prudency of the costs flowing from the contact administration, it would be unable to perform its charge to establish just and reasonable rates.

**Q. Has the ACC asserted its jurisdiction on the prudency of the costs flowing from the power contract administration?**

A. The ACC has asserted jurisdiction over the prudency of the Company's power costs in Order 56134. In response to RUCO Data Request 4.2, Citizens cites the PPFAC hearings order, quoting the order to say "if it had been demonstrated that any of Citizens purchased power and fuel costs were not prudent, then those costs would not be allowed to be passed through to ratepayers (p. 4, Order 56134, 1988). Further, the response states "The test for recoverability of costs flowing through the PPFAC mechanism is no different from any other cost of service. If a cost is deemed by the Commission to be reasonable and to have been prudently incurred, it should be fully recoverable from ratepayers."

The PPFAC proceedings were not designed to replace Citizens' judgment in writing, signing and managing contracts. Moreover, circumstances have changed since the PPFAC proceedings cited by the Company. However, the Company has not responded to changed circumstances. Neither the Commission nor Staff addresses the contract or management of the contract in the stranded cost/unbundling Settlement. The issue was basically just how to calculate stranded cost. The Company did not alert the parties to the potential for a large increase, but rather stated that it was engaged in negotiations that would modify the contract and would reduce costs.

**Q. How did you estimate the potential savings from winning, at FERC. the issue of the treatment of forward purchases in the SIC computation?**

A. This can best be illustrated using the SIC computation for a single hour using the actual data. On June 16, 2000, hour 17, Citizens' total requirements were about 264 MW. During that hour APS purchased a total of about 1,090 MW, including a mix of forward and spot purchases. The average price of all APS purchases in the hour was about $168/MWh (16.8 cents/kWh).

Attachment S-16 describes APS' SIC calculation methodology, which essentially bases the SIC on the most expensive purchases regardless of when they are made. To determine Citizens' bill for our example hour, APS averaged the cost of only its most expensive 264 MW of purchases (assigning them to contract Schedules A, B, and C). The weighted average price of the most expensive purchases was about $488/MWh (48.8 cents/kWh).

Attachment S-17 illustrates APS' purchases for the example hour, along with the derivation of the average price and APS' SIC price. Had the SIC been based on the average of APS' purchases in the hour, rather than the most expensive, CUC's cost for the hour would have been about $84,000 lower.

To estimate the impact over the summer, we performed this same calculation for every hour of the day for a number of days. We calculated what a minimum bill for those days would have been if APS had used this method, and compared it to the actual computation of SICs on the bill. The difference indicates the bill reduction that would result from using this methodology. We then assumed that all daily costs from July to September could have been reduced by the same percentage. This would have produced a total bill reduction of $20 million. This computation is contained in Attachment S-18.

## XIII. COMMENTS CONCERNING THE NEW CONTRACT

**Q. What were the terms of the New Contract?**

A. According to Citizens, the New Contract provided long-term price stability, the elimination of future stranded costs should customers choose alternative suppliers, and administrative simplicity. The New Contract provided a fixed price per kWh for the next 7 years.

**Q. What will the impact of the New Contract be on the PPFAC?**

A. The Company has calculated a fixed charge based on the contract and upon an assume line loss percentage. The fixed charge under the new contract will increase the existing PPFAC by $0.01781/kWh (Amended Application, p.8). The contract will have reduced Citizens' power bills for the summer of 2001 from what they would have been under the previous contract.

**Q. What did Citizens do to justify its decision to sign the new contract with APS?**

A. Citizens computed what its power bills would have been if its power costs remained at the level that it experienced in May 2001. If costs had remained at this level, average power costs for the summer of 2001 would have been $30 million higher than under the New Contract. Citizens also justified its contract by noting that its fixed rate pricing is favorable "...compared to long-term power contracts recently entered into by the California Department of Water Resources..." (RUCO Data Response 4.5)

**Q. Were there any alternatives to signing a new contract or remaining on the existing contract?**

A. After the summer of 2000, one alternative that was available, short of litigation, would have been to have cancelled the contracts at the earliest possible date. This would have meant a longer term commitment to Schedule A than to the new contract, but only a two year commitment for Schedules B and C. Before the summer of 2000, Citizens could have attempted to renegotiate the Old Contract much earlier than it actually did. By the time it discussed what resulted in the MOU, prices were rising. By mid July 2001, market prices had already fallen from the levels of May 2001, and since many fundamental predictors suggested that market prices would continue to fall, future costs under the existing contract might be less than they have been in recent months. Another alternative would be to finalize a treatment of stranded cost and to have encouraged customers to search for alternative suppliers.

**Q. Did Citizens perform any analyses designed to determine what future market prices were likely to be, and how costs under the New Contract would compare to what it would pay under the old contract, or under alternative scenarios?**

A. There is no evidence that Citizens performed such analyses, or even that it monitored the spot or forward power market immediately prior to signing the new contract. The Company's analysis which indicates what savings would be if prices remained at the May 2000 level does not seem to have been informed by the most current information on the market, or by any long-run projection.

**Q. Does the Arizona Corporation Commission need to approve the New Contract?**

A. As I understand it, the ACC neither needs to nor has the authority to approve the new contract, as it is a wholesale contract under FERC jurisdiction. I have not conducted an analysis sufficient to recommend approval of the contract. The issue of the prudency of this contract should be examined in the Company's next rate case.

**Q. What is Citizens requesting that the ACC do with regard to the New Contract and the PPFAC?**

A. Citizens is requesting that the ACC approve a new higher PPFAC so that it can collect its anticipated power costs under the New Contract.

**Q. How does Citizens propose to calculate the retail level PPFAC from its wholesale level charges?**

A. The New Contract contains a fixed per kWh charge for every kWh delivered to Citizens' delivery points. However, kWhs are lost between these delivery points and where sales are measured. Citizens proposes to increase the delivery charge rate to the retail level by using a line loss factor of 10.1 %.

**Q. What is the basis for the line loss adjustment?**

A. This is based on estimate used in a fairly old rate case, based on a comparison of energy and sales from April 1994 – March 1995 (Staff Data Request 4.15).

**Q. Is Citizens' approach correct?**

A. No. While it is necessary to adjust retail rates to reflect line losses, the adjustment should be on the basis of actual current line losses. Current estimates of line losses are lower than the historic number that Citizens proposes to use. If we use the Company's method, the Company will overcollect. The average losses over the last 6 years, however, resulted in an average loss adjustment of only 9.91%, according to the response to Staff Data Request 5.57.

**Q. Why is there confusion about line losses?**

A. The reason is that most utilities do not collect data that allow a perfect computation of line losses. Instead, they have data on energy actually generated, by year, month, and even hour, and data on metered sales to customers. The difference between generated kWhs and sold kWhs is often described inaccurately as the line losses. This is inaccurate because the sales data does not reflect the same time period as the generation data, because it is affected by billing cycles. For instance, the reported sales for January of a given year reflect customer usage that goes back to the previous year. January 2 billings, for instance, probably reflect usage from December 1 through January 2 for the customers billed on January 2. At the other end of the year, most of the customer usage on December 31 will not be billed until the following year. Since customer usage varies with weather, days of the week, growth, holidays, and many other factors, we do not expect sales in a given year to reflect usage very accurately. In some years the measurement described above (the comparison of generation to sales) may overstate line losses, and in other years that same measurement may understate line losses.

**Q. What do you recommend regarding the PPFAC and the new contract?**

A. I recommend that the ACC approve a revised PPFAC adjustor which reflects the new contract. There is no need to modify the $.05194/kWh that is currently in base rates. In order for Citizens to begin collecting approximately enough to cover the cost of the current contract and the increase in transmission costs, the major required modification to the existing PPFAC clause would be to project power costs under the new contract. Although this will create a significant increase to the PPFAC factor, allowing the PPFAC adjustor to increase is a reasonable solution because the PPFAC Bank is currently at a very high level.

**Q. What else would be collected in the PPFAC?**

A. On a going forward basis, the clause would need to contain two parts: 1) a higher base adjustment level; 2) a factor to collect the PPFAC balance as allowed by the Commission.

**Q. Please discuss Citizens' total uncollected costs.**

A. The $87 million that the Company refers to is only the undercollection from May 2000 through May of 2001. Since that time, the PPFAC continues to collect less than costs under the new contract, although the monthly undercollection is at a lower rate than it had been. Citizens proposed to collect this additional amount through an automatic reconciliation factor.

**Q. Do you recommend approval of an automatic reconciliation factor?**

A. No. Recent experience suggests that the Commission should retain greater oversight over Citizens PPFAC. Moreover, this factor would further increase customers' rates by an unknown amount as soon as it went into effect. I recommend rather that Citizens provide the amount of this further undercollection as of the most recent known date, and estimate the additional undercollection through the expected date of the order.

## XIV. CONCLUSIONS

**Q. Please summarize your conclusions.**

A. I recommend that the Commission address the PPFAC as follows:

1. The incremental generation adjustment should be allowed, with a reduction to reflect an average line loss
2. The incremental transmission adjustment should be allowed, again with the line loss adjustment
3. The requested collection of the PPFAC bank should be modified from that proposed by the Company.

**Q. How should the collection of the bank be modified?**

A. The bank should be addressed as two different amounts. One amount is the bill reduction of $49 million that could result from a successful pursuit of the SIC interpretation issue at FERC. The second amount is the remaining amount in the PPFAC balance, plus underrecoveries demonstrated by the Company as of the expected date of the order, less $7 million that I recommend be disallowed because of poor management of the power supply contract by Citizens.

**Q. How do you recommend this collection be structured?**

A. I recommend that the second amount be recovered over 6 years, without carrying costs. With regard to the remaining $49 million, I recommend that the

Commission consider the following incentive-based collection scheme. Once a decision on whether the $49 million or any lesser amount has been overbilled or not, based on a finding regarding the SIC interpretation, the SIC measurement, or any other factor, Citizens shall apply to the Commission for a factor to collect any remaining dollars. The recovery time for those additional dollars should be dependent on the amount of the recovery. If there is no relief, the recovery of the remaining dollars would be over 7 years from the date approved by the Commission, but the recovery period could be shortened by a year for every additional $10 million of relief achieved. In other words, if FERC (or the courts) ruled that Citizens had been overbilled by $10 million, the remaining balance of $39 million could be collected over 6 years. This provides Citizens with ample incentive to pursue this issue vigorously.

**Q. Does this conclude your testimony?**

A. Yes, it does.

**LEE SMITH**
**LA CAPRA ASSOCIATES**
Senior Economist

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**Ms. Lee Smith** is a Managing Consultant and Senior Economist at La Capra Associates. Ms. Smith has twenty years experience in utility economics and regulation. Her work has encompassed all aspects of utility pricing, cost analysis, forecasting, and both demand-side and supply planning in electric, gas, and water utility cases. Ms. Smith has analyzed issues of electric rate design, including rate unbundling and appropriateness of utility costs in 17 different states for a multitude of utilities and other entities. As a consultant, her clients have included gas and electric utilities, regulatory commissions and other public bodies. Previous to La Capra Associates, Ms. Smith was employed as the Director of Rates and Research at the Department of Public Utilities.

## ACCOMPLISHMENTS

- Advised, provided testimony and participated in settlement discussion on Provider of Last Resort rates for Pennsylvania Office of the Public Advocate.

- Estimated retail class generation rates under continued regulated and retail access Arkansas Public Utilities Commission Staff; analyzed proposed change to System Resource Agreement by Entergy.

- Advised the Ohio Consumer's Counsel in stranded cost policy and rate design issues for all Ohio investor-owned utilities.

- Assisted the Arizona Corporation Commission in developing unbundled rates for all Arizona utilities; preparing positions, and negotiating with utilities on stranded cost and rate design.

- Advised Pennsylvania Office of the Public Advocate staff in restructuring proceedings; presented testimony on rate unbundling in eight cases.

- Assisted Massachusetts Division of Energy Resources in drafting restructuring legislation and negotiating additional restructuring settlements with utilities.

- Represented the Massachusetts Department of Energy Resources at NEPOOL committees engaged in developing the New England Independent System Operator,, and an Open Access Transmission Tariff for New England.

## EMPLOYMENT

**La Capra Associates**
***Managing Consultant since 2000***
**1984 - present**

**Department of Public Utilities:**
***Director of Rates and Research,***
**1982 - 1984**

## EDUCATION

**Ph.D.**, all but dissertation, Tufts University, Economics
**B.A.**, Honors, Brown University,
International Relations and Economics
**Study of Statistics,** Boston College

## HONORS

Bunting Institute Fellowship, 1970-71
Tufts University Economics Department Fellowship, 1967-68
Prize in International Relations, Brown University, 1965

**Data Responses in Attachment S-2:**

| | |
|---|---|
| Staff 6.14 | (p.8, p.29) |
| Staff 4.27 | (p.11) |
| Staff 3.22 | (p.11) |
| Staff 5.41 | (p.14) |
| Staff 5.42 | (p.14) |
| Staff 8.02 | (p.15) |
| Staff 8.05 | (p.15, p.38, p.44) |
| Staff 7.11 | (p.15) |
| Staff 4.1 | (p.16) |
| Staff 5.05 | (p.16) |
| RUCO 1.4 | (p.18) |
| Staff 7.13 | (p.19) |
| Staff 5.36 | (p.19) |
| Staff 5.17 | (p.29) |
| Staff 5.19 | (p.29) |
| RUCO 4.5 | (p.30, p.49) |
| Staff 5.16 | (p.31) |
| RUCO 4.16 | (p.33) |
| Staff 8.37 | (p.34) |
| Staff 5.44 | (p.38) |
| Staff 7.07 | (p.40) |
| Staff 8.09 | (p.41) |
| Staff 7.01 | (p.41) |
| Staff 7.12 | (p.41) |
| Staff 6.19 | (p.42) |
| Staff 8.22 | (p.43) |
| Staff 5.02 | (p.43, p.44) |
| Staff 8.24 | (p.43) |
| RUCO 4.2 | (p.47) |
| Staff 4.15 | (p.51) |
| Staff 5.57 | (p.51) |

**Citizens Communications**
**Docket No. E-01032C-00-0751**
**Arizona Corporation Commission's Sixth Set of Data Requests**

**Witness: Sean Breen**

**Data Request No. 6.14:**

Before May 2000, what was Citizens' view of the probability that actual wholesale electricity prices in the Southwest during May through September 2000 would turn out at or above the prices that actually were observed? Please explain the basis for Citizens' expectations, and provide all workpapers supporting them. Provide any analyses memos, e-mails, or other documentation regarding Citizens' consideration of this topic.

**Response:**

Citizens did not have information that led it to believe that wholesale electricity prices would increase as dramatically as experienced in the summer of 2000. As explained in the response to RUCO Data Request No. 3.1, for the period leading up to May 2000, Citizen' was engaged in settling a billing dispute with APS/PWEC from the May 1999 billing adjustment. Throughout that process, Citizens maintained that the definition of "system incremental cost" ("SIC") in the former Power Service Agreement restricted APS/PWEC, relative to purchased power, to charging Citizens for only "economic purchases," which by definition were lower in cost than the running costs of their owned units. In Citizens' view, the contract definition of SIC effectively shielded the Company and its customers from high wholesale prices. Consequently, there was little to gain by attempting to assess the probability that wholesale price may rise.

# CITIZENS COMMUNICATIONS COMPANY
# ARIZONA ELECTRIC DIVISION'S RESPONSES TO THE RESIDENTIAL UTILITY CONSUMER'S OFFICE FOURTH SET OF DATA REQUESTS
# DOCKET NO. E-01032C-00-0751
October 9, 2001

***Data Response No. 4.27:***
In response to Staff's second data request, LAJ 4.2, please describe the meaning of "Development of Phase III process" identified under the "Billing Audit" section. Did Citizens do anything other than submit data requests to APS with regard to the Phase III audit? Has APS submitted anything to date in response? If so, what did APS submit?

***Respondent:*** Sean Breen

***Response:***
During the "Development of Phase III process," Citizens employed a team of outside experts to explore two key issues: 1) the prudence of APS power procurement practices over the last several years; and 2) the diligence applied in making decisions about short-term purchases to cover Citizens' load. After development of a framework for the audit process, the team developed a comprehensive data request for APS/PWCC to support the required analyses. As indicated in the response to LAJ 4.2, APS/PWCC indicated in a letter dated April 10, 2001, that it would not be responding to the data request. None of the requested data was submitted to Citizens, and no further progress was made on the Phase III audit after the April 10, 2001, notification from APS/PWCC.

**CITIZENS COMMUNICATIONS COMPANY**
**ARIZONA ELECTRIC DIVISION**
**DOCKET NO. E-01032C-00-0751**
**STAFF'S THIRD SET OF DATA REQUESTS**
**NOVEMBER 17, 2000**

**WITNESS: SEAN R. BREEN**

**DATA REQUEST NO WPD 3-22:**

Provide a copy of Citizens' own audit of APS bills. This was supposed to be completed on 10/25/00.

**RESPONSE:**

The requested information is confidential and can not be provided to Staff or its consultants until and unless all parties enter a confidentiality agreement with APS.

Citizens Communications
Docket No. E-01032C-00-0751
Arizona Corporation Commission's Fifth Set of Data Requests

Witness: Sean Breen

**Data Request No. LS 5.41:**

The response to Data Request 4.3 seems to indicate that PW does not provide Citizens with detailed information regarding what charges are based on purchased power versus owned-generation costs. Is this correct?

**Response:**

Yes, this is correct. The standard billing information provided in the APS/PWEC bill under the former contract does not include detailed information about purchased-power versus owned-generation costs. The information that Citizens has obtained on this subject was through a follow-up data request.

Citizens Communications
Docket No. E-01032C-00-0751
Arizona Corporation Commission's Fifth Set of Data Requests

**Witness: Sean Breen**

## Data Request No. LS 5.42:

If the answer to 5.41 above is yes, how does Citizens confirm that it is being billed the correct amount?

## Response:

The only way Citizens can confirm that it is being billed the correct amount with respect to purchased-power versus owned- generation is by requesting and obtaining additional information from APS/PWEC. This has occurred on a number of occasions in the past. For instance, in the dispute that arose in conection with the May 1999 APS/PWEC billing adjustment [see pg. 14 of Citizens' original application in this docket, filed 9/28/00 ], Citizens was able to review in detail the bill components relating to APS owned-generation and purchased-pwer, based on information provided in response to our formal request. Ultimately, this matter was settled by a $1.5 million refund from APS/PWEC. Similarly, the the scope of the Phase II audit included a review of APS purchases used to serve Citizens' load, based on specifically requested data that APS/PWEC subsequently provided.

**Citizens Communications**
**Docket No. E-01032C-00-0751**
**Arizona Corporation Commission's Eighth Set of Data Requests**

**Witness: Sean Breen**

## Data Request No. 8.02:

Please specify the billing months in 1999 when Citizens disagreed with how APS was interpreting the SIC provision.

## Response:

In May 1999, Citizens received revised bills from APS/PWEC covering the periods January through November of 1998. Citizens immediately notified APS/PWEC that it was disputing the revised bills and began a comprehensive review of APS/PWEC billing procedures. During this review, which continued for approximately one year, Citizens expressed concerns about how APS/PWEC was calculating the SIC in its billing process. Consequently, the differences between the parties in interpreting the SIC provision related to the historic period of the contract, during which APS/PWEC billed purchased power costs as part of its SIC. This potentially included every month of 1999, because the nominal charges in Schedules A, Off-Peak and Schedule B are based on APS/PWEC's SIC, and during that period, APS/PWEC routinely purchased at least a portion of Citizens' load requirements. The differences between the parties with respect to these past billing practices were settled as part of the May 18, 2000, Memorandum of Understanding (provided in response to Staff Data Request 5.44) with a payment by APS/PWEC to Citizens of $1.5 million. The disposition of that payment is descripted in the response to Data Request No. 7-11.

Citizens Communications
**Docket No. E-01032C-00-0751**
**Arizona Corporation Commission's Eighth Set of Data Requests**

**Witness: Sean Breen**

**Data Request No. 8.05:**

Precisely how did APS compute the SIC? How did Citizens determine how APS was computing the SIC? When and how did Citizens approach APS with its opinion on the SIC computation? What was the outcome of this dispute?

**Response:**

APS included purchased power in its SIC calculations, whether obtained for economic or reliability purposes. During the initial discussions in connection with the 1999 billing dispute, APS took the position that its SIC, for purposes of billing Citizens, was simply either its most expensive unit dispatched or actual purchase in the hour, regardless of how the quantity of such purchases compared with Citizens' load in that same hour. Thus, if Citizens' load was 100MW in a particular hour and APS/PWEC's highest cost purchases in that hour were 50 MW at $100/MWh and 50 MW at $80/MWh, APS/PWEC would bill Citizens $100/MWh for all $100 MW.

Following Citizens' objections to this clearly erroneous concept, APS/PWEC agreed that it would compute weighted average prices to Citizens, reflecting the applicable prices and quantities of the purchases used to meet Citizens' load. While that would have been an improvement, APS/PWEC nevertheless continued to bill Citizens based on the cost of reliability purchases, which in Citizens' view, was clearly inconsistent with the contract language.

Citizens first approached APS/PWEC with its concerns about the SIC computation in the summer of 1999, in the context of the billing dispute process. APS/PWEC's responded with the assertion that all their purchased power was "economic" and therefore fully chargeable to Citizens' under the terms of the contract. APS/PWEC maintained this position through the remainder of 1999 and early 2000, and only agreed to negotiate when they needed Citizens' cooperation in connection with their planned FERC Market-Based Rates filing. The outcome of the dispute was the May 2000 MOU (provided in response to Staff Data Request LS 5.44), in which Citizens believed it had negotiated contract terms that appropriately resolved the SIC issues.

Citizens Communications
Docket No. E-01032C-00-0751
Arizona Corporation Commission's Seventh Set of Data Requests

Witness: Carl Dabelstein

**Data Request No. 7.11:**

Did Citizens receive the refund of $1.5 million that was mentioned in the MOU?

**Response:**

Citizens did receive the $1.5 million refund from APS. Consistent with the Arizona Corporation Commission's directives to mitigate stranded costs, and as proposed by Citizens in connection with the Stranded Cost settlement agreement negotiations, the $1.5 million was credited to the regulatory asset – Deferred DSM Program Costs.

# CITIZENS COMMUNICATIONS COMPANY
# ARIZONA ELECTRIC DIVISION'S RESPONSES TO THE ARIZONA CORPORATION COMMISSION STAFF'S FOURTH SET OF DATA REQUESTS
# DOCKET NO. E-1032C-00-0751



**October 2, 2001**

<u>LAJ 4.1</u>: Re: Application, Page 3, Lines 19 and 20. Provide the key contract provisions that the AEC and APS interpreted differently and provide each party's interpretation.

***<u>Respondent</u>:*** Sean Breen

***<u>Response</u>:*** There were two principal areas of disagreement concerning the interpretation of the contract: the definition of "System Incremental Cost (SIC)" and how SIC was charged for the base block of Schedule A.

In the contract, the definition of System Incremental Cost was limited to purchases "for economic purposes" that "would not otherwise be needed " to serve Citizens' load. Citizens contended that it was not responsible for all of Arizona Public Service's (APS) purchased power costs, but only for economic purchases, i.e., those lower than the avoided cost of APS' high cost generating unit. Under APS' interpretation of the SIC, the hourly incremental cost of all purchases were chargeable to Citizens to the extent it was taking power applicable to SIC billing. [See, Power Service Agreement, section 4.1.1.1, line 16 and 17.]

The second area of dispute related to how the parties interpreted the Schedule A charges. Schedule A includes a "base block" of 100 megawatts each hour, plus the right to take up to 75 more MW each hour during "off-peak" hours. Citizens paid APS a fixed monthly demand charge for the right to take this power. Citizens' interpretation of the contract was that pricing for the base block of Schedule A was based on the embedded cost of the APS system and that this portion of the load should not be subject to SIC pricing. APS took the position that the ability to charge Citizens for the full cost of purchased power was set forth in specific provisions Service Schedules A, B and C, which provided that Citizens "shall be responsible for purchased power costs, and for any other costs incurred by APS in fulfilling its obligations for power and energy under this Service Schedule which otherwise would not have been incurred." [See, Power Service Agreement, Schedule A, Exhibit B, page 2, section III]

Attached is correspondence between Citizens and APS that further details the parties positions:

**Citizens Communications**
**Docket No. E-01032C-00-0751**
**Arizona Corporation Commission's Fifth Set of Data Requests**

**Witness: Sean Breen**

**Data Request No. LS 5.05:**

On p. 3 the Application states that analysis "failed to identify any significant practices that would have resulted in excessive costs for AED." Does this mean the audit concluded that:

a. the power bills were appropriate;
b. that the power bills were consistent with APS' interpretation of the contract;
c. that PW's purchasing practices were prudent and appropriate;
d. or something else – please specify.

**Response:**

The quoted statement refers mainly to the Phase II audit process, the results of which have been provided to Staff under a confidentiality agreement. The scope of the audit included an assessment of the potential of APS to pass higher power costs than appropriate on to Citizens. No such occurrences were discovered. The scope of the Phase I and Phase II audits did not include contract interpretation. A review of APS/PWEC's purchasing practices were to be addressed in Phase III of the audit process, which was not completed. (For additional discussion, please see Citizens' response to Staff Data Request LAJ4.27).

CITIZENS COMMUNICATIONS COMPANY
ARIZONA ELECTRIC DIVISION
DOCKET NO. E-01032C-00-0751
FIRST SET OF DATA REQUESTS
OCTOBER 4, 2000

WITNESS: RESAL CRAVEN

**DATA REQUEST NO 1.4:**

Page 3 - Please provide copies of all power bills from APS to Citizens under the wholesale contract for the months April 2000 through September 2000.

**RESPONSE:**

See attached copies of the power bills.

THE POWER TO MAKE IT HAPPEN
P.O. BOX 53999 • PHOENIX, ARIZONA 85072-3999

August 31, 2000

Mr. Sean Breen
Citizens Utilities Co.
1300 S. Yale St.
Flagstaff, AZ 86001

Dear Sean:

Attached please find the July, 2000 invoice covering APS' service to Citizens Utilities. This also is being sent to Kingman for payment. This invoice is based on the pricing methodologies contained in our Memorandum of Understanding dated May 18, 2000.

This invoice includes a credit from a revision of the June, 2000 invoice sent on August 24, 2000. The August 24th rendition of the June invoice was revised to include the Surplus Hedging credit which was shown in June but inadvertently not added to the billing total.

APS received FERC acceptance of our compliance filing (Docket ER00-2268-000) on August 25, 2000. In this filing FERC provided that, effective June 20, 2000, APS shall recalculate any formulas that use SIC (System Incremental Cost) by using the Palo Verde Index shaped by SP-15 Hourly Index (PV/SP15 Index) substituted for SIC with the customer invoice to reflect the lower of these two methods. This additional limit affects the maximum and minimum billing amounts and the power rates for all schedules.

To comply with FERC's mandate, APS reviewed the effects on the June, 2000 bill and determined that there was no effect since the PV/SP15 Index yielded a higher bill for each schedule. This same comparison is shown on the July invoice (attached) and will be included in all future invoices.

Please call with any questions or comments concerning any of this.

Sincerely,

Dennis L Beals

Dennis Beals

cc: Teri Rice

Citizens Communications
Docket No. E-01032C-00-0751
Arizona Corporation Commission's Fifth Set of Data Requests

Witness: Sean Breen

**Data Request No. LS 5.36:**

Please provide any memos, analyses, or other documents received by or produced by Citizens during the April – July 2001 period regarding current and future market prices.

**Response:**

While Citizens personnel routinely visit the New York Mercantile Exchange Website to review market prices for energy products and do read industry publications on the subject, no memos, analyses, or other documents were received or produced relative to future electric market prices during the April 2001 – July 2001 period.

Citizens Communications
**Docket No. E-01032C-00-0751**
Arizona Corporation Commission's Seventh Set of Data Requests

**Witness: Sean Breen**

## Data Request No. 7.13:

At any point during the spring of 2000, did Citizens ask APS whether it expected that it would need to purchase power to meet Citizens load during the upcoming summer of 2000?

## Response:

Citizens has no record or recollection of asking this specific question to APS/PWEC in the spring of 2000, however, based on earlier discussions, Citizens was aware that APS/PWEC did not have adequate system generation to meet its native load plus Citizens' load. Please see the response to Data Request 7.5 for a summary of key topics of negotiation during the Spring of 2000.

Citizens Communications
Docket No. E-01032C-00-0751
Arizona Corporation Commission's Fifth Set of Data Requests

Witness: Sean Breen

**Data Request No. LS 5.17:**

Before the May 2000 Pinnacle Market-Based Pricing filing at FERC, did Citizens ever consider the possibility that it could be charged much higher energy rates based on the cost of purchased power for any of its power schedules?

**Response:**

As a point of clarification, the market-based rate filing by Pinnacle West did not create the opportunity for APS/PWEC to charge SIC under the contract. The SIC provision existed prior to that filing. Citizens did understand that a possibility existed of being billed subject to the ceiling or floor provisions of the contract prior to May 2000. What was unanticipated was the ***extraordinary*** increase in market prices that coincided with floor pricing under the agreement.

Citizens Communications
Docket No. E-01032C-00-0751
Arizona Corporation Commission's Fifth Set of Data Requests

**Witness: Sean Breen**

**Data Request No. LS 5.19:**

If the answer to number 5.15 is yes, did Citizens consider or make any estimates of the impact on it of SIC pricing? If so, please provide.

**Response:**

Citizens did not prepare estimates of SIC pricing prior to May 2000.

# CITIZENS COMMUNICATIONS COMPANY
# ARIZONA ELECTRIC DIVISION'S RESPONSES TO THE RESIDENTIAL UTILITY CONSUMER'S OFFICE FOURTH SET OF DATA REQUESTS
# DOCKET NO. E-01032C-00-0751
# October 9, 2001

***Data Request No. 4.5:***
Provide the complete basis for the claim that the new power supply contract with APS will result in substantial future savings for customers. In particular, please provide the wholesale market price projections for the Arizona region that you relied on in coming to this conclusion.

***Respondent:*** Sean Breen

***Response:***
Please see the responses to Staff Data Requests LAJ 4.9 and LAJ 4.10. Citizens believes that the savings for summer 2001 alone are closer to the upper limit of the range estimate of $30 - $70 million based on the understanding that Citizens would have been billed costs similar to its May 2001 bill had it remained under the former contract. Citizens did not develop an independent forecast of spot market prices to evaluate customer savings. As a reasonable and conservative proxy, Citizens did compare its new contract pricing to long-term contracts recently entered by the California Department of Water Resources ("CDWR"). Citizens' new contract is a load-following, all-requirements agreement with no restrictions relative to future load growth (or load loss to competition), load shape or load factor, while the bulk of the CDWR contracts were for defined blocks of energy and/or capacity for defined hours (e.g. 6 days/week, 16 hours/day or 7 days/week, 24 hours/day). Citizens did not identify a single comparable CDWR contract with lower pricing than the new APS/PWCC contract. The only fixed-price, long-term contract with similar pricing (Calpine, $58.60/MWh) was for a ten-year commitment to a 7 X 24 block of capacity and energy, which is not comparable to Citizens' new contract.

Finally, the forecasting of future wholesale prices as a means of evaluating savings of the new APS/PWCC contract is a complex and uncertain exercise providing results of questionable value. While Citizens is relatively certain about near-term summer 2001 savings under the new contract, neither Citizens nor any credible party can represent that a particular level of savings will occur in the future given the inherent volatility of energy markets.

CITIZENS COMMUNICATIONS COMPANY
ARIZONA ELECTRIC DIVISION'S RESPONSES TO THE
RESIDENTIAL UTILITY CONSUMER'S OFFICE
FOURTH SET OF DATA REQUESTS
DOCKET NO. E-01032C-00-0751
October 9, 2001

*Response to Data Request No. 4.5 Cont:*

Citizens does observe, however, that the question of long-term savings levels requires consideration of the asymmetrical risks involved. On the downside, market prices could fall, thus reducing savings. However, they could not fall below the producers' marginal cost of production. On the upside, market prices could increase, thus increasing the savings realized. Even with FERC-imposed price caps in place in Western markets, prices can rise as high as the cost of the least efficient unit needed to satisfy regional load requirements. Given the continuing uncertainty about the long-term balance between electric supply and demand in the West, and in light of recent volatility of Western power and natural gas markets, Citizens submits there is substantial risk for high future wholesale electric prices. Moreover, the likelihood for high prices is greatest when load in the region at there highest levels, i.e summer months. Since roughly 45% of Citizens' annual power purchases occur between June and September, its opportunities for realizing savings under its fixed price contract are enhanced.

Citizens Communications
**Docket No. E-01032C-00-0751**
**Arizona Corporation Commission's Fifth Set of Data Requests**

**Witness: Sean Breen**

**Data Request No. LS 5.16:**

If the answer to number 5.15 is yes, did PW provide any verbal information or documents regarding the impact of this change? Is yes, please provide this information.

**Response:**

Pinnacle West verbally explained an example of a calculation similar to Table A, which is inlcuded in Exhibit D of Pinnacle West Capital Corporation's April 21, 2000 FERC filing. Pinnacle West also sent a letter to Citizens, dated April 17, 2000, explaining the impacts of the change. Copies of Table A and the April 2000 letter are attached.

CITIZENS COMMUNICATIONS COMPANY
ARIZONA ELECTRIC DIVISION'S RESPONSES TO THE
RESIDENTIAL UTILITY CONSUMER'S OFFICE
FOURTH SET OF DATA REQUESTS
DOCKET NO. E-01032C-00-0751
October 9, 2001

***Data Request No. 4.16:***
What is the cost per kWh of operating the Valencia unit?

***Respondent:*** Sean Breen

***Response:***
The "Valencia unit" is actually three gas turbine units. Based on the average heat rate of 17,903 Btu/kWh from recent turbine runs, and a fuel oil cost of $1.00/gallon, the fuel cost for generation would be $.13/kWh. In addition to the fuel cost, there is a relatively small variable O&M cost.

Citizens Communications
**Docket No. E-01032C-00-0751**
**Arizona Corporation Commission's Eighth Set of Data Requests**

**Witness: Carl Dabelstein**

**Data Request No. 8.37:**

When were the improvements that were made to the Valencia generators started and completed?

**Response:**

Such expenditures were made during the period from the Fall 2000 through Spring 2001.

Citizens Communications
Docket No. E-01032C-00-0751
Arizona Corporation Commission's Fifth Set of Data Requests

Witness: Sean Breen

**Data Request No. LS 5.44:**

Please provide the APS/Citizens' MOU dated May 18, 2000, which is referenced in the August 2000 power bill.

**Response:**

A copy of the requested document is attached.

**Terms of a Potential Restructuring of the Existing Power Supply Agreement Between Citizens Utilities and APS**

The terms and conditions contained herein shall become effective on the earlier of (i) July 1, 2000, or (ii) upon issuance of a FERC order no longer subject to judicial review, approving Pinnacle West Capital Corporation's Market-Rate Tariff and modified Code of Conduct filing Docket ER00-2268-000, without changes or modifications unacceptable to Pinnacle West ("Start Date").

1. Terminate Service Schedule A (SSA) Off-Peak, Service Schedule B (SSB) and Service Schedule C (SSC) 12/31/03.

   - Reprice SSA Off-Peak, SSB and SSC as a single block of energy as follows:

     From Start Date through December 31, 2000 (Period 1) and each calendar year thereafter through December 31, 2003 (Periods 2-4), Citizens can choose one of the following pricing methods:

     a. A fixed price for an entire period in $/mwh supplied by APS (APS will supply this price one month prior to the start of the period);

     or

     b. A monthly price in $/mwh set at a base level equal to the actual 1999 revenues paid by Citizens, divided by the 1999 energy deliveries by month adjusted by the ratio of the forecasted monthly natural gas price(s) to the actual natural gas price(s) for the corresponding month(s) in 1999. Citizens shall have the right to set the price for any number of months within a period in advance, but cannot change the price once established. For purposes of this calculation, the gas prices for periods greater than one month will be determined on a load weighted basis reflecting 1999 energy deliveries under SSA Off-Peak, SSB and SSC.

        Citizens can request APS to set the price for a month or more within a period based on this methodology, if they so request prior to the 25th day of the month preceding the first month prices are to be set.

   - With the understanding that APS retains the ability to call for load interruption (i.e. operation of the Valencia turbines) under specified contingency conditions, no other requirements under SSC affecting the Valencia turbines continue to be valid under this agreement.

2. Pricing for Service Schedule A Base Block will remain unchanged except starting May 1, 2002, Citizens shall have the ability to reduce the contract demand below the current 104 mw level based on the following criteria:

   By January 1 of each year, starting January 1, 2002, Citizens may request a reduction in the Base contract demand for the following May 1 through April 30 time period, up to a maximum of their actual net measurable and verifiable loss of load.

   Once reduced, the contract demand cannot be increased unless by mutual agreement. The actual mechanics and details of how load will be measured are to be worked out prior to the Start Date. Net load loss shall be based on the difference between added customer load and customers leaving Citizen's system.

3. As a settlement of all outstanding billing issues, APS shall pay Citizens $1.5 million, due on the Start Date.

4. APS and Citizens recognize the need to alter the Power Service Agreement and/or its Service Schedules to accommodate power deliveries into Citizens' service area by competitive energy service providers. The parties agree to work together to do so by June 30, 2000.

5. With the parties agreement on the provisions contained herein, as evidenced by the signatures below, Citizens agrees not to file a protest in Pinnacle West Capital Corporations Market-Rate Tariff filing, Docket No. ER00-2268-000 or it's impending 203 filings covering asset divestiture and shall withdraw its existing intervention.

Jack Davis
Arizona Public Service
Date: 5/18/00

Citizens Utilities
Date: 5/18/00

**Citizens Communications**
**Docket No. E-01032C-00-0751**
**Arizona Corporation Commission's Seventh Set of Data Requests**

**Witness: Sean Breen**

**Data Request No. 7.07:**

For what specific reason, and on what date, did negotiations on the new contract that was envisioned in the May MOU cease?

**Response:**

Citizens suspended its negotiations on the restructured contract in mid-July 2000, following receipt of its power bill for June 2000, and switched its focus to discussions with APS/PWEC to establish the propriety and reasonableness of unprecedented high bills. Discussions on contract restructuring resumed in August, but abruptly ended on August 29, 2000, when APS/PWEC withdrew a commitment made earlier in the negotiations. The attached document is a copy of a memorandum prepared at that time of the reversal of position by APS/PWEC. Certain confidential information has been redacted from the memorandum. The redacted information will be provided for review to APS/PWEC with a request that it release the data to Staff.

**Citizens Communications**
**Docket No. E-01032C-00-0751**
**Arizona Corporation Commission's Eighth Set of Data Requests**

**Witness: Sean Breen**

## Data Request No. 8.09:

The July Revision 1 bill and the August bill have a footnote "This invoice was based on the APS/Citizens Memorandum of Understanding Dated May 18, 2000." Did these bills revise Schedules B and C?

## Response:

From Citizens perspective, the replacement contracts envisioned in the May 18, 2000, MOU were never executed. Therefore it was a unilateral decision on the part of APS/PWEC to bill Citizens beginning July 2000 under the terms of the MOU. As set forth under provision No. 1 of the MOU, Service Schedules A Off-Peak, B, and C were to be repriced as a single block of energy, based on terms described thereafter. Citizens never formally accepted the contract modifications envisioned in the May 2000 MOU, and therefore, did not regard the July billing as revising Schedules B and C. All bills from May 2000 onward were paid under protest.

**Citizens Communications**
**Docket No. E-01032C-00-0751**
**Arizona Corporation Commission's Seventh Set of Data Requests**

**Witness: Paul Flynn**

**Data Request No. 7.01:**

Please explain, in detail, why you decided not to pursue your dispute with APS over contract interpretation.

**Response:**

Citizens takes issue with the characterization in this request. Citizens has committed substantial resources to pursuing its contract dispute with APS at some length, including, as discussed in the testimony, collecting extensive purchase power and other data from APS and intensively reviewing that data.

As stated by Mr. Breen in his Direct Testimony (at p. 4, ll. 14-18), "[g]iven the inevitability of a protracted legal process, the uncertainty of the outcome of the litigation, and the reality of continuing high charges under the PSA, Citizens shifted its focus to the possibility of negotiating prospective changes in the contract."

The 1995 Power Service Agreement, its service schedules, the rate stipulations underlying those schedules, and the letter of intent and other agreements that preceded it, are complex and, viewed as a whole and with the benefit of hindsight, include some apparent ambiguities. The purchased power pricing methodologies employed by APS in connection with the PSA, and FERC's policies on system incremental costs, requirements contracts, coordination contracts, and similar matters, add greatly to the complexity of the pricing analysis under the PSA. This complexity, the ambiguities in the PSA and related agreements, and the difficulty in applying their terms in the context of extremely high wholesale power market prices that, it can fairly be said, were not previously contemplated by any of the parties to this agreement, or by the regulators that reviewed this agreement over the years, significantly increase the uncertainty of the outcome of any litigation over the PSA.

What is more certain is that a litigation outcome likely would take several years, and that interim relief would be difficult to obtain in any contract action. Two litigation options were considered: a civil lawsuit in state court and a complaint to the FERC. Neither of these alternatives proved to be attractive. In addition to the concerns expressed above as to the likelihood of ultimate success,

**Citizens Communications**
**Docket No. E-01032C-00-0751**
**Arizona Corporation Commission's Seventh Set of Data Requests**

**Witness: Paul Flynn**

**Data Response No. 7.01 Cont:**

considerations of time and cost weighed heavily in the decision not to pursue litigation. It was estimated that, depending on the alternative pursued, litigation would not be concluded for 3 to 5 years from inception. Litigation costs, through appeal, were estimated in the hundreds of thousands of dollars. In addition, because the company had been unable to obtain some sort of interim relief from the Arizona Commission that would allow for the collection of power costs during the pendency of any litigation regarding the PSA, the PPFAC bank balance would continue to grow. Assuming power costs remained at levels that the company had experienced for the past year, the bank balance could be expected to exceed $200 million by the time litigation was concluded.

The surest path to immediate relief to avoid a repeat of the high charges experienced in the Summer of 2000 was to negotiate new prospective contract terms, which is the path Citizens prudently followed.

**Citizens Communications**
**Docket No. E-01032C-00-0751**
**Arizona Corporation Commission's Seventh Set of Data Requests**

**Witness: Carl Dabelstein**

**Data Request No. 7.12:**

If not, is there still a dispute outstanding regarding bills from the summer of 1999.

**Response:**

There remain no outstanding disputes with APS with respect to power supply bills for the summer of 1999.

Citizens Communications
Docket No. E-01032C-00-0751
Arizona Corporation Commission's Sixth Set of Data Requests

Witness: Sean Breen

**Data Request No. 6.19:**

Please explain what options CUC could have used to hedge the price of power under the APS contract against high-price outcomes such as those that occurred in summer 2000? For each type of hedging option that was available, please explain why CUC did not utilize it.

**Response:**

Information about energy price hedging techniques and mechanisms is generally available. Citizens sought approval in its original filing for implementing energy risk management initiatives and asked that the Commission establish guidelines for recovering costs of such initiatives. Citizens did not implement these initiatives in the past because: 1) it believed that its contract with APS/PWEC shielded customers from high prices; and 2) the absence of prior approval and guidelines from the Commission were necessary before proceeding.

Citizens Communications
Docket No. E-01032C-00-0751
Arizona Corporation Commission's Eighth Set of Data Requests

Witness: Sean Breen

**Data Request No. 8.22:**

Did you pursue this issue with APS? If so, what was their response. Provide any written material on this issue.

**Response:**

This issue was discussed with APS, mainly in the context of face-to-face meetings. Their response was that the APS/PWEC interpretation of the contract allowed them to allocate costs in the manner described in the response to Data Request 8.21. The confidential materials provided (following APS/PWEC sign-off) in connection with Data Request 8.03, addresses this issue. Please see, in particular, correspondence from APS/PWEC dated September 7, 1999.

**Citizens Communications**
**Docket No. E-01032C-00-0751**
**Arizona Corporation Commission's Fifth Set of Data Requests**

**Witness: Sean Breen**

**Data Request No. LS 5.02:**

Is it Citizens' testimony that it has decided not to pursue recovery from Pinnacle West of any of the $85 million under-recovery? If yes, when was this decision made, and by whom? Has Citizens made any commitment to APS or to Pinnacle West not to pursue recovery of any of these costs?

**Response:**

It is Citizens' testimony that agreement with APS/PWEC to restructure the then-existing power supply arrangements was intended to resolve all contested matters. Please see the response to Staff Data Request LAJ 4.2 for a chronology of the discussions between the companies. Citizens' senior management made the decision to explore alternative means for resolution of the existing matters. There are no written agreements concerning any commitment to APS/PWEC not to pursue recovery of costs under the former power supply contract.

Citizens Communications
**Docket No. E-01032C-00-0751**
**Arizona Corporation Commission's Eighth Set of Data Requests**

**Witness: Sean Breen**

## Data Request No. 8.24:

If the answer to 8-19 is no, what was Citizens rationale for not pursuing this issue?

## Response:

As noted in the response to Data Request No. 8.23, Citizens would have argued this issue if it had pursued litigation or a FERC complaint to resolve its disputes with APS/PWEC. As indicated in Citizens' application and testimony, Citizens regarded the litigation to be uncertain, costly, and time-consuming and instead resolved matters by entering a new contract with APS/PWEC, which provided significant cost benefits.

CITIZENS COMMUNICATIONS COMPANY
ARIZONA ELECTRIC DIVISION'S RESPONSES TO THE
RESIDENTIAL UTILITY CONSUMER'S OFFICE
FOURTH SET OF DATA REQUESTS
DOCKET NO. E-01032C-00-0751
October 9, 2001

***Data Request No. 4.2:***
Please provide a month-by-month detail of the $87 million calculation. In particular, show specifically how the changes in the Western wholesale power market prices have increased the balance of unrecovered costs as claimed on page 2, lines 9-11 of the Amended Application.

***Respondent:*** Sean Breen

***Response:***
Please see the attached spreadsheet for the requested data. The line entitled "Average $/Sales" provides an indicator of when wholesale market prices increased the unrecovered costs. It replicates the data that was submitted to Staff on the monthly PPFAC reports. In each month where the "Average $/Sales" exceeds $0.05194/kWh, the base PPFAC charge in Citizens' rates, the bank balance was increased for that month. Months where this value greatly exceeds the base charge indicate months where the high wholesale power costs, as exhibited by the charges in APS Service Schedules A and B, materially impacted the PPFAC bank balance.

**CITIZENS UTILITIES COMPANY**
**ARIZONA ELECTRIC DIVISION**
**PPFAC Activity April 2000 - June 2001**

| | Unit | Apr-00 | May-00 | Jun-00 | Jul-00 | Aug-00 | Sep-00 | Oct-00 | Nov-00 | Dec-00 | Jan-01 | Feb-01 | Mar-01 | Apr-01 | May-01 | Jun-01 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Starting PPFAC Bank Balance | $ | -$2,677,249 | -$2,202,722 | $3,640,382 | $14,510,656 | $28,646,264 | $46,631,627 | $54,263,437 | $55,873,647 | $55,060,194 | $56,353,359 | $58,239,760 | $58,986,861 | $60,161,059 | $65,734,437 | $84,677,034 |
| Sales | kWh | 83,320,477 | 85,050,223 | 112,473,401 | 126,673,741 | 139,810,082 | 128,820,086 | 104,748,270 | 88,540,355 | 85,510,881 | 101,821,634 | 97,342,033 | 82,356,003 | 98,063,301 | 88,821,802 | 120,342,085 |
| PPFAC Revenues | $ | $3,887,182 | $3,975,027 | $5,217,574 | $5,878,928 | $8,479,303 | $5,885,719 | $6,861,275 | $4,302,164 | $4,441,425 | $5,278,222 | $5,055,945 | $4,277,716 | $4,470,128 | $4,603,011 | $8,250,588 |
| Valencia generation $ | | $56 | $26,723 | $117,708 | $73,973 | $52,303 | $19,370 | $17,860 | $3,306 | $38,464 | $0 | $0 | $0 | $0 | $540,884 | $887,402 |
| APS cost: | | | | | | | | | | | | | | | | $8,095,677 |
| Schedule A | | $2,838,347 | $5,378,793 | $7,240,005 | $8,931,151 | $10,225,703 | $8,577,100 | $4,415,717 | $2,786,935 | $3,712,780 | $5,903,482 | $5,095,670 | $4,357,130 | $6,234,351 | $12,487,315 | . |
| Schedule B | | $1,017,410 | $3,631,954 | $7,581,611 | $8,763,275 | $11,050,350 | $4,503,574 | $1,299,237 | $587,004 | $993,379 | $2,040,529 | $1,084,851 | $479,804 | $1,310,235 | $6,812,985 | . |
| Schedule C | | $146,230 | $491,939 | $1,259,174 | $2,788,730 | $4,010,368 | $2,215,678 | $1,526,994 | $1,059,618 | $1,027,143 | $2,215,432 | $1,456,858 | $1,226,913 | $2,061,648 | $3,070,449 | . |
| Demand / WAPA | | $335,092 | $335,387 | $343,297 | $343,593 | $360,064 | $357,555 | $347,554 | $347,555 | $362,057 | $348,970 | $347,555 | $347,555 | $347,555 | $347,555 | $359,717 |
| Pre-paid Demand Amort. | | $15,539 | $15,539 | $15,539 | $15,539 | $15,539 | $16,539 | $15,539 | $15,539 | $15,539 | $0 | $0 | $0 | $0 | $0 | . |
| Less exempt customer $ | | -$10,943 | -$64,204 | -$61,448 | -$52,784 | -$70,056 | -$42,834 | -$23,162 | -$9,351 | -$14,957 | -$19,587 | -$15,427 | -$16,194 | -$30,587 | -$71,364 | . |
| Less/Plus Hedging $ | | $0 | $0 | -$408,039 | -$848,942 | -$1,179,625 | -$126,452 | -$1,128,255 | -$1,301,895 | -$348,889 | -$3,446,773 | -$2,156,460 | -$943,294 | $120,304 | $813,779 | . |
| Less IWISF Refunds | | | | | | | | | | -$50,927 | | | | | | |
| er Supply & Transmission Costs | $ | $4,341,731 | $9,818,131 | $16,087,848 | $20,014,536 | $24,464,656 | $13,517,529 | $8,471,485 | $3,488,711 | $5,734,589 | $7,042,052 | $5,803,046 | $5,451,914 | $10,043,506 | $23,581,503 | $9,343,796 |
| Average $/Sales | $/kWh | $0.052105 | $0.114631 | $0.143100 | $0.158001 | $0.175236 | $0.108566 | $0.061782 | $0.039400 | $0.067063 | $0.069297 | $0.059615 | $0.066197 | $0.116699 | $0.266093 | $0.077644 |
| Monthly increase / decrease | $ | 474544 | $5,843,144 | $10,870,227 | $14,135,649 | $17,985,407 | $7,831,778 | $1,610,160 | -$813,438 | $1,293,178 | $1,763,845 | $747,100 | $1,174,190 | $5,573,373 | $18,978,601 | $2,660,022 |
| Applicable Adjustments | $ | 5 | -$40 | $47 | -$41 | -$44 | $32 | $50 | -$15 | -$13 | $122,556 | $1 | $9 | $5 | -$36,005 | |
| Net Bank increase / decrease | $ | $474,549 | $5,843,104 | $10,870,274 | $14,135,608 | $17,985,362 | $7,831,810 | $1,610,210 | -$813,453 | $1,293,165 | $1,886,401 | $747,101 | $1,174,199 | $5,573,378 | $18,942,597 | $2,660,022 |
| Ending Balance | $ | -$2,202,722 | $3,640,382 | $14,510,656 | $28,646,264 | $46,631,627 | $54,263,437 | $55,873,647 | $55,060,194 | $56,353,359 | $58,239,760 | $58,986,861 | $60,161,059 | $65,734,437 | $84,677,034 | $87,337,856 |

## Proxy Purchased Power Costs (Greater than 10 cents)

| | Schedule A | | Schedule B | |
|---|---|---|---|---|
| | Billing Energy | Total Amount | Billing Energy | Total Amount |
| Aug-99 | 0 | $0 | 1,105,621 | $170,941 |
| Sep-99 | 0 | $0 | 0 | $0 |
| Oct-99 | 0 | $0 | 149,172 | $25,732 |
| Nov-99 | 0 | $0 | 0 | $0 |
| Dec-99 | 0 | $0 | 0 | $0 |
| Jan-00 | 0 | $0 | 0 | $0 |
| Feb-00 | 0 | $0 | 0 | $0 |
| Mar-00 | 0 | $0 | 0 | $0 |
| Apr-00 | 0 | $0 | 969,639 | $162,301 |
| May-00 | 1,194,263 | $494,477 | 5,696,644 | $1,937,636 |
| Jun-00 | 1,455,378 | $507,635 | 14,189,581 | $4,588,811 |
| Jul-00 | 77,376,000 | $8,931,151 | 57,578,826 | $8,763,275 |
| Aug-00 | 77,376,000 | $10,225,703 | 59,074,510 | $11,050,350 |
| Sep-00 | 0 | $0 | 33,726,016 | $4,503,574 |
| Oct-00 | 0 | $0 | 11,609,245 | $1,299,237 |
| Nov-00 | 0 | $0 | 0 | $0 |
| Dec-00 | 0 | $0 | 9,370,157 | 969,460 |
| Jan-01 | 0 | $0 | 15,054,727 | $2,040,529 |
| Feb-01 | 0 | $0 | 10,763,939 | $1,084,851 |
| Mar-01 | 0 | $0 | 0 | $0 |
| Apr-01 | 0 | $0 | 6,915,427 | $1,310,235 |
| May-01 | 77,155,987 | $12,467,315 | 29,685,364 | $6,612,985 |
| Jun-01 | - | - | - | - |
| Total | 234,557,629 | $32,626,282 | 255,888,868 | $44,519,919 |

## Proxy APS-Owned Unit Costs (Less than 10 cents)

| | Schedule A | | Schedule B | |
|---|---|---|---|---|
| | Billing Energy | Total Amount | Billing Energy | Total Amount |
| Aug-99 | 94,982,700 | $3,516,284 | 37,931,559 | $2,137,206 |
| Sep-99 | 85,514,833 | $3,256,299 | 29,005,475 | $1,505,570 |
| Oct-99 | 77,531,856 | $2,978,652 | 14,567,280 | $863,109 |
| Nov-99 | 73,772,536 | $2,866,827 | 3,558,610 | $150,447 |
| Dec-99 | 81,116,696 | $3,005,096 | 14,278,845 | $561,838 |
| Jan-00 | 80,461,551 | $2,919,401 | 13,403,372 | $552,794 |
| Feb-00 | 73,532,587 | $2,790,262 | 8,203,016 | $331,179 |
| Mar-00 | 77,874,910 | $2,857,080 | 9,096,184 | $350,657 |
| Apr-00 | 75,763,880 | $2,838,347 | 15,367,746 | $855,109 |
| May-00 | 83,077,204 | $4,884,316 | 24,836,985 | $1,694,318 |
| Jun-00 | 90,382,701 | $6,732,371 | 25,424,939 | $2,992,801 |
| Jul-00 | 0 | $0 | 0 | $0 |
| Aug-00 | 0 | $0 | 0 | $0 |
| Sep-00 | 74,840,319 | $6,577,100 | 0 | $0 |
| Oct-00 | 76,451,619 | $4,515,717 | 0 | $0 |
| Nov-00 | 74,726,253 | $2,786,935 | 7,729,169 | $587,004 |
| Dec-00 | 77,359,135 | $3,712,780 | 0 | $0 |
| Jan-01 | 77,352,455 | $5,903,482 | 0 | $0 |
| Feb-01 | 69,809,676 | $5,095,670 | 0 | $0 |
| Mar-01 | 76,844,709 | $4,357,130 | 6,442,838 | $479,804 |
| Apr-01 | 74,014,567 | $6,234,351 | 0 | $0 |
| May-01 | 0 | $0 | 0 | $0 |
| Jun-01 | 137,722,016 | $8,096,677 | - | - |
| Total | 1,633,132,203 | $85,924,776 | 209,846,019 | $13,061,835 |

## Schedule C - Proxy Purchased Power Costs

| | BillEng Energy | Total Amount | Ceiling/Floor = Purchased Power |
|---|---|---|---|
| Aug-99 | - | - | - |
| Sep-99 | - | - | - |
| Oct-99 | - | - | - |
| Nov-99 | - | - | - |
| Dec-99 | - | - | - |
| Jan-00 | - | - | - |
| Feb-00 | - | - | - |
| Mar-00 | - | - | - |
| Apr-00 | - | - | - |
| May-00 | - | - | - |
| Jun-00 | 2,527,863 | $1,259,174 | Ceiling |
| Jul-00 | 17,331,201 | $2,788,730 | Floor |
| Aug-00 | 17,198,476 | $4,010,388 | Floor |
| Sep-00 | 16,460,357 | $2,215,678 | Floor |
| Oct-00 | 13,885,309 | $1,526,994 | Ceiling |
| Nov-00 | 14,280,375 | $1,059,618 | Ceiling |
| Dec-00 | 15,066,139 | $1,027,143 | Ceiling |
| Jan-01 | - | - | - |
| Feb-01 | - | - | - |
| Mar-01 | 14,965,867 | $1,226,913 | Floor |
| Apr-01 | 14,221,218 | $2,061,648 | Floor |
| May-01 | 13,711,013 | $3,070,449 | Floor |
| Jun-01 | N/A | | |
| Total | 139,647,818 | $20,246,737 | |

## Schedule C - Proxy APS-Owned Unit Costs
## Nominal Charge

| | BillEng Energy | Total Amount |
|---|---|---|
| Aug-99 | 2,573,868 | $269,650 |
| Sep-99 | 2,523,895 | $236,777 |
| Oct-99 | 2,938,652 | $253,464 |
| Nov-99 | 8,959,941 | $387,206 |
| Dec-99 | 4,195,215 | $179,438 |
| Jan-00 | 3,494,536 | $164,451 |
| Feb-00 | 6,441,308 | $263,622 |
| Mar-00 | 5,020,972 | $220,762 |
| Apr-00 | 1,049,388 | $146,230 |
| May-00 | 1,789,898 | $491,939 |
| Jun-00 | - | - |
| Jul-00 | - | - |
| Aug-00 | - | - |
| Sep-00 | - | - |
| Oct-00 | - | - |
| Nov-00 | - | - |
| Dec-00 | - | - |
| Jan-01 | 16,345,130 | $2,215,432 |
| Feb-01 | 14,455,004 | $1,456,858 |
| Mar-01 | - | - |
| Apr-01 | - | - |
| May-01 | - | - |
| Jun-01 | N/A | |
| Total | 59,787,807 | $6,285,828 |

**LAJ 4.15**: Re: Application, Page 7, Line 17, provide documentation that verifies that the 10.69 percent energy loss rate was used in the last rate case.

***Respondent***: Sean Breen

***Response***: Please see the memo attached from James L. Harrison, Citizens' consultant who conducted the research related to this loss factor calculation, and the accompanying spreadsheet.

**From:** Jim Harrison [jharrison@manapp.com]
**Sent:** Thursday, August 23, 2001 5:19 PM
**To:** Sean Breen; Rebecca Weber
**Cc:** Carl Vath
**Subject:** Losses

After some deliberation and research Carl and I have come to the following conclusions:

The unbundled Supply PPFAC rate (excluding any transmission charges) that corresponds to the new APS contract ($0.05879 / kWh at their interconnection to WAPA) should be **$0.06583** based on the losses implicitly utilized by the ACC (10.69%) in establishing the current figure of $0.05194 (sum of APS and WAPA charges).

The original PPFAC rate was computed by dividing test year energy costs by test year metered sales, so neither the Company, the staff nor the ACC presented data on appropriate loss factors. The rate case loss factor calculations are based on a number of assumptions:

1. Purchases from APS referred to in Sylvain LaCasse's testimony (Energy of Schedule SJL-1) represent metered quantities at the WAPA interconnections with CU-AED (this assumption is based on Resal Crave and Terri Rice confirming that APS purchases are metered at this point),
2. WAPA losses in the rate case's test year were 4.00% (the best recollection of Resal Craven is that they haven't changed), and
3. Staff calculations to revise Company sales figures (that developed the .05194 rate) employed the same loss factors as the Company computed (the staff workpapers compute incremental purchased power costs by multiplying their revised sales figures times average purchase power costs, implicitly using the loss factor in the Company's initial filing).

Carl's calculations are show on the attached file. As a test of the reasonableness of this figure, we computed a similar loss factor for the period 1997 to 1999. One would expect that the significant post-test year improvements in the transmission and distribution would reduce losses. The comparative figure of 10.06% is consistent with these facts, validating the rate case loss factor of 10.69%.

from the office of:
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Management Applications Consulting, Inc.
2921 Windmill Road Suite 4
Sinking Spring, PA 19608
eMail: jharrison@manapp.com
Phone: 610 670 9199
Fax: 610 670 9190

## A THE FOLLOWING IS AN EXCERPT FROM A STUDY SHOWING THE TOTAL SALES IN KWH



Citizens Utilities, Inc.
Arizona Electric Division
Analysis of Purchased Power

| Description | As Filed | Staff Adjusted | ACC Ordered |
|---|---|---|---|
| Total sales, kWh | 931,112,000.00 | 961,383,000.00 | 957,612,936.00 |
| Purchased Power Costs | 48,590,222.00 | 49,933,478.00 | 49,792,438.00 |
| Unit Cost | 0.05219 | 0.05194 | 0.05200 |
| ACC Approved Test Year Adjusted Sales | | | 957,612,936 |
| ACC Approved Base Level for PPFAC | | | 0.05194 |

## B BASED ON THE DIRECT TESTIMONY OF SYLVAIN J. LACASSE IN SEPTEMBER 1995

FROM EXHIBIT SJL-1 SHOWING PURCHASE POWER COSTS

| ENERGY AND COSTS FOR THE TEST YEAR APRIL 1994 - MARCH 1995 | Purchase Power Cost | Energy | |
|---|---|---|---|
| | $ 48,779,210.00 | 1,000,831.2 | MWH |
| | | OR | |
| | | 1,000,831,200.00 | KWH |

## C TO DETERMINE THE "LOSS AMOUNT":

ENERGY (MWH) SHOWS COSTS OF APPROXIMATELY $48.6 MILLION
THIS COINCIDES WITH THE AS FILED AMOUNTS IN A ABOVE

| | | | |
|---|---|---|---|
| PURCHASED | line (5) of B | 1,000,831,200 | TEST YEAR |
| WAPA Losses | | 4% | |
| WAPA ADJUSTED PURCHASED | (4)/[1-(5)] | 1,042,532,500 | WAPA ADJUSTED |
| SALES | line (1) of A | 931,112,000 | AS FILED |
| UNACCOUNTED FOR AND COMPANY USE | (6) - (8) | 111,420,500 | DIFFERENCE |
| PERCENT OF SENDOUT | (10)/(6) | 10.69% | |
| Purchased power cost at delivery to WAPA (from R Weber - CU) | | $0.05879 | |
| CALCULATION OF UNIT COSTS AT METER | | | |
| Unit cost at Meter | (13)/[1-(11)] | $0.06583 | |

Citizens Communications
**Docket No.** E-01032C-00-0751
Arizona Corporation Commission's Fifth Set of Data Requests

**Witness: Sean Breen**

**Data Request No. LS 5.57:**

Please calculate the weighted average of these "loss rates" over these 6 years.

**Response:**

The weighted average is calculated in the attachment file, Weighted Average for LS 5_57.xls. In responding to this request, an error in the reported Sales and Purchases data was discovered. (The Loss Rate figures were correct and do not change.) This correction is reflected in the attachment.

LS 5.57 attachment

The table as previously reported in LAJ 4.16:

| | Sales | Purchases | Loss Rate |
|---|---|---|---|
| 1995 | 951,745 | 1,048,714 | 9.25% |
| 1996 | 953,933 | 1,051,510 | 9.97% |
| 1997 | 959,033 | 1,060,422 | 10.76% |
| 1998 | 965,040 | 1,067,947 | 9.25% |
| 1999 | 968,680 | 1,076,841 | 8.97% |
| 2000 | 1,205,243 | 1,354,994 | 11.05% |

Corrected version for LS 5.57:

| | Sales | Purchases | Loss Rate |
|---|---|---|---|
| 1995 | 951,745 | 1,006,765 | 5.47% |
| 1996 | 1,031,815 | 1,100,252 | 6.22% |
| 1997 | 1,050,065 | 1,129,653 | 7.05% |
| 1998 | 1,081,556 | 1,144,164 | 5.47% |
| 1999 | 1,118,388 | 1,179,425 | 5.18% |
| 2000 | 1,205,243 | 1,354,994 | 11.05% |
| | 6,438,812 | 6,915,253 | 6.89% |

The weighted average of the loss rates is calculated as follows:

Total Sales for the 6 years = 6,438,812
Total Purchases = 7,146,930

1 – (6,438,812 / 7,146,930) = .09908 or 9.91%

Attachment S-3

# Timeline of Events Regarding CUC/APS Contract

| | |
|---|---|
| June-95 | Contract Deliveries Begin |
| July-98 | Large spot market price increases in eastern markets. |
| August-98 | ICF predicts 1-in-3 chance of price spikes in California. |
| May-99 | APS re-bills for 1998 contract deliveries. |
| June-99 | Citizens protests APS' 1998 bills. Large spot market price increases in eastern markets. |
| July-99 | Citizens learns that APS' SIC calculations include reliability purchases. |
| August-99 | Citizens begins to debate SIC interpretation with APS |
| September-99 | |
| October-99 | |
| November-99 | |
| December-99 | |
| January-00 | |
| February-00 | |
| March-00 | |
| April-00 | APS asks Citizens to discuss market pricing filing |
| May-00 | Citizens and APS sign Memorandum of Understanding; Citizens and APS begin negotiations regarding contractural issues |
| June-00 | Citizens receives high APS bill for May deliveries |
| July-00 | APS bills for June 2000, and re-bills for May and June 2000; Initial results of Audit of APS' Bills |
| August-00 | APS bill for July deliveries refers to new contract; Citizens objects |
| September-00 | |
| October-00 | |
| November-00 | Citizens begins work on Valencia units |
| December-00 | |
| January-01 | |
| February-01 | |
| March-01 | |
| April-01 | |
| May-01 | Valencia units run for economic reasons |
| June-01 | Citizens billed retroactively on new contract |
| July-01 | Citizens and APS sign new contract |
| August-01 | |
| September-01 | |
| October-01 | |
| October-01 | |

Attachment S-4
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WESTERN SYSTEMS COORDINATING COUNCIL
SUMMARY OF ACTUAL LOADS AND RESOURCES
ARIZONA-NEW MEXICO-SO. NEVADA POWER AREA

ACTUAL YEAR 1998
ACTUAL HYDRO CONDITIONS

| PEAK DEMAND - MEGAWATTS | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LOADS - FIRM | 13107 | 12715 | 12075 | 12872 | 14183 | 18186 | 20177 | 20177 | 18045 | 13784 | 11778 | 13842 |
| INTERRUPTIBLE AND LOAD MGT | 251 | 251 | 264 | 251 | 250 | 256 | 253 | 252 | 236 | 257 | 262 | 264 |
| TOTAL LOAD | 13358 | 12966 | 12339 | 13123 | 14433 | 18442 | 20430 | 20429 | 18281 | 14041 | 12040 | 14106 |
| RESOURCES - HYDRO - CONVENTIONAL | 1351 | 1351 | 1400 | 1415 | 1415 | 1415 | 1415 | 1415 | 1415 | 1400 | 1400 | 1400 |
| HYDRO - PUMPED STORAGE | 165 | 165 | 165 | 213 | 213 | 213 | 213 | 213 | 213 | 165 | 165 | 165 |
| STEAM - COAL | 8540 | 8540 | 8540 | 8540 | 8540 | 8540 | 8540 | 8540 | 8540 | 8525 | 8525 | 8525 |
| STEAM - OIL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| STEAM - GAS | 2479 | 2479 | 2479 | 2475 | 2466 | 2460 | 2460 | 2460 | 2460 | 2470 | 2479 | 2479 |
| NUCLEAR | 2782 | 2782 | 2782 | 2782 | 2712 | 2712 | 2712 | 2712 | 2712 | 2712 | 2782 | 2782 |
| COMBUSTION TURBINE | 2059 | 2059 | 2055 | 2053 | 1832 | 1716 | 1716 | 1716 | 1716 | 1738 | 1963 | 1963 |
| COMBINED CYCLE | 1589 | 1589 | 1589 | 1581 | 1486 | 1466 | 1466 | 1466 | 1466 | 1494 | 1589 | 1589 |
| GEOTHERMAL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| INTERNAL COMBUSTION | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| COGENERATION | 305 | 305 | 305 | 305 | 295 | 287 | 305 | 305 | 305 | 305 | 305 | 305 |
| OTHER | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 |
| TOTAL RESOURCES | 19274 | 19274 | 19319 | 19369 | 18964 | 18814 | 18832 | 18832 | 18832 | 18813 | 19212 | 19212 |
| FORCED OUTAGES | 1609 | 1611 | 800 | 374 | 322 | 171 | 226 | 499 | 399 | 447 | 526 | 261 |
| INOPERABLE CAPABILITY | 16 | 17 | 17 | 13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| SCHEDULED MAINTENANCE | 1193 | 1314 | 2139 | 1661 | 814 | 25 | 26 | 25 | 25 | 691 | 1109 | 824 |
| TOTAL UNAVAILABLE CAPABILITY | 2818 | 2942 | 2956 | 2048 | 1136 | 196 | 252 | 524 | 424 | 1138 | 1635 | 1085 |
| NET RESOURCES | 16456 | 16332 | 16363 | 17321 | 17828 | 18618 | 18580 | 18308 | 18408 | 17675 | 17577 | 18127 |
| FIRM/JOINT PART. IMPORTS - CAL-MEX | -393 | -387 | -392 | -387 | -499 | -732 | -2202 | -2139 | -816 | -391 | -381 | -391 |
| NWPP | -100 | -150 | -250 | -225 | -405 | -670 | -645 | -670 | -615 | -50 | -50 | -50 |
| SWPP | -150 | -100 | -130 | -200 | -100 | -250 | -250 | -300 | -310 | -100 | -130 | -135 |
| RMPA | -499 | -497 | -494 | -545 | -564 | -588 | -598 | -598 | -582 | -492 | -487 | -498 |
| TOTAL IMPORT | -1142 | -1134 | -1266 | -1357 | -1568 | -2240 | -3695 | -3707 | -2323 | -1033 | -1048 | -1074 |
| FIRM/JOINT PART. EXPORTS - CAL-MEX | 3826 | 3773 | 3772 | 3772 | 3765 | 3761 | 3770 | 3766 | 3766 | 3777 | 3788 | 3788 |
| NWPP | 466 | 466 | 467 | 467 | 497 | 417 | 417 | 417 | 417 | 691 | 691 | 691 |
| RMPA | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 |
| TOTAL EXPORT | 4332 | 4279 | 4279 | 4279 | 4302 | 4218 | 4227 | 4223 | 4223 | 4508 | 4519 | 4519 |
| NET EXPORTS/IMPORTS | 3190 | 3145 | 3013 | 2922 | 2734 | 1978 | 532 | 516 | 1900 | 3475 | 3471 | 3445 |
| JOINT PARTICIPATION TRANSFERS | 3429 | 3429 | 3429 | 3429 | 3418 | 3418 | 3418 | 3418 | 3418 | 3433 | 3444 | 3444 |
| NET FIRM TRANSFERS* | -239 | -284 | -416 | -507 | -684 | -1440 | -2886 | -2902 | -1518 | 42 | 27 | 1 |
| NET RESOURCES AND NET TRANSFERS | 16695 | 16616 | 16779 | 17828 | 18512 | 20058 | 21466 | 21210 | 19926 | 17633 | 17550 | 18126 |
| MARGIN OVER FIRM LOAD - MW | 3588 | 3901 | 4704 | 4956 | 4329 | 1872 | 1289 | 1033 | 1881 | 3849 | 5772 | 4284 |
| MARGIN OVER FIRM LOAD - PERCENT | 27.4 | 30.7 | 39.0 | 38.5 | 30.5 | 10.3 | 6.4 | 5.1 | 10.4 | 27.9 | 49.0 | 30.9 |

*NET EXPORTS/IMPORTS LESS JOINT PARTICIPATION TRANSFERS (MINUS SIGN INDICATES PURCHASE).
JOINT PARTICIPATION GENERATION IS INCLUDED BY TYPE UNDER "RESOURCES" IN EACH PARTICIPANT'S AREA.

Attachment 5-4
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WESTERN SYSTEMS COORDINATING COUNCIL
SUMMARY OF ACTUAL LOADS AND RESOURCES
CALIFORNIA - MEXICO POWER AREA
U.S. SYSTEMS

ACTUAL YEAR 1998
ACTUAL HYDRO CONDITIONS

| PEAK DEMAND - MEGAWATTS | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LOADS - FIRM | 35831 | 35022 | 34618 | 36352 | 32936 | 40745 | 48532 | 53246 | 52081 | 39626 | 35062 | 37370 |
| INTERRUPTIBLE AND LOAD MGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2018 | 0 | 0 | 0 |
| TOTAL LOAD | 35831 | 35022 | 34618 | 36352 | 32936 | 40745 | 48532 | 53246 | 54099 | 39626 | 35062 | 37370 |
| RESOURCES - HYDRO - CONVENTIONAL | 8988 | 9656 | 9731 | 10146 | 10327 | 10219 | 10299 | 9984 | 10038 | 8530 | 8105 | 9506 |
| HYDRO - PUMPED STORAGE | 3436 | 3448 | 3453 | 3449 | 3466 | 3438 | 3411 | 3377 | 3371 | 3388 | 3410 | 3427 |
| STEAM - COAL | 4340 | 4340 | 4340 | 4340 | 4340 | 4321 | 4321 | 4321 | 4321 | 4355 | 4355 | 4355 |
| STEAM - OIL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| STEAM - GAS | 18618 | 18618 | 18618 | 18618 | 18618 | 18618 | 18618 | 18618 | 18618 | 18618 | 18618 | 18618 |
| NUCLEAR | 5342 | 5342 | 5342 | 5342 | 5331 | 5331 | 5331 | 5331 | 5331 | 5331 | 5342 | 5342 |
| COMBUSTION TURBINE | 2193 | 2186 | 2179 | 2172 | 2075 | 1992 | 1997 | 2006 | 1995 | 2073 | 2179 | 2193 |
| COMBINED CYCLE | 1594 | 1594 | 1594 | 1594 | 1532 | 1532 | 1532 | 1532 | 1532 | 1534 | 1594 | 1594 |
| GEOTHERMAL | 2353 | 2353 | 2351 | 2357 | 2341 | 2355 | 2353 | 2351 | 2350 | 2349 | 2349 | 2353 |
| INTERNAL COMBUSTION | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| COGENERATION | 4930 | 4871 | 4879 | 4706 | 5120 | 5223 | 5323 | 5310 | 5311 | 5314 | 5254 | 5063 |
| OTHER | 1264 | 1234 | 1174 | 1192 | 1129 | 1264 | 1328 | 1296 | 1283 | 1242 | 1251 | 1228 |
| TOTAL RESOURCES | 53078 | 53662 | 53681 | 53936 | 54299 | 54313 | 54533 | 54146 | 54170 | 52754 | 52477 | 53699 |
| FORCED OUTAGES | 3480 | 3619 | 4289 | 310 | 0 | 1372 | 975 | 212 | 25 | 410 | 264 | 1339 |
| INOPERABLE CAPABILITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| SCHEDULED MAINTENANCE | 4373 | 4174 | 5660 | 4580 | 4391 | 520 | 515 | 429 | 362 | 2752 | 4252 | 3448 |
| TOTAL UNAVAILABLE CAPABILITY | 7853 | 7793 | 9949 | 4890 | 4391 | 1892 | 1490 | 641 | 387 | 3162 | 4516 | 4787 |
| NET RESOURCES | 45225 | 45869 | 43732 | 49046 | 49908 | 52421 | 53043 | 53505 | 53783 | 49592 | 47961 | 48912 |
| FIRM/JOINT PART. IMPORTS - NM-AZ/SN | -3742 | -3742 | -3742 | -4832 | -4054 | -4661 | -4588 | -4733 | -4742 | -4933 | -4817 | -5065 |
| MEXICO | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -40 | 0 | 0 |
| NWPP | -2223 | -2767 | -2094 | -3721 | -1950 | -3676 | -4983 | -7799 | -7194 | -2640 | -3711 | -3088 |
| TOTAL IMPORT | -5965 | -6509 | -5836 | -8553 | -6004 | -8337 | -9571 | -12532 | -11936 | -7613 | -8528 | -8153 |
| FIRM/JOINT PART. EXPORTS - NM-AZ/SN | 379 | 379 | 379 | 1374 | 1844 | 2103 | 2843 | 3998 | 3764 | 1416 | 1482 | 1519 |
| MEXICO | 0 | 0 | 0 | 0 | 0 | 150 | 130 | 320 | 360 | 220 | 10 | 0 |
| NWPP | 1946 | 2623 | 2043 | 2831 | 2515 | 441 | 1225 | 1041 | 1888 | 595 | 890 | 2133 |
| TOTAL EXPORT | 2325 | 3002 | 2422 | 4205 | 4359 | 2694 | 4198 | 5359 | 6012 | 2231 | 2382 | 3652 |
| NET EXPORTS/IMPORTS | -3640 | -3507 | -3414 | -4348 | -1645 | -5643 | -5373 | -7173 | -5924 | -5382 | -6146 | -4501 |
| JOINT PARTICIPATION TRANSFERS | -3363 | -3363 | -3363 | -3363 | -3352 | -3352 | -3352 | -3352 | -3352 | -3367 | -3378 | -3378 |
| NET FIRM TRANSFERS* | -277 | -144 | -51 | -985 | 1707 | -2291 | -2021 | -3821 | -2572 | -2015 | -2768 | -1123 |
| NET RESOURCES AND NET TRANSFERS | 45502 | 46013 | 43783 | 50031 | 48201 | 54712 | 55064 | 57326 | 56355 | 51607 | 50729 | 50035 |
| MARGIN OVER FIRM LOAD - MW | 9671 | 10991 | 9165 | 13679 | 15265 | 13967 | 6532 | 4080 | 4274 | 11981 | 15667 | 12665 |
| MARGIN OVER FIRM LOAD - PERCENT | 27.0 | 31.4 | 26.5 | 37.6 | 46.3 | 34.3 | 13.5 | 7.7 | 8.2 | 30.2 | 44.7 | 33.9 |

*NET EXPORTS/IMPORTS LESS JOINT PARTICIPATION TRANSFERS (MINUS SIGN INDICATES PURCHASE).
JOINT PARTICIPATION GENERATION IS INCLUDED BY TYPE UNDER "RESOURCES" IN EACH PARTICIPANT'S AREA.

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**Table III-4**
**Forecasted vs. Actual Unavailable Generation (MW)***

| | WSCC | | | California/Southern Nevada | | | Arizona-New Mexico | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Forecasted | Actual | Difference | Forecasted | Actual | Difference | Forecasted | Actual | Difference |
| 1988 | 8,313 | 19,767 | (11,454) | 1,198 | 7,444 | (6,246) | 270 | 1,090 | (820) |
| 1989 | 9,639 | 22,645 | (13,006) | 2,150 | 6,422 | (4,272) | 236 | 1,824 | (1,588) |
| 1990 | 5,759 | 16,342 | (10,583) | 303 | 6,150 | (5,847) | 0 | 2,862 | (2,862) |
| 1991 | 9,465 | 24,851 | (15,386) | 606 | 7,460 | (6,854) | 214 | 677 | (463) |
| 1992 | 7,489 | 16,223 | (8,734) | 335 | 5,162 | (4,827) | 0 | 921 | (921) |
| 1993 | 7,453 | 16,301 | (8,848) | 1,162 | 4,519 | (3,357) | 1 | 1,379 | (1,378) |
| 1994 | 6,954 | 12,457 | (5,503) | 839 | 4,579 | (3,740) | 255 | 967 | (712) |
| 1995 | 7,638 | 14,035 | (6,397) | 1,027 | 5,215 | (4,188) | 16 | 1,015 | (999) |
| 1996 | 7,665 | 12,243 | (4,578) | 418 | 6,237 | (5,819) | 24 | 586 | (562) |
| 1997** | 6,446 | 12,795 | (6,349) | 280 | 5,019 | (4,739) | 17 | 608 | (591) |
| 1998 | 5,741 | | | 0 | | | 17 | | |

* Actual Unavailable Generation includes Maintenance, Forced Outages, and Inoperable Capacity

** In 1998, the WSCC changed the boundaries of the reporting regions. The forecasted values for 1997 reflect the old boundaries. The actual value reported for 1997, and the forecasted values for 1998, are for the redefined regions. Southern Nevada is included in the Arizona-New Mexico region. The new California region includes Mexico.

Source: *10-Year Coordinated Plan Summary*, Western Systems Coordinating Council, Issues May 1988 through May 1998

**Average Summer (Jun-Aug) Temperature**
Arizona 1990-2001

| Year | Temperatu Deg. F | Rank[1] Based on 1990-2001 | Rank[1] Based on 1895-2001 |
|---|---|---|---|
| 2001 | 79.3 | 9 | 95 |
| 2000 | 80.2 | 10 | 103 |
| 1999 | 77.7 | 3 | 64 |
| 1998 | 78.5 | 6 | 80 |
| 1997 | 78.1 | 4 | 71 |
| 1996 | 80.7 | 11 | 105 |
| 1995 | 78.5 | 6 | 80 |
| 1994 | 81.4 | 12 | 106 |
| 1993 | 78.2 | 5 | 76 |
| 1992 | 77.1 | 1 | 43 |
| 1991 | 77.1 | 1 | 43 |
| 1990 | 78.6 | 8 | 84 |

Source: National Climactic Data Center

[1] Highest temperature rank denotes the hottest year for the period. Lowest temperature rank denotes the coldest year for the period.

**Average Summer (Jun-Aug) Temperature**
California 1990-2001

| Year | Temperature Deg. F | Rank[1] Based on 1990-2001 | Rank[1] Based on 1895-2001 |
|---|---|---|---|
| 2001 | 74.3 | 10 | 89 |
| 2000 | 74.0 | 8 | 83 |
| 1999 | 71.8 | 1 | 15 |
| 1998 | 73.0 | 5 | 51 |
| 1997 | 73.5 | 6 | 71 |
| 1996 | 75.6 | 12 | 104 |
| 1995 | 72.7 | 4 | 41 |
| 1994 | 74.9 | 11 | 99 |
| 1993 | 72.4 | 2 | 33 |
| 1992 | 73.8 | 7 | 79 |
| 1991 | 72.4 | 2 | 33 |
| 1990 | 74.0 | 8 | 83 |

Source: National Climactic Data Center

[1] Highest temperature rank denotes the hottest year for the period. Lowest temperature rank denotes the coldest year for the period.

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WESTERN SYSTEMS COORDINATING COUNCIL
SUMMARY OF ESTIMATED LOADS AND RESOURCES
ARIZONA-NEW MEXICO-SO. NEVADA POWER AREA

YEAR 1999
ADVERSE HYDRO CONDITIONS

| PEAK DEMAND - MEGAWATTS | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LOADS - FIRM | 14312 | 13329 | 12453 | 13779 | 16030 | 18693 | 19729 | 19870 | 18235 | 14968 | 12908 | 14141 |
| INTERRUPTIBLE AND LOAD MGT | 640 | 643 | 662 | 664 | 625 | 634 | 641 | 632 | 654 | 651 | 626 | 634 |
| TOTAL LOAD | 14952 | 13972 | 13115 | 14443 | 16655 | 19327 | 20370 | 20502 | 18889 | 15619 | 13534 | 14775 |
| RESOURCES - HYDRO - CONVENTIONAL | 1351 | 1351 | 1400 | 1415 | 1415 | 1415 | 1415 | 1415 | 1415 | 1400 | 1400 | 1400 |
| HYDRO - PUMPED STORAGE | 165 | 165 | 165 | 213 | 213 | 213 | 213 | 213 | 213 | 165 | 165 | 165 |
| STEAM - COAL | 8525 | 8525 | 8525 | 8525 | 8525 | 8525 | 8525 | 8525 | 8525 | 8525 | 8525 | 8525 |
| STEAM - OIL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| STEAM - GAS | 2479 | 2479 | 2479 | 2475 | 2466 | 2460 | 2460 | 2460 | 2460 | 2470 | 2479 | 2479 |
| NUCLEAR | 2782 | 2782 | 2782 | 2782 | 2712 | 2712 | 2712 | 2712 | 2712 | 2712 | 2782 | 2782 |
| COMBUSTION TURBINE | 1961 | 1961 | 1957 | 1955 | 1736 | 1716 | 1716 | 1716 | 1716 | 1738 | 1957 | 1961 |
| COMBINED CYCLE | 1589 | 1589 | 1589 | 1581 | 1486 | 1466 | 1466 | 1466 | 1466 | 1494 | 2122 | 2122 |
| GEOTHERMAL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| INTERNAL COMBUSTION | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| COGENERATION | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 |
| OTHER | 0 | 0 | 0 | 0 | 1 | 2 | 2 | 2 | 2 | 2 | 0 | 0 |
| TOTAL RESOURCES | 19161 | 19161 | 19206 | 19255 | 18863 | 18818 | 18818 | 18818 | 18818 | 18815 | 19739 | 19743 |
| INOPERABLE CAPABILITY | 13 | 13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 13 | 13 |
| SCHEDULED MAINTENANCE | 983 | 1031 | 1904 | 2508 | 754 | 3 | 17 | 17 | 506 | 2069 | 1127 | 725 |
| TOTAL UNAVAILABLE CAPABILITY | 996 | 1044 | 1904 | 2508 | 754 | 3 | 17 | 17 | 506 | 2069 | 1140 | 738 |
| NET RESOURCES | 18165 | 18117 | 17302 | 16747 | 18109 | 18815 | 18801 | 18801 | 18312 | 16746 | 18599 | 19005 |
| FIRM/JOINT PART. IMPORTS - CAL-MEX | -379 | -379 | -379 | -379 | -489 | -724 | -724 | -724 | -724 | -379 | -379 | -379 |
| NWPP | -79 | -66 | -50 | -58 | -804 | -872 | -867 | -870 | -847 | -65 | -49 | -67 |
| SWPP | -318 | -318 | -318 | -318 | -318 | -318 | -318 | -318 | -318 | -318 | -318 | -318 |
| RMPA | -773 | -758 | -762 | -820 | -833 | -866 | -872 | -875 | -848 | -740 | -749 | -775 |
| TOTAL IMPORT | -1549 | -1521 | -1509 | -1575 | -2444 | -2780 | -2781 | -2787 | -2737 | -1502 | -1495 | -1539 |
| FIRM/JOINT PART. EXPORTS - CAL-MEX | 3967 | 3967 | 3857 | 3857 | 3846 | 3846 | 3851 | 3851 | 3851 | 3846 | 3967 | 3967 |
| NWPP | 691 | 691 | 417 | 417 | 417 | 417 | 417 | 417 | 417 | 416 | 896 | 896 |
| RMPA | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 |
| TOTAL EXPORT | 4698 | 4698 | 4314 | 4314 | 4303 | 4303 | 4308 | 4308 | 4308 | 4302 | 4903 | 4903 |
| NET EXPORTS/IMPORTS | 3149 | 3177 | 2805 | 2739 | 1859 | 1523 | 1527 | 1521 | 1571 | 2800 | 3408 | 3364 |
| JOINT PARTICIPATION TRANSFERS | 3444 | 3444 | 3444 | 3444 | 3433 | 3433 | 3433 | 3433 | 3433 | 3433 | 3444 | 3444 |
| NET FIRM TRANSFERS* | -295 | -267 | -639 | -705 | -1574 | -1910 | -1906 | -1912 | -1862 | -633 | -36 | -80 |
| PLANNED PURCHASES/SALES | -622 | -621 | -573 | -725 | -960 | -1490 | -1706 | -1815 | -1299 | -1315 | 30 | -40 |
| NET RESOURCES AND NET TRANSFERS | 19082 | 19005 | 18514 | 18177 | 20643 | 22215 | 22413 | 22528 | 21473 | 18694 | 18605 | 19125 |
| MARGIN OVER FIRM LOAD - MW | 4770 | 5676 | 6061 | 4398 | 4613 | 3522 | 2684 | 2658 | 3238 | 3726 | 5697 | 4984 |
| MARGIN OVER FIRM LOAD - PERCENT | 33.3 | 42.6 | 48.7 | 31.9 | 28.8 | 18.8 | 13.6 | 13.4 | 17.8 | 24.9 | 44.1 | 35.2 |

*NET EXPORTS/IMPORTS LESS JOINT PARTICIPATION TRANSFERS (MINUS SIGN INDICATES PURCHASE).
JOINT PARTICIPATION GENERATION IS INCLUDED BY TYPE UNDER "RESOURCES" IN EACH PARTICIPANT'S AREA.

Attachment S-7
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WESTERN SYSTEMS COORDINATING COUNCIL
SUMMARY OF ESTIMATED LOADS AND RESOURCES
ARIZONA-NEW MEXICO-SO. NEVADA POWER AREA

YEAR 2000
ADVERSE HYDRO CONDITIONS

| PEAK DEMAND - MEGAWATTS | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LOADS - FIRM | 14534 | 13527 | 12644 | 13997 | 16345 | 19090 | 20222 | 20321 | 18651 | 15296 | 13174 | 14433 |
| INTERRUPTIBLE AND LOAD MGT | 707 | 716 | 731 | 728 | 728 | 751 | 752 | 749 | 763 | 765 | 743 | 742 |
| TOTAL LOAD | 15241 | 14243 | 13375 | 14725 | 17073 | 19841 | 20974 | 21070 | 19414 | 16061 | 13917 | 15175 |
| RESOURCES - HYDRO - CONVENTIONAL | 1351 | 1351 | 1400 | 1415 | 1415 | 1415 | 1415 | 1415 | 1415 | 1400 | 1400 | 1400 |
| HYDRO - PUMPED STORAGE | 165 | 165 | 165 | 213 | 213 | 213 | 213 | 213 | 213 | 165 | 165 | 165 |
| STEAM - COAL | 8525 | 8525 | 8525 | 8525 | 8525 | 8525 | 8525 | 8525 | 8525 | 8525 | 8525 | 8525 |
| STEAM - OIL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| STEAM - GAS | 2479 | 2479 | 2479 | 2475 | 2466 | 2460 | 2460 | 2460 | 2460 | 2470 | 2479 | 2479 |
| NUCLEAR | 2782 | 2782 | 2782 | 2782 | 2712 | 2712 | 2712 | 2712 | 2712 | 2712 | 2782 | 2782 |
| COMBUSTION TURBINE | 1961 | 1961 | 1957 | 1955 | 1736 | 1716 | 1716 | 1716 | 1716 | 1738 | 1957 | 1961 |
| COMBINED CYCLE | 2122 | 2122 | 2122 | 2114 | 1978 | 1958 | 1958 | 1958 | 1958 | 1986 | 2122 | 2122 |
| GEOTHERMAL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| INTERNAL COMBUSTION | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| COGENERATION | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 |
| OTHER | 0 | 0 | 0 | 0 | 2 | 9 | 9 | 9 | 9 | 9 | 0 | 0 |
| TOTAL RESOURCES | 19694 | 19694 | 19739 | 19788 | 19356 | 19317 | 19317 | 19317 | 19317 | 19314 | 19739 | 19743 |
| INOPERABLE CAPABILITY | 13 | 13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 13 | 13 |
| SCHEDULED MAINTENANCE | 618 | 819 | 2473 | 2374 | 788 | 3 | 17 | 17 | 373 | 1857 | 956 | 528 |
| TOTAL UNAVAILABLE CAPABILITY | 631 | 832 | 2473 | 2374 | 788 | 3 | 17 | 17 | 373 | 1857 | 969 | 541 |
| NET RESOURCES | 19063 | 18862 | 17266 | 17414 | 18568 | 19314 | 19300 | 19300 | 18944 | 17457 | 18770 | 19202 |
| FIRM/JOINT PART. IMPORTS - CAL-MEX | -379 | -379 | -379 | -379 | -489 | -619 | -619 | -619 | -619 | -379 | -379 | -379 |
| NWPP | -39 | -22 | 0 | -237 | -585 | -586 | -597 | -602 | -653 | -99 | -93 | -114 |
| SWPP | -343 | -343 | -343 | -343 | -343 | -343 | -343 | -343 | -343 | -343 | -343 | -343 |
| RMPA | -773 | -758 | -762 | -820 | -833 | -866 | -872 | -875 | -848 | -740 | -749 | -775 |
| TOTAL IMPORT | -1534 | -1502 | -1484 | -1779 | -2250 | -2414 | -2431 | -2439 | -2463 | -1561 | -1564 | -1611 |
| FIRM/JOINT PART. EXPORTS - CAL-MEX | 3967 | 3967 | 3857 | 3857 | 3846 | 3846 | 3851 | 3851 | 3851 | 3846 | 3967 | 3967 |
| NWPP | 896 | 896 | 417 | 417 | 417 | 417 | 417 | 417 | 417 | 416 | 896 | 896 |
| RMPA | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 |
| TOTAL EXPORT | 4903 | 4903 | 4314 | 4314 | 4303 | 4303 | 4308 | 4308 | 4308 | 4302 | 4903 | 4903 |
| NET EXPORTS/IMPORTS | 3369 | 3401 | 2830 | 2535 | 2053 | 1889 | 1877 | 1869 | 1845 | 2741 | 3339 | 3292 |
| JOINT PARTICIPATION TRANSFERS | 3444 | 3444 | 3444 | 3444 | 3433 | 3433 | 3433 | 3433 | 3433 | 3433 | 3444 | 3444 |
| NET FIRM TRANSFERS* | -75 | -43 | -614 | -909 | -1380 | -1544 | -1556 | -1564 | -1588 | -692 | -105 | -152 |
| PLANNED PURCHASES/SALES | -224 | -120 | -121 | -207 | -1324 | -2238 | -3078 | -3057 | -2011 | -511 | -18 | -223 |
| NET RESOURCES AND NET TRANSFERS | 19362 | 19025 | 18001 | 18530 | 21272 | 23096 | 23934 | 23921 | 22543 | 18660 | 18893 | 19577 |
| MARGIN OVER FIRM LOAD - MW | 4828 | 5498 | 5357 | 4533 | 4927 | 4006 | 3712 | 3600 | 3892 | 3364 | 5719 | 5144 |
| MARGIN OVER FIRM LOAD - PERCENT | 33.2 | 40.6 | 42.4 | 32.4 | 30.1 | 21.0 | 18.4 | 17.7 | 20.9 | 22.0 | 43.4 | 35.6 |

*NET EXPORTS/IMPORTS LESS JOINT PARTICIPATION TRANSFERS (MINUS SIGN INDICATES PURCHASE).
JOINT PARTICIPATION GENERATION IS INCLUDED BY TYPE UNDER "RESOURCES" IN EACH PARTICIPANT'S AREA.

interrupted. These customers receive a rate discount for accepting the risk of being curtailed. The market signal they send is not one that places a value on reliability.

Table III-2 shows what the forecasted and actual peak demand reserve margins would have been over the last ten years, for the same areas in **Table III-1**, after meeting interruptible (nonfirm) loads. **Table III-2** clearly illustrates that as reserve margins shrink, interruptible load customers that choose not be curtailed under tight supply conditions will adversely impact system reliability. Had the California ISO been in operation in 1997, it would have had to issue a Stage II alert. The ISO would have requested that the utility distribution companies (UDCs) curtail their interruptible load customers because they would have been unable to maintain a minimum operating reserve of 5 percent.[32]

**Table III-2**
**Forecasted vs. Actual Reserve Capability**
**After Serving Interruptible Loads**

| Year | WSCC | | California/Southern Nevada* | | Arizona-New Mexico* | |
|---|---|---|---|---|---|---|
| | Forecasted | Actual | Forecasted | Actual | Forecasted | Actual |
| 1988 | 40.3% | 24.3% | 33.3% | 12.2% | 35.9% | 19.1% |
| 1989 | 35.6% | 23.5% | 29.4% | 17.1% | 32.8% | 13.6% |
| 1990 | 34.6% | 21.8% | 33.3% | 10.4% | 32.7% | 5.9% |
| 1991 | 28.4% | 13.4% | 30.3% | 11.2% | 27.5% | 25.9% |
| 1992 | 27.1% | 17.8% | 24.8% | 9.1% | 28.5% | 15.7% |
| 1993 | 24.4% | 14.5% | 23.4% | 13.2% | 28.9% | 17.4% |
| 1994 | 24.3% | 16.0% | 20.7% | 8.8% | 22.0% | 13.2% |
| 1995 | 19.6% | 18.4% | 14.3% | 10.3% | 20.0% | 9.3% |
| 1996 | 21.0% | 15.7% | 22.4% | 6.0% | 14.7% | 7.7% |
| 1997 | 23.7% | 14.0% | 19.1% | 3.7% | 15.1% | 3.7% |
| 1998 | 21.5% | | 18.7% | | 12.8% | |
| Average 1988-1997 | 27.9% | 17.9% | 25.1% | 10.2% | 25.8% | 13.1% |

* In 1998, the WSCC changed the boundaries of the reporting regions. The forecasted values for 1997 reflect the old boundaries. The actual value reported for 1997, and the forecasted values of 1998, are for the redefined regions. Southern Nevada is included in the Arizona-New Mexico region. The new California region includes Mexico.
Source: *10-Year Coordinated Plan Summary*, Western Systems Coordinating Council, Issues May 1987 through May 1998

It is widely acknowledged that greater demand elasticity is needed in this new competitive electricity market, not only for improving system reliability during peak demand hours, but as a means to limit volatility in market prices and improve overall market efficiency. The UDCs are designing participating load agreements so that large or aggregated customers can choose to shed load when the price would otherwise be higher than they are willing to pay. The UDC will then be able to bid the demand of participants into the PX market like any other resources.

[32] The ISO does not count interruptible load as part of its operating reserve because: 1) it is not available in ten minutes, 2) it involves a voluntary action on the part of the customer, and 3) it is not directly under their control because it entails a contract between the UDC and end-use customer under a CPUC tariff.

WSCC Summary of Estimated Loads and Resources (Oct. 1999) Attachment S-9

Data as of January 1, 1999

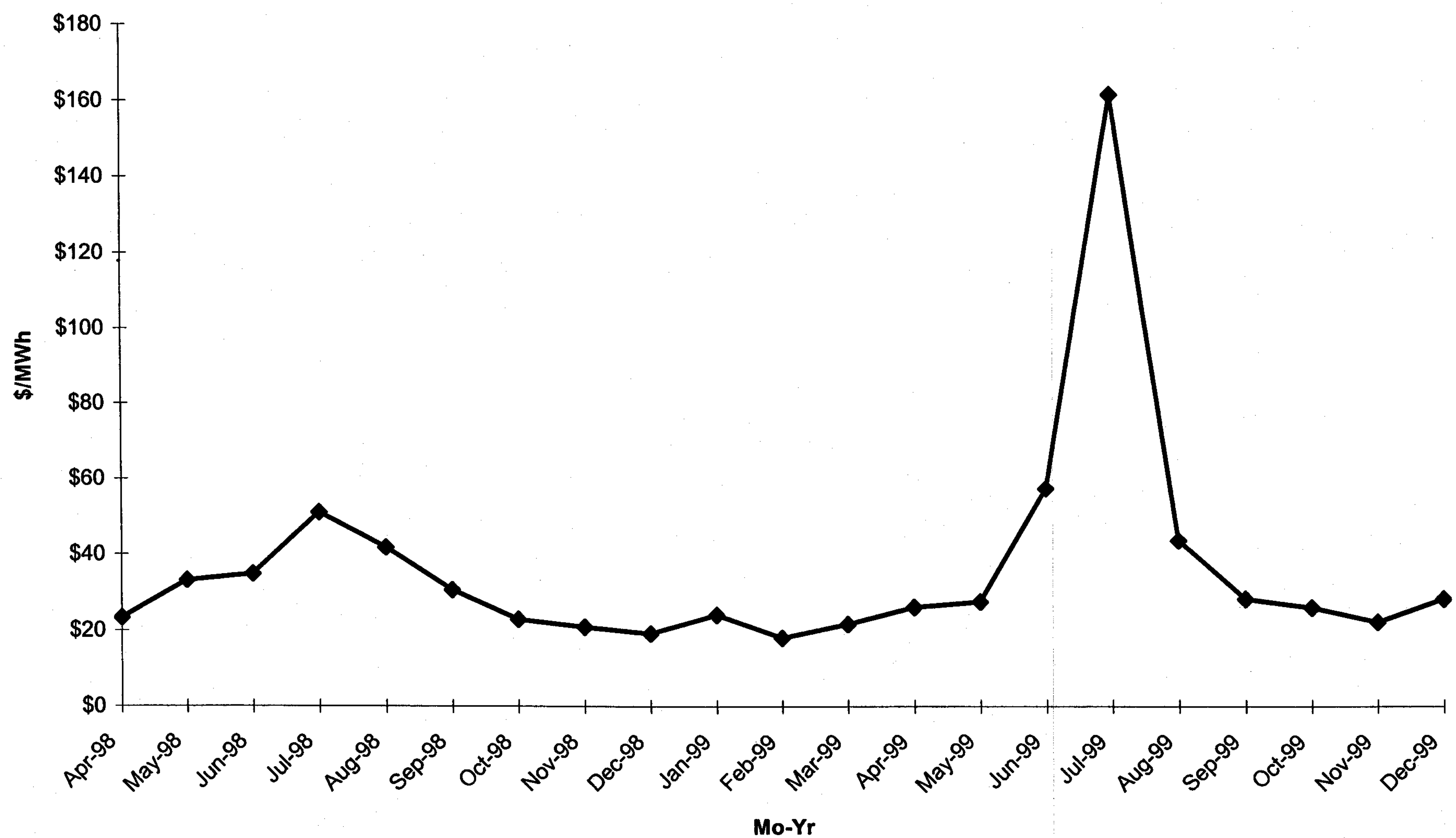
## *1999 FORECAST - Arizona/New Mexico*

| | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **PEAK DEMAND - MW** | | | | | | | | | | | | |
| Loads - FIRM | 14,312 | 13,329 | 12,453 | 13,779 | 16,030 | 18,693 | 19,729 | 19,870 | 18,235 | 14,968 | 12,908 | 14,141 |
| Interruptible/load mgmt. | 640 | 643 | 662 | 664 | 625 | 634 | 641 | 632 | 654 | 651 | 626 | 634 |
| TOTAL LOAD | 14,952 | 13,972 | 13,115 | 14,443 | 16,655 | 19,327 | 20,370 | 20,502 | 18,889 | 15,619 | 13,534 | 14,775 |
| **RESOURCES** | | | | | | | | | | | | |
| Hydro | 1,351 | 1,351 | 1,400 | 1,415 | 1,415 | 1,415 | 1,415 | 1,415 | 1,415 | 1,400 | 1,400 | 1,400 |
| Pumped Storage | 165 | 165 | 165 | 213 | 213 | 213 | 213 | 213 | 213 | 165 | 165 | 165 |
| STEAM - Coal | 8,525 | 8,525 | 8,525 | 8,525 | 8,525 | 8,525 | 8,525 | 8,525 | 8,525 | 8,525 | 8,525 | 8,525 |
| STEAM - Oil | - | - | - | - | - | - | - | - | - | - | - | - |
| STEAM - Gas | 2,479 | 2,479 | 2,479 | 2,475 | 2,466 | 2,460 | 2,460 | 2,460 | 2,460 | 2,470 | 2,479 | 2,479 |
| Nuclear | 2,782 | 2,782 | 2,782 | 2,782 | 2,712 | 2,712 | 2,712 | 2,712 | 2,712 | 2,712 | 2,782 | 2,782 |
| CT | 1,961 | 1,961 | 1,957 | 1,955 | 1,736 | 1,716 | 1,716 | 1,716 | 1,716 | 1,738 | 1,957 | 1,961 |
| CC | 1,589 | 1,589 | 1,589 | 1,581 | 1,486 | 1,466 | 1,466 | 1,466 | 1,466 | 1,494 | 2,122 | 2,122 |
| Geothermal | - | - | - | - | - | - | - | - | - | - | - | - |
| IC | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| COGEN | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 |
| OTHER | - | - | - | - | 1 | 2 | 2 | 2 | 2 | 2 | - | - |
| TOTAL RESOURCES | 19,161 | 19,161 | 19,206 | 19,255 | 18,863 | 18,818 | 18,818 | 18,818 | 18,818 | 18,815 | 19,739 | 19,743 |
| **Forced Outages - based on historic** | | | | | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 | | | |
| Inoperable Capacity | 13 | 13 | - | - | - | - | - | - | - | - | 13 | 13 |
| Sched. Maintenance | 983 | 1,031 | 1,904 | 2,508 | 754 | 3 | 17 | 17 | 506 | 2,069 | 1,127 | 725 |
| TOTAL UNAVAILABLE | 996 | 1,044 | 1,904 | 2,508 | 1,854 | 1,103 | 1,117 | 1,117 | 1,606 | 2,069 | 1,140 | 738 |
| NET RESOURCES | 18,165 | 18,117 | 17,302 | 16,747 | 17,009 | 17,715 | 17,701 | 17,701 | 17,212 | 16,746 | 18,599 | 19,005 |
| FIRM/JOINT IMPORTS | | | | | | | | | | | | |
| CAL-MEX | (379) | (379) | (379) | (379) | (489) | (724) | (724) | (724) | (724) | (379) | (379) | (379) |
| NWPP | (79) | (66) | (50) | (58) | (804) | (872) | (867) | (870) | (847) | (65) | (49) | (67) |
| SWPP | (318) | (318) | (318) | (318) | (318) | (318) | (318) | (318) | (318) | (318) | (318) | (318) |
| RMPA | (773) | (758) | (762) | (820) | (833) | (866) | (872) | (875) | (848) | (740) | (749) | (775) |
| TOTAL IMPORT | (1,549) | (1,521) | (1,509) | (1,575) | (2,444) | (2,780) | (2,781) | (2,787) | (2,737) | (1,502) | (1,495) | (1,539) |
| FIRM/JOINT EXPORTS | | | | | | | | | | | | |
| CAL-MEX | 3,967 | 3,967 | 3,857 | 3,857 | 3,846 | 3,846 | 3,851 | 3,851 | 3,851 | 3,846 | 3,967 | 3,967 |
| NWPP | 691 | 691 | 417 | 417 | 417 | 417 | 417 | 417 | 417 | 416 | 896 | 896 |
| RMPA | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 |
| TOTAL EXPORT | 4,698 | 4,698 | 4,314 | 4,314 | 4,303 | 4,303 | 4,308 | 4,308 | 4,308 | 4,302 | 4,903 | 4,903 |
| NET EXPORTS/IMPORTS | 3,149 | 3,177 | 2,805 | 2,739 | 1,859 | 1,523 | 1,527 | 1,521 | 1,571 | 2,800 | 3,408 | 3,364 |
| JOINT TRANSFERS | 3,444 | 3,444 | 3,444 | 3,444 | 3,433 | 3,433 | 3,433 | 3,433 | 3,433 | 3,433 | 3,444 | 3,444 |
| NET FIRM TRANSFERS* | (295) | (267) | (639) | (705) | (1,574) | (1,910) | (1,906) | (1,912) | (1,862) | (633) | (36) | (80) |
| PLANNED PURCHASES/SALES | -622 | -621 | -573 | -725 | -960 | -1490 | -1706 | -1815 | -1299 | -1315 | 30 | -40 |
| Net Resources + Net Trans. | 19,082 | 19,005 | 18,514 | 18,177 | 19,543 | 21,115 | 21,313 | 21,428 | 20,373 | 18,694 | 18,605 | 19,125 |
| Margin over firm load - MW | 4,770 | 5,676 | 6,061 | 4,398 | 3,513 | 2,422 | 1,584 | 1,558 | 2,138 | 3,726 | 5,697 | 4,984 |
| Margin over firm load - % | 33% | 43% | 49% | 32% | 22% | 13% | 8% | 8% | 12% | 25% | 44% | 35% |

*NET EXPORTS/IMPORTS LESS JOINT PARTICIPATION TRANSFERS (MINUS SIGN INDICATES PURCHASE).
JOINT PARTICIPATION GENERATION IS INCLUDED BY TYPE UNDER "RESOURCES" IN EACH PARTICIPANT'S AREA.

Attachment S-10

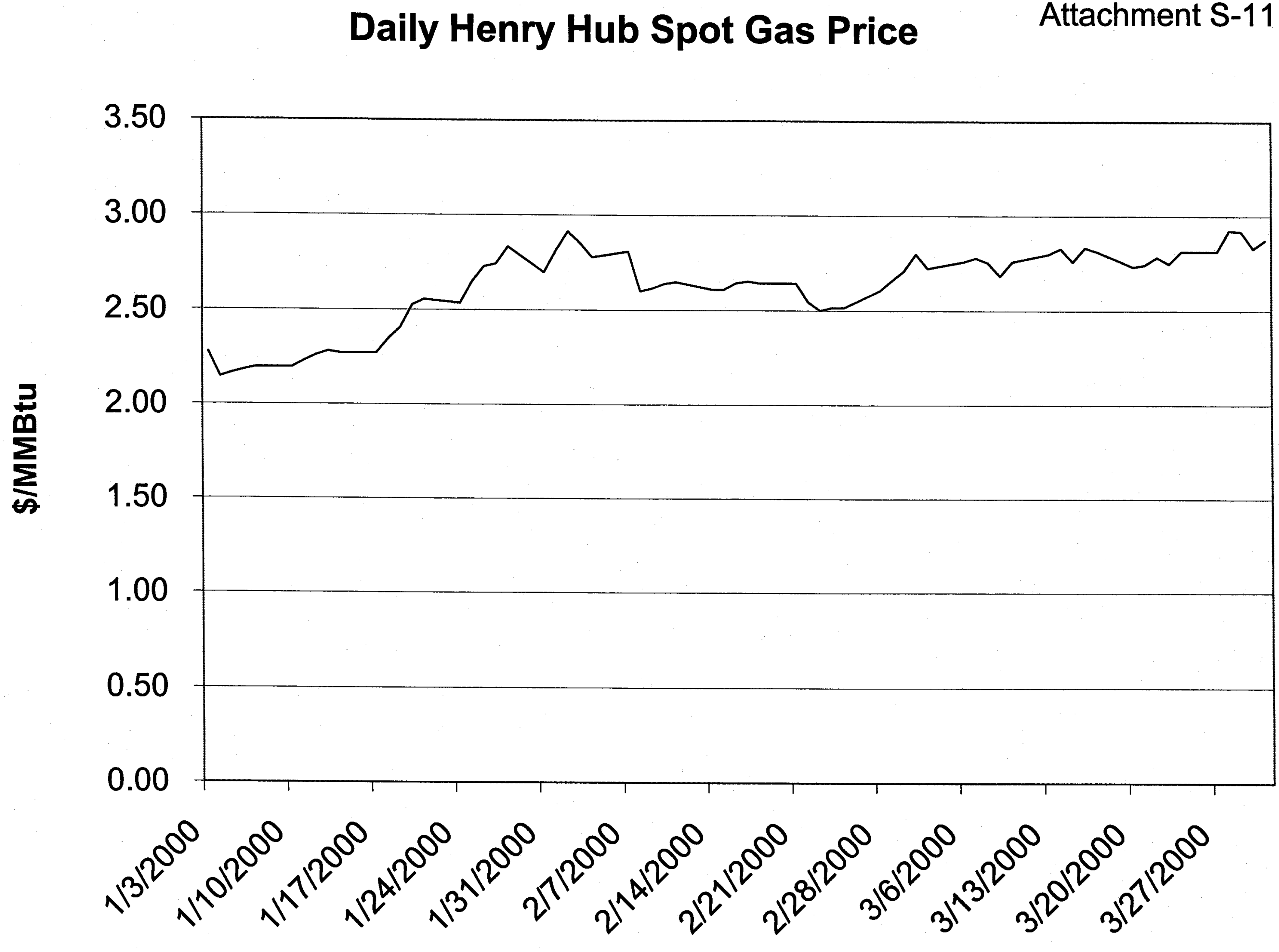
## All-Bus PJM Monthly On-Peak Average LMP ($/MWh)
## April 1998 - December 1999



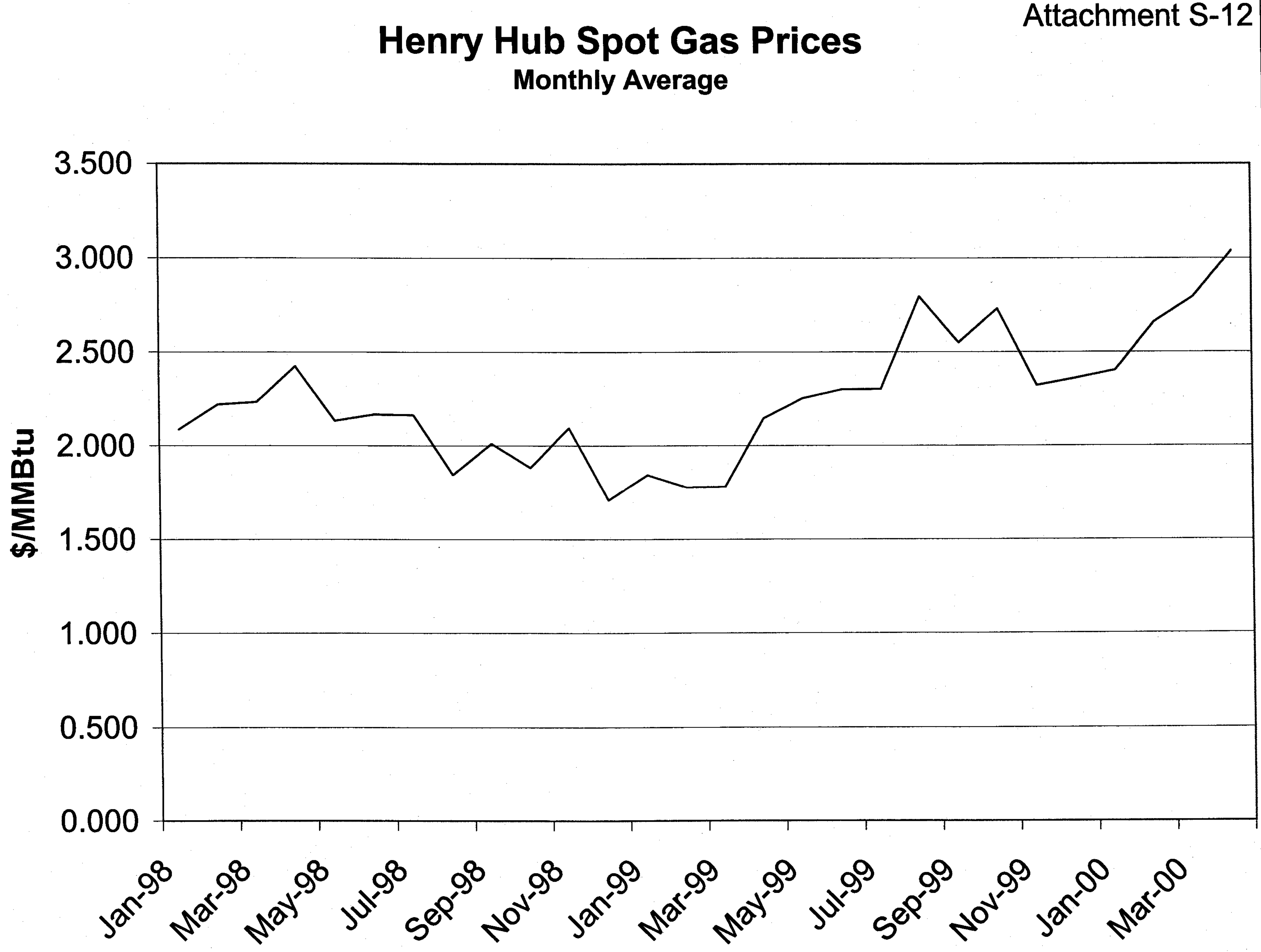

Source: Monthly realtime LMP from PJM Interconnection, LLC, pjm.com.

Note: On peak defined as Monday - Friday, 6am - 10pm.

Attachment S-11



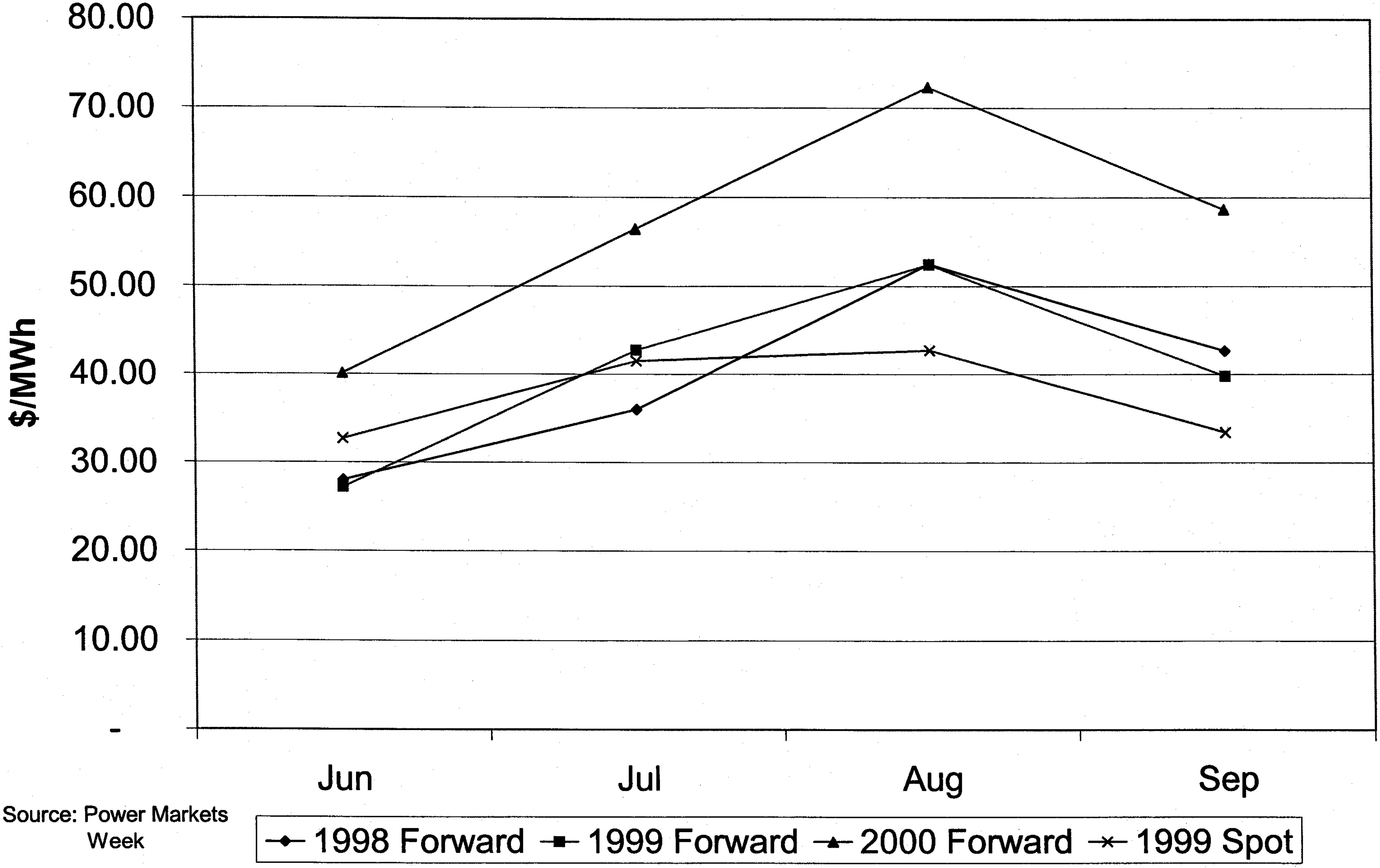
Attachment S-12



Attachment S-13

# Average Palo Verde Forward Prices

On Peak Delivery



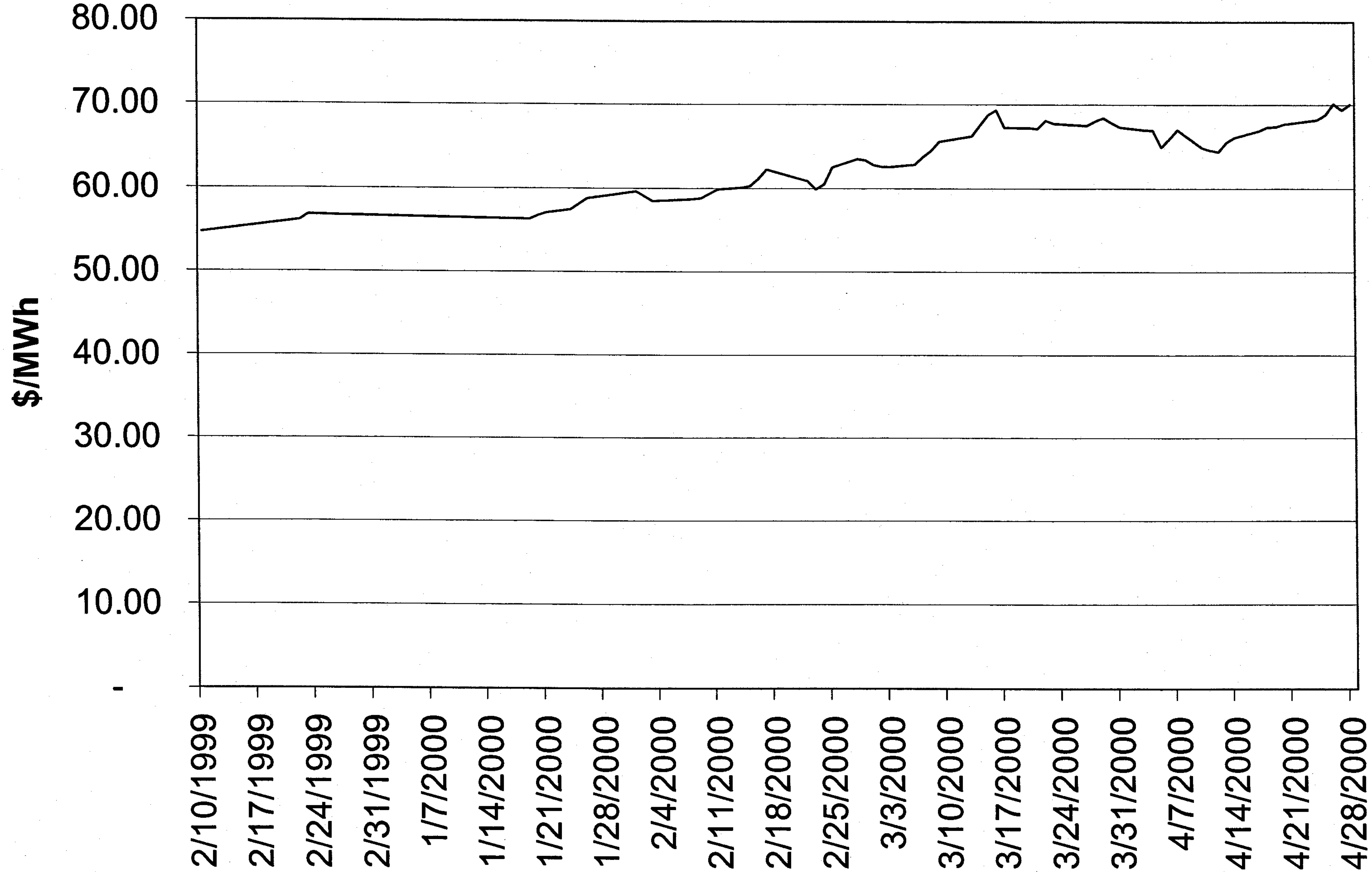

Source: Power Markets Week

On Peak Hours are Monday through Saturday, Hours 7 to 22. The 1998 and 1999 forward prices are the average transacted price over the life of the contract. For 2000 the average is the transaced price from July 1999 through April 2000.

Attachment S-14

# Daily Palo Verde Forward Prices

**3rd Quarter Delivery, On Peak Hours**




Source: Power Markets Week

## Potential Power Cost Savings from a Forward Purchase

Power Purchased for Third Quarter 2000 Delivery

| Purchase | Price for 3rd Quarter Delivery | | |
|---|---|---|---|
| Month | Avg Price[1] | Service Fee[2] | Price to CU |
| Jan | $57.50 | $2.00 | $59.50 |
| Feb | $60.72 | $2.00 | $62.72 |
| Mar | $66.33 | $2.00 | $68.33 |
| Apr | $67.01 | $2.00 | $69.01 |

Potential 3rd Quarter Savings with 100 MW On Peak Block

| Purchase | Delivery Month | | | |
|---|---|---|---|---|
| Month | July | Aug | Sep | Total |
| Jan | $3,685,899 | $4,894,636 | $2,319,725 | $10,900,260 |
| Feb | $3,552,042 | $4,755,631 | $2,185,868 | $10,493,542 |
| Mar | $3,318,556 | $4,513,165 | $1,952,382 | $9,784,103 |
| Apr | $3,290,544 | $4,484,075 | $1,924,370 | $9,698,989 |

[1] Average price of all listed transactions in given month for 3rd quarter delivery
[2] Hypothetical transaction fee Citizens would need to pay to APS.

Explanation of SIC Calculation (APS method)

To determine the SIC by contract schedule two central pieces of information are needed. The first is hourly detail for Citizens' load by contract schedule and the second is the hourly data on which APS owned units were run and the purchases made by APS for that hour's load. The hourly data for APS' owned units and purchases must contain the total output (MW) of the units and the size of any purchases (MW) as well as the cost for the output and the purchases ($/MWh). APS' method of calculating the SIC features the following steps:

1. Sort the hourly data by $/MWh in ascending order so that the most expensive unit or purchase is located at the bottom of the list or stack.

2. Compute the total hourly billing load by contract schedule.

3. Apply any Schedule C load to the most expensive unit or purchase from the stack. If that unit or purchase sufficiently covers the entire C load any remaining available capacity is applied to Schedule B load. If there is no schedule C load in that hour, than Schedule B is priced at the most expensive unit or purchase in the stack. Likewise if there is also no Schedule B load in that hour, the most expensive unit or purchase gets applied to Schedule A. If the most expensive unit or purchase does not sufficiently cover the entire Schedule C load proceed to the second most expensive unit used to cover any remaining C load.

4. Continue up the stack in descending cost until the entire schedule load is covered. If more than one unit or purchase is used, a weighted average is computed for that contract schedule's SIC.

5. Repeat for Schedule B and lastly for Schedule A.

# Purchases by APS - a 1 Hour Illustration

*June 16, 2000 - hour 17*

| Purchase | MW | Price ($/MWh) | Total Cost |
|---|---|---|---|
| 1 | 50 | $35.00 | $1,750 |
| 2 | 230 | $43.45 | $9,994 |
| 3 | 250 | $43.45 | $10,863 |
| 4 | 25 | $50.00 | $1,250 |
| 5 | 25 | $50.00 | $1,250 |
| 6 | 50 | $70.00 | $3,500 |
| 7 | 25 | $70.00 | $1,750 |
| 8 | 25 | $70.00 | $1,750 |
| 9 | 50 | $75.00 | $3,750 |
| 10 | 10 | $160.00 | $1,600 |
| 11 | 25 | $185.00 | $4,625 |
| 12 | 25 | $200.97 | $5,024 |
| 13 | 100 | $201.32 | $20,132 |
| 14 | 200 | $578.82 | $115,764 |
| **Total** | **1,090** | | **$183,001** |

*Note:*
*Citizens' Schedule C load = 32.451 MWh; Schedule B load = 127.131 MWh; Schedule A load = 104 MWh; total = 263.582 MWh.*
*Load data from discovery response RUCO 5.3.*
*APS purchase data from Citizens' auditor file, APS stack - June.xls.*

**Average Price of All APS Purchases ($/MWh)**
$183,001 / 1,090 MW = **$167.89**

**APS Calculation of SIC for Citizens Contract**

| Stacked MW's | # MW's stacked | Contract Schedule | Price ($/MWh) |
|---|---|---|---|
| 0 - 32.451 | 32.451 | C | $578.82 |
| 32.451 - 159.582 | 127.131 | B | $578.82 |
| 159.582 - 200 | 40.418 | A | $578.82 |
| 200 - 263.582 | 63.582 | A | $201.32 |
| | 263.582 | | |

Weighted average price of purchases charged to Citizens = **$487.76**

# APS SIC billing method v. Average APS Purchase Price

*Summary: Estimated Citizens savings for 10 sample days, July 2000*

| Date | CUC pays average APS purchase price | APS SIC method | Delta |
|---|---|---|---|
| July 05 | $230,828 | $348,881 | ($118,053) |
| July 07 | $277,558 | $253,297 | $24,262 |
| July 09 | $193,717 | $218,190 | ($24,473) |
| July 11 | $315,877 | $393,021 | ($77,144) |
| July 15 | $281,054 | $286,779 | ($5,725) |
| July 17 | $340,699 | $426,533 | ($85,834) |
| July 20 | $507,759 | $914,062 | ($406,303) |
| July 23 | $439,351 | $491,282 | ($51,932) |
| July 25 | $809,809 | $1,449,879 | ($640,070) |
| July 27 | $759,202 | $1,242,139 | ($482,937) |
| **Total** | **$4,155,853** | **$6,024,063** | **($1,868,210)** |
| **Daily Avg** | **$415,585** | **$602,406** | **($186,821)** |
| **Projected full July** | **$12,883,144** | **$18,674,594** | **($5,791,450)** |

*Note:*
Projected July shortcut method = 97% of actual July 2000 revision 1 bill of $19,226,175.

| Month | Actual bill | Potential Overbill |
|---|---|---|
| June | $8,506,762 | $2,638,156 |
| July | $19,226,175 | $5,962,509 |
| August | $24,591,125 | $7,626,312 |
| September | $13,296,352 | $4,123,525 |
| **Total** | **$65,620,414** | **$20,350,502** |

*Note:*
*September actual bill does not include any potential surplus hedging benefits.*