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EXHIBIT
APS-1
Admitted

DIRECT TESTIMONY OF PETER M. EWEN

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

November 4, 2002

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DIRECT TESTIMONY OF PETER M. EWEN
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000A-02-0051, et al.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

My name is Pete Ewen. I am the Manager of the Forecasts Department at Arizona Public Service Company ("APS" or "Company"). In that role, I am responsible for preparing short-range and long-range forecasts of system peak demand and energy sales and identifying the optimal dispatch of available resources that will minimize the cost of meeting those energy requirements.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received Bachelors and Masters degrees in Economics from Arizona State University in 1985 and 1988, respectively. I have analyzed and forecasted electric energy and demand growth since 1988, first as a Staff member of the Arizona Corporation Commission ("Commission") and, since 1990, as an employee for APS. I have specifically analyzed the actual dispatch of our generating units in combination with market purchases to serve native load demand since 1998, and assumed full responsibility for making the optimal dispatch and associated fuel cost projections in 2000. I was formerly President of the Arizona Economic Round Table, a group of Arizona-based economists that specialize in studying the Arizona economy, and I am still a member of that organization. I also serve on the Joint Legislative Budget Committee's Finance Advisory Committee. This consists of a group of state economists who advise the Joint Legislative Budget Committee staff on the adequacy of the economic projections underlying their state revenue projections. I am also Chairman of

the Arizona State University ("ASU") Dean's Board of Excellence, which is a group of local businessmen and women who support the College of Business Honors Program by mentoring students, funding scholarships, and providing insights to students and faculty on managing through topical business challenges.

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

My testimony will explain and document the methods by which APS has estimated its unmet needs for capacity and energy for the period 2003 through 2012. It was that estimated need that will serve as the basis for Mr. Thomas Carlson's testimony on the Company's proposed procurement plan.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR DIRECT TESTIMONY?

A. APS's unmet needs for capacity and energy are derived from a comparison of the expected energy and peak demand requirements over the next ten years with the availability of APS resources to meet those needs. As would be expected for a utility having a system load factor in the low 50% range, our unmet capacity needs far exceed our unmet energy needs. That is, the number of hours for which we require additional supply beyond that which our own resources and firm contracts can provide is relatively low, which means that the amount of energy that accompanies the additional capacity is also low. Specifically for 2003, I estimate that we need to acquire approximately 1,400 MW of capacity (22% of peak requirements) and some 650 GWH of energy. from the competitive wholesale market to meet the reliability needs of the APS system. Meeting these reliability needs means that APS has enough resources to meet

the single hour of highest peak demand each year plus a reserve amount to protect against unforeseen plant outages and unanticipated demand, and that all of our customers' energy needs can be served as well. Virtually all of this capacity and energy is needed during the third quarter of 2003 (July, August and September). Capacity needs grow by roughly 6.0% per year, reaching 1,877 MW by 2007, or 25% of peak requirements. In contrast, energy needs grow by 25% per year to 1,940 GWH by 2007. See Attachment PME-1.

These figures are based on the definition of unmet need set forth in Staff's Final Report on Track B Issues ("Staff Report") dated October 25, 2002. See Staff Report at 35, lines 4 - 8. Such definition follows directly from the Commission's order in Track A. See Decision No. 65154 (September 10, 2002). This includes some small modifications to address the Commission's Environmental Portfolio Standard ("EPS") requirements and reliability must-run ("RMR") issues, both of which are described later in my testimony. See also Staff Report at 6, lines 9 – 14. Specifically, we took our most current load and energy forecasts for the years 2003 through 2012 and added a 15% capacity reserve requirement for APS generation and non-firm purchases. We then subtracted out the following:

(1) capacity and energy that can be met from generation resources owned by APS as of September 1, 2002 and included in APS retail rates;

(2) capacity and energy that can be met from wholesale contracts with non-affiliated suppliers that were entered into prior to September 1, 2002;

(3) a calculation of RMR that necessarily must come from non-APS resources; and

(4) the EPS grid-connected resources that APS has or will acquire during these years assuming continuation of present funding for the EPS.

III. THE DEMAND AND ENERGY FORECASTS

Q. DID APS USE ITS MOST RECENT FORECAST OF DEMAND AND ENERGY TO DETERMINE ITS ASSESSMENT OF UNMET NEED?

A. Yes. For purposes of this calculation, we are using our most recent forecast of demand and energy completed in October of this year. This (or the relevant components of it) is the same forecast that serves as the basis for the Company's operating budget in 2003, including revenue and fuel expense projections, generating unit production cost and capacity factor targets, and construction expenditures related to providing service for customer growth. The October 2002 forecast is also an important feature of the Company's power supply, transmission network, and distribution network expansion plans. In addition to tying in to the Company's operating plan, the load forecast (or its major components) is also shared with credit rating agencies, current and prospective lenders, the Western Electric Coordinating Council ("WECC"), and other parties as necessary to address critical business issues. As a result, it has always been important for the load forecast we use internally to be the very best expectation of our true demand and energy growth.

The methods used to produce the load forecast are consistent with methods that are used across the industry and are similar to the methods that were documented in each of the Company's most recent IRP filings (in 1992 and 1995). Furthermore, as I describe later in my testimony, the accuracy of these

methods (particularly in the near-term) is quite good with an average error rate of less than two percent when projecting the next year's energy demand.

Q. COULD YOU PLEASE DESCRIBE IN DETAIL THE METHODOLOGY AND KEY ASSUMPTIONS IN THE OCTOBER 2002 FORECAST?

A. Yes. As I mentioned earlier, our most recent forecast of energy sales and peak demand is the starting point for calculating our expected unmet needs for the next five years. Schedule PME-2 shows the amounts we are projecting for energy sales and peak demand by customer class. From the exhibit, one can see that the forecast used here includes all of our expected retail load plus a small amount of demand from cost-of-service based wholesale contracts with the City of Williams and the partial requirements contracts with the irrigation and electrical districts. Technically, these wholesale contracts should be subtracted from both the forecast and existing resources, but including them in both produces the same result and avoids the need to make adjustments to existing data. These wholesale contracts amount to only 7 MW of coincident peak demand in the forecast.

Forecast Overview

Our current forecast expects energy sales to grow at an average annual rate of 4.1%, with higher growth rates occurring in the near term as the economy and associated electricity demand recovers from the downturn in economic activity. This compares with the most recent 5-year average growth rate from 1997 to 2002, on a weather-normalized basis, of 3.4% and the corresponding 10-year average growth rate, which is also 3.4%. Schedule PME-3 shows these growth rates by class of customer. One of the striking results that can be observed in this Schedule is the rapid growth in electricity sales for the residential and

business classes in 1999 and 2000, followed by the sharp slowdown in 2001. As I describe the drivers of these changes, I believe I can illustrate why we have adopted the methods we use as well as show the kinds of uncertainties that naturally occur with each forecast.

Eighty-nine percent of our energy sales are made to "mass market" residential and business customers. That is, for 11% of our energy sales represented by our largest customers with discrete load requirements and trends, we have on-going contact that allows us to include in the forecast amounts that relate specifically to those businesses and their unique conditions. Historically, this percentage has been a larger number, but has declined in recent years as APS firm wholesale load declined and our largest copper mining customers experienced contractions in their businesses. Because of the obvious logistical limitations involved in contacting many smaller customers and because individual customers below a certain demand threshold are unlikely to influence the demand forecast in a significant way, APS utilizes most of its forecasting resources in developing and enhancing methods for forecasting these "mass market" sales.

Q. HOW DO YOU GO ABOUT FORECASTING THESE "MASS MARKET" SALES?

A. Over relatively longer periods of time (five years or more), 70-80% of the electricity demand APS experiences is the result of economic growth in our service territory. The principal measures of economic growth that APS uses in preparing its forecasts are Arizona population growth, associated household growth, Arizona job growth, and office and retail building floor space additions in metro Phoenix. Historical and forecast values for these variables can be seen in Schedule PME-4.

Because of the unique nature of energy usage in the respective residential and business customer classes, we handle these parts of the forecast separately. I will describe each in turn.

Residential Forecast

Residential sales forecasts result from separate forecasts of the number of residential customers and average residential use per customer. The residential customer forecast is determined by breaking down state-level population forecasts into county-level forecasts, using a projected householder rate by age with an estimated age distribution of the population to determine the number of households in each county, and estimating from historical trends the percent of new households that are likely to be in APS's service territory. This is particularly important for the metro Phoenix area where Salt River Project ("SRP") and APS have split the new single family housing market roughly 50/50 over the past nine years. This "new customer market share" estimate also takes into account various seasonal trends that are inherent in the historical data, which means that it captures such factors affecting demand and energy as winter visitor and college student household impacts. These partial residents are typically not included in the official U.S. Bureau of the Census ("Census") and Arizona Department of Economic Security ("DES") definitions of population and households since these agencies strive to capture the number of permanent residents.

Breaking down the customer growth by county also allows for a more precise estimate of the growth in expected use per customer growth since the APS

territory spans such a large area of the state and incorporates both low-lying desert and high country areas. The weather-sensitive electricity uses are obviously quite different between the two areas with respect to both cooling and heating applications. Other major electricity-using devices also show differences between the two areas, in particular the number of homes with swimming pools (and therefore pool pump motors). Schedule PME-5 shows some of the differences in major appliance ownership between the two areas.

In order to forecast average residential use per customer, APS has relied on both econometric and end-use based methods. The econometric methods involve statistically estimating the historical relationship between monthly average use per customer or monthly average use per square foot (using average home size in the denominator) over time and such independent variables as weather, the real (inflation-adjusted) price of electricity, and specific variables designed to capture the effects of increasing efficiency in air conditioners, heat pumps, and refrigerators as well as the incremental market share for electric heating and electric water heating.

Although widely used and historically fairly accurate, these traditional econometric models have not been as effective in predicting either the high level of usage growth we observed in 1999 and 2000 or the significant decline in usage we observed in 2001. For example, weather-normalized use per customer increased through most of the 1990s by between 0.5% and 1.0% per year. This was, in part, driven by adding incrementally larger homes and some minor increases in base per customer usage—both of which were only partly offset by increasing efficiency in these new homes and from periodic replacement of

older less efficient air conditioners, heat pumps and refrigerators in established homes. However, beginning in the middle of 1999 and carrying through most of 2000, average residential usage increased much more rapidly than these models suggested it would. These deviations from historical trends were then reversed in a fairly dramatic way in the summer of 2001 – again without much support from the econometric models.

In an effort to better understand these trends, APS used a technique in 2001 known as conditional demand analysis ("CDA") to identify the key sources of growth and decline in usage in these years. CDA is a statistical technique that allows the econometrician to separate the systematic differences in usage across households according to the systematic differences in household characteristics. These characteristics include home size (in square feet), number of people living in the home, the type and age of heating and cooling equipment in the home and the presence or absence of other key appliances. The results of the CDA process are estimates of the annual energy consumption for each electric end use included in the model. Notably, while APS has conducted similar studies in the past, 2001 was the first study that allowed us to estimate the stand-alone electricity consumption effects of home computers.

Several key findings emerged from this analysis. First, virtually all of the "above normal" increase in usage in 1999 and 2000 was accounted for by non-weather-sensitive equipment. At least ¼ or more of the growth in residential usage from 1997 to 2000 was accounted for by growth in personal computer ownership. Much of the remaining growth was likely driven by the increased personal ownership of other household electronics such as audio and visual equipment,

non-computer home office equipment (e.g., fax machines), and computer-related equipment (e.g., printers). Data from the U.S. Bureau of Economic Analysis ("BEA") show that the year 1999 was specifically characterized by exceptionally high purchases of household electronics. The declining real price of these electronic appliances in conjunction with the high household income gains in those years (related partly to higher real wages and partly to the wealth effect of large capital gains in the stock market) is the most likely explanation for these trends. Second, the relative intensity of weather-sensitive usage (on a constant efficiency and square foot basis) changed very little in 1999 and 2000. In contrast, the cooling intensity (the degree to which customers cooled their residence) in the desert region declined by 6% in 2001, which amounted to about 115 kWh per customer per month. That is, holding weather, home size, and A/C efficiency constant, APS observed a behavior-related conservation effect of 115 kWh per customer per month, which is equivalent to every customer raising the thermostat by 2.5°. Given the media coverage of blackouts in California, the conservation appeals from Arizona's Governor and the Company's own messages asking customers to conserve, it was not unexpected to see some impact from conservation. However, the historical experience with voluntary calls for conservation would not have predicted the magnitude of this conservation effort, which was quite unexpected. A third key finding was that the vast majority of other electricity usage trends remained relatively stable.

Taking all of these factors into account, APS is presented with some challenges for projecting residential usage trends going forward. Since the econometric model has difficulty in fully handling these sorts of effects (primarily because independent proxy variables that would help explain the historical statistical

deviations are difficult to find), APS has relied more on an end-use approach that provides for greater control over the assumptions regarding the conservation effect and the household base usage increase. To that end, APS initially projected for 2002 that roughly 75% of the 2001 conservation effect would dissipate and that the contribution from new household electronics would run at roughly 1/3 of its growth in 1999 and 2000. What we have found, however, is that only about 50% of the conservation effect has dissipated, but base usage has increased faster than we had anticipated. Therefore, we have revised our forecast of residential usage up slightly to allow the conservation effect to dissipate completely over the next two years and for base usage to increase at a somewhat stronger pace for the next two to three years. Both of these assumptions are consistent with our view of the business cycle as well as the fading memories of the crisis-marked summer of 2001. The residential customer forecast that makes up the remainder of the residential sales forecast has been revised down slightly to account for the weaker growth to date than we had originally anticipated and the recognition that the overall rebound in economic activity is likely to be less robust in the next year or two.

Non-Residential Forecast

With respect to business sales, APS uses an econometric model relating monthly commercial and industrial class sales (excluding sales to large mining loads) to independent factors such as job growth (for Arizona excluding Pima County), office and retail building floor space additions (in metro-Phoenix only), the real price of electricity and weather effects. Historical job growth data is defined as non-farm payroll employment as published by DES in concert with the U.S. Bureau of Labor Statistics ("BLS"). Job growth has been used by APS for many

years to forecast sales to business customers. The job growth data have certain advantages: it is the single best measure of economic activity available (meaning that it is published on a timely basis and, relative to other available measures, has generally smaller revisions to the previously published data); it has sufficient detail to allow us to exclude the effects of economic activity in Tucson Electric Power's ("TEP") service territory; and, it contains industry detail that could potentially help explain changes in energy intensity trends over time. Furthermore, the use of historical and projected labor force participation rates by age and sex allow for a consistency tie between the population growth and age distribution assumptions driving residential customer growth and the job growth that should naturally correspond with this.

Since 1999, however, APS has relied almost exclusively on a model based more on floor stock additions. While overall job growth and floor space additions are both strongly correlated over time with non-residential sales, the floor space projections can be prepared to account for significant changes in non-residential market share between APS and SRP in metro-Phoenix. Job growth projections cannot. Our near-term floor space projections are driven in large part by detailed commercial building construction activity available from the ASU Real Estate Center. In 1999 and 2000, APS and SRP experienced trends in metro-Phoenix commercial building construction activity that deviated significantly from the historical share that each has received from that activity. Specifically, APS received 62% of the new construction market in 1999 compared to the historical average of 50%, and it was the location of these construction projects that led to the significant increase in business customer sales in 1999 and 2000. While the floor space data has imperfections as well – coverage is only for metro-Phoenix,

it excludes many building types such as manufacturing, warehouse, and hospital facilities, and it covers only the leased portion of the commercial real estate market – its advantages make it superior, at the moment, to using job growth as the main proxy for business customer electricity demand growth.

As shown in Schedule PME-3, business sales in 2001 actually declined in response to the slowing economy. In particular, office vacancy rates in metro-Phoenix have climbed to almost 18% and manufacturing activity has declined substantially over the past year and a half. APS expects sales growth in 2003 and 2004 to increase at rates consistent with those of the late 1990s as the economy continues its gradual recovery. This should mean that office vacancy rates should start declining as absorption turns positive and exceeds new supply and as the manufacturing sector begins to recover. Initial signs are that manufacturing job growth in metro Phoenix has stabilized and may start increasing in the 4th quarter of 2002 or 1st quarter of 2003. Significant uncertainty remains, though, as to the health of this sector and its relative strength going forward.

Q. HOW ACCURATE HAVE APS LOAD AND ENERGY FORECASTS BEEN OVER TIME?

A. I have just described some trends in electricity consumption that make forecasting an inherently imprecise exercise. Now, I would like to expand a bit on the broader accuracy question. Schedule PME-6 shows the relative accuracy of retail energy and peak demand forecasts going back to 1993, measured by mean absolute percent error, by the time horizon being compared against. This table demonstrates that the forecasting accuracy is good, but as one would expect, the level of accuracy declines the farther out into the future one is

forecasting. For example, retail energy sales projections one year ahead have missed on average by plus or minus 1.6% for the last 5 years. In contrast, 5-year ahead forecasts – starting with the 1992 forecast for 1997 and ending with the 1996 forecast for 2001 – show an average error rate of 10.3%. A similar result is apparent for projections of retail peak demand, although the error rates are somewhat higher (reflecting the obviously more difficult task of predicting the single highest demand hour each year compared to the total amount of energy required). The individual forecasts used to calculate these error rates are shown in Schedule PME-7.

Q. DOES THIS MEAN WE SHOULD NOT RELY ON FORECASTS?

A. No. But these comparisons highlight the difficulty forecasters face in attempting to achieve a high degree of accuracy far out into the future and correspondingly stress the need for continual adjustment and updating of the forecasts as new information becomes available. Forecasts from the early 1990s were certainly influenced by the slow pace of the economic recovery coming out of the 1990-91 recession and the uncertainty of how strong population migration would turn out to be and what kinds of jobs would be created in the coming decade. Importantly, the DES population estimates, which were relied on to establish the overall trends in population migration and job growth, proved to be terribly inaccurate through 1995. This was only discovered through the results of a special census for Maricopa County in 1995, which census was published in 1996. The result was that DES had underestimated the population growth in metro-Phoenix by 60%, or by some 117,000 people between 1990 and 1995. During this same time, many forecasters, including those at APS, were concerned that the housing growth that had been observed in the prior several

years was far more than could be supported by the underlying population growth estimated by DES. We therefore expected that a retrenchment of growth would emerge in the then-near future. Of course, hindsight has shown that this was not the case.

In addition, some of the major investment projects that occurred in metro-Phoenix during the mid-1990s, including the $1 billion expansion of Intel's manufacturing facility in Chandler, the construction of the $350 million Bank One Ballpark, the expansion of the Mayo Clinic facilities and other major projects, had a substantial impact on construction and manufacturing jobs. These in turn ultimately affected income growth and population migration in both the APS and SRP service areas in ways that exceeded the expectations for economic growth at the time the forecasts were prepared and are the type of events that are very difficult to predict more than just a few years ahead.

APS also faces the additional uncertainty of whether retail access will emerge as a significant factor. Although many indicators suggest that the most likely impact will be small, nobody can predict how conditions might change such that a significant retail access market emerges, thus significantly impacting both future load forecasts and the difficulty in accurately making such forecasts. An important consideration with respect to the current forecast is that we have made no adjustment to account for any potential retail access amount. That is, we have not reduced our forecast of peak demand and energy by one MW or one MWH in the expectation that we might lose standard offer customers to competitive retail energy service providers.

Aside from even these influences, the peak demand forecasts also suffer from further uncertainty because the conversion from forecasts of energy sales to class coincident peak contributions is dependent on a reconciliation of each year's system peak with the results from a randomly drawn statistical sample of retail customers. The load factors that have resulted from the class coincident peak contributions have historically been volatile. On top of this volatility is added volatility from the estimate of system losses at the time of the system peak. System loss rates coincident with the system peak are based on historical observation on the EHV system, engineering estimates of distribution level losses, and a remaining "plug" amount that captures any remaining difference between the class-level estimates and the overall system demand. This final "plug" amount contains any estimation errors from the estimate of distribution losses, sampling error from the class-level demand estimates, Company use at the time of the system peak and power theft at the time of the system peak. Schedule PME-8 shows how these rates have changed, by component, over time. What should be apparent from these descriptions is just how difficult it is to accurately forecast such unknowns, with the conclusion that, at best, a forecast can pick a middle-of-the-road expected value and recognize that actual results will most likely be somewhat different.

A final consideration in assessing the overall forecast accuracy is that the forecasts through 1998 also included an expectation that Commission-authorized demand-side management ("DSM") programs would continue to be a major restraining factor in the growth of retail energy needs. Since then, funding for such DSM has been redirected to the EPS.

This discussion should serve to highlight some of the key uncertainties residing in the current forecast and how those uncertainties loom larger the farther out in time a forecast attempts to reach. One of the main issues that confronts forecasters today is the question of whether the economic growth experienced in the 1990s will be repeated, or even exceeded, in the next 10 years. We simply can't say for sure whether it will or will not, even though our expected growth rates are fairly comparable to those experienced in the past.

IV. RESERVES

Q. HOW DID YOU CALCULATE THE RESERVE REQUIREMENT?

A. The reserve margin is calculated using a 15% reserve margin on APS generating capacity and unit contingent purchases. This reserve margin is consistent with the levels we have used in the recent past. Setting planned reserves at 15% actually provides a higher capacity requirement than the 12% level that FERC defaults to in its Standard Market Design NOPR. A 15% reserve margin is also consistent with the range of 13% to 17% included in the Public Service of Colorado 2001 IRP filing, which was cited favorably by some participants in the Track B workshops held by the Commission over the summer. As a practical matter, though, the reserve margin has no impact on the amount of unmet energy needs. And increasing this number reduces the overall capacity factor on the competitively procured portion of APS's needs.

The applicability of the reserve margin only to our own generating assets is consistent with our past purchasing practice where all of our reliability purchases have been executed on a firm basis where the seller of such service carries the associated reserves. Typically, the Company's optimal dispatch

projections explicitly assume that purchases are for firm delivery as prices for those products are the only ones readily observable in the market.

V. APS RESOURCES

Q. HOW DID YOU DETERMINE APS CAPACITY AND ENERGY RESOURCES FOR PURPOSES OF THE DETERMINATION OF UNMET NEED?

A. The physical capability of the APS resources for capacity purposes is calculated by using the net accredited capacity of each unit less any seasonal de-ratings that would apply at summer peak times. These amounts are shown in Schedule PME-9. With respect to our generating capacity, several small changes can be observed over the period 2003 through 2007. The first is that we are and have been committed to replace the steam generators at each of the Palo Verde units. These replacements were planned and equipment ordered years ago. They are scheduled to take place in extended outages in the Fall of 2003 (Unit 2), the Fall of 2005 (Unit 1), and the Fall of 2007 (Unit 3) and will have the effect of restoring the design capacity of each of the units by roughly 26 MW. The second item is the planned retirement of the Childs/Irving hydro facilities at the end of 2004 under an agreement that APS has reached with several environmental groups. This is in addition to placing in cold reserve the older West Phoenix steam units 4 and 6, which units are not reflected in the 2003 through 2012 figures. These units could, however, be reactivated at some future date should they become necessary for reliability purposes.

For determining unmet energy, we have calculated the output of each unit to the extent that it could meet APS's hourly load forecast, but have also reduced that output for expected planned and forced outages and other important operating

characteristics limiting output such as ramp rates and minimum loading levels. The planned outages include the longer outages for the Palo Verde units in 2003, 2005 and 2007 when their steam generators are being replaced. The 10-year planned maintenance schedule is shown in Schedule PME-10. Schedule PME-11 shows the projected forced outage rates used in these calculations along with the historical forced outage rates for the past ten years for each unit. As was the case in the load forecast, the assumptions we have used here are consistent with the assumptions we have used in developing the Company's operating plans and that have been shared with other outside parties, including plant co-owners, to address important business issues.

The capability of the eligible purchased power contracts to serve APS retail load is treated similarly to that of the generating assets, and their summer capacity is also included in Schedule PME-9. From the Schedule, one can see that the capacity under the SRP Territorial and Contingent purchase increases by about 8 MW per year in keeping with a formula specified in that particular contract. Capacity factor limitations apply to and have been modeled for the diversity exchange contract with Pacificorp. Additionally, 125 MW of forward reliability purchases from non-affiliated parties for firm 100% capacity factor on-peak capacity and energy are included for 2003. Originally, all four of such contracts were executed in March 2000. However, one of them, a 25 MW deal with Enron, had to be replaced in 2001 when Enron collapsed.

Q. CAN YOU DESCRIBE WHY THE APS UNIT AND LONG-TERM CONTRACT ENERGY AMOUNTS IN SCHEDULE PME-1 ARE DIFFERENT FROM APS'S RESPONSE TO STAFF'S DATA REQUEST DATED OCTOBER 22, 2002?

A. Yes. Although each of the amounts has been adjusted, the adjustments are generally fairly minor and do not materially affect the amount of unmet energy needs APS has calculated. The largest change in the early years relates to a purchase contract for 2003 that was inadvertently classified as a reliability purchase and therefore counted against the unmet energy needs in that year. (APS has made forward purchases for 2003 beyond the reliability purchases itemized in Response to Staff's Data Request dated October 22, 2002. These purchases are in place primarily to protect the Company against rising prices during the summer of 2003 and during the extended Palo Verde outage in the fall of 2003.) Other changes are driven by an apparent double-count of certain solar and renewable energy amounts, but these changes are quite small.

Q. WHAT ADJUSTMENTS DID YOU MAKE TO THE NEEDS ASSESSMENT TO ACCOUNT FOR RMR GENERATION?

A. The calculation for RMR generation from other than APS generating facilities relies on the current estimate of 3,535 MW of APS transmission import capability into the metropolitan Phoenix area plus the use of the 660 MW of APS's local generation. The capability for the local generation can be seen in Schedule PME-9. The specific units counted as local generation are West Phoenix combined cycle units 1-3, Ocotillo steam units 1 and 2, Ocotillo combustion turbine units 1 and 2, and West Phoenix combustion turbine units 1 and 2. Forecasted demand in the metro-Phoenix area is a calculated number. APS also carries reserves of 110 MW for the single largest APS generation hazard inside the constrained area. The relationship between the metro-Phoenix demand and the total system demand can be seen in Schedule PME-12. APS believes this amount of its unmet needs should be identified and addressed

separately in the overall procurement plan because of the unique delivery issues associated with such needs.

Q. WHAT FACTORS AFFECT THE CALCULATION OF RMR NEEDS?

A. The amount of APS generation will remain constant unless and until APS retires units within the transmission constraint, as was the case when we placed the old West Phoenix steam units into cold reserve. What can and will vary over time are the calculation of forecasted metro-Phoenix load, the single largest hazard, and Valley transmission import capacity.

Q. WHAT IS YOUR RECOMMENDATION ON THE FINAL DETERMINATION OF RMR?

A. In response to the Track A decision, APS is conducting an RMR study under Commission Staff supervision which is scheduled to be completed by January 2003. This study should address all of the above considerations. I propose using my RMR figures as placeholders until completion of the RMR study mandated by Decision No. 65154, which can then be included in the final bid package.

Q. WHAT IS THE FINAL ADJUSTMENT?

A. APS has reduced its level of unmet needs by including its current plan for grid-connected solar and renewable resources under the EPS requirements. The plan assumes that the EPS standard continues at its current funding levels. For purposes of calculating the unmet capacity and energy needs, APS has not counted any credits it has earned (for early installation, etc.) that might help it meet the standard, but included only the amount of real capacity and energy that we believe will be physically produced by these resources.

Q. DID NOT THE STAFF REPORT INDICATE THAT QF CONTRACTS WOULD BE NON-CONTESTIBLE?

A. Yes, and APS has a QF contract for at least 25 MW of capacity. APS is not subtracting this amount because capacity and energy are provided at the customer's discretion and would not necessarily be available to meet either our peak capacity or annual energy demands. It does seem appropriate that any future agreements with QFs should be subject to whatever procurement process is determined to be appropriate by the Commission in Track B, which I believe was a consensus position during the Track B workshops.

VI. ECONOMY ENERGY AND UNFORECAST NEEDS

Q. WILL APS ALSO BE ACQUIRING ENERGY FROM THE COMPETITIVE WHOLESALE MARKET ON AN ECONOMIC BASIS IN ADDITION TO ITS FORECASTED UNMET NEEDS?

A. Using a relatively current forward curve for power and natural gas prices, APS would expect to make economic purchases that displace production from its existing generation assets and the SRP T&C contract. These amounts are shown in Schedule PME-13. However, these purchase amounts are quite sensitive to movements in the spread between power and natural gas prices (the so-called "spark spread"). Schedule PME-13 also shows that a relatively mild increase or decrease of 10% in the spark spread will affect the amount of economic purchases in 2003 by -16% and +20%, respectively. Although not within the definition of unmet needs in the Staff Report, Mr. Carlson will discuss procurement of economy energy and other unforecasted short-term energy (and demand) needs in his testimony.

Q. WHAT ABOUT UNANTICIPATED RELIABILITY NEEDS NOT SHOWN IN YOUR NEEDS ASSESSMENT?

A. Almost certainly such unforecasted needs will exist, and it is the main reason that resource plans include a planning reserve margin. Unanticipated outages,

the extension or rescheduling of planned outages, unusually hot weather, etc., can all require additional purchases to be made. This is discussed at page 4 of the Staff Report, lines 25 – 27. Mr. Carlson also addresses these secondary procurements in his testimony.

VII. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. Although load and energy forecasting is as much art as science, APS takes great pains to produce as accurate a forecast as possible. Critical business and financial decisions are made in reliance on that forecast. As to the other portions of my needs assessment, I have tried to follow the basic formula set forth in the Staff Report, which the Company believes is consistent with the Commission's order in Decision No. 65154.

Q. DOES THAT CONCLUDE YOUR PREFILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, it does.

SCHEDULE PME-1
APS Projected Unmet Capacity and Energy Needs
2003 - 2012

Capacity (MW)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Total standard offer load [1]	5,723	6,023	6,269	6,522	6,787	7,064	7,357	7,667	7,914	8,127
+ 15% reserve margin [2]	598	602	602	606	606	609	609	609	609	609
- Physical capability of APS units [3]	(3,927)	(3,953)	(3,949)	(3,975)	(3,975)	(4,001)	(4,001)	(4,001)	(4,001)	(4,001)
- Full capability of purchase contracts [4]	(955)	(837)	(844)	(852)	(860)	(868)	(876)	(884)	(893)	(902)
- RMR generation from non-APS units [5]	(29)	(184)	(338)	(493)	(647)	(802)	(956)	(1,111)	(1,265)	(1,426)
- Planned renewable energy supply under EPS [6]	(9)	(17)	(23)	(29)	(34)	(46)	(56)	(70)	(79)	(89)
= Net unmet reliability needs [7]	1,401	1,634	1,717	1,779	1,877	1,956	2,077	2,210	2,285	2,318

Energy (GWH)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Total standard offer load [1]	26,494	27,841	28,999	30,178	31,388	32,670	33,983	35,305	36,425	37,531
- Physical capability of APS units [3]	(24,016)	(25,242)	(25,663)	(26,496)	(26,941)	(28,179)	(28,707)	(29,182)	(29,567)	(29,931)
- Full capability of purchase contracts [4]	(1,798)	(1,672)	(1,986)	(2,044)	(2,281)	(2,140)	(2,358)	(2,551)	(2,719)	(2,870)
- RMR generation from non-APS units [5]	(0)	(2)	(8)	(27)	(72)	(141)	(248)	(398)	(540)	(705)
- Planned renewable energy supply under EPS [6]	(41)	(85)	(114)	(142)	(154)	(197)	(221)	(267)	(290)	(312)
= Net unmet reliability needs [7]	639	840	1,228	1,469	1,940	2,013	2,449	2,907	3,309	3,713

[1] Standard offer load includes all retail customer energy and coincident peak demands plus APS wholesale contracts served by APS resources from Oct 2002 budget projections. Under Staff's proposal, this calculation would be updated prior to any actual procurement.

[2] Reserve margin is calculated on APS generation and known contingent purchases only.

[3] Includes the production from all rate-based APS generation units subject to standard planned and forced outage assumptions.

[4] Includes firm purchase contracts entered into prior to September 1, 2002.

[5] RMR generation assumes a Valley import limit of 3,535 MW, 660 MW of local APS generation, and 110 MW of required reserves. To the extent that bidders can demonstrate higher import capability or import capability is increased, RMR would be reduced, all else remaining the same. The present import limit of 3,535 MW assumes timely completion of the Southwest Valley line and also uses its most recent (and higher) capacity rating.

[6] Includes solar and renewable resource additions planned each year under current funding levels. To the extent the Commission approves higher funding levels, capacity and energy under EPS will increase.

[7] Energy figures do not include economy purchases, which as noted in Schedule PME-13 would add some 3,700 gwh in 2003 (and more in subsequent years) assuming present forecasts of gas and power costs.

SCHEDULE PME-2
Annual System Energy and Peak Demand

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
ENERGY BY CLASS OF CUSTOMER										
1. RESIDENTIAL mWh	10,934,903	11,534,451	12,077,288	12,631,134	13,135,134	13,639,135	14,153,175	14,701,351	15,084,873	15,476,427
2. COMMERCIAL & INDUSTRIAL mWh	13,459,066	14,113,291	14,646,156	15,188,184	15,809,596	16,497,394	17,204,130	17,885,076	18,543,216	19,180,129
3. IRRIGATION mWh	34,781	33,531	32,374	31,229	30,128	29,079	28,050	27,078	26,126	25,215
4. STREETLIGHTING mWh	108,247	112,469	116,639	120,777	124,906	129,024	133,135	137,245	140,661	144,076
5. APS WHOLESALE mWh	204,950	206,868	208,936	211,026	213,136	215,267	217,420	219,594	221,790	224,008
6. LOSSES mWh	1,751,730	1,840,843	1,917,363	1,995,310	2,075,353	2,160,101	2,246,902	2,334,300	2,408,380	2,481,530
8. APS OWN LOAD Total mWh	26,493,677	27,841,453	28,998,756	30,177,660	31,388,254	32,670,000	33,982,813	35,304,645	36,425,046	37,531,386
PEAK DEMAND BY CLASS OF CUSTOMER										
1. RESIDENTIAL mW	2,599	2,743	2,874	3,007	3,127	3,247	3,370	3,500	3,591	3,685
2. COMMERCIAL & INDUSTRIAL mW	2,483	2,578	2,704	2,792	2,909	3,036	3,174	3,320	3,448	3,545
3. IRRIGATION mW	8	8	7	7	6	6	6	6	6	5
4. STREETLIGHTING mW	-	-	-	-	-	-	-	-	-	-
5. APS WHOLESALE mW	7	7	7	7	7	7	8	8	8	8
6. LOSSES mW	626	687	677	709	737	767	800	834	862	885
8. APS OWN LOAD Total mW	5,723	6,023	6,269	6,522	6,787	7,064	7,357	7,667	7,914	8,127

SCHEDULE PME-3
Annual Energy Growth Rates

ENERGY GROWTH HISTORY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	Average 93 TO 97	Average 98 TO 02	Average 92 TO 02
1. RESIDENTIAL	2.7%	5.2%	3.5%	5.7%	6.5%	4.3%	5.7%	6.5%	8.5%	1.7%	6.3%	5.1%	5.7%	5.4%
2. COMMERCIAL & INDUSTRIAL	0.9%	3.6%	3.9%	3.9%	4.9%	3.4%	3.7%	4.3%	11.9%	-1.3%	3.4%	3.9%	4.3%	4.1%
3. MINING LOADS	5.6%	-0.7%	-0.2%	2.2%	0.2%	1.4%	7.0%	-30.3%	-35.6%	-3.1%	-39.5%	0.6%	-22.4%	-11.7%
4. IRRIGATION	-26.0%	-5.6%	18.3%	-9.6%	1.8%	-7.7%	-24.9%	18.1%	-12.8%	-67.0%	13.8%	-1.1%	-21.9%	-12.1%
5. STREETLIGHTING	3.1%	1.8%	2.2%	2.1%	7.5%	2.0%	5.4%	3.8%	3.6%	2.0%	5.3%	3.1%	4.0%	3.6%
6. APS WHOLESALE	-1.3%	-46.9%	3.5%	-21.2%	-10.9%	-13.2%	-29.3%	-2.8%	42.7%	-14.3%	-22.3%	-19.6%	-8.2%	-14.1%
7. RETAIL + APS WHOLESALE SALES	1.6%	1.6%	3.5%	3.8%	4.9%	3.3%	4.2%	2.4%	8.0%	-0.5%	3.1%	3.4%	3.4%	3.4%

ENERGY GROWTH FORECAST	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Average 03 TO 07	Average 08 to 12	Average 03 to 12
1. RESIDENTIAL	6.4%	5.5%	4.7%	4.6%	4.0%	3.8%	3.8%	3.9%	2.6%	2.6%	5.0%	3.3%	4.2%
2. COMMERCIAL & INDUSTRIAL	5.6%	5.0%	3.9%	3.8%	4.2%	4.5%	4.4%	4.1%	3.8%	3.5%	4.5%	4.0%	4.3%
3. MINING LOADS	-8.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-1.7%	0.0%	-0.8%
4. IRRIGATION	6.4%	-3.6%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-1.6%	-3.5%	-2.6%
5. STREETLIGHTING	3.2%	3.9%	3.7%	3.5%	3.4%	3.3%	3.2%	3.1%	2.5%	2.4%	3.6%	2.9%	3.2%
6. APS WHOLESALE	33.1%	0.9%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	6.7%	1.0%	3.8%
7. RETAIL + APS WHOLESALE SALES	5.9%	5.1%	4.2%	4.1%	4.0%	4.1%	4.0%	3.9%	3.2%	3.0%	4.6%	3.6%	4.1%

Schedule PME-4
History and Forecast of Key Economic Indicators

	Population (in thousands)		Payroll Employment (in thousands)				Floorspace (Maricopa County)			
							Office		Retail	
	Arizona	Maricopa	Maricopa County		Arizona		Sq. ft. (000s)	% Change	Sq. ft. (000s)	% Change
1992	3,955	2,287	990	1.2%	1,517	1.7%	38,280	0.0%	70,333	3.4%
1993	4,072	2,355	1,036	4.6%	1,584	4.4%	38,280	0.0%	71,379	1.5%
1994	4,214	2,444	1,106	6.8%	1,692	6.8%	38,280	0.0%	73,801	3.4%
1995	4,379	2,551	1,189	7.4%	1,796	6.1%	38,280	0.0%	75,634	2.5%
1996	4,545	2,664	1,273	7.0%	1,892	5.4%	38,306	0.1%	78,136	3.3%
1997	4,707	2,779	1,344	5.6%	1,985	4.9%	39,152	2.2%	82,115	5.1%
1998	4,864	2,890	1,419	5.6%	2,075	4.5%	39,967	2.1%	85,621	4.3%
1999	5,017	2,995	1,487	4.8%	2,163	4.3%	44,830	12.2%	88,547	3.4%
2000	5,169	3,097	1,541	3.6%	2,243	3.7%	47,519	6.0%	91,489	3.3%
2001	5,324	3,196	1,557	1.1%	2,266	1.0%	51,418	8.2%	96,875	5.9%
2002	5,479	3,300	1,557	0.0%	2,271	0.2%	54,218	5.4%	98,375	1.5%
2003	5,634	3,404	1,619	4.0%	2,357	3.8%	54,618	0.7%	101,375	3.0%
2004	5,790	3,509	1,707	5.4%	2,476	5.0%	55,018	0.7%	103,875	2.5%
2005	5,947	3,614	1,799	5.4%	2,599	5.0%	56,718	3.1%	107,572	3.6%
2006	6,105	3,720	1,878	4.4%	2,703	4.0%	59,681	5.2%	112,951	5.0%
2007	6,263	3,826	1,959	4.3%	2,807	3.9%	62,390	4.5%	117,831	4.3%
2008	6,420	3,932	2,017	3.0%	2,884	2.8%	65,163	4.4%	122,816	4.2%
2009	6,577	4,038	2,076	2.9%	2,962	2.7%	68,028	4.4%	127,956	4.2%
2010	6,735	4,145	2,128	2.5%	3,033	2.4%	70,527	3.7%	132,793	3.8%
2011	6,893	4,252	2,189	2.9%	3,114	2.7%	73,351	4.0%	137,214	3.3%
2012	7,051	4,359	2,244	2.5%	3,185	2.3%	76,021	3.6%	141,290	3.0%

SCHEDULE PME-5
APS RESIDENTIAL CUSTOMER
MAJOR APPLIANCE OWNERSHIP
By Area

Estimates [3] for All Existing Customers Across All Dwelling Types	DESERT AREA [1]	HIGH COUNTRY [2]
COOLING		
A/C or Heat Pump Only	86%	29%
Evaporative Only	7%	35%
Combination	5%	2%
Other (window/wall units, gaspack)	2%	6%
None	0%	28%
HEATING		
Electric	67%	28%
Natural Gas	29%	47%
Propane	2%	15%
Other	1%	10%
None	1%	0%
WATER HEATING		
Electric	56%	29%
Natural Gas	41%	55%
Propane	2%	15%
Solar	1%	1%
CLOTHES DRYING		
Electric	72%	61%
Natural Gas	15%	21%
Propane	0%	5%
None	13%	13%
RANGE/OVEN		
Electric	78%	45%
Natural Gas	20%	38%
Propane	2%	16%
None	0%	1%
OTHER ELECTRIC EQUIPMENT		
Refrigerator	100%	100%
Swimming Pool	18%	1%
Spa	7%	7%
Microwave Oven	97%	96%
Dishwasher	82%	61%
Clothes Washer	91%	90%
Home Computer	69%	60%
Freezer	26%	44%
Color Television	99%	98%
Cable TV / Sat. Dish	44%	46%
VCR	94%	95%
Home Stereo Syst.	74%	73%
DVD Player	25%	18%
Printer	59%	51%

NOTES:
(1) Desert Area defined as Phoenix, Yuma, Casa Grande, Eloy, Coolidge, Gila Bend, Wickenburg, and surrounding areas.
(2) High Country defined as Prescott, Sedona, Flagstaff, Winslow, Payson, Globe, Bisbee, Douglas and surrounding areas
(3) Estimates made from surveying a sample of 3,000 randomly selected APS residential customers.
Sample stratified by Area and Age of Dwelling. Survey conducted in May of 2001.

Schedule PME-6
Accuracy of Peak Demand and Energy Forecasts

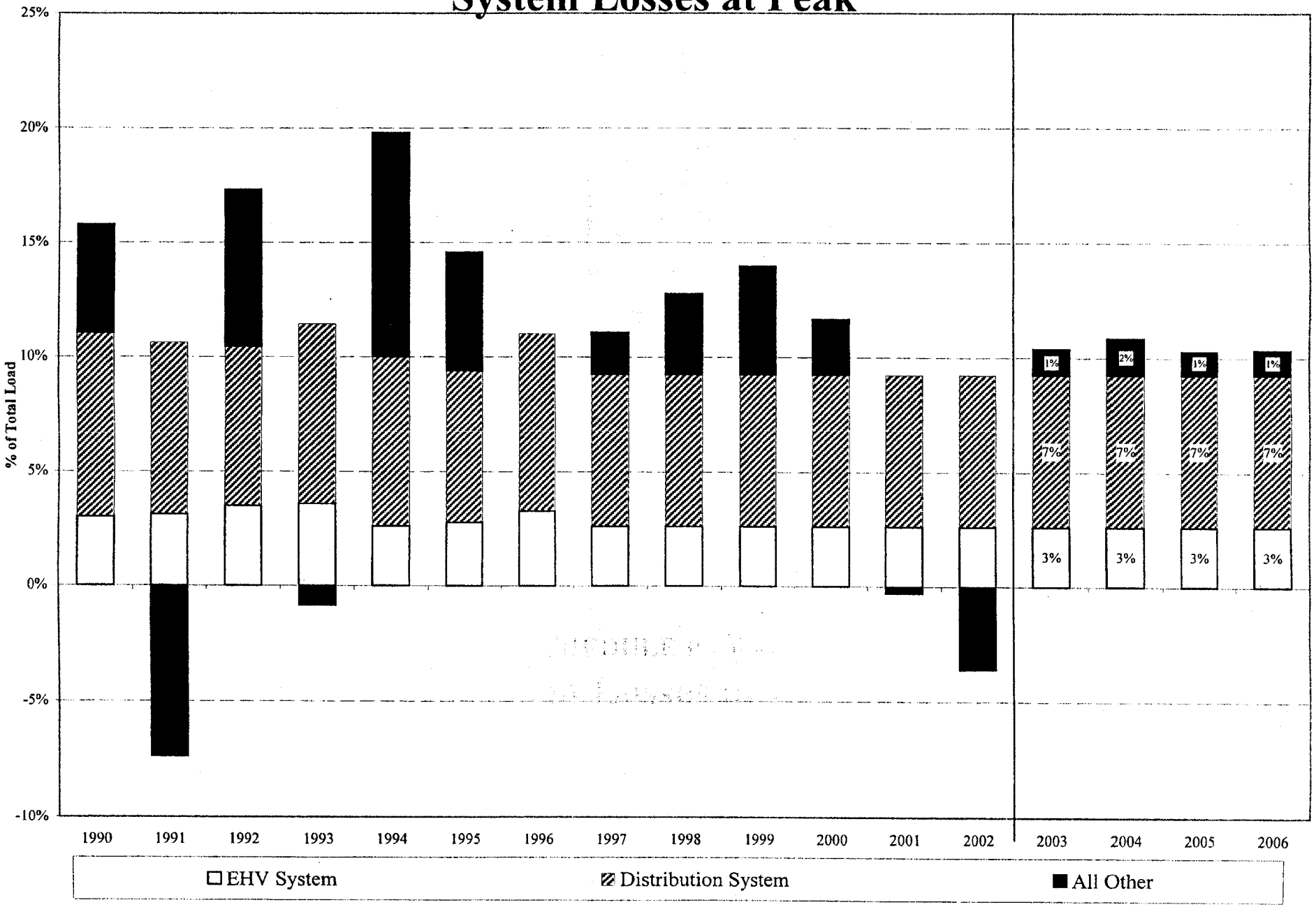
Years Projected Ahead	Mean Absolute Percent Error: Retail Energy Sales	Mean Absolute Percent Error: Retail Peak Demand
1	1.6%	3.1%
2	2.5%	4.6%
3	4.5%	7.2%
4	8.3%	14.7%
5	10.3%	18.1%

Schedule PME-7
Forecasts of Retail Customer Peak Demands and Energy Sales
By Date of Forecast

Forecast / Date	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Annual Retail Peak Forecasted Demand (MW)											
Jan 1992	3,465	3,561	3,650	3,786	3,879	3,978	4,051	4,116	4,189	4,266	4,341
Feb 1993		3,565	3,657	3,792	3,843	3,895	3,980	4,067	4,135	4,210	4,281
Oct 1993			3,705	3,791	3,804						
Feb 1994			3,705	3,791	3,804	3,884	3,946	4,026	4,103	4,178	4,258
Oct 1994				3,833	3,924	4,001					
Jun 1995				3,833	3,924	4,001	4,128	4,259	4,388	4,497	4,612
Oct 1995					4,005	4,085	4,158				
May 1996					4,005	4,085	4,158	4,223	4,340	4,447	4,556
Oct 1996						4,207	4,296	4,372			
Feb 1997						4,200	4,268	4,344	4,478	4,627	4,769
Oct 1997							4,488	4,664	4,831		
Feb 1998							4,488	4,664	4,831	4,987	5,132
Oct 1998								4,778	4,938	5,113	
Apr 1999								4,835	5,010	5,195	5,322
Oct 1999									5,048	5,260	5,417
Apr 2000									5,091	5,361	5,597
Oct 2000										5,480	5,699
Apr 2001										5,491	5,808
Oct 2001											5,610
Apr 2002											5,532
Actual Peak Demand (MW)	3,796	3,802	4,214	4,420	4,575	4,609	5,072	4,935	5,479	5,687	5,803
Annual Retail Forecasted Sales (GWH)											
Jan 1992	16,005	16,599	17,171	17,874	18,476	18,910	19,319	19,710	20,145	20,588	
Feb 1993		16,505	17,020	17,762	17,974	18,203	18,566	19,047	19,425	19,836	
Oct 1993			17,117	17,720	17,694						
Feb 1994			17,021	17,536	17,975	17,545	18,097	18,144	18,470	18,887	
Oct 1994				17,926	17,975	17,545					
Jun 1995				17,926	18,505	18,831	19,332	19,602	20,058	20,048	
Oct 1995					18,730	19,374	19,957				
May 1996					18,699	19,382	19,972	20,542	21,161	21,710	
Oct 1996						19,500	20,237	20,922			
Feb 1997						19,514	20,196	20,828	21,467	22,181	
Oct 1997							20,382	21,172	21,953		
Feb 1998							20,382	21,172	21,953	22,645	
Oct 1998								21,110	21,846	22,610	
Apr 1999								21,110	21,846	22,610	
Oct 1999									21,286	22,157	
Apr 2000									21,460	22,598	
Oct 2000										23,365	
Apr 2001										23,276	
Actual Retail Sales (GWH)	16,035	16,365	17,465	17,749	19,021	19,817	20,463	21,075	22,535	23,399	

SCHEDULE PME - 8

System Losses at Peak



SCHEDULE PME-9
SEASONAL CAPACITY BY RESOURCE

	Summer Capacity (MW)										
Unit	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Palo Verde 1	362	362	362	362	388	388	388	388	388	388	388
Palo Verde 2	362	362	388	388	388	388	388	388	388	388	388
Palo Verde 3	363	363	363	363	363	363	389	389	389	389	389
Four Corners 1	170	170	170	170	170	170	170	170	170	170	170
Four Corners 2	170	170	170	170	170	170	170	170	170	170	170
Four Corners 3	220	220	220	220	220	220	220	220	220	220	220
Four Corners 4	111	111	111	111	111	111	111	111	111	111	111
Four Corners 5	111	111	111	111	111	111	111	111	111	111	111
Navajo 1	105	105	105	105	105	105	105	105	105	105	105
Navajo 2	105	105	105	105	105	105	105	105	105	105	105
Navajo 3	105	105	105	105	105	105	105	105	105	105	105
Cholla 1	110	110	110	110	110	110	110	110	110	110	110
Cholla 2	245	245	245	245	245	245	245	245	245	245	245
Cholla 3	260	260	260	260	260	260	260	260	260	260	260
W. Phx. CC 1	80	80	80	80	80	80	80	80	80	80	80
W. Phx. CC 2	80	80	80	80	80	80	80	80	80	80	80
W. Phx. CC 3	80	80	80	80	80	80	80	80	80	80	80
Ocotillo Steam 1	110	110	110	110	110	110	110	110	110	110	110
Ocotillo Steam 2	110	110	110	110	110	110	110	110	110	110	110
Saguaro Steam 1	110	110	110	110	110	110	110	110	110	110	110
Saguaro Steam 2	100	100	100	100	100	100	100	100	100	100	100
W. Phx CT 1	50	50	50	50	50	50	50	50	50	50	50
W. Phx CT 2	50	50	50	50	50	50	50	50	50	50	50
Ocotillo CT 1	50	50	50	50	50	50	50	50	50	50	50
Ocotillo CT 2	50	50	50	50	50	50	50	50	50	50	50
Saguaro CT 1	50	50	50	50	50	50	50	50	50	50	50
Saguaro CT 2	50	50	50	50	50	50	50	50	50	50	50
Yucca 1	18	18	18	18	18	18	18	18	18	18	18
Yucca 2	18	18	18	18	18	18	18	18	18	18	18
Yucca 3	52	52	52	52	52	52	52	52	52	52	52
Yucca 4	51	51	51	51	51	51	51	51	51	51	51
Douglas	15	15	15	15	15	15	15	15	15	15	15
Childs / Irving	4	4	4	-	-	-	-	-	-	-	-
APS Gen Total	3,927	3,927	3,953	3,949	3,975	3,975	4,001	4,001	4,001	4,001	4,001
SRP T&C	343	350	357	364	372	380	388	396	404	413	422
Pacificorp Exchange	480	480	480	480	480	480	480	480	480	480	480
APS Resource Total	**4,750**	**4,757**	**4,790**	**4,793**	**4,827**	**4,835**	**4,869**	**4,877**	**4,885**	**4,894**	**4,903**

SCHEDULE PME-9
SEASONAL CAPACITY BY RESOURCE

	Winter Capacity (MW)										
Unit	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Palo Verde 1	362	362	362	362	388	388	388	388	388	388	388
Palo Verde 2	362	362	388	388	388	388	388	388	388	388	388
Palo Verde 3	363	363	363	363	363	363	389	389	389	389	389
Four Corners 1	170	170	170	170	170	170	170	170	170	170	170
Four Corners 2	170	170	170	170	170	170	170	170	170	170	170
Four Corners 3	220	220	220	220	220	220	220	220	220	220	220
Four Corners 4	111	111	111	111	111	111	111	111	111	111	111
Four Corners 5	111	111	111	111	111	111	111	111	111	111	111
Navajo 1	105	105	105	105	105	105	105	105	105	105	105
Navajo 2	105	105	105	105	105	105	105	105	105	105	105
Navajo 3	105	105	105	105	105	105	105	105	105	105	105
Cholla 1	110	110	110	110	110	110	110	110	110	110	110
Cholla 2	245	245	245	245	245	245	245	245	245	245	245
Cholla 3	260	260	260	260	260	260	260	260	260	260	260
W. Phx. CC 1	92	92	92	92	92	92	92	92	92	92	92
W. Phx. CC 2	92	92	92	92	92	92	92	92	92	92	92
W. Phx. CC 3	92	92	92	92	92	92	92	92	92	92	92
Ocotillo Steam 1	110	110	110	110	110	110	110	110	110	110	110
Ocotillo Steam 2	110	110	110	110	110	110	110	110	110	110	110
Saguaro Steam 1	110	110	110	110	110	110	110	110	110	110	110
Saguaro Steam 2	100	100	100	100	100	100	100	100	100	100	100
W. Phx CT 1	62	62	62	62	62	62	62	62	62	62	62
W. Phx CT 2	62	62	62	62	62	62	62	62	62	62	62
Ocotillo CT 1	62	62	62	62	62	62	62	62	62	62	62
Ocotillo CT 2	62	62	62	62	62	62	62	62	62	62	62
Saguaro CT 1	62	62	62	62	62	62	62	62	62	62	62
Saguaro CT 2	62	62	62	62	62	62	62	62	62	62	62
Yucca 1	22	22	22	22	22	22	22	22	22	22	22
Yucca 2	22	22	22	22	22	22	22	22	22	22	22
Yucca 3	62	62	62	62	62	62	62	62	62	62	62
Yucca 4	61	61	61	61	61	61	61	61	61	61	61
Douglas	19	19	19	19	19	19	19	19	19	19	19
Childs / Irving	4	4	-	-	-	-	-	-	-	-	-
APS Gen Total	4,067	4,067	4,089	4,089	4,115	4,115	4,141	4,141	4,141	4,141	4,141
SRP T&C	336	343	350	357	364	372	380	388	396	404	413
APS Resource Total	**4,403**	**4,410**	**4,439**	**4,446**	**4,479**	**4,487**	**4,521**	**4,529**	**4,537**	**4,545**	**4,554**

SCHEDULE PME-10

2003						PLANNED OUTAGE SCHEDULE				Month from Last O.H.	
PLANT	UNIT	O.H. TYPE	TOT. #DYS	ST/OT	CAPACITY	START	END	START	END	Last O/H	Months
PALO VERDE	1				362					11/02/02	14
	2	ST GEN REF	76		362			09/27/03	12/11/03	04/20/02	18
	3	REF	36		363	03/29/03	05/03/03			11/03/01	18
NAVAJO	1	MINOR	41		105	01/18/03	02/27/03			02/18/01	25
	2				105					02/24/02	23
	3	MAJOR	58		105	03/08/03	05/04/03			03/25/01	26
FOUR CORNERS	1				170					05/26/02	19
	2				170					04/04/01	33
	3	MAJOR	47		220	03/25/03	05/10/03			12/05/00	30
	4	Reliab Wash	14		111	02/01/03	02/14/03			04/04/01	23
	5	RELIAB.	14		111			11/29/03	12/12/03	03/29/02	21
CHOLLA	1				110					03/09/01	34
	2				245					05/18/02	20
	3	MINOR	36		260	02/15/03	03/22/03			04/02/00	36
WEST PHOENIX	CC1	Mini	7		85	03/01/03	03/07/03			04/25/02	21
	CC2	HGP	42		85			10/04/03	11/14/03	03/03/02	21
	CC3	Comb	28		85	03/29/03	04/25/03			12/13/02	4
	GT1	Mini	7		55	02/08/03	02/14/03			01/18/02	13
	GT2	Mini	7		55	01/25/03	01/31/03			01/18/02	13
OCOTILLO	1	MINOR	21		110	03/01/03	03/21/03			03/31/01	24
	2	MINOR			110					04/07/02	21
	GT1	Mini	7		55	04/19/03	04/25/03			02/01/02	15
	GT2	Mini	7		55	01/11/03	01/17/03			04/19/02	9
SAGUARO	1	MINOR	21		110	02/02/03	02/22/03			04/03/02	11
	2	MINOR	21		100			11/01/03	11/21/03	05/10/02	19
	GT1	Comb	35		55	03/02/03	04/05/03			04/25/01	24
	GT2	Mini	5		55	01/21/03	01/25/03			04/20/01	33
DOUGLAS	GT	Comb	28		16	05/01/03	05/28/03				
YUCCA	GT1				19					02/12/02	23
	GT2				19					03/02/02	22
	GT3				55					04/28/01	33
	GT4				54					05/05/02	20

SCHEDULE PME-10

2004						PLANNED OUTAGE SCHEDULE				Month from Last O.H	
PLANT	UNIT	O.H. TYPE	TOT. #DYS	ST/OT	CAPACITY	START	END	START	END	Last O/H	Months
PALO VERDE	1	REF	36		362	04/03/04	05/08/04			11/02/02	18
	2				362					12/11/03	13
	3	REF	36		363	10/02/04	11/06/04			05/03/03	18
NAVAJO	1				105					02/27/03	22
	2	MAJOR	58		105	01/31/04	03/28/04			02/24/02	25
	3				105					05/04/03	20
FOUR CORNERS	1				170					05/26/02	32
	2	MAJOR	44		170	03/27/04	05/09/04			04/04/01	38
	3				220					05/10/03	20
	4	MAJOR	70		111	01/03/04	03/12/04			02/14/03	13
	5				111					12/12/03	13
CHOLLA	1	MINOR	21		110	02/14/04	03/05/04			03/09/01	36
	2				245					05/18/02	32
	3	MINOR			260					03/22/03	22
WEST PHOENIX	CC1	Comb	28		85	03/27/04	04/23/04			04/25/02	24
	CC2	Mini	7		85	01/19/04	01/25/04			11/14/03	14
	CC3	Mini	7		85	02/20/04	02/26/04			04/25/03	21
	GT1	Mini	7		55	01/05/04	01/11/04			02/14/03	11
	GT2	Mini	7		55	02/02/04	02/08/04			01/31/03	12
OCOTILLO	1				110					03/21/03	22
	2	MINOR	21		110	10/30/04	11/19/04			04/07/02	32
	GT1	Comb	35		55	02/21/04	03/26/04			04/25/03	11
	GT2	Comb	35		55	01/03/04	02/06/04			01/17/03	13
SAGUARO	1	MINOR	21		110	01/24/04	02/13/04			02/22/03	12
	2	MINOR	21		100	11/29/04	12/19/04			11/21/03	13
	GT1	Mini	5		55	10/13/04	10/17/04			04/05/03	21
	GT2	Comb	35		55	03/26/04	04/29/04			04/20/01	37
DOUGLAS	GT	Mini	5		16	05/05/04	05/09/04			05/28/03	19
YUCCA	GT1	Mini	3		19	01/24/04	01/26/04			02/12/02	35
	GT2	Mini	3		19	02/09/04	02/11/04			03/02/02	35
	GT3	Comb	6		55	05/03/04	05/08/04			04/28/01	45
	GT4				54					05/05/02	32

SCHEDULE PME-10

2005 PLANNED OUTAGE SCHEDULE

PLANT	UNIT	O.H. TYPE	TOT. #DYS	ST/OT	CAPACITY	START	END	START	END	START	END	START	END	Month from Last O.H Last O/H	Months
PALO VERDE	1	ST GEN REF	76		363			10/01/05	12/15/05					05/08/04	18
	2	REF	36		363	04/02/05	05/07/05							12/11/03	17
	3				365									11/06/04	
NAVAJO	1	MAJOR	58		105	01/08/05	03/06/05							02/27/03	25
	2				105									03/28/04	
	3				105									05/04/03	
FOUR CORNERS	1	MAJOR	44		170	02/19/05	04/03/05							05/26/02	35
	2				170									05/09/04	
	3				220									05/10/03	
	4	RELIAB.	10		111	11/05/05	11/14/05							03/12/04	
	5	MINOR	18		111	04/11/05	04/28/05							12/12/03	17
CHOLLA	1				110									03/05/04	
	2	MAJOR	42		245	04/04/05	05/15/05							05/18/02	36
	3				260									03/22/03	
WEST PHOENIX	CC1	Mini	7		85	01/03/05	01/09/05							04/23/04	
	CC2	Comb	28		85			10/08/05	11/04/05					11/14/03	24
	CC3	MAJOR	84		85	01/15/05	04/08/05							04/25/03	24
	GT1	Mini	14		55	01/26/05	02/01/05	10/01/05	10/07/05					01/11/04	21
	GT2	Mini	14		55	04/09/05	04/15/05	12/10/05	12/16/05					02/08/04	23
OCOTILLO	1	MAJOR	58		113	02/26/05	04/24/05							03/21/03	26
	2				113									11/19/04	
	GT1	Mini	7		55	02/02/05	02/08/05							03/26/04	11
	GT2	Mini	7		55	04/30/05	05/06/05							02/06/04	15
SAGUARO	1	MINOR	35		110	02/14/05	03/20/05							02/13/04	13
	2	MINOR	21		100			10/24/05	11/13/05					12/19/04	11
	GT1	Gen Insp	35		55	03/28/05	05/01/05							04/05/03	25
	GT2	Mini	5		55	02/04/05	02/08/05							04/29/04	
DOUGLAS	GT	Mini	5		16	05/14/05	05/18/05							05/28/03	
YUCCA	GT1				19									02/12/02	
	GT2				19									03/02/02	
	GT3				55									04/28/01	
	GT4	Comb	6		54			10/17/05	10/22/05					05/05/02	

SCHEDULE PME-10

PLANNED OUTAGE SCHEDULE

2006														Month from Last O.H	
PLANT	UNIT	O.H. TYPE	TOT. #DYS	ST/OT	CAPACITY	START	END	START	END	START	END	START	END	Last O/H	Months
PALO VERDE	1				363									11/05/05	
	2	REF	36		363			09/30/06	11/04/06					05/07/05	18
	3	REF	36		365	04/01/06	05/06/06							11/06/04	18
NAVAJO	1				105									03/06/05	
	2				105									03/28/04	
	3	MAJOR	31		105	03/04/06	04/03/06							05/04/03	36
FOUR CORNERS	1	Reliabil.	8		170			11/11/06	11/18/06					04/03/05	
	2				170									05/09/04	
	3	MAJOR	57		220	01/28/06	03/25/06							05/10/03	35
	4				111									03/12/04	
	5	Reliabil.	9		111			10/28/06	11/05/06					04/28/05	
CHOLLA	1				110									03/05/04	
	2				245									05/15/05	
	3	MINOR	21		260	03/25/06	04/14/06							03/22/03	37
WEST PHOENIX	CC1	MAJOR	84		85	01/03/06	03/27/06							04/23/04	23
	CC2	Mini	7		85	04/03/06	04/09/06							11/04/05	
	CC3	Mini	7		85	04/15/06	04/21/06							04/08/05	
	GT1	Mini	7		55			11/29/06	12/05/06					10/07/05	14
	GT2				55									12/16/05	
OCOTILLO	1				113									04/24/05	
	2	MINOR	21		113			10/28/06	11/17/06					11/19/04	24
	GT1	Mini	7		55	04/22/06	04/28/06							02/08/05	15
	GT2	Mini	7		55	05/08/06	05/14/06							05/06/05	12
SAGUARO	1	MINOR	21		110	03/04/06	03/24/06							03/20/05	12
	2	MINOR	21		100			11/06/06	11/26/06					11/13/05	13
	GT1	Mini	5		55	05/06/06	05/10/06							05/01/05	
	GT2	Gen Insp	35		55	01/20/06	02/23/06							04/29/04	22
DOUGLAS	GT	Mini	5		16	05/17/06	05/21/06							05/28/03	
YUCCA	GT1				19									02/12/02	
	GT2				19									03/02/02	
	GT3				55									04/28/01	
	GT4	Mini	3		54	05/15/06	05/17/06							05/05/02	

SCHEDULE PME-10

2007 PLANNED OUTAGE SCHEDULE

PLANT	UNIT	O.H. TYPE	TOT. #DYS	ST/OT	CAPACITY	START	END	START	END	START	END	START	END	Month from Last O.H Last O/H	Months
PALO VERDE	1	REF	36		363	03/31/07	05/05/07							11/05/05	18
	2				363									11/04/06	
	3	ST GEN REF	76		365	09/29/07	12/13/07							05/06/06	18
NAVAJO	1				105									03/06/05	
	2	MAJOR	31		105	03/03/07	04/02/07							03/28/04	37
	3				105									04/03/06	
FOUR CORNERS	1				170									04/03/05	
	2	MAJOR	35		170	02/10/07	03/16/07							05/09/04	35
	3	Reliab	8		220			12/01/07	12/08/07					03/25/06	
	4	MINOR	18		111	04/28/07	05/15/07							03/12/04	39
	5				111									04/28/05	
CHOLLA	1	MAJOR	42		110	03/17/07	04/27/07							03/05/04	38
	2				245									05/15/05	
	3				260									04/14/06	
WEST PHOENIX	CC1	Mini	7		85	01/02/07	01/08/07							03/27/06	
	CC2	MAJOR	84		85	01/13/07	04/06/07							11/04/05	17
	CC3	Comb	28		85	04/14/07	05/11/07							04/08/05	25
	GT1				55									12/05/06	
	GT2	Mini	7		55	01/27/07	02/02/07							12/16/05	14
OCOTILLO	1	MINOR	21		113	03/03/07	03/23/07							04/24/05	23
	2				113									11/17/06	
	GT1	Mini	7		55	04/02/07	04/08/07							04/28/06	12
	GT2	Mini	7		55	05/08/07	05/14/07							05/14/06	12
SAGUARO	1	MINOR	21		110	03/01/07	03/21/07							03/24/06	12
	2	MINOR	21		100			11/17/07	12/07/07					11/26/06	13
	GT1	Mini	5		55	03/29/07	04/02/07							05/01/05	
	GT2	Mini	5		55	01/24/07	01/28/07							02/23/06	
DOUGLAS	GT	Gen Insp	35		16	04/14/07	05/18/07							05/28/03	48
YUCCA	GT1	Comb	6		19	01/15/07	01/20/07							02/12/02	
	GT2	Comb	6		19	02/05/07	02/10/07							03/02/02	
	GT3				55									04/28/01	
	GT4				54									05/05/02	

SCHEDULE PME-10

2008 PLANNED OUTAGE SCHEDULE

PLANT	UNIT	O.H. TYPE	TOT. #DYS	ST/OT	CAPACITY	START	END	START	END	START	END	START	END	Month from Last O.H Last O/H	Months
PALO VERDE	1	REF	36		362			10/04/08	11/08/08					05/05/07	18
	2	REF	36		362	03/29/08	05/03/08							11/04/06	18
	3				363									11/03/07	14
NAVAJO	1				105									03/06/05	47
	2	MAJOR	29		105	03/01/08	03/29/08							04/02/07	12
	3				105									04/03/06	33
FOUR CORNERS	1	MAJOR	35		170	04/26/08	05/30/08							04/03/05	38
	2	Reliab.	8		170			11/09/08	11/16/08					03/16/07	22
	3				220									03/25/06	34
	4		10		111			10/03/08	10/12/08					05/15/07	20
	5	MAJOR	89		111	01/19/08	04/16/08							04/28/05	36
CHOLLA	1				110									04/27/07	20
	2	MINOR	21		245	02/09/08	02/29/08							05/15/05	34
	3				260									04/14/06	33
WEST PHOENIX	CC1	HGP	28		85	01/05/08	02/01/08							03/27/06	23
	CC2	Mini	7		85	04/21/08	04/27/08							04/06/07	21
	CC3	Mini	7		85	04/08/08	04/14/08							05/11/07	20
	GT1	Mini	7		55	04/15/08	04/21/08							12/05/06	17
	GT2	Mini	7		55	03/01/08	03/07/08							02/02/07	13
OCOTILLO	1				110									03/23/07	22
	2	MINOR	21		110			11/01/08	11/21/08					11/17/06	25
	GT1	HGP	56		55	01/05/08	02/29/08							04/08/07	11
	GT2	HGP	56		55	03/24/08	05/18/08							05/14/07	12
SAGUARO	1	MINOR	21		110	01/19/08	02/08/08							03/21/07	11
	2	MINOR	21		100			11/01/08	11/21/08					12/07/07	12
	GT1	Mini	5		55	03/09/08	03/13/08							05/01/05	45
	GT2	Mini	5		55	03/28/08	04/01/08							02/23/06	35
DOUGLAS	GT	Mini	5		16	04/22/08	04/26/08							05/18/07	20
YUCCA	GT1				19									02/12/02	84
	GT2				19									03/02/02	83
	GT3	Mini	3		55			10/20/08	10/22/08					04/28/01	93
	GT4				54									05/05/02	81

SCHEDULE PME-10

2009 PLANNED OUTAGE SCHEDULE

PLANT	UNIT	O.H. TYPE	TOT. #DYS	ST/OT	CAPACITY	START	END	START	END	START	END	START	END	Month from Last O.H Last O/H	Months
PALO VERDE	1				363									11/08/08	
	2	REF	36		363			10/03/09	11/07/09					05/03/08	18
	3	REF	36		365	04/04/09	05/09/09							11/03/07	18
NAVAJO	1				105									03/06/05	
	2				105									03/29/08	
	3	MAJOR	59		105	01/02/09	03/01/09							04/03/06	35
FOUR CORNERS	1	Reliab.	8		170			11/14/09	11/21/09					05/30/08	
	2				170									03/16/07	
	3	MAJOR	36		220	02/19/09	03/26/09							03/25/06	37
	4				111									05/15/07	
	5	Reliab.	9		111			10/24/09	11/01/09					04/16/08	
CHOLLA	1				110									04/27/07	
	2				245									02/29/08	
	3	MAJOR	42		260	03/21/09	05/01/09							04/14/06	37
WEST PHOENIX	CC1	Mini	7		85	02/12/09	02/18/09							02/01/08	
	CC2	Comb	28		85			11/03/09	11/30/09					04/06/07	32
	CC3	Comb	28		85	01/10/09	02/06/09							05/11/07	21
	GT1	Comb	56		55	01/17/09	03/13/09							04/21/08	11
	GT2	Comb	56		55	03/07/09	05/01/09							03/07/08	14
OCOTILLO	1	MINOR	21		113	02/26/09	03/18/09							03/23/07	24
	2				113									11/21/08	
	GT1	Mini	7		55	02/02/09	02/08/09							02/29/08	12
	GT2	Mini	7		55	04/30/09	05/06/09							05/18/08	12
SAGUARO	1	MINOR	21		110	02/21/09	03/13/09							02/08/08	13
	2	MINOR	21		100			10/31/09	11/20/09					11/21/08	12
	GT1	Mini	5		55	04/04/09	04/08/09							05/01/05	
	GT2	Mini	5		55	02/04/09	02/08/09							02/23/06	
DOUGLAS	GT	Mini	5		16	05/14/09	05/18/09							05/18/07	
YUCCA	GT1				19									02/12/02	
	GT2				19									03/02/02	
	GT3				55									04/28/01	
	GT4				54									05/05/02	

SCHEDULE PME-10

2010 PLANNED OUTAGE SCHEDULE

PLANT	UNIT	O.H. TYPE	TOT. #DYS	ST/OT	CAPACITY	START	END	START	END	START	END	START	END	Month from Last O.H Last O/H	Months
PALO VERDE	1	REF	36		363	04/03/10	05/08/10							11/08/08	18
	2				363									11/07/09	
	3	REF	36		365			10/02/10	11/06/10					05/09/09	18
NAVAJO	1				105									03/06/05	
	2	MINOR	32		105	02/01/10	03/04/10							03/29/08	24
	3				105									03/01/09	
FOUR CORNERS	1				170									05/30/08	
	2	MAJOR	35		170	04/03/10	05/07/10							03/16/07	38
	3	Reliab.	8		220			11/06/10	11/13/10					03/26/09	
	4	MAJOR	59		111	01/23/10	03/22/10							05/15/07	35
	5				111									04/16/08	
CHOLLA	1	MINOR	21		110	03/13/10	04/02/10							04/27/07	36
	2				245									02/29/08	
	3				260									05/01/09	
WEST PHOENIX	CC1	Comb	28		85	02/12/10	03/11/10							02/01/08	26
	CC2	Mini	7		85	01/10/10	01/16/10							11/30/09	
	CC3	Mini	7		85	04/24/10	04/30/10							02/06/09	
	GT1	Mini	7		55	01/26/10	02/01/10							03/13/09	11
	GT2	Mini	7		55	05/15/10	05/21/10							05/01/09	13
OCOTILLO	1				113									03/18/09	
	2	MINOR	21		113			11/29/10	12/19/10					11/21/08	25
	GT1	Mini	7		55	03/13/10	03/19/10							02/08/09	13
	GT2	Mini	7		55	04/21/10	04/27/10							05/06/09	12
SAGUARO	1	MINOR	21		110	02/21/10	03/13/10							03/13/09	12
	2	MINOR	21		100			11/29/10	12/19/10					11/20/09	13
	GT1	Mini	5		55	03/28/10	04/01/10							05/01/05	
	GT2	Mini	5		55	02/04/10	02/08/10							02/23/06	
DOUGLAS	GT	Mini	5		16	05/14/10	05/18/10							05/18/07	
YUCCA	GT1				19									02/12/02	
	GT2				19									03/02/02	
	GT3				55									04/28/01	
	GT4				54									05/05/02	

SCHEDULE PME-10

2011						PLANNED OUTAGE SCHEDULE						Month from Last O.	
PLANT	UNIT	O.H. TYPE	TOT. #DYS	ST/OT	CAPACITY	START	END	START	END	START	END	Last O/H	Months
PALO VERDE	1	REF	36		363			10/01/11	11/05/11			05/08/10	18
	2	REF	36		363	04/02/11	05/07/11					11/07/09	18
	3				365							11/06/10	
NAVAJO	1	MAJOR	57		105	03/04/11	04/29/11					03/06/05	75
	2				105							03/04/10	
	3				105							03/01/09	
FOUR CORNERS	1	MAJOR	35		170	04/16/11	05/20/11					05/30/08	36
	2	Reliab.	8		170			11/06/11	11/13/11			05/07/10	
	3				220							03/26/09	
	4	Reliab.	10		111			10/13/11	10/22/11			03/22/10	
	5	MINOR	18		111	02/12/11	03/01/11					04/16/08	35
CHOLLA	1				110							04/02/10	
	2	MINOR	21		245	03/21/11	04/10/11					02/29/08	38
	3				260							05/01/09	
WEST PHOENIX	CC1	Mini	7		85	04/09/11	04/15/11					03/11/10	
	CC2	Comb	28		85			10/24/11	11/20/11			11/30/09	24
	CC3	HGP	42		85	01/29/11	03/11/11					02/06/09	25
	GT1	Mini	7		55	01/03/11	01/09/11					02/01/10	11
	GT2	Mini	7		55	05/14/11	05/20/11					05/21/10	12
OCOTILLO	1	MINOR	21		113	02/26/11	03/18/11					03/18/09	24
	2				113							12/19/10	
	GT1	Mini	7		55	01/15/11	01/21/11					03/19/10	10
	GT2	Mini	7		55	04/30/11	05/06/11					04/27/10	12
SAGUARO	1	MINOR	21		110	02/26/11	03/18/11					03/13/10	12
	2	MINOR	21		100			11/28/11	12/18/11			12/19/10	12
	GT1	Mini	5		55	03/28/11	04/01/11					05/01/05	
	GT2	Mini	5		55	02/11/11	02/15/11					02/23/06	
DOUGLAS	GT	Mini	5		16	05/11/11	05/15/11					05/18/07	
YUCCA	GT1				19							02/12/02	
	GT2				19							03/02/02	
	GT3	MAJOR	16		55	04/09/11	04/24/11					04/28/01	122
	GT4				54							05/05/02	

SCHEDULE PME-10

2012 PLANNED OUTAGE SCHEDULE

PLANT	UNIT	O.H. TYPE	TOT. #DYS	ST/OT	CAPACITY	START	END	START	END	START	END	START	END	Month from Last O.H Last O/H	Months
PALO VERDE	1				362									11/05/11	14
	2	REF	36		362			09/29/12	11/03/12					05/07/11	18
	3	REF	36		363	03/31/12	05/05/12							11/06/10	18
NAVAJO	1				105									04/29/11	20
	2				105									03/04/10	34
	3	MINOR	31		105	02/03/12	03/04/12							03/01/09	37
FOUR CORNERS	1	RELIAB.	9		170			11/07/12	11/15/12					05/20/11	20
	2				170									05/07/10	32
	3	MAJOR	35		220	02/21/12	03/26/12							03/26/09	37
	4				111									03/22/10	34
	5	RELIAB.	9		111			10/06/12	10/14/12					03/01/11	22
CHOLLA	1				110									04/02/10	33
	2				245									04/10/11	21
	3	MAJOR	42		260	03/05/12	04/15/12							05/01/09	36
WEST PHOENIX	CC1	HGP	42		85	01/16/12	02/26/12							03/11/10	24
	CC2	Mini	7		85	04/04/12	04/10/12							11/20/11	14
	CC3	Mini	7		85	04/21/12	04/27/12							03/11/11	22
	GT1	Mini	7		55	01/03/12	01/09/12							01/09/11	12
	GT2	Mini	7		55	05/19/12	05/25/12							05/20/11	12
OCOTILLO	1				110									03/18/11	22
	2	MINOR	21		110	11/26/12	12/16/12							12/19/10	24
	GT1	Mini	7		55	04/14/12	04/20/12							01/21/11	15
	GT2	Mini	7		55	02/27/12	03/04/12							05/06/11	10
SAGUARO	1	MINOR	21		110	01/24/12	02/13/12							03/18/11	11
	2	MINOR	21		100	10/27/12	11/16/12							12/18/11	11
	GT1	Mini	5		55	02/25/12	02/29/12							05/01/05	93
	GT2	Mini	5		55	03/26/12	03/30/12							02/23/06	83
DOUGLAS	GT	Mini	5		16	05/05/12	05/09/12							05/18/07	68
YUCCA	GT1	Mini	3		19			10/01/12	10/03/12					02/12/02	133
	GT2	Mini	3		19			10/08/12	10/10/12					03/02/02	132
	GT3				55									04/24/11	21
	GT4				54									05/05/02	130

SCHEDULE PME-11
HISTORICAL AND PROJECTED EFFECTIVE FORCED OUTAGE RATES
(%)

Unit	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Palo Verde 1	5	10	4	3	6	5	3	3	5	1	0	3	3	3	3	3	3	3	3	3	3	3
Palo Verde 2	5	5	6	7	1	2	4	3	1	3	1	3	3	3	3	3	3	3	3	3	3	3
Palo Verde 3	14	5	6	3	1	2	4	3	1	2	4	3	3	3	3	3	3	3	3	3	3	3
Four Corners 1	12	8	13	8	9	4	9	13	9	9	14	9	8	9	7	7	8	7	7	8	8	8
Four Corners 2	9	7	10	9	7	6	6	10	18	8	10	9	9	7	7	8	7	7	8	7	7	7
Four Corners 3	11	12	10	8	6	10	15	15	9	12	8	13	11	11	12	10	9	10	9	9	9	9
Four Corners 4	7	7	8	7	6	10	5	12	12	10	11	10	10	10	10	9	9	9	9	9	9	9
Four Corners 5	12	5	5	11	4	5	32	13	10	9	15	10	10	10	10	10	10	9	9	9	9	9
Navajo 1	4	3	8	2	6	2	4	3	1	2	6	5	5	5	5	5	5	5	5	5	5	5
Navajo 2	5	6	4	4	3	7	13	5	3	3	1	6	6	6	6	6	6	6	6	6	6	6
Navajo 3	5	6	5	3	2	4	6	2	3	3	4	5	5	5	5	5	5	5	5	5	5	5
Cholla 1	4	2	1	6	1	4	8	6	8	11	21	6	7	6	6	7	6	6	7	6	6	6
Cholla 2	3	6	2	4	1	4	3	10	18	7	13	7	6	7	6	6	7	6	6	7	7	7
Cholla 3	6	2	2	2	3	3	2	2	6	7	6	6	6	5	6	6	5	6	6	5	5	5
W. Phx. CC 1	6	55	3	10	5	0	1	4	8	3	10	5	6	7	7	7	7	7	8	8	8	8
W. Phx. CC 2	2	1	5	1	1	1	1	14	3	13	4	5	6	7	7	7	7	7	8	8	8	8
W. Phx. CC 3	1	11	30	1	1	0	1	1	4	0	6	5	6	7	7	7	7	7	8	8	8	8
Ocotillo Steam 1	1	0	0	0	32	11	8	0	5	3	6	6	6	6	6	6	6	6	6	6	6	6
Ocotillo Steam 2	2	15	1	1	12	11	14	12	2	6	9	6	6	6	6	6	6	6	6	6	6	6
Saguaro Steam 1	8	4	0	2	6	10	1	0	3	11	11	7	7	7	7	7	7	7	7	7	7	7
Saguaro Steam 2	0	0	0	4	44	35	2	39	1	2	9	12	12	9	7	7	7	7	7	7	7	7
W. Phx CT 1	4	2	24	10	12	3	20	29	29	8	5	10	11	12	12	12	12	12	12	12	12	12
W. Phx CT 2	29	5	24	30	96	17	2	15	14	6	11	10	11	12	12	12	12	12	12	12	12	12
Ocotillo CT 1	69	0	78	26	66	30	5	90	87	30	7	10	11	12	12	12	12	12	12	12	12	12
Ocotillo CT 2	74	5	64	20	1	82	23	20	51	26	8	10	11	12	12	12	12	12	12	12	12	12
Saguaro CT 1	100	97	10	5	8	31	32	37	0	19	12	10	11	12	12	12	12	12	12	12	12	12
Saguaro CT 2	11	6	28	12	24	10	11	18	10	16	11	10	11	12	12	12	12	12	12	12	12	12
Yucca 1	0	0	0	0	0	0	0	0	12	0	1	10	10	10	10	10	10	10	10	10	10	10
Yucca 2	8	0	0	0	0	0	0	0	3	0	1	10	10	10	10	10	10	10	10	10	10	10
Yucca 3	2	1	3	0	0	13	11	1	16	3	3	10	10	10	10	10	10	10	10	10	10	10
Yucca 4	0	14	0	0	0	2	0	62	13	8	20	10	10	10	10	10	10	10	10	10	10	10
Douglas	73	26	34	99	0	13	47	0	40	5	7	10	10	10	10	10	10	10	10	10	10	10

Schedule PME-12

Historical Peak Demands
Total APS System and APS Metro Phoenix Demand

	1996	1997	1998	1999	2000	2001	2002	Average
Total System Peak	4,575	4,609	5,072	4,935	5,479	5,687	5,803	
Wholesale Loads No Longer Served by System Resources	254	249	248	263	295	322	312	
Large Mining Loads	173	176	174	85	94	38	35	
System Peak excluding Lines 2 and 3	4,148	4,184	4,650	4,587	5,090	5,327	5,456	
Metro Phoenix Peak Demand	3,162	3,162	3,419	3,406	3,698	4,218	4,206	
Metro Demand as Share of Total Demand	76.2%	75.6%	73.5%	74.3%	72.7%	79.2%	77.1%	75.5%

SCHEDULE PME-13
POTENTIAL ECONOMY ENERGY PURCHASES

	With Current Market Prices			Electric Prices 10% Higher		Electric Prices 10% Lower	
Year	Economic Purchase Amount (GWH)	Average Palo Verde On-Peak Electric Price ($/MWH) [1]	Average San Juan Basin Natural Gas Price ($/MMBTU) [1]	Economic Purchase Amount (GWH)	Percent Change	Economic Purchase Amount (GWH)	Percent Change
2003	3,705	39.42	3.60	3,122	-15.7%	4,418	19.2%
2004	4,033	40.13	3.50	3,465	-14.1%	4,699	16.5%
2005	6,695	40.25	3.36	5,795	-13.4%	7,673	14.6%
2006	6,948	40.53	3.35	6,032	-13.2%	8,025	15.5%
2007	8,320	40.77	3.38	7,341	-11.8%	9,296	11.7%
2008	6,785	41.79	3.46	6,095	-10.2%	7,591	11.9%
2009	7,964	42.83	3.55	7,274	-8.7%	8,787	10.3%
2010	9,136	43.90	3.64	8,427	-7.8%	9,911	8.5%
2011	10,167	45.00	3.73	9,428	-7.3%	10,951	7.7%
2012	11,099	46.13	3.82	10,300	-7.2%	11,871	7.0%

[1] Power and natural gas prices were determined from market quotes through 2007 and escalated by 2.5% per year thereafter.

EXHIBIT
APS-2
admitted

DIRECT TESTIMONY OF THOMAS J. CARLSON

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

November 4, 2002

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DIRECT TESTIMONY OF THOMAS J. CARLSON
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000A-02-0051, et al.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

My name is Thomas J. Carlson. I am the Head of Trading for Arizona Public Service Company ("APS" or "Company"). In that role, I am responsible for procuring purchase power and natural gas for APS, and also the marketing of surplus APS generation and natural gas.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science degree from the University of South Dakota in 1977. Prior to coming to APS, I worked in marketing and market research positions with the airline and motor transportation industries. I held a similar position when I joined APS in 1988. In 1992, I began in the gas trading and fuel management area of the Company, rising to Director of Generation Fuel Procurement for APS. When trading functions were transferred to Pinnacle West Marketing & Trading ("M&T") after the 1999 APS Settlement Agreement with the Commission, and in anticipation of generation divestiture, I became an M&T employee. With the Commission's decision to reverse course on divestiture in Decision No. 65154 (September 10, 2002), I was transferred back to APS and assumed my current duties.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony will describe a proposed APS procurement plan for what APS witness Pete Ewen has determined to be the Company's reliability-driven

capacity and energy needs that cannot be met by the Company's existing generation and purchase power contracts, which I believe is the subject of Track B. I then discuss the potential acquisition through a separate but parallel process of what are presently classified as "reliability must-run" (RMR") needs of the Company. I also address competitive short-term purchases for both economic and reliability reasons that would fall outside the broader Track B procurement.

I say "proposed" procurement plan not just because the Commission may require a different plan, but also to emphasize the evolving nature of the procurement process itself. APS has already made significant changes to the procurement proposal outlined in its July 2002 filing in the proceeding (and discussed during the workshops). No doubt further refinements will occur between now and the actual 2003 Track B procurement as a result of these proceedings and continued dialogue with Staff and other parties. However, our goals, and I believe those expressed by Commission Staff in its final report of October 25, 2002 ("Staff Report"), are unchanged—to acquire the unmet needs of APS customers in an economic and reliable manner through a fair and open process.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR DIRECT TESTIMONY?

A. APS's proposed plan calls for a multi-layered procurement effort. The first part will be a request for proposals ("RFP") to be issued no later than the end of February 2003 seeking three basic products:

(1) capacity only (the right to capacity at a fixed or floating price

with no obligation to take energy) from a specific generator or group of generators;

(2) capacity plus some minimum level of energy taken from a specific generator or group of generators during specified months and hours; and

(3) physical "call" options having the same general characteristics as the first product except physical call options are usually exercised at specific fixed or "strike" prices.

Contract lengths will be as short as one quarter and as long as four years. The percent mix of the listed product types that APS will procure in the initial RFP will be determined by then-existing market conditions, credit quality, deliverability, and other relevant factors.

The intent is to request bids for 100% of the unmet reliability needs for 2003, 2004, 2005, and 2006 through this process. But APS may elect to acquire more or less than these amounts during any year or in total depending on the actual responses to this RFP and then existing or forecasted market conditions. APS could also reject all the bids if they do not satisfy the Company's needs or are unreasonable in terms of price, reliability, etc. To the extent that APS unmet needs cannot be economically and reliably met through the initial RFP, or as stated above, any part of such need goes "uncovered" in the initial RFP solicitation, those uncontracted and still unmet reliability needs would be addressed either by short-term market purchases (for 2003) or in a subsequent formal procurement. Such procurement would likely take place in early 2004,

depending on the results of the RFP and may in 2004 switch to a descending clock auction process, which remains a long-term procurement option .

RMR needs from non-APS resources will be handled somewhat differently. APS will separately but concurrently solicit proposals for such needs. If a proposal is received that can demonstrate to the Company's satisfaction deliverability on reasonable terms within the Phoenix load constraint, APS will consider it on the same price, credit–worthiness, reliability of both supply and delivery, etc., criteria as will be applied to the more general Track B solicitation.

Finally, short-term and economy purchases (e.g., balance of month, day ahead, and real time) would be made much as they are today, as is recommended in the Staff Report. Maximum flexibility in making these purchases has benefited and should continue to benefit APS customers. Short-term purchases have been a critical part of prudent power procurement for many decades and are necessary to match a changing market with changing load requirements. APS is studying an expanded role for independent brokers and/or electronic trading platforms to determine whether these or other steps are necessary for affiliate transactions, but will not unnecessarily burden the procurement process with red tape and prescriptive rules at the expense of customer benefits.

A last part of my testimony, although intertwined with the rest , is a discussion of risk management. In other words, how will APS manage the risks of this Commission-ordered procurement to best protect its customers? This encompasses both the traditional risks of commodity availability and commodity price, and also the relatively new world of counter-party risk. It also addresses the risks newly created by the Track B process itself. Although it would be

inappropriate to discuss in any detail APS risk management tools in a public forum involving prospective bidders, it is today evident that counter-party risk is a dominant consideration in determining the length of power agreements in the current financial climate. Establishing strong credit requirements at the outset of the contract is a first line of defense. Periodic collateral call provisions are the next layer of credit protection, although they are of limited value when needed most. In a world where strong A-rated companies can fall all the way to junk status in a year or less, only resource diversity and/or shorter term transactions or some combination can provide that final layer of protection for our customers.

III. THE RFP

Q. WHY IS APS NOW PROPOSING A SIMPLIFIED RFP PROCESS FOR THE 2003 PROCUREMENT INSTEAD OF THE AUCTION PROCESS DISCUSSED IN ITS JULY 2002 COMMENTS AND DURING MUCH OF THE WORKSHOP?

A. First of all, the July 2002 filing describing a descending clock auction process was intended to be a framework for further discussion, not a "take it or leave it" proposal. APS has been listening to the proponents of RFPs throughout the workshops and has taken some of their comments to heart. Although we are still concerned that the often highly subjective nature of the RFP process could lead to higher costs and more controversy, we propose to reduce that subjectivity by more narrowly defining the products to be solicited and by bidder pre-qualification.

Second, the nature of our needs has changed since July and even since the early workshops in Track B. At that time, the Company fully anticipated that it would

be divesting all of its generation, with or without the proposed purchase power agreement ("Proposed PPA") submitted to the Commission in the Fall of 2001. In either event, APS needs would have been for a more standard, higher load factor energy product. With the requirement that APS keep its generation and competitively procure the needs that cannot be met from such resources, this means that the Company needs significantly more capacity than energy, and generally requires both only during limited times of the year and times of day. Dispatchable capacity and energy products, or their equivalent, become far more attractive, as do capacity reserves without any associated energy.

Third, there is a timing element at work here. Back in July, APS indicated the need to begin the acquisition process some five to six months before delivery. This means a significant acceleration of the Staff-proposed schedule even assuming a new proposed delivery date beginning with the third quarter ("Q3") of 2003. Formal auctions require considerable up front lead-time for retaining an outside auction administrator, for software development, and for testing and training on the part both of prospective bidders and utility personnel.

Fourth, the process suggested by Staff in the Staff Report is not particularly conducive to an auction. Auctions work best when there is up-front agreement on the process and the understanding that because regulators have pre-approved the structure of the auction, they will accept the results of the auction by providing adequate assurances of full cost recovery by the purchasing utility. Alternatively, the utility can be given full authority to conduct an auction free from contemporaneous direct regulatory involvement, excepting for the usual

prudence review in subsequent rate proceedings. The Staff Report's proposal does neither.

This does not mean that APS has given up on the auction process. Indeed, if permitted by the Commission as a result of this Track B proceeding, the Company is very much interested in exploring such an auction process for its 2004 procurement of all or portions of any remaining unmet need for years after 2003 that is not acquired through the 2003 RFP.

Q. COULD YOU PLEASE DESCRIBE THE PRODUCTS APS WOULD SEEK IN THIS RFP?

A. Yes. As I mentioned earlier, our most critical need in the next several years is for capacity. We also require limited amounts of energy during peak periods. Therefore we will seek bids in minimum 25 MW blocks for just capacity and also for similar blocks of capacity with minimum energy purchases during the months of July through September of each year from the hours of HE0700 through HE2200, seven days a week. APS will require capacity-only offers to be firm with reserves. Capacity with energy offers may be either firm or contingent during the months and hours described above. In the case of the latter, the prospective seller may either firm up the proposal with its own reserves or APS will add the expected cost of reserves to the offer to make it comparable with firm power.

In addition to firm blocks of energy, APS will seek physical call options in the RFP process. Physical call options are rights to purchase a specific amount of capacity and energy at a predetermined "strike" price for a specified period of time. For example, if APS owned a $50/MW daily physical call option on

75MW of "6 x 16" power for July through September 2003, APS would have a daily option to purchase for the following day power at the agreed upon strike price of $50/MWH for the 16 hour on-peak period. The power provided is physically firm and not unit contingent. Although physical call options do exist that are dispatchable (that is, the buyer does not have to take the entire block of energy at the strike price, but rather only what is actually needed), these carry a premium for dispatchability, and the market is thinner than for the more standard "6 x 16" product.

Q. AT WHAT DELIVERY POINTS WILL APS ACCEPT DELIVERY OF POWER PROCURED UNDER THIS RFP?

A. That will be finalized when the deliverability analysis discussed on page 15 of the Staff Report is completed. However, it appears the following delivery points, subject to existing or forecast constraints, can be utilized: Palo Verde, Navajo, Mead, North Gila, Liberty, Pinnacle Peak, Westwing, Jojoba, Four Corners, Gila Bend, and Kyrene. And, as I discussed earlier, entities that can demonstrate deliverability to a suitable point of delivery within the Phoenix load constraint may also bid for non-APS RMR needs.

Q. WILL THE COMPANY BE SEEKING ANY ANCILLARY SERVICES IN THE 2003 RFP?

A. Other than reserves, the answer is no. APS will provide ancillary services. This may change in the future as either a viable market for such services is developed in Arizona or because WestConnect or a similar entity assumes the role of ancillary service provider within the APS service territory.

Q. WHAT IS THE PROCUREMENT HORIZON FOR THE 2003 RFP AS YOU HAVE DESCRIBED IT IN YOUR TESTIMONY?

A. For both the reasons described in our July 2002 filing and the present credit crisis in the industry; we are looking at up to a four-year procurement. That is, we will accept proposals for as short as one quarter and up to four years.

As noted last July, the establishment and operation of a RTO may expand the number of potential bidders in the Arizona market by facilitating access to Arizona by out of state and even out of region suppliers. FERC's proposed Standard Market Design is another wild card that may affect both the price and availability of transmission for one set of potential bidders *vis-a-vis* others.

Counter-party credit problems, which I discuss later in my testimony, have dramatically affected the term of power acquisition transactions. The credit quality of its sellers is obviously important to the buyer in case of seller default. But that does not mean you only assure yourself of such credit quality after a default has occurred. That would be like worrying about fire insurance after the fire has started. Moreover, it is not just the seller's credit when the deal is inked that must concern the buyer, but what that credit will be during the term of the transaction. Historically, most deals, whether multi-year or day-ahead, were with other utilities. Even with the advent of merchant traders and producers, most had credit equal to or greater than some utilities. Times have dramatically changed in the past 24 months. Many counter-parties are experiencing severe credit problems. Credit downgrades have been frequent and widespread. Some counter-parties such as Enron have disappeared altogether. As such, APS has established credit criteria that allow transactions to occur while minimizing the reliability and financial risk to APS and its customers. These criteria determine

whether APS can, for example, do a multi-year deal for a particular seller, while another may be extended credit only for day-ahead sales.

Q. HOW MUCH CAPACITY AND ENERGY WOULD APS SOLICIT FOR THE YEARS 2003 THROUGH 2006 VIA THIS PROPOSED RFP?

A. All the unmet capacity and energy needs shown on Mr. Ewen's Schedule PME-1. As indicated in my SUMMARY, the non-APS RMR amounts shown for these years would be solicited simultaneously by a separate RFP. In the case of the latter, the prospective seller will have to demonstrate to the Company's satisfaction that it has or can acquire firm transmission rights over non-APS transmission to a delivery point within the Phoenix load constraint or that it owns or controls generation within that constrained area.

Although APS will accept proposals for all or a portion of the entire estimated unmet reliability needs for these years, that does not necessarily mean APS will execute contracts covering 100% of such needs. Consistent with the Staff Report, APS would reserve the right to reject any and all offers, even for 2003, if they are unacceptable in terms of price and reliability. See Staff Report at 16. This will be discussed more in the RISK MANAGEMENT section of my testimony.

Q. WHAT WILL YOU DO IF YOU DO NOT ACCEPT SUFFICIENT BIDS TO COVER ALL YOU UNMET NEEDS FOR 2004 THROUGH 2006?

A. Such needs would be addressed in a subsequent competitive procurement or procurements. Also, as a new load and energy forecast is made in 2003, the amount of forecasted unmet reliability needs could increase or decrease for these subsequent years. In any event, APS would likely either repeat the RFP process or move to an auction such as was described in the July filing using, however,

the energy products then appropriate for APS, which are likely to remain capacity intensive and energy light for the immediately foreseeable future. As is indicated in the Staff Report at page 40, we would need to review how the 2003 solicitation worked before finalizing plans for subsequent competitive solicitations.

Q. WHAT WOULD APS DO IF THERE ARE NOT ENOUGH ACCEPTABLE OFFERS FOR EVEN THE COMPANY'S 2003 UNMET RELIABILITY NEEDS?

A. Given the short time between the end of this Track B proceeding and Q3 of 2003, I do not even like to think of that possibility. However, should that happen, the solicitation would fail. See Staff Report at 33. In such a situation, APS would work closely with Staff, the independent monitor, and bidders to determine why the solicitation had failed and whether a second formal solicitation was possible for 2003. If not, APS would propose to use the same process as it would otherwise use for short-term purchases from the competitive wholesale market—a process discussed later in my testimony.

Q. HAS APS DEVELOPED ALL THE DETAILS SURROUNDING THE PROPOSED RFP?

A. No, but APS intends to follow the description of solicitation materials discussed in the Staff Report beginning on page 17. Thus, most of the details as to pre-qualification, form of contract, the time for responses to the RFP and the time bids will remain open, the handling of preferred versus secondary delivery points for purposes of bid evaluation, bid fees, etc., will be part of the bid package. The most recent Procedural Order in this proceeding greatly accelerated the time for submitting even this level of detail concerning the Company's procurement plan as compared to anything that had been discussed

in the workshops or contained within either the draft or final Staff Report. APS has attempted to comply with this unexpected filing mandate to the best of its ability within the time permitted.

IV. SHORT-TERM PROCUREMENTS

Q. WILL EITHER THE 2003 RFP OR THE POSSIBLE AUCTION IN 2004 AND BEYOND, IF SUCCESSFUL, RESULT IN THE ACQUISITION OF THE PRECISE AMOUNT OF ALL APS PURCHASE POWER UNMET NEEDS FOR 2003 THROUGH 2006?

A. Only under the most implausibly fortuitous circumstances would this be the case. We are talking here about forecasted unmet needs, and the one thing we all know about forecasts is that they will be "off" by some amount. The weather will be hotter or cooler than forecast. Population influx will be more or less than forecast. APS generating units will experience more or less forced outages. Planned outages will be shortened, lengthened, postponed or accelerated. Perhaps the biggest unknown is the degree to which retail access cuts into our forecasted demand and energy.

I could go on, but I think I have made my point. APS will continuously make short-term purchases to cover short positions and sell existing resources to liquidate long positions. Even when resources are acquired well in advance, there is a constant re-evaluation of their continued appropriateness from both a need and cost perspective. APS also routinely makes economy purchases (i.e., purchases of energy that are made when it is less expensive to buy short-term power from the market than it would be to continue generating power using APS-owned generation) on a balance of month, day-ahead, and/or real-time basis. None of these purchases can be reasonably planned years in advance and even the ability to predict them given a specified load forecast involves

numerous unknown variables. And as is the case with those resources acquired to meet capacity and energy reliability needs, these short-term economy purchases are continually managed right up to the moment of expected use to produce the best results for our customers.

Q. HOW WOULD APS GO ABOUT MAKING SUCH PURCHASES?

A. As indicated in the Staff Report, APS would continue to make such purchases in the ordinary course of business as it does today. See Staff Report at 4. In the specific case of economic purchases, these are cost-driven. Presently, most of our load demand is met with baseload nuclear and coal fired generation. For APS and much of the West, the marginal generating resource is gas-fired. APS can either purchase gas to run in one of its own units or purchase gas-fired generation. If APS can generate electricity at a lower cost than the then anticipated market price of power, we normally secure forward gas (gas purchased today for delivery at some future date) to meet that anticipated economy energy need. Conversely, if forward purchase power (power purchased today for delivery at some future date) costs were lower, we would normally secure forward power and reduce forward gas purchases. Even after this initial decision is made (gas versus purchase power), we continually monitor market conditions, and our initial gas or power position may be liquidated and replaced with its alternative many times until the time of anticipated use by APS to serve customers.

At present, APS secures economy and other short-term purchases through the following process. Forward markets for energy are presented to APS daily in a myriad of ways, including direct contact with counter-parties, use of brokers,

and access with online trading systems. Each day, APS reviews its current position and the value of the forward energy market and determines whether or not to procure economy or other short-term energy. Factors such as weather, load, credit, plant outages, natural gas prices (spot and future), and product type all impact the procurement process. Economy purchases are driven primarily by price and credit. Other short term and real time purchases are driven more by price and reliability.

A few new procedures are being studied and may be added regarding affiliate transactions. APS is looking at the practicality of securing short-term purchases (30 days or less) from independent brokers and the use of "blind" (i.e., the identity of specific pre-qualified sellers in not known to the buyer) electronic trading platforms such as ICE and Bloomberg. APS already uses such devices for some short-term purchases today and will consider expanding their use or consider yet other process changes for affiliate transactions if they increase the efficiency and transparency of its short-term purchasing practices and if they do not compromise the ultimate goal of producing maximum consumer benefits. And, in situations when there are unanticipated and immediate threats to reliability, APS will do what is necessary when it is necessary to address that threat.

V. RISK MANAGEMENT

Q. PLEASE IDENTIFY THE TYPES OF RISK WHICH APS AND ITS CUSTOMERS ARE FACED WITH BECAUSE OF THIS TRACK B PROCUREMENT?

A. Any restriction on the Company's ability to procure its power needs limits its flexibility and increases risk. For example, waiting until March of 2003 to

acquire Q3 of 2003 reliability needs increases price risk since windows of opportunity between now and March would be foreclosed by this process. APS is addressing this risk by entering into appropriate hedges this fall and winter. Such hedges have historically been used and will continue to be used to mitigate price and commodity risk. This will not reduce the amounts of capacity and energy potentially secured through the RFP, but it will protect the Company and its customers from price increases between now and April 2003, Predefining the products to be procured is necessary for an manageable RFP process given schedule envisioned by the Staff Report, but it may increase the risk that a different but adaptable product might have produced a lower cost. Dictating that a specified amount of the defined products must be acquired increases both price risk (if sellers know you have to buy, the price will be higher) and volume risk (purchased too much or too little). Being required to acquire the product in a single solicitation carries with it the same increased risk. Perhaps the largest risk is that the process will compromise the Company's ability to insist on credit-worthiness both at the outset and through the term of any purchase agreement. I would also add that some risks in the Track B process outlined in the Staff report likewise affect potential sellers, and they will expect additional compensation to assume these risks.

Q. WHY NOT COMMIT TO BUYING ALL YOUR FORECAST NEEDS FOR 2003 THROUGH 2006 THROUGH THE PROPOSED 2003 RFP?

A. It would be imprudent to make such a commitment in advance of the bidding, though it may not be imprudent to actually acquire all such needs. My goal is to meet APS customer needs for reliable and economic power as efficiently as possible—period. I cannot fulfill that mission unless I have the flexibility to say "no." As long as I have the power to say no, I have options, which means I have

leverage in the negotiation with suppliers to serve those APS customer needs. If I am required to make a specific level of purchases regardless of price or credit-worthiness, either current or forecast, I lose that power and leverage, and customers get either more costly or less reliable service or both.

Q. WITHOUT GIVING OUT ANY TRADE SECRETS, HOW DO YOU GO ABOUT PUTTING TOGETHER A BALANCED PORTFOLIO OF PRODUCTS BOTH AS TO TERM AND PRICE?

A. You study the market (both present and future), weigh credit considerations, evaluate regulatory risk, and factor in the inherent uncertainty of any load forecast. There is no magic formula, and if there were, I would not disclose it to potential suppliers in this public forum. That would be the same as giving up my power to say no, which is something no prudent buyer would ever surrender. But I can say that I will assemble the best portfolio of the three product types solicited, with diversity of terms (lengths) and of the various resources standing behind those products, as is possible given the bids received, the nature of our unmet needs, then-prevailing market conditions and other relevant factors. The goal is to bring incremental reliability and cost value to APS customers. And in doing so, I am mindful that the best hedge our customers have in this entire process in the broad portfolio of the Company's existing capacity and energy resources, a hedge I intend to use to maximize that value.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. In my testimony, I have introduced the Company's current thinking on Track B procurement. It is largely premised both on Mr. Ewen's needs assessment and the Staff Report. Although a riskier and potentially more costly

proposal than the Company's existing procurement strategy, it is consistent with the Commission's orders to date and still preserves significant flexibility, the most important aspect of which is the ability to reject any or all bids received as a result of this process.

Q. DOES THAT CONCLUDE YOUR PREFILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, it does.

EXHIBIT

APS-3

Admitted

DIRECT TESTIMONY OF STEVEN M. WHEELER

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

November 12, 2002

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DIRECT TESTIMONY OF STEVEN M. WHEELER ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

(Docket No. E-00000A-02-0051, et al.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

My name is Steven M. Wheeler. I am Senior Vice President, Regulation, System Planning and Operations for Arizona Public Service Company ("APS" or "Company"). In that role, I am responsible for all regulatory matters affecting the Company before the Arizona Corporation Commission ("Commission") and the Federal Energy Regulatory Commission ("FERC"). I am further responsible for the planning and operation of the APS transmission system and for the Company's resource planning in general.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelors degree from Princeton University in 1971. I graduated from Cornell University School of Law in 1974. From 1974 until 2001, I was an attorney with Snell & Wilmer LLP in Phoenix, Arizona, involved in general business, real estate, environmental and public utility issues. During my 27 years at the firm, I represented APS and other public utilities in numerous state and FERC proceedings involving utility rate and service matters, generation and transmission siting, electric industry restructuring, resource planning and prudence reviews.

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

A. My testimony will respond to certain sections of the Commission's Utilities

Division Staff ("Staff") Report in this proceeding dated October 25, 2002 ("Staff Report"). I also suggest certain modifications to that Staff Report.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR DIRECT TESTIMONY?

It is the Company's understanding that Staff wishes the Commission to formally adopt and approve the Staff Report. APS fully endorses the stated goals of the Staff Report and supports much of the substance. Moreover, the Company appreciates Staff's willingness to assist in the Track B procurement process through active involvement and advice. But as is often the case, the devil is in the details.

I am concerned both about the practicality of the Staff Report's proposed timeline for this Track B procurement and that certain substantive proposals in the Staff Report may prove counterproductive and could frustrate the goals of a workable competitive procurement. Either concern could lead to higher power costs for APS and its customers. Therefore, I ask the Staff and the Commission to consider modifying the Staff Report in a manner that will (1) encourage more robust participation by sellers in the Track B procurement process; (2) reduce the regulatory uncertainty facing buyers, including APS, from this process; and (3) improve the objectivity and transparency of the Track B procurement process. These modifications include the following:

- Commission approval of the results of the Track B procurement
- Commission assurance of full cost recovery of power acquired through any Commission-mandated procurement
- Refinement of the role of both Staff and the independent

monitor during and after the Track B solicitation to bring finality to the process

- Modification of the "price to beat," both in concept and in application
- More careful and precise definition of the actual scope and objectives of the required "Standards of Conduct" to avoid unintended counterproductive consequences
- Assurance by the Commission that confidential information will indeed be kept confidential through the bidding process

III. THE TENSION BETWEEN GOALS AND PROCESS

Q. DOES APS AGREE WITH THE STATED GOALS OF THE STAFF REPORT?

A. Absolutely. At pages 1 and 3 of the Staff Report, Staff endorses a transparent, open, flexible and understandable process that seeks reliable power at reasonable prices. Although the Staff Report goes on to make other statements concerning how it believes its goals can be accomplished, the overall objectives of transparency and consumer benefit are something APS can heartily endorse.

I also wish to thank Staff for its use of an open collaborative process in developing the Staff Report. I believe that Staff listened to our comments and concerns even if they did not always agree with or adopt APS' position in the final Staff Report.

Q. COULD YOU THEN PLEASE EXPLAIN WHY YOU ARE CONCERNED THAT THE STAFF'S PROPOSED TRACK B SCHEDULE AND PROCESS MIGHT BE IN CONFLICT WITH THIS OVERRIDING GOAL OF TRANSPARENCY AND CUSTOMER BENEFIT?

A. There are several aspects of the Staff proposal that may not contribute to a "transparent process." Indeed, they could add significant uncertainty for both buyers and sellers—uncertainty that could discourage at least some potential

sellers and add to the costs of procurement, thus thwarting an important part of Staff's overarching objective—reasonable costs for customers.

Specifically, I am first referring to the absence of clear Commission, or even Staff, acceptance of the results of a power procurement process that Staff designed and that will be closely overseen by Staff and its independent monitor. This creates great uncertainty as to the eventual recoverability of costs incurred by APS through a process that represents such a significant change from its current procurement strategy—something of concern to both APS and potential sellers of power to APS.

I am also concerned about the "price to beat" concept. It is unclear how such a "price to beat" will be developed or how it will be applied. To the extent it will represent some mysterious "black box" number that will surface only after purchase power agreements will be executed, "price to beat" contributes to uncertainty rather than transparency.

The role of Staff and the independent monitor during the solicitation appear to contemplate numerous opportunities for the bidders to attempt to negotiate "around" the utility to influence the process or suggest new procurement protocols to enhance their position at either the expense of other bidders or the buyer, or both. See, e.g., Staff Report at 8, lines 11 through 15; and 9, lines 11 through 14. I suggest that all discussions should be directly between bidders and the utility, with the participation of Staff and/or the independent monitor.

The apparent opportunity for significant post-bidding "negotiation" of issues that should be resolved during the pre-solicitation process is also not helpful to the cause of transparency. See Staff Report at 23, lines 26 through 28. It may also prove impractical. The timeline shown on page 29 of the Staff Report allows barely two weeks for post-bid evaluation and post-bid negotiation. If this process requires evaluation of numerous non-conforming bids suggesting alternative credit criteria, alternative products, or alternative transmission delivery points, there is simply insufficient time to do so in a manner that effectively protects the interests of APS customers. Knowing that the utility may be pressured to make a hurried analysis and decision, bidders may be tempted to engage is bid gaming. They could do so by confusing the process with a myriad of non-conforming bids and other variations in hopes of creating an overly complex and subjective process that could translate into higher customer costs.

Q. DO YOU HAVE ANY OTHER COMMENTS ABOUT THE STAFF REPORT'S PROPOSED TIMELINE?

A. As I discussed above, the post-bidding timeline is extremely short. In addition to the two-week window for evaluation and negotiation, which is further impacted by the requirement for extensive monitor and Staff involvement in this process, there is the need to await the monitor's report and any Commission approval of such report before any contracts can actually be executed. And if one or more of the unsuccessful bidders challenges the monitor's report, or if the Commission otherwise decides to review the solicitation process (see Staff Report at 12, lines 5 through 10), contract execution could be even more significantly delayed.

As it is, the schedule contemplates awarding contracts for reliability needs at the end of April for deliveries that will start barely two months later. Mr. Carlson,

head of APS Procurement, tells me that this is simply too close for comfort. Many otherwise interested bidders may have already sold forward their capacity for 2003 by this time, or market prices may have turned unexpectedly higher. APS would normally have secured or significantly hedged its third quarter of 2003 supplies well in advance of the beginning of the second quarter. That is why APS had proposed last July a 2003 bid based on a plan to be approved and in place by September 2002. That proposal was rendered moot by the Commission's Track A order.

IV. ROLE OF STAFF AND THE COMMISSION

Q. WHAT ROLE WOULD APS RECOMMEND FOR STAFF AND THE COMMISSION IN THIS AND ANY FUTURE TRACK B SOLICITATION?

A. Because Staff understandably wants to be heavily involved in the Track B solicitation process, Staff should be an active partner with a clearly defined role and commensurate responsibilities. At each stage of the pre-solicitation process, Staff should be able to comment on the assembly of the bid package and the identification of potential bidders. APS could either accept such comments or reject them, but Staff would be thereafter precluded from raising additional issues concerning pre-solicitation. The same process would then be used during the solicitation and the post-solicitation review and evaluation. Given the intense supervision of this entire process by Staff and the independent monitor, I would hope (as a matter of simple fairness) that comments and criticisms could be offered contemporaneously. This would provide the utility an opportunity to address such concerns while at the same time continuing on with the solicitation. After the evaluation is complete, and provisional contracts awarded to the winning bidders, the Commission should either affirmatively approve such

contracts within 15 days or alternatively, deem them as being approved if the independent monitor's report (Staff Report at 11) concludes that the solicitation was effective and fair. In either event, Commission approval should constitute a finding that the utility acted prudently and reasonably in entering into the approved contracts, both individually and collectively. Such finding should also provide for full and timely cost recovery, either through a purchase power adjustment mechanism or some similar procedure. Commission and Staff assurance of cost recovery is especially appropriate given that the Commission has mandated this procurement through a formal process and on a schedule not entirely of the Company's choosing, and which is in contrast to the flexibility allowed in the current version of A.A.C R14-2-1606 (B).

Q. WHAT ARE THE ADVANTAGES OF THESE SUGGESTIONS?

A. During the solicitation and pre-solicitation process, it affords the utility an opportunity to address and rectify actual or perceived flaws in the solicitation. At the end of the solicitation, it provides certainty to the buyer and seller that the awarded contracts will be honored and receive full rate recognition. This should reduce or eliminate any regulatory risk premium being added to the bids and encourage buyers to be more aggressive in accepting bids, especially those that do not meet Staff's "price to beat" or those for quantities above the needs described at page 4 of the Staff Report. Finally, the contemporaneous approval of Track B contracts prevents the later potential application of impermissible hindsight in evaluating utility prudence and will remove a potentially contentious issue in future rate proceedings

V. PRICE TO BEAT

Q. WHAT IS THE COMPANY'S REACTION TO THE "PRICE TO BEAT" CONCEPT?

A. APS has no objections to the general "concept" of "price to beat" or similar "safe harbor" provisions in the solicitation. However, the Staff Report says little about how the "price to beat" will be determined, although what it does say causes me some concern. It is also clear that the utility will not be told of the "price to beat" until it is too late. A "safe harbor" does little good if the location of the harbor is hidden until after the ship has already foundered.

Q. WHEN SHOULD STAFF DISCLOSE THE "PRICE TO BEAT" TO THE UTILITY AS PART OF THE BID EVALUATION PROCESS?

A. The relevant "price to beat" should be revealed to the utility on a confidential basis after the bidding is complete and during the evaluation process. It should certainly be revealed prior to any contracts being signed. Such disclosure would not affect the bidding in either this Track B solicitation or in future solicitations.

Q. WHY SHOULD THE "PRICE TO BEAT" BE DISCLOSED TO THE UTILITY PRIOR TO CONTRACT EXECUTION?

A. If Staff's evaluation indicates that a bid or set of bids is, in some sense, too high, I would strongly argue that the public interest would best be served by so informing the utility before contractual commitments are made that could impose unnecessarily higher costs on customers. The proposal to keep "price to beat" as a Staff secret that would be revealed at some unknown future moment to support disallowance of power costs for which the utility was already contractually committed was a change in the final Staff Report from earlier drafts. Yet, I fail to see any public policy purpose in not disclosing "price to beat," or for that matter other specific Staff concerns, before such contractual commitments are made.

Q. WHAT ARE YOUR CONCERNS ABOUT THE ACTUAL DETERMINATION OF "PRICE TO BEAT"?

A. The Staff Report seems to contemplate a single price or price forecast for a given product. This implies a degree of precision that is likely unobtainable and assumes a superior ability in price forecasting that is difficult to demonstrate except with hindsight. This benchmark price would appear especially difficult to apply if the bid price were indexed to, for example, the price of natural gas or to some measure of power price inflation. Even when used in evaluating a multi-year fixed price product, the "price to beat" should be based on executable forward market prices obtainable from independent brokers. Alternatives such as the non-market-based "cost-of-service" or scenario-based price forecasts do not accurately reflect the current discounted value of the product or products actually available for purchase in the market.

VI. STANDARDS OF CONDUCT

Q. WILL APS SUBMIT STANDARDS OF CONDUCT AS PROPOSED IN THE STAFF REPORT?

A. Yes. APS will comply with any Track B procurement requirement ordered by the Commission.

Q. WHAT ISSUES WILL BE ADDRESSED BY ANY SUCH STANDARDS OF CONDUCT?

A. These are listed at page 38 of the Staff Report. However, some of the specific language on these issues in the Staff Report could be interpreted in such an overly literal fashion as to be internally inconsistent and counterproductive to efficient power procurement by the Company. APS will work with Staff to clarify these points. What I can say today is that with or without Standards of Conduct as proposed by Staff, APS employees will conduct this solicitation, and they will act solely in the best interests of APS and its customers. Any Pinnacle

West employees used by APS for this solicitation will also be required to act in the best interests of APS and its customers.

Q. COULD YOU CITE A FEW EXAMPLES OF WHAT YOU ARE REFERRING TO CONCERNING LANGUAGE IN THE STAFF REPORT THAT APPEARS TROUBLING IF TAKEN LITERALLY?

A. Yes. At page 19, lines 15 through 19 of the Staff Report, it appears that any APS personnel involved with APS generation cannot "participate in the solicitation preparation or evaluation of bids, or have any contact regarding the solicitation with any personnel assigned to conduct the solicitation . . ." Because Mr. Carlson, the Company's witness on Track B solicitation and head of the Company's power procurement department, is part of APS generation, this prohibition would make it impossible for APS to even conduct the Track B solicitation. And APS also receives shared services such as legal, risk management and environmental support from Pinnacle West Capital Corporation ("Pinnacle West"), which (through a separate division) is "involved in the sale or marketing of resources from generating assets owned by the utility [APS]." APS does not propose to attempt to prepare a solicitation and evaluate bids without legal assistance, or without input on environmental and credit issues. This would be a disservice to our customers.

Similarly, at page 37, the Staff Report uses absolutes such as "all contact" or "no contact" when describing the "wall" it proposes to erect between APS and its affiliates. I assume (or at least hope) that contacts not relating to the Track B solicitation such as those from the Pinnacle West employee benefits personnel, or from other shared services, were not intended to be swept into the scope of this prohibition. Although page 38 does so qualify the Staff Report's apparent

intent, there are sufficient examples to the contrary to warrant cooperation between Staff and the Company in compiling any such Standards of Conduct.

VII. CONFIDENTIALITY OF DATA

Q. WHY IS DATA CONFIDENTIALITY AN ISSUE IF THE STAFF REPORT PROVIDES FOR CONFIDENTIALITY OF UTILITY COST INFORMATION, FORECASTS OF MARKET PRICES AND OTHER PROPRIETARY UTILITY DATA?

A. The parties, both buyers and sellers, require a Commission order that validates Staff's position on confidentiality. Specifically, the Staff Report states that: "[P]rice and cost forecasts for power supplies and fuel costs prepared by, or available to the utility, will not be made available to bidders." See Staff Report at 13, lines 12 through 14. Page 8, lines 24 through 26 speaks of other information that may be restricted. Other data is available only to those who have entered into protective agreements. See Staff Report at 13, lines 10 through 12. The discovery process in this proceeding has made it perfectly clear to me that "confidential" should mean "confidential" and not "sort of confidential" or "partially confidential" or "confidential until somebody asks for it." This is a highly competitive business, and there are millions of dollars at stake for APS and its customers and for potential sellers as well. If they are to fully and enthusiastically participate in this process, they must have absolute assurance that their competitively sensitive and proprietary information will be protected from competitors or those engaged in the Track B bidding.

VIII. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. APS appreciates Staff's efforts to develop a workable procurement process that aims to benefits consumers. My comments are made in the sincere hope that

the recommendations in my testimony will lead to less uncertainty, greater participation, more openness, and fewer disputes down the road. All of these will improve the likelihood of realizing the goals laid down at the beginning of that Staff Report.

Q. DOES THAT CONCLUDE YOUR PREFILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, it does.

EXHIBIT
APS-4
Admitted

REBUTTAL TESTIMONY OF PETER M. EWEN

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

November 18, 2002

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REBUTTAL TESTIMONY OF PETER M. EWEN
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000A-02-0051, et al.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Pete Ewen. I am the Manager of the Forecasts Department at Arizona Public Service Company ("APS" or "Company").

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony will respond to certain assertions made in this proceeding by Panda/TECO witness Dr. Craig Roach and National Energy Group ("NEG") witness Mr. Thomas Broderick. Specifically, I will provide additional explanation of my calculation of unmet needs, address the accuracy of the October 2002 APS load forecast, and provide additional clarification regarding the determination and treatment of reliability must-run ("RMR") requirements, as well as reserve margin calculations.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. As I explained in my direct testimony, I derived APS's unmet needs for capacity and energy from a comparison of APS's expected energy and peak demand requirements with the availability of APS resources to meet those needs. I calculated this amount by following the definition set out by the Commission in Track A and adopted in the October 25, 2002 Staff Report ("Staff Report").

See Decision No. 65154 (September 10, 2002); see also Staff Report at 4. In essence, this calculation simply affirms that APS's procurement of power from the wholesale market will be done under two separate processes – a formal solicitation process for our reliability needs and an economy energy procurement process. My rebuttal testimony further demonstrates both how accurate APS's forecasts have been and that the estimate of unmet needs provided and explained to the merchant Intervenors at the November 6 workshop is the appropriate estimate to use.

III. CALCULATION OF UNMET NEED

Q. WOULD YOU PLEASE SUMMARIZE AGAIN HOW YOU ESTIMATED APS'S UNMET ENERGY NEEDS?

A. Briefly, I derived APS's unmet needs for capacity and energy from a comparison of the expected energy and peak demand requirements over the next ten years with the availability of APS resources to meet those needs. The specific analysis is discussed in great detail in my direct testimony so I will not repeat those details here.

Q. DO YOU BELIEVE THAT YOU HAVE UNDERSTATED APS'S UNMET ENERGY NEEDS AS ASSERTED BY DR. ROACH AND MR. BRODERICK?

A. Not in the least. I calculated APS's unmet needs by following the definition set out by the Commission in Track A (see Decision No. 65154) and in the Staff Report. This prescribed methodology is an accurate depiction of APS's reliability needs.

Q. DO YOU BELIEVE THAT YOU MISUNDERSTOOD THE COMMISSION'S OR STAFF'S INTENT?

A. No, I do not. In Decision No. 65154, the Commission ordered APS to "acquire, at a minimum, any required power that cannot be produced from its own existing assets,

through the competitive procurement process as developed in the Track B proceeding." (Decision No. 65154 at 23, 33, emphasis added.) Staff provided further guidance in the Staff Report when it explained:

> The Staff believes the solicitation in 2003 should be for the energy and capacity the utility cannot supply from generation assets that are included in the utility's rate base, from contracts in effect, as of September 1, 2002, and from generation sources it must take as a result of law or regulation (QF's and Environmental Portfolio sources). [Emphasis added.]

(Staff Report at 35, lines 4-8.) Not coincidentally, I believe Tucson Electric Power ("TEP") has used precisely the same method as I did for calculating its unmet needs and has not been criticized by any witness in these proceedings.

Q. WHAT ABOUT THE REFERENCE TO "AT A MINIMUM" IN THE DECISION?

A. The Commission explained that APS "may decide to retire or displace inefficient, uneconomic, environmentally undesirable plants," an action that might result in an increase in unmet needs. (Decision No. 65154, fn. 8 at 23.) APS has already accounted for such factors in its forecast. As a result, my direct testimony addressed our retirement plans and discussed economic displacement through a separate process. See Testimony of Peter M. Ewen at 18, 22.

Q. HOW WOULD YOU RESPOND TO DR. ROACH'S AND MR. BRODERICK'S ASSERTIONS THAT THEIR REVISED CALCULATIONS OF APS'S UNMET NEEDS BETTER COMPARE TO "STAFF'S CALCULATION"?

A. It is important to note that Staff did not prepare an independent calculation of APS's unmet needs. Instead, as noted in the Staff Report, Staff portrayed APS's unmet needs based on information provided by APS at a workshop in August. As I explained at the November 6 workshop, those numbers were merely "estimates" based on then available information and assumptions. They were

never intended to be definitive forecasts that would precisely define or limit the power to be procured in a process that would start deliveries almost a year later.

Q. DO YOU BELIEVE THAT YOUR ESTIMATE OF UNMET NEEDS APPROPRIATELY ADDRESSES THE ECONOMIC VALUE OF APS'S EXISTING PLANTS?

A. Yes, I do. Contrary to the assertion by Mr. Broderick, this calculation of unmet needs does not at all "overstat[e] the economic level of output of its exiting [sic] units." (Testimony of Thomas Broderick at 3.) In fact, it does not even attempt to portray the economic value of the existing units. My direct testimony, in concert with Mr. Carlson's direct testimony, clearly distinguished the procurement of power from the wholesale market into two separate processes – a formal solicitation for our reliability needs (unmet capacity and energy needs as defined by the Staff report), and an economy energy procurement process that allows APS to make periodic smaller-scale purchases on an on-going basis to displace its own generation when it is economic to do so.

As Mr. Carlson describes in his rebuttal testimony, purchasing from the market in this manner is the best way to acquire sufficient quantities of economic energy without "moving the market" to the disadvantage of APS customers. Although this procurement strategy, which will be conducted in a fair, unbiased and equitable manner, may not result in the one time, large volume contracts that the merchant generators desire, it provides for the greatest amount of competition by not foreclosing the selective participation of other regional generators who may have excess capacity only at certain times of each year. Allowing APS to maximize its possible pool of suppliers at times of its choosing will be the most effective way of maintaining downward pressure on prices throughout the procurement process, thereby providing

the greatest benefits to APS and its customers. Because the benefits of separating these two types of needs is so clear, I will focus the remainder of my rebuttal testimony on the issues relating to the accuracy of our load forecast and on the mischaracterizations of our unmet needs assessment.

IV. LOAD FORECAST ACCURACY

Q. HOW DID APS USE ITS MOST RECENT FORECAST OF DEMAND AND ENERGY TO DETERMINE ITS ASSESSMENT OF UNMET NEED?

A. As I explained in my direct testimony, I determined APS's unmet needs using our most recent forecast of demand and energy completed in October of this year. In calculating those unmet needs, I used methods that are consistent with the industry and that are similar to the methods documented in each of the Company's most recent IRP filings (in 1992 and 1995). Furthermore, the accuracy of these methods (particularly in the near-term) is very good, with an average error rate of less than two percent when projecting the next year's energy demand.

Q. GIVEN THEIR GENERALIZED CRITICISMS, DID EITHER DR. ROACH OR MR. BRODERICK CRITICIZE ANY SPECIFIC ELEMENT OF YOUR LOAD FORECASTING METHODOLOGY?

A. No.

Q. DID EITHER WITNESS PROPOSE ANY ALTERNATIVE ASSUMPTIONS OR METHODOLOGIES BE ADOPTED FOR THE RETAIL CUSTOMER LOAD FORECAST?

A. No.

Q. WOULD YOU RESPOND TO DR. ROACH'S ASSERTION THAT APS'S LOAD FORECAST REFLECTS A PERSISTENT UNDERESTIMATION OF PEAK LOAD?

A. Yes. I explained in great detail in my direct testimony the steps that APS applies in preparing its load forecast. As I indicated there, APS has every incentive to be as accurate as possible in its forecasting efforts. I also described some of the unique circumstances that led to faster than projected growth during the time in question. It also is clear that the merchant generators would prefer as high a forecast as possible, because a higher forecast naturally leads to a higher projected unmet need. As a practical matter, the forecasting process at APS is one that considers the range of possible outcomes in the future and selects the outcome that has the greatest probability of being right. Hindsight review may reveal that the projected value we selected was too low or too high for a period of time, but that does not help much in selecting the next expected case forecast. A flipped coin can turn up heads three or four times in a row, but the chances of the next flip being heads is still just 50/50. As a case in point, we have projected growth in Arizona population for the next two years to average 2.8%. We know, however, that depending on how the economy rebounds from this latest recession, we reasonably could see population growth anywhere between 2.4% and 3.2%. The amount of demand uncertainty related to this one variable alone is about 130 Mw. Obviously, other factors also will affect the actual growth in peak demand. While we all hope that economic growth will recover stronger than we have predicted, there is no guarantee that it will. If it does, though, one can not conclude that our current forecast is "poor."

Q. WOULD YOU PLEASE RESPOND TO DR. ROACH'S ALLEGATIONS THAT APS HAS ENGAGED IN UNSPECIFIED FORECASTING "GIMMICKS"?

A. It seems particularly notable that Dr. Roach reaches his "conclusion" based only on a reference to supposed prior underforecasting. Dr. Roach never identifies any such specific "gimmicks," nor can he, because none were used. Moreover, as I explain in more detail below, APS's forecasting has been remarkably accurate, particularly in the last few years.

Q. DOES AN EXAMINATION OF APS'S HISTORICAL FORECAST ACCURACY PRESENT A COMPLETE PICTURE JUSTIFYING THE ASSERTIONS BY DR. ROACH AND MR. BRODERICK THAT APS FORECASTS ARE UNREASONABLE?

A. No, it does not. Unfortunately, and based only on a superficial examination of our historical forecast accuracy, Dr. Roach and Mr. Broderick conclude that APS has conducted "poor forecasting." That is simply not true. A better way to assess how "good" a forecast was may be to compare that forecast against others trying to forecast the same thing. Put another way, the *ex post* identification of forecast "error" using the lens of perfect hindsight does not "prove" that the forecast was unreasonable when made.

Schedule PME-1R shows APS's forecasting performance as compared to other contemporaneous energy demand forecasts prepared by Western U.S. utilities for the Western Electric Coordinating Council's ("WECC's") 10-Year Coordinated Plan. The schedule presents average peak demand and energy forecast errors in recent years for APS side by side with the forecast errors of all utilities within each of the four regions of the WECC. It is notable that such a presentation should be statistically biased against APS because the aggregate forecast errors for a region will always be lower than the average of the forecast errors from the individual companies contributing to

the forecast. That is, the accuracy of the aggregated forecasts benefits from some companies overforecasting and some companies underforecasting. The very best that the average of the individual forecasts can do is to match the aggregated forecast accuracy; the average of the individual forecasts can never do better than the aggregated forecast.

What can be observed from the schedule is that APS's forecast accuracy is remarkable when stacked up against other regional utilities. No single region has forecasted peak demand more accurately 1-year ahead or 2-years ahead than has APS since 1998. On a 3-year ahead basis, only one region achieved accuracy results even comparable to APS. The accuracy results for energy forecasts show that APS had more accurate forecasts than any region for 1-year ahead forecasts, was comparable to two regions and far better than the other two regions for 2-year ahead forecasts, and was vastly better than three of the four regions for 3-year ahead forecasts. Again, this comparison is naturally biased against APS.

Q. WHAT DO THE ABOVE COMPARISONS DEMONSTRATE?

A. It should be clear from the above comparisons that APS's load forecasts are strikingly accurate, particularly in the last few years, when compared to the industry. When you consider that accuracy in this situation (*i.e.,* where APS has every incentive for an accurate forecast while the merchant Intervenors' preference would be for as high a forecast as possible, regardless of support), APS's load forecasts are precisely the forecasts that should be relied upon for the procurement process.

Q. HOW DO YOU RESPOND TO MR. BRODERICK'S PROPOSED ADDITIONS OF NON-APS LOAD TO YOUR FORECAST?

A. I reject Mr. Broderick's adjustments to the forecast to add in non-APS load. He includes in the APS retail and wholesale standard offer load forecast amounts for wholesale customers who are no longer APS customers. For example, the largest of these customers, Citizens Telecommunications Corporation ("Citizens"), asked to cancel its agreement with APS and negotiated a new contract with Pinnacle West Marketing and Trading ("M&T") in June 2001, long before Track B was established. APS has no responsibility or obligation to meet this contract load with APS generation nor does M&T serve it using any APS resources.

Q. WOULD YOU EXPLAIN THEN WHY SUCH NON-APS LOAD IS INCLUDED IN CERTAIN PEAK DEMAND INFORMATION AND EXCLUDED FROM OTHER INFORMATION?

A. Yes. Mr. Broderick is correct that these M&T customers are included in the presentation of certain peak demand information and excluded from other information, and I can certainly see how that might be superficially confusing. In one case (the higher peak demand number), the presentation of peak demand represents the Company's <u>delivery</u> obligation, or the maximum demand that our transmission and distribution system was required to carry in that year. In the other case (the lower peak demand number), the presentation of peak demand represents the APS <u>generation</u> obligation, or the maximum demand that APS was required serve from its own generation resources. With respect to Citizens, M&T owns the generation obligation via the June 2001 contract. APS, of course, retains the delivery obligation because Citizens' load is in the APS control area. Although not the ideal way to do it, we provided these separate representations of peak demand in the discovery process only because in our

historical data we do not have the weather-normalized system peak excluding Citizens and TOUA prior to 2001.

Q. WHAT ABOUT THE FOUR CONTRACTS THAT MR. BRODERICK ARGUES SHOULD BE TREATED AS PINNACLE WEST CONTRACTS?

A. Mr. Broderick's assertion is wrong. Schedule PME-2R attached to this testimony shows six contracts and the dates they were signed. One can see from the schedule that four contracts for the summer of 2003 were transacted between March 28, 2000 and March 30, 2000 by APS. The counterparties on these contracts were Williams, Morgan Stanley, Constellation and Enron. These purchases were made for the purpose of serving our retail customer load. The last two contracts in the schedule were both transacted on November 29, 2001. One is a sale from APS back to Enron to close out the purchase from Enron as a result of Enron's bankruptcy. The other contract, also entered into on November 29, 2001, was with Morgan Stanley and was the replacement contract for the closed out Enron position. APS's net purchase position did not change as a result of these last two transactions.

Notably, for each of those original four contracts, the purchaser was APS and not Pinnacle West as alleged by Mr. Broderick. (See Testimony of Thomas Broderick at 15.) Because these contracts were provided in discovery, it is difficult for me to understand why or how Mr. Broderick could possibly have concluded that these were Pinnacle West contracts that were somehow "assigned" to APS. (See Testimony of Thomas Broderick at 15.) There is no legitimate justification for removing these contracts from APS's pre-existing resources.

Q. ARE DR. ROACH'S AND MR. BRODERICK'S CRITICISMS OF OUR RMR CALCULATIONS VALID?

A. No. As one can see in Schedule PME-1 attached to my direct testimony, the amounts of capacity and energy for RMR service are quite small. Because they are so small and clearly could be met by <u>any</u> non-APS unit within metro-Phoenix, I find it difficult to comprehend Dr. Roach's position that these tiny amounts represent a shield for in-Valley Pinnacle West Energy Corporation ("PWEC") units. Nothing in my testimony or in Mr. Carlson's testimony could be construed as remotely suggesting such an attempt. I find the accusation even more remarkable in light of Mr. Carlson's direct testimony to the effect that APS will entertain any bids for such non-APS RMR service and could select a winning bidder other than PWEC if the price were more favorable and deliverability was assured. To restate my direct testimony, APS desires to keep the procurement of non-APS RMR service separate (but concurrent) because of the unique nature of the service required.

V. <u>NOVEMBER ESTIMATE OF UNMET NEEDS</u>

Q. WHAT WERE THE DIFFERENCES BETWEEN THE ESTIMATES OF UNMET NEEDS APS PROVIDED IN AUGUST AND THOSE PROVIDED AT THE NOVEMBER WORKSHOP?

A. At the November 6 workshop, I provided a handout to all of the participants, including Mr. Broderick and Dr. Roach, that explained and reconciled the differences between the calculation of estimated unmet needs provided in August and the calculation provided in November, and that handout is attached here as Schedule PME-3R. From the schedule, one can see that the APS estimate of unmet capacity need was lowered by 549 Mw in 2003, 655 Mw in

2004, and 904 Mw in 2005. One can also see that the estimate of unmet energy need was reduced by 5,095 gwh in 2003, 5,370 gwh in 2004 and 6,027 gwh in 2005.

Q. WHY DO YOU KEEP REFERRING TO THESE CALCULATIONS AS "ESTIMATES"?

A. Because they are. As I described in my direct testimony, they are based on a variety of critical forecast assumptions such as: the rate of economic growth; the relative intensity of electric usage; the rate of adoption of new electricity using devices; hotter or cooler weather; and power plant and transmission system performance. The actual unmet need can only be determined in real time and totaled after the fact. Thus, I caution everyone not to impart a degree of precision and finality to these estimates that is unrealistic.

Q. WOULD YOU PLEASE EXPLAIN THE ADJUSTMENTS MADE BETWEEN AUGUST AND NOVEMBER?

A. Yes. Several adjustments were included in the November estimates that make that estimate more accurate.

First, the load forecast was revised in late September (released in October), as it typically is, as a result of completing the summer and being able to assess the actual as compared to expected growth in peak demand. The new load forecast lowered the peak demand for 2003 by 212 Mw, but raised the energy forecast by 89 gwh. While the revisions to forecasted peak demand and energy amounts usually go in the same direction, in this instance they did not because the previous forecast had added too much demand for the amount of energy in the

forecast. The result was a projected load factor that was far lower than what had historically been experienced. The October 2002 forecast corrected this anomaly. Schedule PME-4R shows the system load factors that resulted from each forecast and compares them with the historical experience. One can clearly see that the current forecast has an appropriately balanced peak demand and energy forecast.

The second adjustment relates to the portrayal of reserve margin. In my direct testimony, I described quite clearly how and why I calculated the reserve margin the way I did. Specifically, our historical practice has been to purchase firm capacity and energy products where the seller provides reserves, and this is a standard procurement practice across the industry. The two long-term contracts described in discovery – the SRP Territorial purchase and the Pacificorp diversity exchange – both are examples of firm purchases where the sellers (SRP and Pacificorp) provide the reserves. In contrast, the contingent portion of the SRP purchase is not firm, so APS does carry reserves for this portion of the contract.

Although Dr. Roach takes great exception to this method, it should be clear that his portrayal of a higher reserve requirement is only a matter of presentation that does <u>not</u> affect the calculation of unmet needs. That is, there is a total reserve margin associated with APS's load that must be provided, and the assignment of reserves to one party or another comes down to whether a purchase is firm or contingent. As Mr. Carlson describes in his testimony, a firm purchase (where the seller provides reserves) normally will be more valuable and command a higher price than a contingent purchase (where the buyer takes on the reserve

risk). Traditionally, when APS has evaluated its capacity reliability needs, we have concluded that we must have firm capacity to cover our peak needs. This is precisely why Mr. Carlson included firm capacity as one of the products APS would be soliciting. While I believe it is slightly misleading to portray the APS unmet need as including all of the required reserves (because our reliability needs must be met with firm capacity) just to produce a higher number, it does not have any effect on the ultimate solicitation. Firm capacity offers naturally will be worth more than contingent offers, and the change in reserve margin presentation has absolutely no effect on the amount of energy APS needs for reliability purposes. In other words, I could accept Dr. Roach's method of presenting reserve requirements, but that would not increase the amount of our solicitation for firm power to meet our reliability needs.

Q. DID YOU TREAT RMR SERVICE DIFFERENTLY BETWEEN THE AUGUST AND NOVEMBER ESTIMATES OF UNMET NEEDS?

A. Yes. Another factor that contributed to the differences in unmet needs was the preliminary "placeholder" estimate of the amount of RMR service that may be required in the metro-Phoenix load pocket included in the estimate of unmet needs provided at the November workshop. That estimate was not available at the time the August estimate of unmet needs was prepared, and APS clearly indicated so at the time.

Q. WHAT ABOUT THE IMPACT OF ENERGY PRODUCED BY APS OWNED GENERATION ON THE ESTIMATES OF UNMET NEEDS?

A. Perhaps the single largest adjustment between the August and November estimates of unmet needs relates to the amount of energy produced by APS owned generation and firm purchases (or, conversely, the amount of unmet energy need). Although the appropriate recognition of the March 2000 contract

purchases lowered the unmet energy need by 215 gwh, the remainder of the adjustment largely came from the exclusion of the PWEC units in the modeling process. Prior to the Commission's Track A order, APS had assumed that the new PWEC combined cycle units would be dedicated to native load and, as a result, all of the resource projections until that time dispatched those units alongside the APS units at marginal running costs rather than market value. As more efficient units, these new units understandably were dispatched ahead of the older gas-fired generation, leaving the older gas-fired generation with many hours where they were idle or running at lower capacity factors.

When the Commission defined how to calculate unmet needs in the Track A order, and Staff provided its further guidance in the Staff Report, the new PWEC units were appropriately excluded from the dispatch model and the system was redispatched. In the absence of these new units, the older gas-fired generation was forced to make up the slack, and the idle and low capacity factor hours evaporated. Note that neither the August nor November dispatch runs included economy energy. This explains why the economy energy figures shown on Schedule PME-13 of my direct testimony do not match the PWEC energy amounts provided in the August 2002 workshop handout. Once you introduce economy energy and remove the PWEC units, the PWEC energy from the August handout is replaced by a combination of both increased output from APS units and energy.

Q. DO YOU BELIEVE THAT THIS METHOD UNDERESTIMATES APS'S RELIABILITY NEEDS?

A. No. This method provides the current best estimate of APS's reliability needs. The estimates will continue to be refined, however, in future years, just as in

past years. As explained in more detail in Mr. Carlson's testimony, APS will procure additional energy as it is economic to do so.

Q. WOULD YOU PLEASE SUMMARIZE THE DIFFERENCES BETWEEN THE AUGUST AND NOVEMBER ESTIMATES OF UNMET NEEDS?

A. Yes. To summarize the above discussion, the August estimate of unmet needs differed from my November presentation because it (i) was computed using a different methodology for dedicated merchant unit energy, (ii) omitted roughly 185 Mw and 215 gwh of legitimate preexisting purchase contracts, (iii) portrayed reserve margin differently, (iv) did not include the special conditions of metro Phoenix RMR service, and (v) used a load forecast that was subsequently updated. These adjustments are reflected in the estimate included in my direct testimony and provided at the November workshop and more accurately reflect APS's unmet needs for reliability purposes.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. I have responded to the comments made by Dr. Roach and Mr. Broderick regarding the calculation of APS's unmet needs and the accuracy of our forecast. I have again explained the adjustments made to develop the more accurate calculation of unmet needs provided at the November 6 workshop. I also have attempted to make clear that APS has every incentive to prepare an accurate forecast and has a good track record in preparing those forecasts. The fact that I may not have addressed any specific witnesses' argument does not imply agreement with such argument.

Q. DOES THAT CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes, it does.

Schedule PME-1R
Comparison of Recent Forecast Accuracy
APS vs. Other WECC Regions

	Mean Absolute Percent Error				
	APS	Northwest Power Pool Area	Rocky Mountain Power Area	Arizona, New Mexico, S. Nevada Power Area	California, Mexico Power Area
Summer Peak Demand					
1-Year Ahead					
1998 forecast for 1999	2.3%	16.8%	1.6%	0.4%	1.3%
1999 forecast for 2000	2.8%	16.5%	9.8%	3.7%	0.7%
2000 forecast for 2001	1.5%	9.3%	11.1%	3.4%	11.4%
Average	2.2%	14.2%	7.5%	2.5%	4.5%
2-Years Ahead					
1998 forecast for 2000	5.1%	14.3%	7.9%	6.9%	3.6%
1999 forecast for 2001	2.6%	7.5%	15.9%	8.1%	7.0%
Average	3.9%	10.9%	11.9%	7.5%	5.3%
3-Years Ahead					
1998 forecast for 2001	5.6%	5.4%	14.2%	11.9%	10.3%
Energy Load					
1-Year Ahead					
1998 forecast for 1999	0.2%	4.1%	5.7%	2.1%	1.1%
1999 forecast for 2000	5.9%	1.7%	7.7%	2.7%	1.5%
2000 forecast for 2001	0.1%	10.4%	7.5%	2.6%	5.9%
Average	2.1%	5.4%	7.0%	2.5%	2.8%
2-Years Ahead					
1998 forecast for 2000	3.2%	3.7%	2.4%	2.1%	5.3%
1999 forecast for 2001	5.6%	11.4%	10.6%	5.8%	2.8%
Average	4.4%	7.6%	6.5%	4.0%	4.1%
3-Years Ahead					
1998 forecast for 2001	3.5%	13.2%	5.8%	7.2%	1.9%

SCHEDULE PME-2R

APS CONTRACT NO. 59894

APS CONTRACT NO. 59895
APS CONTRACT NO. 59896

Williams Energy Marketing & Trading Company

Physical Confirmation

To: Arizona Public Service Company
Attn: Don Stoneberger
Date: March 31, 2000
Fax: (602) 250-2325
Ref.: 84236

Pursuant and subject to the terms and conditions of the Western Systems Power Pool Agreement, this confirms the following Transaction negotiated between Steve Culliton of Williams and Don Stoneberger of Arizona Public Service Company.

Transaction Date: March 30, 2000

Buyer: Arizona Public Service Company

Seller: Williams Energy Marketing & Trading Company

Product: Electricity Firm On-Peak Power Pacific Prevailing Time

Term	Quantity	Fixed price	Differential
July 1-31,2001	10,000 MWh's (25 MW's)	per MWh	N/A
August 1-31,2001	10,800 MWh's (25 MW's)	per MWh	N/A
September 1-30,2001	9,600 MWh's (25 MW's)	per MWh	N/A
July 1-31,2002	10,400 MWh's (25 MW's)	per MWh	N/A
August 1-31,2002	10,800 MWh's (25 MW's)	per MWh	N/A
September 1-30,2002	9,600 MWh's (25 MW's)	per MWh	N/A
July 1-31,2003	10,400 MWh's (25 MW's)	per MWh	N/A
August 1-31,2003	10,400 MWh's (25 MW's)	per MWh	N/A
September 1-30,2003	10,000 MWh's (25 MW's)	per MWh	N/A

Schedule:
Mon-Sat HE PPT 07:00 thru 22:00, excl holidays
Mon-Sat HE PPT 07:00 thru 22:00, excl holidays
Mon-Sat HE PPT 07:00 thru 22:00, excl holidays

Holiday Calendar: NERC

Contract Quantity: 92,000 MWh's

Delivery Point(s): Palo Verde Switchyard

Types of Service: Service Schedule C2 X

Performance Obligation: X FIRM ____ NON-FIRM

Special Provisions:

These specific terms and conditions together with the Western Systems Power Pool Agreement shall constitute the entirety of the agreement between Buyer and Seller unless Company furnishes to Williams notice of alleged errors by facsimile, other electronic transmission, or first class mail by the earlier of the fifth (5th) Business Day following the Business Day of receipt of this Confirmation from Williams or six (6) hours prior to the Period of Delivery, this Confirmation shall be conclusive evidence of the Transaction that is the subject matter thereof, and shall, along with the terms herein, be the final expression of all its terms, notwithstanding any failure of Company to execute such Confirmation.

WILLIAMS ENERGY MARKETING & TRADING COMPANY

By: Greg Hickl
Director of Power Trading

Prepared by: Angela Perry , Risk Control Management
Phone No: (918) 573-2000
Fax No: (918) 573-8233

Ref: 84236

ARIZONA PUBLIC SERVICE COMPANY

Signature: For David Hansen DJ

Print Name: David A. Hansen

Title: Director, Bulk Power Marketing & Resource Operations

Date: 4.5.00

4/4/00

Attachment PANDARA 9.1-6(b) (1)(2)

MORGAN STANLEY CAPITAL GROUP INC.
1585 BROADWAY
NEW YORK, NEW YORK

Revised Confirmation
May 15, 2000

Arizona Public Service Company
Attn: Frank Moreno
Fax 602-250-3199

APS CONTRACT NO. 59890
59891
59892

MS Reference: e76373
Trade Date: March 30, 2000

This is to confirm Morgan Stanley Capital Group Inc.'s (MSCGI) sale of firm energy to Arizona Public Service Company (APS). This transaction has been concluded under the Western System Power Pool (WSPP) Master Agreement as revised February 1, 2000, and as may be amended from time to time. With additional terms as stated below:

Buyer:	APS
Seller	MSCG
Term:	July 1, 2001 through September 30, 2001 July 1, 2002 through September 30, 2002 July 1, 2003 through September 30, 2003
Delivery:	Monday through Saturday, Hours Ending 0700 through 2200 Pacific Prevailing Time (PPT), excluding NERC Holidays.
Quantity:	Fifty (50) MW of firm energy per hour.
Delivery Location:	Palo Verde
Energy Price:	$ per MWH
Scheduling:	All scheduling will be completed by the Business Day prior to the day of delivery.

Morgan Stanley Real-Time Communications and Scheduling:

212-761-8748 Office
212-761-9292 Fax

Please confirm that the terms stated herein accurately reflect the agreement reached between APS and MSCG by returning an executed copy of this Confirmation Letter. (Fax: 212-761-0292.)

Morgan Stanley Capital Group Inc.
Joseph F. Delaney, III
Principal

ARIZONA PUBLIC SERVICE COMPANY

Signature: For David Hansen DS

Print Name: David A. Hansen

Title: Director, Bulk Power Marketing & Resource Operations

Date: 5-23-00

JM 5/19/00

FILE

APS CONTRACT NO. 59853, 59854, 59855

Constellation Power Source

111 Market Place • Suite 500 • Baltimore, Maryland 21202 • Fax 410-468-3540

FROM: CONSTELLATION POWER SOURCE
TO: ARIZONA PUBLIC SERVICE
ATTN: DON STONEBERGER
FAX: 16022503719
PH: 602-250-2809
CC: NATSOURCE, INC.
ATTN: FEIERSTEIN MITCH

Tue 28Mar00 06:55:38 pm

CONFIRMATION AGREEMENT

This will confirm the verbal agreement reached on 28 MARCH 2000 between ARIZONA PUBLIC SERVICE ("Counterparty") and Constellation Power Source, Inc. ("CPS") (each individually a "Party" and collectively the "Parties") regarding a power purchase and sale transaction (the "Agreement") on the following terms and conditions:

1. Commercial Terms. The "Commercial Terms" of this transaction are as follows:

REF:	ELS2JUP,ELS2JUQ,ELS2JUR
Trade Date :	28 MARCH 2000
Buyer:	ARIZONA PUBLIC SERVICE P.O. BOX 53999 PHOENIX, AZ 85072-3999 U.S.
Seller:	CONSTELLATION POWER SOURCE,INC. 111 MARKET PLACE SUITE 500 BALTIMORE, MARYLAND 21202
Delivery Point:	DELIVERED AT PALO VERDE
Type of Transaction:	Firm energy sale pursuant to Service Schedule C-2 to the Western Systems Power Pool Agreement as revised effective as of February 1, 2000 (the "WSPP Agreement").

Goldman Sachs

Goldman Sachs Power L.L.C. is the exclusive advisor to Constellation Power Source.

Delivery Period:	July 1, 2001 - September 30, 2001 July 1, 2002 - September 30, 2002 July 1, 2003 - September 30, 2003
Hourly Quantity:	25 MWH
Daily Quantity:	400 MWH per business day
Total Quantity:	92,000 MWH for the delivery period
Price :	USD PER MEGAWATT HOUR
Other Terms :	6X16 (HE 07:00 TO HE 22:00 PPT MONDAY-SATURDAY EXCLUDING NERC HOLIDAYS) Scheduling to be completed with CPS in accordance with WSCC Guidelines.

2. Governing Law.
This Agreement and the rights and duties of the Parties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the state of New York, without regard to principles of conflicts of law. Each Party herein waives its respective right to any jury trial with respect to any litigation arising under or in connection with this Agreement.

3. Advisor.
Goldman Sachs Power LLC ("GSP") is the exclusive advisor to CPS and not a principal of CPS. From time to time, CPS may designate one or more employees of GSP as CPS's agent for purposes of performing its obligations under this Agreement. CPS shall be solely responsible for any and all obligations and liabilities associated with this Agreement and for any and all actions or inactions of such employees. Neither GSP, Goldman, Sachs & Co. nor J. Aron & Company, nor any of their affiliates, has any responsibility for, or liability with respect to this Agreement.

All provisions contained or incorporated by reference in the Western Systems Power Pool Agreement effective as of February 1, 2000, and as amended from time to time between the Parties, will govern this Confirmation except as expressly modified herein.

Please execute below as indicated and return to us by fax.

Regards,

Constellation Power Source, Inc.

ERIC PLATEIS
TRADER
CONSTELLATION POWER SOURCE, INC.
BALTIMORE OFFICE

PHONE : 410-468-3530
FAX : 410-468-3540

Agreed by Counterparty:

By: DAVID A. HANSEN
DIRECTOR, BULK POWER MARKETING
Title: + RESOURCE OPERATIONS

.ARON. T.FAX. C.ELS2JUP,ELS2JUQ,ELS2JUR. .ENDARON.

ml 3/31/00

59886; 59887; 59888

Deal No. 315589.1

Enron Power Marketing, Inc.
P.O. Box 4428
Houston, Texas 77210-4428
(FAX) (713) 646-2491

April 24, 2000

Mark Wiesinger
Arizona Public Service Company
400 N 5th St
Phoenix, AZ 85004

Fax No. (602) 250-3719

REVISED CONFIRMATION LETTER

This Revised Confirmation Letter supersedes the prior Confirmation Letter dated March 31, 2000, and shall confirm the agreement reached on March 30, 2000 between Arizona Public Service Company and Enron Power Marketing, Inc. ("EPMI") regarding the sale of Firm Energy under the terms and conditions that follow:

Seller: Enron Power Marketing, Inc.

Buyer: Arizona Public Service Company

Type of Commodity: WSPP Schedule C Firm Energy in effect as of February 1, 2000, as periodically amended.

Term: Sunday, July 1, 2001 through Sunday, September 30, 2001. Hour Ending (HE) 0700 through HE 2200 (16 Hours each day), Monday through Saturday only, excluding NERC Holidays;

Monday, July 1, 2002 through Monday, September 30, 2002. Hour Ending (HE) 0700 through HE 2200 (16 Hours each day), Monday through Saturday only, excluding NERC Holidays;

Tuesday, July 1, 2003 through Tuesday, September 30, 2003. Hour Ending (HE) 0700 through HE 2200 (16 Hours each day), Monday through Saturday only, excluding NERC Holidays; Pacific Prevailing Time.

Type of Commodity: Firm Energy

Price: US Dollars $[redacted]/MWh.

Quantity: 25 Mws of Firm Energy per hour.

Delivery Point(s): PALO VERDE

Scheduling: EPMI Real Time Operations: 1-800-684-1336

Deal No. 315589.1

This confirmation letter is being provided pursuant to and in accordance with Western Systems Power Pool Agreement ("WSPP Agreement"), as amended periodically with FERC approval, to which Arizona Public Service Company and EPMI are parties. Terms used but not defined herein shall have the meanings ascribed to them in the WSPP Agreement.

Please confirm that the terms stated herein accurately reflect the agreement reached on March 30, 2000 between you and EPMI by returning an executed copy of this letter by facsimile to EPMI at (713) 646-2491. Your response should reflect the appropriate party in your organization who has the authority to enter into this transaction. If you have any questions please call (713) 853-1886.

Arizona Public Service Company	Enron Power Marketing, Inc.
By:	By:
Name: DAVID A. HANSEN	Name: Tim Belden
Title: DIRECTOR, BULK POWER MARKETING & RESOURCE OPS	Title: Vice President

Attachment Page 1 of 2

APS

THE POWER TO MAKE IT HAPPEN™

APS Contract No. 63860
Cathy Pocock
Bulk Power Marketing & Resource Operations
P. O. Box 53999, M/S 9831
Phoenix, Arizona 85072-3999
Telephone: (602) 250-3622
Facsimile: (602) 250-3199
November 30, 2001

CONFIDENTIAL

To: Enron Power Marketing, Inc.

The following terms and conditions shall govern the transaction of November 29, 2001 between Matt Motley on behalf of Enron Power Marketing, Inc. ("EPMI") and Cathy Pocock on behalf of Arizona Public Service Company ("APS") whereby EPMI agreed to purchase and receive and APS agreed to sell and deliver energy as follows:

Seller:	Arizona Public Service Company 400 N. 5th Street, M/S 9842 Phoenix, Arizona 85004	**Buyer:**	Enron Power Marketing, Inc. P.O Box 4428 Houston, Texas 77210-4428
Confirm Administrator:	Margie Logan (602) 250-2809 (phone) (602) 250-3719 (fax)	**Confirm Administrator:**	Melissa Murphy (713) 853-1886 (phone) (713) 646-2443 (fax)
Preschedule:	(602) 250-4371	**Preschedule:**	(800) 684-1336
Real Time:	(602) 250-4470	**Real Time:**	(800) 684-1336
Quantity (MW/hr.):	25 Megawatts	**Quantity (MWh):**	30,800 MWh
Price ($/MWh):		**Type of energy:**	Firm
Start date:	July 1, 2003	**End date:**	September 30, 2003
Day(s) of week:	Monday through Saturday excluding Sundays and NERC holidays	**Hours:**	H. E. 0700-2000, Pacific Prevailing Time ("PPT").

Delivery Point: Palo Verde
Transmission Contingencies: None **Generation Contingencies:** None

Enabling Agreement: APS and EPMI enter into this transaction pursuant to and in accordance with Service Schedule C (SSC) of the WSPP Agreement, to which APS and EPMI are parties. Terms used but not defined herein shall have the meanings ascribed to them in the WSPP Agreement.

Additional Terms: Per attached.

If the above accurately reflects the terms and conditions of the agreement between APS and EPMI on November 29, 2001, please sign a copy of this Agreement and return it via fax to the APS Confirm Administrator listed above.

Arizona Public Service Company	Enron Power Marketing, Inc.
Signature: [signature]	Signature: Considered Accepted
Print Name: David A. Hansen	Print Name: Final Since Response
Title: Director, Bulk Power Marketing & Resource Operations	Title: Was Not Received Within Business Days Of Receipt
Date: 12-5-01	Date:

CP 12/14/01

dhs 12/31/01

E:\common\CONTRACT\PWRSALES\ENRON\Sell\63860 aps cp sale.doc

Additional Terms

Scheduling: Preschedules shall be exchanged for all deliveries of energy, including identifications of receiving and generating control areas under this Agreement by 11:00 a.m. Pacific Prevailing Time on the last work day observed by both Parties prior to the scheduled date of delivery. Interchange scheduling shall be conducted in accordance with Western Systems Power Pool (WSPP) Operating Procedure No. 1.

Special Provisions: Deliveries will be made except during interruptions or reductions which are due to uncontrollable forces as defined in Section 10 of the Western Systems Power Pool Agreement, dated July 1, 2001, as it may be amended ("WSPP Agreement"), in which case the obligations of both Parties will be reduced for the duration of the interruption or reduction.

APS shall supply firm energy in accordance with WSPP Service Schedule C utilizing available generation or purchased power resources at the point of delivery. If, in order to maintain firm energy deliveries, APS is required to obtain additional generation or transmission resources, APS shall absorb all additional costs incurred, including any charges for generation, transmission or ancillary services.

NERC Holidays: The following shall be deemed holidays for purposes of this Agreement: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas Day.

Additional Terms and Conditions: Neither Party shall transfer or assign all or any part of this Agreement or its rights or obligations hereunder or otherwise dispose of any right, title or interest herein without the prior written consent of the other Party, which consent shall not be unreasonably withheld or delayed. Notwithstanding the foregoing, either Party may, without the need for consent from the other Party, (a) transfer, pledge, or assign this Agreement as security for any financing; (b) transfer, assign or delegate this Agreement or its rights or obligations hereunder to an Affiliate of such party; or (c) transfer, assign or delegate this Agreement to any person or entity succeeding to all or substantially all of the assets of such party; ***provided, however,* that any such assignee shall agree to be bound by the terms and conditions hereof and, *provided, further,* that any transfer, assignment or delegation that does not require consent hereunder shall not, in any way, release the assignor from liability for full performance of any obligations (and only those obligations) arising under this Agreement prior to the effective date of the transfer, assignment or delegation.** To the extent a transfer does not require consent, the transferring Party shall provide prompt notice to the other party of the transfer and the effective date thereof. Any transfer in violation of this section shall be deemed null and void.

The definition of Affiliate: **"Affiliate"** means, with respect to any person, any entity controlled, directly or indirectly, by such person, any entity that controls, directly or indirectly, such person, or any entity directly or indirectly under common control with such person. For this purpose, "control" of any entity or person means ownership of a majority of the voting power of the entity or person.

Billing and Payment: Monthly billings and payment shall be in accordance with Section 9 of the WSPP Agreement. Billings and payment shall be sent to:

Arizona Public Service Company
Attention: Cash Management, Station 8104
P. O. Box 53920
Phoenix, AZ 85072-3920

Enron Power Marketing, Inc.
Attention: Client Services Manager
P.O. Box 4428
Houston, TX 77210-4428

APS Contract No. 63860 shall be included on all correspondence or invoices in reference to this agreement.

Attachment PAWDA DR 1
Q1-6 (b)(i)(5)

PINNACLE WEST
CAPITAL CORPORATION

PWMT Confirmation No. 63863

Cathy Pocock
Pinnacle West Marketing & Trading
P. O. Box 53999, M/S 9831
Phoenix, Arizona 85072-3999
Telephone: (602) 250-3622
Facsimile: (602) 250-3199

November 30, 2001

TRANSACTION CONFIRMATION
CONFIDENTIAL

To: Morgan Stanley Capital Group, Inc.

This Transaction Confirmation ("Confirmation") confirms the verbal agreement reached November 29, 2001 between Tom Funk, on behalf of Morgan Stanley Capital Group, Inc. ("MSCG"), and Cathy Pocock, on behalf of Pinnacle West Marketing & Trading, a division of Pinnacle West Capital Corporation ("PWMT"), whereby MSCG agreed to sell and deliver and PWMT agreed to purchase and receive energy pursuant to WSPP Service Schedule C (SSC) as follows:

Quantity (MW/hr.):	25 Megawatts	**Product:**	30,800 MWh
Price ($/MWh):		**Delivery Point:**	Palo Verde
Start date:	July 1, 2003	**End date:**	September 30, 2003
Type of Energy:	Firm		
Schedule:	H. E. 0700-2200 Pacific Prevailing Time ("PPT") Monday through Saturday excluding Sunday & NERC holidays.		
Special Provision:	WSPP Schedule C with liquidated damages.		

If you are in disagreement over any of the provisions stated above, please contact Cathy Pocock upon receipt of this Confirmation.

SCHEDULE PME-3R
APS ESTIMATE OF UNMET CAPACITY AND ENERGY NEEDS
COMPARISON OF CURRENT (11/04/02) ESTIMATE TO PREVIOUS ESTIMATE
2003-2005

	2003			2004			2005		
	11/4/2002 Estimate	Workshop Estimate	Change	11/4/2002 Estimate	Workshop Estimate	Change	11/4/2002 Estimate	Workshop Estimate	Change
Peak Demand and Capacity (MW)									
Peak Demand	5,723	5,935	(212)	6,023	6,267	(244)	6,269	6,570	(301)
Planned Reserves	598	712	(114)	602	752	(150)	602	788	(186)
APS Units and Long Term Contracts	4,757	4,697	60	4,790	4,730	60	4,793	4,737	56
Forward Hedges	125	-	125	-	-	-	-	-	-
Non-APS RMR	29	-	29	184	-	184	338	-	338
Renewables	9	-	9	17	-	17	23	-	23
Net Unmet Needs	1,401	1,950	(549)	1,634	2,289	(655)	1,717	2,621	(904)
Energy (GWH)									
Energy Sales + Losses	26,494	26,405	89	27,841	27,733	108	28,999	28,979	20
APS Nuclear Generation	8,333	8,333	-	8,901	8,901	-	8,513	8,513	-
APS Coal Generation	12,498	11,726	772	12,762	11,852	910	12,936	12,079	857
APS Gas/Hydro Generation	3,184	254	2,930	3,600	363	3,237	4,214	548	3,666
Long Term Contracts	1,583	295	1,288	1,672	345	1,327	1,986	479	1,507
Forward Hedges	215	-	215	-	-	-	-	-	-
Non-APS RMR	-	-	-	2	-	2	8	-	8
Renewables	41	62	(21)	85	83	2	114	105	9
Net Unmet Needs	640	5,735	(5,095)	819	6,189	(5,370)	1,228	7,255	(6,027)
PWEC Unit Energy Displacement	-	5,728	(5,728)	-	6,170	(6,170)	-	7,217	(7,217)
Unmet Needs Net of Displaced Energy	640	7	633	819	19	800	1,228	38	1,190

Schedule PME-4R
APS System Load Factor

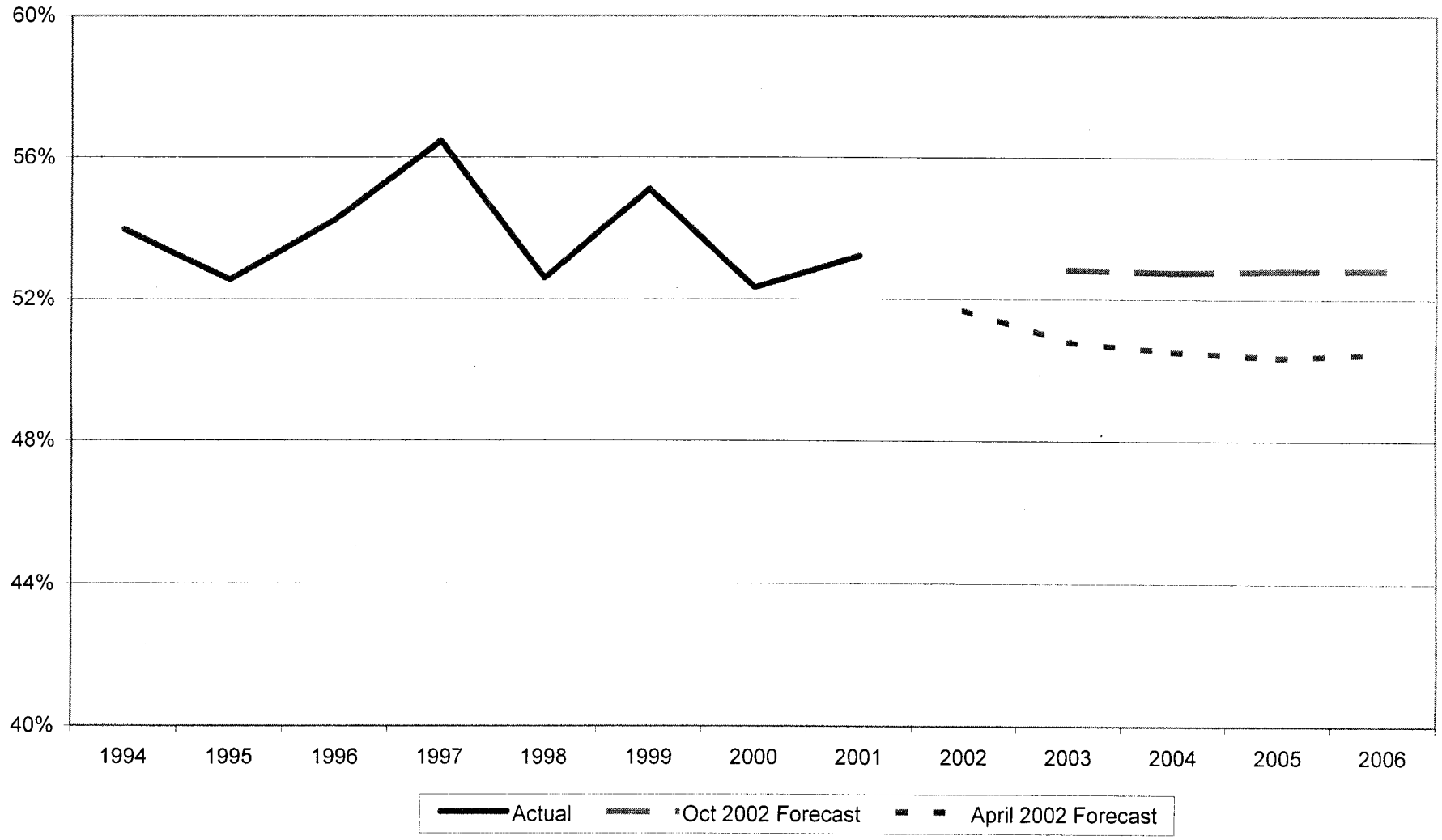

EXHIBIT
APS-5
Admitted

REBUTTAL TESTIMONY OF THOMAS J. CARLSON

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

November 18, 2002

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REBUTTAL TESTIMONY OF THOMAS J. CARLSON
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000A-02-0051, et al.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

My name is Thomas J. Carlson. I am the Head of Trading for Arizona Public Service Company ("APS" or "Company").

Q. DID YOU PREVIOUSLY SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony will respond to criticisms of the proposed APS power procurement program, and of APS itself, by Panda/TECO witness Dr. Craig R. Roach, National Energy Group ("NEG") witness Thomas Broderick, Wellton/Mohawk witness Robert W. Kendall, and to a lesser extent Sempra witness E. Douglas Mitchell and Reliant witness Curtis L. Kebler. These witnesses have either misunderstood that program or are attempting to mischaracterize that program to the Commission. They are attempting to both increase the size of the procurement and focus the scope of the procurement on what these sellers would like to sell rather than what APS and its customers need to buy. They have also drawn precisely the wrong conclusions from the California experience in 2000-2001, and not surprisingly, therefore, have proposed a "solution" that is more likely to replicate that experience in Arizona than prevent it.

Second, I will describe a specific proposal for the procurement of short-term economy energy needs that brings some of the thoughts expressed in my direct testimony into more focus. Although I am still opposed to using the same formal Track B process as is contemplated for securing our reliability needs, APS is willing to consider a compromise to satisfy the concerns expressed by some parties. Specifically, a system of quarterly "mini-Track B" procurements could be implemented for a significant portions of our estimated economic energy needs.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. APS today benefits from one of most sophisticated and innovative power procurement programs in the United States. It has allowed the Company to successfully manage risk and control costs during extremely turbulent and volatile market conditions. The proof is in seven straight years of rate reductions. To criticize APS for not having experience in formal power auctions or RFPs for "asset-backed" unit contingent products is like criticizing a New Yorker for not knowing how to milk a cow or a modern PC-owner for not using a main frame or understanding Fortran. In the case of the former, it is a skill-set of little value given the New Yorker's circumstances and needs. For the latter, you have a somewhat antiquated method of computing that has been superceded from both a hardware and software perspective.

The "APS economy energy proposal" (Testimony of Dr. Craig R. Roach at 5) is not just an APS proposal. It is the same approach to economy energy and other short-term purchases apparently used by Tucson Electric Power Company

("TEP"), which Dr. Roach uncritically accepts, and embraced by TEP witness David Hutchens. It flows directly from the language used in the Staff Report, which in turn comes directly from the Commission's language in the Track A order, Decision No. 65154 (September 10, 2002).

Our (and I presume TEP's) short-term procurement program is the polar opposite of the mandatory real-time purchase scheme used in California. Indeed, it is the Panda/TECO proposal for an RFP process seeking largely unit-backed contingent power that is eerily reminiscent of Gray Davis' California. It could lock APS and its customers into 365 days a year capacity costs during the next couple years to meet a less than 90 days a year capacity need.

There may be a significant risk to our customers in entering into 10 or 20-year agreements (except under special circumstances, which I discuss in my rebuttal testimony), as is recommended by some of the witnesses in this proceeding. Regional Transmission Organizations ("RTOs") and some manner of FERC-mandated Standard Market Design ("SMD") are coming and could significantly affect the relative economics of differing generators. Retail access may be down, but it would be foolish to assume it is dead. Credit problems plague the electric power industry, and it is difficult to know who will be in business 10 or 20 months from now, let alone 10 or 20 years. Power markets will remain soft for at least the next year or two, and may well get softer before they firm up. Although APS will consider any serious offer from a credit-worthy supplier, there is simply no need for APS and its customers to be forced into accepting long-term contracts today.

APS does use least cost evaluative criteria, including dispatch simulation and forward pricing models, over the period for which it is primarily soliciting bids, which is the period 2003 through 2006. Although it is important to simultaneously evaluate the impact of major transmission additions on longer-term proposals, this can be done, as proposed by Dr. Richard Rosen in this proceeding, through a less-software driven iterative process. Moreover, no such transmission additions are planned until after 2006, and the Company is leery of most long-term purchase power commitments for the reasons set forth above.

III. APS POWER PURCHASING EXPERIENCE

Q. BOTH IN DATA REQUESTS AND IN THEIR TESTIMONY, SOME OF THE MERCHANT INTERVENORS HAVE QUESTIONED THE COMPANY'S EXPERIENCE IN RFP SOLICITATIONS, FORMAL AUCTION PROCESSES, AND EVEN IN SECURING THE ENERGY PRODUCTS DESCRIBED IN YOUR DIRECT TESTIMONY. ARE ANY OF THOSE CONCERNS VALID?

A. Not in the least. For example, Dr. Roach accuses APS of not having "much experience in these products." (See Testimony of Dr. Craig R. Roach at 13.) In fact, APS utilizes one of the most innovative and advanced utility power procurement programs in the country. We have a proven track record of managing price, volume and reliability risks through a sophisticated combination of physical and financial derivatives, physical and financial hedges, swaps and other trading devices. APS has long hedged both long and short positions in both power and fuel through various call and put options, costless collars, butterfly options, etc., to reduce and manage costs without exposing customers to large capital investment risks. It is a program that has been in place for years, and since 1998, a period of incredibly unstable and volatile markets

for both power and natural gas, it has allowed APS to meet or beat the market, not just at the time of purchase but also at the time of delivery.

None of these savings were the result of issuing RFPs. I have personally conducted many RFPs in my former role as APS Director of Generation Fuel Procurement, and they have almost universally resulted in above-market bids. This will nearly always be the case when there is an established and viable trading market for the good or service being procured. If the RFP bidders were satisfied just to receive the going market price for their good or service, they would simply sell into the market today and avoid the cost and uncertainty of the RFP process. It is because they expect to receive above-market prices, either due to some manner of product differentiation (my megawatts are better than their megawatts) or the lack of equivalent market alternatives for the buyer (e.g., Colorado, which has no liquid trading hubs, or where the buyer is not permitted by circumstances or the regulator to say "no"), that they generally wish to participate in an RFP process in the first instance.

Now, RFPs do serve a valuable role when soliciting "designer" or specialty energy products such as reliability must-run ("RMR"), DSM or renewable energy, or even when evaluating the design and construction of a new power plant (just like the mainframe computer in the example from my Summary is still useful in analyzing problems requiring vast amounts of computer memory). And, as suggested by my direct testimony proposal, they can be used when a structured procurement is required for regulatory purposes and there is insufficient time and/or consensus about products and results to use a more sophisticated auction process. Although somewhat cheaper than some forms of

auction, the costs of an RFP do not fare well compared to an average $12 cost of conducting a power transaction through the Intercontinental Exchange ("ICE"), a web-based power market procurement site (whose original founders included, incidentally, Reliant and Duke, among others). It's not so much that the RFP process does not work, but that the market has worked and will work better and less expensively for most of the products we need.

For the highly structured procurement of large quantities of standard power products through a wholly transparent process, I agree with Mr. Kebler that there are advantages to an auction. I do not share his confidence that one could be assembled on such an *ad hoc* basis with no agreement on process and no apparent acceptance by Staff of the results for purposes of assured full cost recovery. I would also note that this is a process that APS historically has never needed, and APS customers would not have benefited from the Company's incurring the considerable cost of developing any particular experience in such procurements. But if and when the need for and regulatory acceptance of this form of procurement is more apparent, APS will be ready to acquire the expertise necessary to successfully utilize this procurement tool.

IV. THE "APS ECONOMY ENERGY PROPOSAL"

Q. DID APS PROPOSE "ITS" ECONOMY ENERGY PROCUREMENT PROGRAM JUST TO AVOID MAKING PURCHASES FROM PANDA/TECO, NEG AND THE OTHER MERCHANT INTERVENORS?

A. Of course not. APS has proposed to acquire economy energy and other short-term needs using precisely the methodology endorsed by the Staff Report and precisely the methodology used by TEP and supported by Mr. Hutchens, whom I will simply quote:

> Q. What is TEP's position on Staff's recommendation [p. 4:25] that "short term power, and daily, weekly or monthly power acquired to meet unplanned needs, would however continue to be purchased in the normal course of business as it is today"?
>
> A. TEP strongly agrees with this position. It is an obvious necessity that the utility be afforded discretion to enter into short-term transactions. As Staff recognizes, this gives the utility the opportunity to economically displace plant or contract energy with cheaper market power or purchase to cover unplanned needs arising from temperature extremes and unplanned generation or transmission outages without jeopardizing system reliability by being unnecessarily burdened with a cumbersome procurement process.

(Testimony of David Hutchens at 8, emphasis added.) I can't help but note that Dr. Roach takes absolutely no exception to either TEP's calculation of unmet need or its suggested procurement of that need, including economy energy.

Q. DID "APS PROPOSE THIS [THE 'APS ECONOMY ENERGY PROPOSAL'] NOW" IN ORDER TO "SUBVERT THE [TRACK B] SOLICITATION" AND IN THE HOPE OF BUYING "FROM ITS AFFILIATE'S REDHAWK PLANT AT SPOT MARKET PRICES?"

A. No. Dr. Roach's inflammatory statements (Testimony of Dr. Craig R. Roach at 15) are neither historically correct as to the origin and timing of this proposal, nor are they prospectively accurate as to APS' intent or ability to favor Pinnacle West Energy Corporation ("PWEC") generation in making economy purchases.

During the first Track B workshops, APS fully anticipated divestiture of all its existing generation (with the exception of renewables), and under such circumstances, the distinction between reliability needs and economic needs was meaningless, and so it probably comes as no surprise that neither APS or TEP made much effort to distinguish them. However, by the time APS actually distributed its first rough "guesstimate" of unmet needs in the late August Track B workshop, it was evident that divestiture was not going to happen, and the

Company's representative went to great lengths to state that the numbers given for both APS and non-APS generation should be reduced to reflect economy purchases, which the Company did not propose to procure through the formal Track B process. Thus, neither the "APS economy energy proposal" or, for that matter, the "TEP economy energy proposal" should have been a surprise to anyone and were certainly not unveiled on November 4th as some sort of plot to "subvert" Track B.

As to Dr. Roach's second allegation, APS very much wishes to buy economy energy at or below spot prices from anyone willing to sell it, including affiliates. That is why, in part, the vast majority of APS' needs for economy energy and short-term capacity are procured today through "blind" mechanisms, that is, the identity of the underlying seller is unknown to the buyer at the time of purchase. Sellers of economy energy come from a group of pre-screened (by a third party such as ICE or Bloomberg) entities that simply sign up with either or both of these trading platforms or work through an unaffiliated (to APS) energy broker. As indicated in my direct testimony, APS should reserve the right to do what is necessary, including buying directly from an affiliate, to maintain reliable service to our customers. But this Panda/TECO and NEG rhetoric about there being some sort of vast inter-affiliate conspiracy to purchase economy energy from Redhawk or West Phoenix rather than through the formal Track B process is not just overblown, it is just plain wrong.

Q. ASIDE FROM THE AFFILIATE ISSUE OR WHOSE "ECONOMY ENERGY PROPOSAL" IT WAS, DOES APS INTEND TO EXPOSE ITS CUSTOMERS TO THE TYPE OF SPOT MARKET RISK THAT PROVED SO EXPENSIVE IN CALIFORNIA?

A. Just the opposite. APS has voluntarily sought short-term (day-ahead, month-ahead and real-time), economy purchases for many years, including during all of the California mess. It has done so within the confines of frozen or declining retail rates. So I think we know a thing or two about managing short-term market risk and volatility. It involves close cooperation between both the power desk and the natural gas desk to come up with the right combination of hedges and counter-hedges. This permits APS to more closely align needs with resources while mitigating and managing market price risk.

What California did wrong in the first instance was not its creation of a highly liquid spot market, which was a very good thing. Their mistake was to force (not allow) its utilities to purchase all (not a small portion) of both their reliability and economy needs (APS is generally only talking about purchasing the latter) in the real-time market (APS usually buys only a very small percentage of its economy energy in the real-time or even day-ahead markets, with the balance coming from month-ahead purchases, which along with APS generation and gas hedges, are then used to hedge the real-time and day-ahead purchases). California's utilities were not permitted to protect themselves with either physical or financial hedges, and they were stripped of much of their native load generation, which is the ultimate hedge. California then set up a wholly separate day-ahead market and allowed traders and marketers to arbitrage between the two, create congestion in one to drive up prices in the other, and employ any other "creative" market manipulation they could think of at the time. None of these factors are present in the APS proposal, and the suggestion by Dr. Roach and others to the contrary are an attempt to lead the

Commission in the direction of the second, and larger, major mistake made in California.

In response to an inherently flawed and manipulated market structure and set of market rules, which had bled California's major electric utilities of their credit, the state next overreacted by hastily negotiating a multitude of precisely the sort of unit-contingent, "pay for performance," long-term contracts as are urged by Dr. Roach and other merchant witnesses. Convinced then, as these witnesses are now attempting to convince this Commission, that market prices could only go up, California now turned a one or two year problem (from the inflated spot market purchases) into a 10 or 20 year problem with uneconomic long-term contracts.

Arizona's utilities avoided the mistakes caused by California's spot market straightjacket. They do not want to now fall victim to the greater mistake of assuming, as did California, that the merchants will voluntarily negotiate below-market price agreements for our benefit.

Q. IS APS UNALTERABLY OPPOSED TO ANY CHANGE IN ITS ECONOMY PURCHASE PROGRAM?

A. APS is aware that many parties in Track B are disappointed at the relatively small amount of APS' and TEP's energy needs. And despite the heavy and increasing usage by APS of "blind" procurement techniques for short-term and economy purchases, they are still suspicious of APS dealing with PWEC and Pinnacle West Marketing and Trading ("M&T") in some unfair manner. Therefore, and solely in the spirit of compromise, APS would consider a "mini-Track B" program whereby it would solicit bids for 50% of its annual

anticipated economy energy needs on a quarterly basis. For example, if the annual anticipated need were 4,000 GWH, with 3,000 GWH needed in Q3 and 500 GWH each in Q2 and Q4, with zero in Q1, APS would solicit bids for 50% of each quarter's estimated economy energy need beginning with the first business day of Q1. Sellers could bid on Q2 needs, Q3 needs, Q4 needs, or any combination. If the bids were such that less than 50% of a quarter's needs did not actually end up in signed contracts, the underfilled need would not roll into subsequent quarters. Now, this proposal may be introduced mid-year in 2003, and APS might actually have economy needs even in Q1 of a given year, so the actual sequence of quarters and their respective economy energy needs would be different than in my hypothetical, but the structure would be identical.

Volume, product (for example, peak, super-peak, off-peak, and shoulder) and delivery information would be posted on the Company website prior to the bid date, which will be the first business day of the quarter preceding the quarter for which the energy is first being solicited. Bidders would be pre-qualified as to credit and other contract terms as agreed to by Staff and the independent monitor. Although the bidding would be conducted quarterly, APS would accept bids from and award contracts to bidders for up to four consecutive quarters.

All sealed or faxed bids could be opened and presented, or if conducted electronically through a secure website, received in the presence of Staff and/or the independent monitor. All awarded contracts could be subject to Commission or Staff approval. After the first quarterly solicitation, both APS and the independent monitor would prepare a report evaluating the solicitation both

procedurally and substantively. These quarterly formal solicitations of economy energy could be discontinued after 2004 at the Company's discretion unless prior to September 30, 2004, the Commission found this process to be superior to the Company's traditional method of securing economy energy and ordered its continuance for some specified period of additional time.

Q. COULD THE MERCHANT INTERVENORS USE SUCH A SYSTEM TO SELL APS ECONOMY ENERGY?

A. Absolutely. I know that TECO, Sempra, Reliant, PPL and, I believe, an affiliate of Wellton-Mohawk are already participating in ICE. APS routinely has had transactions executed on its behalf with these entities under the present method of meeting our economy energy needs.

Q. WHAT ABOUT THE ECONOMY AND OTHER SHORT-TERM ENERGY AND CAPACITY NEEDS NOT PURCHASED THROUGH THIS QUARTERLY PROGRAM?

A. APS will acquire all such needs, excepting for immediate reliability needs or when it receives no bids from non-affiliates in response to a solicitation, through non-affiliated suppliers, independent brokers, or electronic trading platforms such as I have discussed both in my direct and rebuttal testimony. Staff could monitor this process and/or conduct audits after-the-fact to assure the Commission that the process is prudent, reasonable and unbiased.

Q. DO YOU BELIEVE THAT THIS PROGRAM COULD RESULT IN HIGHER COSTS TO APS AND APS CUSTOMERS?

A. Quite frankly, yes. It will cost thousands of dollars to set up and administer. And I believe the resulting bids may not be as economical as using our current system of largely electronic procurement. That is because we presently acquire our economy energy in smaller batches (which is less likely to move the market

upward simply by the fact of having such a large procurement at one time). We also would normally spread our economy purchases over several short-term "sub-markets" (real time, day-ahead, month-ahead, etc.) rather than soliciting bids for so much power at one time on a essentially a quarter or year-ahead basis. I am also giving up a little of the present flexibility the Company enjoys in purchasing its remaining economy and short-term energy needs. That is why I am willing to offer this only as a compromise to get this issue resolved and only then on an experimental basis.

Q. ARE THERE ANY OTHER CONDITIONS THE COMPANY WOULD INSIST UPON BEFORE AGREEING TO TEST SUCH AN ECONOMY ENERGY PROCUREMENT PROGRAM?

A. Yes. APS must retain the right to reject all economy energy proposals that it finds unsatisfactory from the standpoint of price or other terms and will be willing to justify that rejection to Staff or to the Commission. Second, if the Commission directs that the program be retained after 2004, such Commission order must authorize full and timely recovery of economy energy costs. Third, any similar economy energy procurement program ordered for TEP should be staggered such that we both are not trying to buy at the same time, which would add to the potential for upward pressure on market prices discussed in my prior answer.

Q. WILL THIS OR ANY ECONOMY ENERGY PROPOSAL, INCLUDING THEIR OWN, SOLVE THE FUNDAMENTAL MARKET CHALLENGES FACED BY ALL THE MERCHANT INTERVENORS?

A. No. The Company's total unmet reliability and economy energy needs are estimated to be in the range of approximately 4,450 GWH (2003) to just under 14,100 GWH (2012), depending on a wide variety of assumptions and forecasts of future events. (See Direct Testimony of Peter M. Ewen at Schedules PME-1

and PME-13.) There are presently some 14,000 MW of merchant generation that has been granted a certificate of environmental compatibility in Arizona alone. All but 500-600 MW of this is combined-cycle gas-fired generation, which is most economical if run at capacity factors in the range of at least 40%. This means there are some 50,000 GWH looking for a home, or approximately 10 times any remotely realistic determination of the Company's unmet needs for 2003-2004. Even by 2012, only about one third of this generation could be supported by APS customers. And this does not consider the additional resources in the market offered by other utilities, merchant plant owners, and energy brokers outside Arizona. Adding all of TEP's unmet reliability and economy energy needs would not materially change this disparity. If these projects are to survive, they are going to have to find markets in California, Nevada, the Pacific Northwest and perhaps Mexico.

V. THE PANDA/TECO PROPOSAL

Q. WOULD APS LIKE TO ACQUIRE CAPACITY PLUS DISPATCHABLE ENERGY AS PROPOSED BY PANDA/TECO WITNESS DR. ROACH?

A. If the price is right for the time I could use that product, yes. In fact, I discussed this in my direct testimony. The second energy product I identified was capacity plus a minimum amount of energy. (See Direct Testimony of Thomas J. Carlson at 3.) I used the word "minimum" purposely to allow for the potential for additional dispatchable energy above that minimum. It would, of course, be up to the bidder to determine whether it was willing to commit any additional energy resources and if so, at what price. I also noted that physical call options, my third energy product, could be dispatchable but that this would carry a premium and might eliminate bidders if I insisted on dispatchability. (*Id.* at 8.)

What I am not looking for, because there is no need from either a reliability or an economy point of view, is year-round and high-priced capacity bundled with that low-cost energy, dispatchable or otherwise. And that is precisely what some of the merchants are trying to sell me. And why do they want to sell me this bundled product even though the Company and its customers don't need it? Because they believe it produces higher margins than selling either the capacity or the energy separately. I do not blame a seller for wanting to sell me its most expensive bundled package of services any more than I should be blamed for wanting to purchase the lowest cost individual services and assembling them into my own package for the benefit of APS customers.

Q. WHY DOES NOT A SIMPLE COMPARISON OF HEAT RATES BETWEEN APS' OLDER GAS-FIRED GENERATION AND THE NEWER COMBINED-CYCLE UNITS OF PANDA AND NEG TELL YOU THAT YOU SHOULD BE SIGNING UP ALL THE UNIT-CONTINGENT, "PAY FOR PERFORMANCE" DEALS YOU CAN GET?

A. Because neither Panda/TECO nor NEG proposes to sell me that low heat rate energy unless I purchase their new capacity on a year round basis. (See Testimony of Dr. Craig R. Roach at 24 – 25.) And the price of that capacity, including fixed O&M, instead of declining every year as it does under cost-of-service pricing, would actually increase by some multiple of inflation. (*Id.*) To then say I can still displace this dispatchable energy on an economic basis (assuming I am not committed by Dr. Roach's and Mr. Broderick's client to minimum take provisions) is like saying I'm free to go to a motel after I've already bought their house.

There is a competitive market for capacity in which the low capacity-cost higher heat rate units determine the lowest price. APS is not the only entity that owns older low cost capacity in the West. Virtually every utility has its own "Ocotillos" and "Saguaros." These units have depreciated capacity costs in the range of $2-5/kW/mo for year-round capacity. This is consistent with the current market value of this kind of capacity, which is only about $2-3/kW/mo. If I limited my purchases to just Q3, that would probably double that figure to, say, $5/kW/mo. In contrast, the cost of a new combined-cycle unit is about $10-15/kW/mo. for year-round capacity. Expanding this differential to the 2000 MW of unit-contingent capacity Dr. Roach would have us bid, this amounts to between $200 million and $300 million in additional capacity costs. Of course, the present market cannot support capacity prices in the $10-15 range, which is why merchant generation is struggling so much. Capacity with a 7000 MMBTU heat rate commands about $4/kw/mo for year-round capacity in today's market. This is still significantly about the price of capacity from 14,000 MMBTU heat rate units, which I previously indicated was in the $2-3 range. Using the $5 price for just Q3 capacity from these admittedly higher heat rate units produces a cost to APS of $30 million compared with the 12-month capacity cost of $96 million from the 7000 MMBTU unit. Thus, unless Panda/TECO is willing to sell me its capacity at a very significant discount from market, let alone from cost, I'm far better off both using my own older generation to firm up energy purchases or buying additional capacity in the market for the same purpose.

I should also add that even on an energy-only basis, the newer combined-cycle units would not always be the best energy solution for our customers. The older APS combustion turbines and combined-cycle units are cheaper to run at low

capacity factors and can be more easily cycled without damage to the unit. They are also essential for reliability, and provide spinning reserves and voltage regulation even during non-RMR hours of the year, as well as providing economic value to APS customers and customers throughout the Southwest through the reserve sharing pool of which APS is a member.

Q. BUT ARE NOT THE HIGHER CAPACITY COSTS OF NEW COMBINED-CYCLE GENERATION OFFSET BY THOSE HIGHER OPERATING EFFICIENCIES THAT BOTH MR. BRODERICK AND DR. ROACH SPEAK OF IN THEIR TESTIMONIES?

A. Over the long run, that might be true, especially if there were not all the indexed escalators to the capacity costs suggested by Dr. Roach. But it's not an "either/or" situation. The current market allows me to get both cheap capacity and Dr. Roach's low cost energy. This is exactly what I was talking about when I indicated that APS should be able to assemble its own package of needed services and not have to accept the package of bundled options proposed by the seller. Anyone who has bought a new car knows the dealer package is seldom the best combination of features at the best price for the buyer's particular needs.

Q. DOES THIS MEAN THAT NO UNIT-CONTINGENT BIDS WILL BE CONSIDERED BY APS?

A. No. I am just trying to tell the Commission and prospective buyers the products I need and want, as well as the market criteria by which I will judge these products. If they wish to discount their offers to meet these criteria, I would be more than happy to seriously consider and even accept such offers.

VI. LONG VS. SHORT-TERM AGREEMENTS

Q. SOME OF THE MERCHANT INTERVENOR WITNESSES, AND EVEN RUCO WITNESS DR. ROSEN, HAVE URGED THE COMPANY TO CONSIDER LONGER TERM PURCHASE AGREEMENTS. WOULD THE COMPANY CONSIDER AGREEMENTS LONGER THAN FOUR YEARS?

A. I would consider any proposal that I thought might be of benefit to the Company and its customers. But I wouldn't compromise their interests just because this or that merchant wished to tie APS up in an above-market deal. The reasons I have proposed limiting the initial Track B solicitation to four years are described in my direct testimony. However, I will elaborate on some of these points in response to the merchants' testimony.

Both NEG and Panda/TECO suggest that asset-backed sales somehow reduce or even eliminate credit concerns. Nothing could be further from the truth. Asset-backed contracts have little value in the market if there is no credit to back up the default risk to the Company. It is fine to say that APS can stop payments for capacity if the seller's unit fails to operate or if the seller simply fails to deliver for any reason. But can the seller pay to the Company and its customers the damages incurred in covering for that default? And can the seller cover these potential damages not just when the contract is entered into, but 10 years down the road?

It has also been suggested at the workshops that if the banks have given a certain generation project total financing, APS ought to be satisfied from a credit perspective. Just because some bank is willing to risk its money without adequate collateral is a poor argument for me risking our customers' money on these same sellers.

Q. AREN'T YOU WORRIED THAT WHEN SOME OF YOUR PROPOSED AGREEMENTS EXPIRE IN 2006, PRICES WILL BE MUCH HIGHER, AS IS SUGGESTED BY DR. ROACH?

A. Dr. Roach discusses this issue at page 28 of his testimony, and yes, I would be concerned if I planned on sitting around until 2006 to see if the situation hypothesized in Dr. Roach's testimony (the end of the power glut) actually materialized. It just doesn't work that way. Risk management is a 365-day per year responsibility, and one that must be met every year. Even assuming that I will have contracted for 100% of all my unmet needs for the next four years during the 2003 Track B solicitation, I could solicit additional contracts in 2004 for delivery in 2007 and beyond, if in fact I believed Dr. Roach's predictions about future power prices. Indeed, the only risk APS faces in this regard would be an inflexible Track B procurement process that prohibited me from making purchases outside some formal, once-a-year RFP.

Q. BUT ARE NOT LONG-TERM AGREEMENTS A HEDGE AGAINST FUTURE PRICE INCREASES?

A. They could be a hedge, especially if not burdened by unlimited price escalators, but they are not the only hedge, and they may not be the best hedge. I certainly believe they may not be a prudent hedge under present market conditions. If you think about it, APS already has the equivalent of long-term contracts for the vast majority of its capacity and energy needs in the form of its rate-based generation assets and existing long-term agreements with SRP and PacifiCorp. APS has proven it can successfully manage price and volume risk, and market volatility, without repeating the mistake of being forced to buy what others want to sell you rather than what you need. When you read about other utilities fleeing into long-term contracts in the present market, they are often utilities

that are very short on existing resources or historically unsuccessful in managing market risk, or both. APS is neither.

Q. ARE YOU SUGGESTING THAT NON-COMFORMING BIDS SUGGESTING LONGER TERMS WOULD BE REJECTED OUT OF HAND IN THE COMPANY'S PROPOSED TRACK B SOLICITATION?

A. No. But I would also counsel that bidder to also submit a conforming bid. The two weeks allotted in the Staff Report is not much time to evaluate longer term proposals, as is suggested in Sempra witness Mitchell's testimony, and so such a proposal would be better considered outside of the formal Track B procedures. As it is, any such long-term bid proposal should be prepared to show:

(1) how APS can be assured of credit-worthiness throughout the proposed term of the agreement;

(2) that the economics of the proposal are relatively insensitive to transmission costs, so that the implementation of RTOs and some form of SMD become less of a concern;

(3) how APS could be protected if it lost significant parts of its retail load to direct access during the term of the agreement; and

(4) that the proposal is not "Christmas-treed" with a bunch of cost escalation provisions unrelated to actual cost increases and limits on even the latter.

VII. APS EVALUATION CRITERIA

Q. YOU EARLIER DISCUSSED THE COMPANY'S USE OF LEAST COST CRITERIA FOR ITS EVALUATION OF OFFERS. IS COST THE ONLY CRITERION?

A. No, but along with credit (which encompasses a prospective seller's past record of performance), it is probably the most important. Other important criteria include deliverability and point of delivery. As discussed in the Staff Report, these criteria will be spelled out in the bid package.

Q. MR. MITCHELL SUGGESTS THE USE OF SOPHISTICATED SYSTEM DISPATCH AND SIMLULATION MODELS TO EVALUATE BIDS? DO YOU AGREE?

A. That is one way, although Mr. Mitchell himself admits there isn't enough time to do that kind of analysis. In fact, the Company does use such tools for its long-term resource planning. But this does not mean that I limit the solicitation to certain products and then try to make those products fit my needs, as is perhaps suggested by Mr. Mitchell at page 8 of his testimony. For my purposes, we use sophisticated market-based models such as RTSIM and UPLAN to first determine the products that best suit our system, and then acquire those products using the various criteria discussed above and also in my direct testimony. Once the bids are received, we will rerun the simulations to make sure we still have the right products for our needs and evaluate the bids accordingly. But I don't want to leave the impression that I allow a computer to decide what the best deal is for our customers. With all the analytical tools available and even with relatively objective evaluation criteria, there is still an element of judgement involved that cannot be delegated to a machine.

Q. MR. KENDALL APPEARS CONCERNED ABOUT HOW APS WILL EVALUATE BIDS OF RENEWABLE ENERGY? DOES RENEWABLE ENERGY HAVE ADDITIONAL ECONOMIC WORTH TO THE COMPANY AND ITS CUSTOMERS?

A. Yes. APS is required to satisfy certain renewable quotas, and if part of that requirement can be obtained as part of this procurement, it reduces the amount

that would have to be otherwise obtained. Thus, if a bid including such resources were received, I would consult with those involved in the renewable program at the Company to determine the additional value such a bid brought to the table. I can say that the additional value is not measured by how much APS collects for renewables, as proposed by Mr. Kendall at page 19 of his testimony. Much of that money will go to existing or already committed renewable projects. I can also say that the Company does not support acquiring all of its renewable energy through one giant hybrid renewable project as suggested by Mr. Kendall at page 17. Distributed as well as grid-connected projects, and projects using different solar and non-solar projects, would appear to me to provide for a more diverse portfolio of renewable investments for the Company and its customers.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. I have attempted to respond to the major points raised by Intervenor witnesses concerning how APS has determined the products for its unmet needs and how the Company proposes to evaluate and acquire its unmet needs for at least the period 2003 through 2006. The fact that I may not have addressed this or that Intervenor witnesses' argument does not imply agreement with such argument. I also hope I have dispelled the notion that APS is some sort of novice in the field of power procurement and risk management, or that it is trying to favor its affiliates at the expense of customers at every turn, as some have alleged. Finally, I have suggested a compromise proposal that, although less flexible and likely to be at least marginally more costly to customers than

our current method of procuring economy energy, the Company would be willing to try on at least a test basis.

Q. DOES THAT CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

WORKPAPERS

Thomas J. Carlson

November 18, 2002

Arizona Public Service Company
Track B Workpapers
Nov 18, 2002

Arizona Merchants
Available Generation
18-Nov-02

	MWs	Capacity Factor (%)	Total Ability GWH
On-line Generation	4,307	40	15,092
Under Construction	4,960	40	17,380
Sub-Total	9,267		32,472
CEC Permitted	5,000	40	17,520
Total	14,267		49,992

Note: Above table reflects generating capacity for State of Arizona. Total GWH is based on 40% capacity factor only

Comparison of installed versus market capacity values
18-Nov-02

	Installed Capacity Costs 18-Nov-02			Market Capacity Values 14-Nov-02	
	Case 1 Older Capacity	Case#2: High New Capacty	Case#3: Low New Capcity	Case #4 Mkt 7 HR Capacity	Case #5 Mkt 12 HR Capacity
MWs	2000	2000	2000	500	500
Cost $ / KW - Mo	4	15	10	4	2.5
Annual Cost Millions	96	360	240	24	15

Market Capacity values based on Independent broker market quotes for Calendar 04 on Nov 14, 2002

EXHIBIT
APS - 6
Admitted

REBUTTAL TESTIMONY OF STEVEN M. WHEELER

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

November 18, 2002

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REBUTTAL TESTIMONY OF STEVEN M. WHEELER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000A-02-0051, et al.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

My name is Steven M. Wheeler. I am Senior Vice President, Regulation, System Planning and Operations for Arizona Public Service Company ("APS" or "Company").

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony will respond to certain accusations by Panda/TECO witness Dr. Craig Roach concerning the Company's motives and past actions. I hope also to put the overall APS rebuttal case into some perspective. Finally, I address Reliant witness Curtis L. Kebler's comments regarding possible standards of affiliate conduct for the present Track B competitive solicitation, as well as certain of the recommendations of Residential Utility Consumer Office ("RUCO") witness Dr. Richard A. Rosen, Law and Water Fund ("LAW Fund") witness Dr. David Berry, and Wellton-Mohawk witness Robert W. Kendall.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

APS is proud of its successful efforts to manage risk, control cost and reduce customers rates during perhaps the most difficult years in the electric utility

industry since the late 1970s. And the Company does not apologize for any of the filings it has made with this Commission. Whether Dr. Roach's client agreed with them or not, APS has always tried to act in the interests of its customers and is doing so in this proceeding.

Second, although Mr. Carlson and Mr. Ewen will rebut specific criticisms of their pre-filed written testimony, I believe that once you get past the invective and the semantic debate over whether a particular need is more or less properly characterized as "reliability," "economy," "reliability must-run," etc., there are significant areas of agreement between APS and some of the merchant intervenors. We agree that APS should procure its needs for purchase power from the competitive market through a process that is reasonable and prudent.

Third, the specific recommendation of Reliant concerning standards of conduct for the upcoming Track B solicitation could, if interpreted literally, eliminate one of the largest of Reliant's (and the other merchant generators') competitors before the solicitation even started. I am, of course, speaking of Pinnacle West Capital Corporation ("Pinnacle West") and its Marketing and Trading division ("M&T"). This is hardly in the interests of APS and its consumers and is not needed to implement a reasonable, fair and open competitive power procurement in Track B.

Finally, although Dr. Rosen, Dr. Berry and Mr. Kendall's testimony on resource planning, demand-side management ("DSM") and the Environmental Portfolio Standard ("EPS") raise some important issues, I cannot support definitive Commission resolution of these matters in this Track B proceeding. There is

simply insufficient time to properly consider and implement these proposals in a manner benefiting APS customers. Some aspects of their recommendations are better considered in separate proceedings already mandated by the Commission, or would be impacted by external events going on at the federal level, the outcome of which cannot be predicted at the present time.

III. PAST APS ACTIONS

Q. HAS APS "CONSISTENTLY MADE PROPOSALS THAT BENEFIT ITS SHAREHOLDERS AT THE EXPENSE OF ITS RATEPAYERS," AS ALLEGED BY DR. ROACH AT PAGE 7 OF HIS TESTIMONY?

A. Absolutely not. APS has provided its customers with rate decreases in 9 of the past 10 years, including the past 7 in a row. These decreases will amount to some 16% by next summer. APS has done so at a time when virtually every utility in the West, including those using the sort of structured procurement process being discussed in this proceeding, have been increasing rates, often significantly. APS and its affiliates have spent literally hundreds of millions of dollars just to keep the lights on in Phoenix and elsewhere in our service territory. APS has a proven track record of managing market volatility and risk that speaks loudest with results—lower costs to our customers.

APS also has benefited its Arizona customers by efficiently marketing the Company's surplus of generation to surrounding states during their time of need. It did so without bending, let alone breaking, the rules or compromising its long-held business ethics, as did so many others. And currently, APS is a leader in securing FERC approval of WestConnect, is a major player in this state's fight against El Paso Natural Gas, and is a partner with the Commission in attempting to modify FERC's Standard Market Design to reflect state and regional

differences. APS has also been recently recognized by Innovest for its environmental leadership as one of the two most environmentally conscious electric utilities in the United States. All of these efforts were and are of significant value to our customers.

Q. WHAT ABOUT THE COMMISSION FILINGS REFERENCED IN DR. ROACH'S TESTIMONY?

A. None of those filings is relevant to Track B. Indeed, for all the claimed linkage between the Company's September 2002 financing application and Track B when they were seeking intervention in the former, no other merchant intervenor witness has even mentioned these other proceedings. In point of fact, APS believed, and continues to believe, that all three of the applications referenced in Dr. Roach's testimony would have, and in the case of the two matters still pending before the Commission, will have important benefits for our customers. And in each such instance, APS asked, and asks now, only an opportunity to make its case and have a decision from the Commission, which is the body APS has to convince.

IV. OVERVIEW OF APS REBUTTAL CASE

Q. WHY DO YOU BELIEVE APS IS IN FUNDAMENTAL AGREEMENT WITH MUCH OF WHAT THE MERCHANT INTERVENOR WITNESSES SAY?

With the exception of National Energy Group ("NEG") witness Thomas Broderick, we appear to agree that we should be determining the Company's unmet needs for Standard Offer retail customers. There are some important differences in how we calculate that need, but the fact that, for the most part, we are trying to determine the same need is encouraging. Second, APS agrees with Dr. Roach, Mr. Broderick and other merchant intervenor witnesses that the

Company should be attempting to acquire the least-cost mix of capacity and energy for its customers consistent with appropriate reliability and credit criteria. However, and as is to be expected between buyer and seller, there is significant disagreement as to what combination of products is best and which products should be acquired when, but at least we can agree on what we are trying to accomplish. Third, APS agrees with the merchant witnesses that ask for reasonable assurances to APS of full cost recovery for power contracts acquired through the Track B process. APS also supports the consensus positions, as reflected in the Staff Report, that the Environmental Portfolio Standard should be addressed in the 2003 proceeding set aside by Commission rule for its review, and that demand-side management ("DSM") should be incorporated into future procurements, but without a mandated set-aside.

V. OTHER SPECIFIC COMMENTS ON INTERVENOR TESTIMONY

Q. IN ADDITION TO DR. ROACH, ARE THERE OTHER INTERVENOR WITNESSES TO WHOM YOU WISH TO RESPOND?

A. Yes. Mr. Kebler suggests a specific and retroactive standard of affiliate knowledge and behavior that is both impractical and counterproductive to the interests of APS customers. Dr. Rosen has urged a return to traditional resource planning such as was briefly practiced in Arizona in the late 1980s and early 1990s. Dr. Berry proposes mandatory DSM procurements outside the Track B process, or at least outside the process used for power supply procurement, combined with a DSM "set aside" similar to that of the EPS. Mr. Kendall takes issue with what the Staff Report has characterized as a consensus position, i.e., that the EPS be addressed separately, although utilities remain free to seek EPS requirements in conjunction with the Track B procurement if they see fit to do

so. While the issues raised by these latter three Intervenor witnesses are certainly important, I cannot support their resolution in this proceeding for a variety of practical and conceptual reasons.

Q. DOES APS OPPOSE STANDARDS OF CONDUCT FOR THE TRACK B PROCURMENT?

A. Not if the Commission believes them necessary. APS, and I specifically, posed no objections to the Staff's general recommendation for Standards of Conduct. But I noted in my direct testimony, APS cannot accept a Standard of Conduct that prevents the Company from effectively conducting the Track B solicitation in a manner that protects its customers. Nor can I support as being in the interests of our customers a Standard of Conduct that excludes automatically "out of the gate" a major potential bidder such as M&T. Taken literally, Mr. Kebler's recommended Standard of Conduct would do either or both of these things.

Mr. Kebler proposes a retroactive Standard of Conduct that requires APS to demonstrate that those APS employees (and Pinnacle West shared services employees) who have "worked on the [Track B] procurement, including its development, execution and review, did not have any improper contact with any utility affiliate that is participating in the competitive solicitation." (Testimony of Curtis L. Kebler at 14, emphasis added.) Mr. Kebler goes on to require that: "[M]embers of the [APS] procurement team should be required to certify that they have no knowledge of the products or offers of any affiliate participating in the competitive solicitation." (*Id.*) Aside from the lack of definition of "improper contact," which definition would be critical in implementing Mr. Kebler's suggestion, APS could not comply with either standard.

The simple facts are these:

- As a result of the 1999 APS Settlement and the Commission's Electric Competition Rules, M&T has performed power procurement, gas supply, scheduling, dispatch, financial and volume risk management and other contract management services required by APS.
- Until August 27, 2002, APS legitimately expected that both its generation and that of Pinnacle West Energy Corporation ("PWEC") would be owned by PWEC and jointly dispatched, operated, and used for APS customer needs, with any surplus marketed elsewhere in the region, also jointly, by M&T.
- APS began formulating its determination of unmet need and its procurement plan prior to August 27, 2002, which formulation of necessity involved M&T employees.
- After August 27, 2002, some M&T functions, specifically those involving APS procurement, began to be transferred back to APS.

APS cannot change history by somehow "undoing" their employees' relations with M&T. Nor could they "attest" they have "no knowledge" of the type of energy products M&T has and is capable of offering (any more than Reliant's energy traders could attest they have "no knowledge" of what M&T does, since Reliant routinely has conducted trades with M&T). What APS can do and is doing is to insulate its procurement team on a going-forward basis from those at M&T who would be involved in formulating or submitting any Track B bid. It

will establish communications protocols concerning the solicitation as proposed by Staff and will not permit those personnel at M&T involved in bidding to have any role in substantive bid evaluation. In sum, we will do what we can without compromising the interests of our customers. But we should not be required to compromise those interests to satisfy every conceivable or speculative merchant "concern," nor can we agree to or promise the impossible.

Q. WHAT IS APS' POSITION ON INTEGRATED RESOURCE PLANNING?

A. I am supportive of the general concept of IRP, and in fact, it is part of my responsibilities at APS. However, the Commission's present integrated resource planning ("IRP") regulations were formulated in the late 1980s and, although only officially "suspended" in 1997, have not been actively utilized since the mid-1990s. Updating these rules to reflect today's electric market, with its myriad of new energy products (both physical and financial) and new players (IPPs, ESCOs, brokers, RTOs, etc.), and to accommodate the increasingly competitive nature of the type of information typically needed for a proper IRP, would require considerable time and effort. We also have the issues of retail access and federal wholesale market design that would need to be factored into any new state IRP process.

I might agree with Dr. Rosen that, <u>if</u> done properly and <u>if</u> reconcilable with continued retail competition and the new wholesale market design being hammered out on the federal level, this time and effort may be a worthwhile investment for both the Commission and utilities such as APS. But those are clearly some extremely important "ifs" that cannot be resolved in this proceeding. Moreover, there is simply no possible way of restarting such a cold

and (as presently written) antiquated engine in time for a 2003 power solicitation.

Even doing so by 2004, as is suggested by Dr. Rosen, would appear ambitious to me. The last set of IRP regulations did not have to worry about either retail competition or federally-mandated regionalization of the planning process, and yet they still took many months to finalize and many more months for the necessary data to be gathered. Typical resource planning proceedings of the time were themselves over a year in length. At best, it would be mid-2004 before the results of Dr. Rosen's proposed IRP process could be implemented in any meaningful fashion.

Q. WHAT ABOUT DR. BERRY'S AND MR. KENDALL'S SUGGESTIONS ON DSM AND THE ESP?

A. I agree that DSM options are difficult to evaluate "head-to-head" with supply options for many of the same reasons as discussed by Dr. Berry. (See Testimony of Dr. David Berry at 4.) It was for that reason, plus the short time allowed under the Staff Report's timeline for bid evaluation, that APS proposed to exclude DSM resources from the first Track B procurement.

I further agree with Dr. Berry that developing a rational and effective DSM program will take time. (*Id.* at 5.) Moreover, since the Commission-directed redeployment of funds to the EPS, there is simply no existing funding source for DSM, nor a process in place for Staff evaluation and approval of DSM programs as existed during most of the 1990s.

Finally, Dr. Berry's "Environmental Risk Management" appears to be something that the Commission could, if it wished, address in any rejuvenated IRP process. I certainly would not support dealing with such an important issue on an *ad hoc* basis in this docket with this meager record.

As to Mr. Kendall's suggestion relative to the EPS, the Commission has already mandated a 2003 review of the entire EPS program. This would appear to be a perfect vehicle for vetting Mr. Kendall's concerns rather than asking the Commission to make a hasty decision in Track B based on the input of a single potential vendor of EPS products. As to the specific situation of Mr. Kendall's client, the Company has presently outstanding a renewables RFP, which RFP I am told remains open at the present time.

Q. ARE THERE OTHER REASONS WHY THE COMMISSION SHOULD DEFER ACTION ON THE RECOMMENDATIONS OF DR. BERRY, DR. ROSEN AND MR. KENDALL?

A. Yes. In Decision No. 65154, the Commission committed to a thorough review of all of the Electric Competition Rules. I can easily imagine that review impacting the practicality, necessity, or even the legality of some of these proposals. Overhanging any individual rule changes is the question of the long-term future of retail competition in this state.

Also, the federal government is considering a variety of initiatives that affect IRP and renewable energy, both central station and distributed. These include the SMD requirements for regional planning and resource adequacy requirements that may or may not consider DSM. There are the planning and transmission expansion roles envisioned for RTOs, such as WestConnect, and

also federal legislation or proposed rulemakings on distributed generation, interconnection, and renewable energy requirements.

In short, there are too many unanswered questions regarding the nature, scope and even continued state role in resource planning to support deciding these and the related issues of DSM and EPS procurement at this time and in this proceeding.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. To do its job of meeting customer demand reliably and at a reasonable price, APS must ask for what every buyer must have—the ability to determine what it needs, when it needs it, and what it is willing to pay—in other words, Mr. Carlson's ability to say "no" to proposals that hamstring the Company at our customers' expense.

Similarly, I urge the Commission to be cautious in adopting proposals that, although appearing to have some potential merit, have not been thoroughly addressed by Staff and the other parties, either during the Track B workshops or in their testimony. The "Law of Unintended Consequences" may not appear in any statute book, but it is well-founded in the human experience, as the still all too recent debacle in California reminds us.

Q. DOES THAT CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes, it does.

EXHIBIT
APS-7
Submitted

REBUTTAL TESTIMONY OF THOMAS GLOCK

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

November 18, 2002

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REBUTTAL TESTIMONY OF THOMAS GLOCK
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000A-02-0051, et al.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Thomas Glock. I am the Manager of Transmission Operations at Arizona Public Service Company ("APS" or "Company").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND EXPERIENCE.

A. I have a Bachelor of Science degree from the University of Arizona. I began working for APS in 1983, and was an operator at the Yucca Power Plant in Yuma, Arizona until 1989. Subsequently, I have spent eleven years as a real-time generation dispatcher and/or managing the Company's Energy Control Center ("ECC"). From 1997 to 2000, I was the Chief Dispatcher and Transmission Section Leader for the ECC. I am a North American Electric Reliability Council ("NERC") and Western Systems Coordinating Council ("WSCC") Certified System Dispatcher. From 2000 until earlier this year, I was the Manager of Interconnections Development, and in that capacity was responsible for all interconnections to APS' transmission system.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I will respond to the claims of some intervenors, including Mr. Thomas Broderick, Mr. Curtis L. Kebler and Mr. Robert W. Kendall that relate to Reliability Must Run ("RMR") issues and transmission import limitations in serving load-constrained areas such as the Valley and Yuma.

II. SUMMARY

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. Some of the merchant generator intervenors suggest that transmission deliverability and RMR should either be ignored or that the risk of any transmission limitations should be placed on APS rather than the seller. This is not the appropriate way to address RMR and deliverability. Instead, the RMR studies that were directed in the Track A order and discussed in the Biennial Transmission Assessment are the appropriate vehicles to quantify and resolve RMR issues.

Wellton-Mohawk goes further, and recommends that all load in the Valley and Yuma areas be contestable. This clearly exceeds the direction given in the Track A order and makes little sense given APS' existing transmission and rate-based generation resources. Wellton-Mohawk's criticisms of APS' resource planning for meeting load serving requirements in Yuma are likewise misplaced.

III. REBUTTAL TO NEG'S AND RELIANT'S RECOMMENDATIONS

Q. NEG'S WITNESS, MR. BRODERICK, RECOMMENDS ELIMINATING RMR FROM THE DETERMINATION OF UNMET NEEDS. DO YOU AGREE WITH HIS REASONING?

A. No. Mr. Broderick contends that there is "substantial uncertainty" about actual and future transmission import limits to serve APS customers. Apparently because of this uncertainty, he recommends that RMR and deliverability into transmission constrained areas such as the Valley simply be ignored in determining APS' unmet needs. This unfairly and inappropriately allocates <u>all risk</u>, including reliability risk, associated with present and future RMR requirements solely to APS. Under Mr. Broderick's logic, APS would have to

buy power that it could not import into the Valley to serve its customers depending on present or future RMR conditions. NEG chose to locate their power plant outside the Valley where they could benefit from access to California and other markets through the Palo Verde hub, so it is inappropriate for them to now demand that APS ignore transmission deliverability issues into the Valley.

Q. DO YOU HAVE OTHER REBUTTAL COMMENTS ON MR. BRODERICK'S TESTIMONY?

A. Yes. Without providing any explanation, Mr. Broderick asserts that subjecting RMR to the main Track B procurement "can serve to demonstrate the validity of the calculated RMR." (Broderick Test. at p. 17.) As I discussed above, finding out that RMR is a real concern after the procurement is completed is hardly good policy or practice. However, APS has proposed that non-APS RMR requirements be separately bid in the procurement, which should provide the same "test" that Mr. Broderick appears to advocate.

Q. HOW WILL RMR REQUIREMENTS BE DETERMINED?

A. Consistent with both Decision No. 65154, the Track A order, and the current Staff Biennial Transmission Assessment, APS will complete an RMR study for both the Valley and Yuma by the end of January. The Valley study will be performed in conjunction with Salt River Project. These studies will determine and document RMR issues in APS' service area and will be completed prior to the competitive bidding commencing in 2003. There appeared to be consensus, or at least no opposition, at the Biennial Transmission Assessment workshops to using this approach for studying and quantifying RMR. Mr. Broderick's suggestion that the issue either be ignored, or be decided without benefit of the

very study that Decision No. 65154 ordered, is certainly contrary to the ongoing work in the Biennial Transmission Assessment.

Q. MR. KEBLER OF RELIANT RESOURCES ALSO CRITICIZED DETERMINING RMR REQUIREMENTS IN THE RMR STUDY. ARE HIS CRITICISMS WARRANTED?

A. No. Throughout both the Track B workshops and in the Biennial Transmission Assessment, I believe it was understood that some details of the solicitation would be developed through January 31, 2003. Reliant was a participant in both proceedings. The RMR studies addressed in both the Track A order and the Biennial Transmission Assessment are simply not yet completed.

Further, the RMR figures are difficult to quantify in advance of the RMR study with the level of precision that Reliant demands. The actual import capability for any given hour, day, or year is dynamic, and thus the RMR requirements will vary based on final path ratings for new transmission lines and other system upgrades, anticipated generator loadings, the actual load and peak demand in the constrained area, and potential changes in system capability resulting from the loss of one electrical element, technically known as single contingency analyses, and the application of Western Electricity Coordinating Council ("WECC") operating requirements.

Q. DID STAFF WITNESS JERRY SMITH RAISE THE ISSUE OF CHANGES TO THE IMPORT LIMITATION AS WELL?

A. Yes. Mr. Smith commented at the final APS Track B Workshop that the figure provided for Valley Import Capability and which is used in APS' needs assessment could be increased in certain years to reflect planned transmission projects. These include the Southeast Valley Project in 2006 and Table Mesa in

2008. I agree in concept. However, neither of these projects have a Certificate of Environmental Compatibility. Nor can APS perform the technical analyses necessary to determine path ratings or the allocation of transmission rights among project participants. In fact, studies are just now being finalized on the Palo Verde-to-Rudd (Southwest Valley) 500 kV transmission line, due to be placed in service in 2003. Given these uncertainties, the most appropriate RMR figures to use in Track B are those based on current data and those that will be determined in the forthcoming RMR studies. This data will, of course, be updated when future projects are closer to being placed into service.

IV. REBUTTAL TO WELLTON-MOHAWK

Q. MR. KENDALL, ON BEHALF OF WELLTON-MOHAWK, RECOMMENDS THAT ALL LOAD INSIDE A LOAD POCKET SHOULD BE MADE CONTESTABLE. DO YOU AGREE?

A. No. Mr. Kendall's recommendation is directly contrary to what I interpret as the contestability standards established in the Track A order, primarily because most of APS' load is in the Valley and Yuma metropolitan areas. Making all that load contestable would ignore APS' existing coal and nuclear units that today serve these areas over existing transmission capacity and which are included in the Company's rates. Further, transmission constraints are by no means a situation unique either to APS or Arizona—it is one present in virtually all major metropolitan areas.

Q. DOES WELLTON-MOHAWK CRITICIZE APS' LOAD SERVING CAPABILITIES IN YUMA?

A. Yes, but their criticism is dramatically overstated. Specifically, Wellton-Mohawk suggests that APS is acting in an environmentally unsound way in meeting its load serving obligations in Yuma. That is incorrect. Most Yuma load

is served from remote generation imported over transmission lines. Local generating capacity is used when the import limits are exceeded, but APS' plants in Yuma meet or exceed all applicable environmental permitting requirements. Also, there is significant operational flexibility in meeting Yuma loads given the location of non-APS power plants in the area and the North Gila transmission line, which allows for energy purchases from the California markets. APS is also making transformer upgrades at substations in the area that will increase transmission import capability.

APS is not in the critical position that Wellton-Mohawk suggests, and I certainly do not think it is necessary for APS to pay any sort of "RMR premium" at this time. As was recognized in the Biennial Transmission Assessment, the as yet still proposed Wellton-Mohawk project is by no means the only option APS has to address future load serving capability at Yuma, and I would not want to foreclose those other options by committing now to a project that does not have either a Certificate of Environmental Compatibility or any financing, particularly given today's difficult credit environment. APS does, however, view the Wellton-Mohawk project as one of several possible future resources for meeting load serving obligations in Yuma.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

1271510.1

Harquahala

1 - 3

EXHIBIT

H-6

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING.	DOCKET NO. E-00000-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606	DOCKET NO. E-01345-01-0822
IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY	DOCKET NO. E-01933A-98-0471

NOTICE OF FILING OF DIRECT TESTIMONY OF

THOMAS BRODERICK

ON BEHALF OF HARQUAHALA GENERATING COMPANY, LLC

Harquahala Generating Company, LLC, by and through its attorneys, hereby files the Direct Testimony of Thomas Broderick, Director, External Relations, West Region, PG&E National Energy Group, pertaining to the issues in "Track B" for the above-captioned proceeding.

RESPECTFULLY SUBMITTED this 12th day of November, 2002

QUARLES & BRADY STREICH LANG LLP
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By _____
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By Sarah Menne

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING.	DOCKET NO. E-00000-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606	DOCKET NO. E-01345-01-0822
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IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY	DOCKET NO. E-01933A-98-0471

DIRECT TESTIMONY OF THOMAS BRODERICK ON BEHALF OF HARQUAHALA GENERATING COMPANY, LLC

November 12, 2002

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Direct Testimony
Of
Thomas Broderick
Harquahala Generating Company LLC
November 12, 2002

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Thomas Broderick. My business address is 845 N. 3rd Ave, Phoenix, AZ 85003. I am Director, External Relations, West Region, PG&E National Energy Group ("NEG"). Harquahala Generating Company, LLC ("HGC") is our 1,092 MW nominal power plant under construction just west of Tonopah, AZ.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND EXPERIENCE.

A. A summary of my professional qualifications and experience is included in Exhibit TB-1 attached to this testimony.

Q. ARE YOU FAMILIAR WITH THE TESTIMONY OF APS WITNESSES MR. EWEN AND MR. CARLSON, THE ACC STAFF 10-25-02 TRACK B REPORT, THE 11-6-02 APS PRESENTATION AND APS' RESPONSES TO DATA REQUESTS IN THIS PROCEEDING?

A. Yes, my colleagues and I at the NEG endeavored to analyze these documents.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. 1. APS understated its current unmet needs in APS Schedule PME-1. In its calculations, APS omitted several APS customers, incorrectly assigned Pinnacle West supply contracts to APS, vastly overstated the economic level of output of its exiting units,

and overstated its RMR requirements. Thus, my direct testimony focuses primarily on recalculating APS' actual unmet needs. The result of my analysis is a restatement in Exhibit TB-2 of APS' Schedule PME-1.

2. I have re-calculated APS' current unmet needs in Exhibit TB-2 as:

	MW	MWh
2003	2,997	5,639,000
2004	3,286	6,694,000
2005	3,519	7,509,000
2006	3,762	8,602,000

To these figures I add approximately 1,946,000 MWh of potential economy interchange purchases that APS can obtain competitively at its discretion.

My re-calculations confirm the reasonableness of Staff's MW and MWh recommendations for APS contained in the 10-25-02 Staff report.

3. APS' proposal over relies on a product with a volatile price - economy interchange purchases. Thus, I recommend that APS issue an RFP in the March 2003 solicitation for the amounts in Exhibit TB-2 and drastically reduce the amounts it intends to procure as economy interchange. My proposal will preserve the ability of ACC Staff to apply a price to beat concept, whereas APS' proposal will make it very difficult.

4. I recommend the ACC Track B order embrace the use of economic criteria called "minimize the net present value of rate impacts" which is presently employed in the Colorado solicitation. This criteria best captures ACC Staff's goals and will result in APS purchasing an equivalent quantity of power that it previously intended to

purchase from its affiliate. If this criteria is embraced, the ACC will not have a need to "take over" the process, but rather APS will enjoy considerable business discretion.

5. My analysis herein exposes what APS has known for several years – the competition in the Track B process will be most fierce for its older and less efficient gas and oil units and between the merchants themselves, including Pinnacle West. In its own earlier plans, APS had created plans to virtually idle their fleet of older gas and oil units. Their actual purchases in 2001 and 2002 demonstrate they were well on their way to doing just that.

6. I recommend that APS file and the ACC approve a protocol for any future competitive procurement of economy interchange energy. The criteria for such a protocol should insure that APS solicits offers from the competitive wholesale market and in a manner that does not allow for inappropriate affiliate transactions or favoritism of particular parties. Such a protocol will reduce the incentive for APS to propose purchases outside of the Track B process.

1. DETERMINATION OF APS UNMET NEEDS

Q. WHY HAVE YOU RESTATED APS SCHEDULE PME-1 THAT SETS FORTH APS UNMET NEEDS?

A. APS has significantly understated both its current capacity ("MW") and energy ("MWh") unmet needs. My restatement in Exhibit TB-1 confirms the appropriateness of the much higher MW and MWh amounts set forth in the ACC Staff report of 10-25-02. As part of the process of restating Schedule PME-1, I present an economic criteria and a specific

formula that can be approved by the ACC and be employed by APS in its final determination of unmet need in January 2003 for use in the March 2003 solicitation. In the testimony that follows, I discuss each component of my restatement and proposed formula. I concentrate on the period 2003 to 2006, although under Staff's proposal contracts of longer duration can be approved when especially favorable economics are demonstrated.

1.A APS MW and MWh Forecasts

Q. WHAT ARE YOUR FINDINGS CONCERNING THE APS MW AND MWH FORECAST?

A. The method APS has selected in determining unmet needs in Schedule PME-1 defines their wholesale customers in a manner unfavorable to the merchants.

According to APS, its 2002 *weather normalized* peak load was 5,850 MW. In the past 5 years, APS' weather normalized peak load has grown an average of 231 MW per year from 4,692 MW to its present figure. Over the 5-year period 2003-2008, APS forecasts its load to grow an average of 268 MW per year.

However, APS is forecasting a ***decline*** in its peak load from 5,850 MW in 2002 to 5,723 MW for 2003. This is the result of APS employing multiple definitions of its own peak load – they assign their wholesale customers to APS or Pinnacle West in various ways. In Schedule PME-1, APS has used the definition that reduces the APS load forecast with the consequence of limiting the amount of capacity and energy subject to competitive procurement.

Q. WHAT ARE THE VARIOUS DEFINITIONS OF PEAK LOAD THAT APS USES?

A. In APS responses to HGC data requests, APS provided two sets of peak load figures and in response to Staff they provided a 3rd set. They provided HGC *actual* peak load, which in 2002 on a weather normalized basis equaled 5,850 (HGC DR 1 Q. A.3c). They also provided an actual peak for *retail customers and current cost-of-service wholesale customers* - in 2002 this was 5,486 (HGC DR 1 Q.A.1). This second figure is 364 MW *less* than the former.

I tracked the second, lower forecast, to APS' calculation of its unmet needs in APS Schedule PME-1.

Q. WHAT EXPLAINS THE DIFFERENCE BETWEEN THE TWO PEAK LOAD FORECAST DEFINITIONS YOU HAVE CITED?

A. APS indicated, "APS forecasts prior to October 2001 included projections of peak demand and energy for Citizens, TOUA and Wickenburg." So, apparently APS desires these three APS power sales contracts to be supplied by Pinnacle West generation.

Q. WHAT IS THE CONSEQUENCE OF RE-ASSIGNING THESE 3 CONTRACTS FROM APS TO PWCC?

A. The change frees up over 300 MW of APS generation historically used to serve these customers. APS is proposing this generation be re-dedicated to serve APS retail customers. The primary consequence reduces both the amount of capacity and energy that APS would otherwise procure in this Track B proceeding. It therefore, reduces the amount that merchants such as Harquahala can compete for in the upcoming competition and merely awards these contracts to Pinnacle West generation.

Q. DO YOU RECOMMEND THAT THE ACC REQUIRE APS TO EMPLOY THE DEFINITION USED BY APS PRIOR TO ITS OCTOBER 2001 FORECAST?

A. Yes. I base this recommendation on the following:

1. APS' official actual peak load still contains these three wholesale customers.
2. APS has not provided actual language from these wholesale contracts specifically showing that Pinnacle West generation is the sole source for serving these customers.
3. Even if they have this information, these long-term contracts went to Pinnacle West after the 1999 Electric Rules and APS Settlements occurred and the contracts last into years when supply is to be competitively procured and so APS proposes that its retail customers be denied the benefit of the competitive wholesale market on an equivalent amount of generation. It would seem that specific approval by the ACC, with these factors in mind, would be needed before APS could cease serving these customers.

Thus, for the purposes of Track B both the MW and MWh to serve these contracts should be moved back into APS Schedule PME-1 and be competitively procured. APS provided a forecast for these three customers for 2003 totaling 313 MW and 1,621,448 MWh. In Exhibit TB-2, I have also used these same amounts for 2004-2006.

My only re-calculation of APS MW and MWh in Exhibit TB-1 is to place these three contracts back under the APS load and energy forecast. These contracts may not seem large in the grand scheme of things, but if Harquahala won them we would feel very fortunate indeed.

Q. IS APS' FORECAST OTHERWISE TOO LOW?

A. The October 2002 forecast of retail MW and MWh appears reasonable. However, chances are somewhat greater that it is too low than too high.

APS' data responses (HGC DR 1 Q.A.5.1) indicate a persistent under forecasting as opposed to frequent alternating back and forth in accuracy. Schedule PME-6 indicates that their MWh forecasts have been much more accurate than their peak load MW forecasts.

Forecasts prepared from 1992 to 1999 persistently under forecasted MW and MWh. Recently, a tendency to over forecast has emerged in forecasts from October 2000 on. However, APS's data response (HGC DR 1 Q.A.6.1) indicated that its most recent projection (October 2002), as compared to its prior April 2002 forecast reduced the 2003 peak load projection by 211 MW, a significant reduction, and one that was carried forward each year thereafter. APS stated that the basis for the large reduction was a "Correction of System Load Factor."

In general, forecasters can be expected to under forecast in the early stages of an economic recovery and over-forecast in the early stages of an economic downturn. Given that APS has just reduced its forecast and we are late in an economic downturn and on the precipice of an economic recovery, the chances are better than 50% that their current forecast is too low. APS has made a large reduction in its most recent October 2002 load forecast, reducing each and every future year and, is therefore, very likely to end the brief period of over forecasting which started with its October 2000 forecast.

1.B CAPABILITY OF APS UNITS

Q. DOES APS' FORECAST OF THE "PHYSICAL CAPABILITY OF APS UNITS" CONTAINED IN APS SCHEDULE PME-1 NEED RESTATEMENT?

A. Yes. As APS notes, their generation varies over time due to outage schedules, economic conditions and other reasons, so its necessary to examine this information closely, particularly as regards economic conditions. APS provided us some historical annual data for 1992-2001 and data through September 2002. The average annual output of the entire existing APS generation for the ten-years ended 2001, was 21,278,000 MWh. The highest year was 2001 at 24,446,051 MWh and the lowest year was 1995 at 19,602,493 MWh. The current year 2002 may end up being among the lowest years as APS generation has been displaced by its purchases from PWEC generation and unspecific "long-term purchases." Through September 2002, the APS units produced 17,095,066 MWh. At an earlier ACC Staff Track B workshop, APS provided its April 2002 forecast for its existing generation of 20,669,120 MWh for 2003 and 21,543,806 MWh for 2004. My analysis suggests that these figures provided by APS at the earlier workshops are reasonable, but that the figures in Schedule PME-1 are not. I build my case by focusing on APS' coal and nuclear generation.

The actual output of APS' coal and nuclear units was as follows:

1999	20,727,061 MWh
2000	21,347,118 MWh
2001	20,958,417 MWh
3-year average 1999-2001	21,010,865 MWh

Thus, I note that the most recent 3-year average of production by the APS coal and nuclear units is approximately equal to the APS forecast of generation for 2003 (at 20,669,120 MWh) and 2004 (at 21,543,896 MWh) for their entire existing generation base.

Q. HOW DID YOU REVISE SCHEDULE PME-1 IN LIGHT OF THIS AND OTHER DATA?

A. I inserted into Exhibit TB-2 the 3-year historical average of APS' coal and nuclear units generation in place of the figures APS used for Physical capability: 21,010,865 MWh. One could argue that even my figure over-states somewhat the future coal and nuclear output given the tightness of the wholesale market during 1999-2001 as coal and nuclear generation was, no doubt, being sold to other utilities during this time. It is, in part, for this reason that later in my testimony I recommend an economy interchange component for the coal and nuclear generation.

Q. CAN YOU MAKE FURTHER REASONABLENESS CHECKS ON THE APPROPRIATENESS OF USING THE PRODUCTION OF APS' COAL AND NUCLEAR UNITS IN DETERMINING UNMET NEEDS?

Yes. In 2001, APS purchased 504,985 MWh from Pinnacle West generation and through September 2002 APS purchased 1,554,314 MWh from PWEC generation. PWEC generation was just beginning to come on-line during these years and APS provided us its plans for purchasing much more in the future than these historical amounts.

However, the impact of APS purchases in 2001 and 2002 from Pinnacle West was already noticeable in reduced generation of APS' older gas and oil units. A few examples:

	2001	2002
Capacity Factors (ACC Staff DR 1 Q.MR 1.3):		
West Phoenix CC 2	60.2%	33.7%
Ocotillo Steam 2	38.5%	10.6%
Saguaro Steam 1	36.7%	9.3%
West Phoenix CT 1	18.4%	2.6%
Ocotillo CT 1	24.4%	3.8%
Yucca 4	11.9%	0.3%

In fact, as compared to 2001 (and 2000 for that matter), all 18 of the APS gas / oil units experienced significant reductions in capacity factor in 2002. This is no surprise since these are precisely the units for which merchant generation such as Pinnacle West's is designed to displace on an economic basis. This process was only just beginning in 2002 with Pinnacle West's Red hawk plant achieving initial commercial operation.

Also, in data responses, APS provided the April 2002 forecast of the APS planned purchased power from the Pinnacle West units. I also compare these figures to the unmet needs in APS Schedule PME-1 plus economy interchange purchases:

	From Pinnacle West	APS Schedule PME-1[1]
2003	5,728,434 MWh	4,196,000 MWh
2004	6,170,100 MWh	4,873,000 MWh
2005	7,217,000 MWh	7,923,000 MWh
2006	7,420,000 MWh	8,417,000 MWh

[1] Plus economy interchange amounts in APS Schedule PME-13.

For 2003 and 2004, the April 2002 planned purchases by APS from Pinnacle West are substantially in excess of APS' calculations of unmet need plus their proposed economy purchases. For 2005 and 2006, APS has proposed significant purchases – however, I have a major concern with the product (economy interchange) APS proposes for those years. At any rate, the figures above confirm that APS' April 2002 plan for generation by its entire existing fleet is equivalent to that which had been historically produced by its coal and nuclear units for reasons which include APS' plans to displace its own existing gas and oil units by purchases from Pinnacle West.

Q. THUS, FOR THE PURPOSES OF THE MARCH 2003 PROCUREMENT, YOU ASSIGN APS' COAL AND NUCLEAR UNITS TO MEETING APS NEEDS, BUT WANT TO COMPETE AGAINST THEIR MORE COSTLY UNITS?

A. Yes. Just as Pinnacle West wanted to economically displace these more costly units, so do we.

As an overview of the wholesale market, the merchants can win against the *total* cost of nuclear and against the cost of a *new* coal plant. The dispatch cost of most of the existing coal units is generally less than the merchant units. As a result, the competition is concentrated on older gas/oil units and between the new merchant units themselves.

Even though my testimony herein relies primarily on various comparisons of historical and future output of APS units, Pinnacle West units, and relative efficiencies, my colleagues have performed sophisticated production costing simulations for 2003-2006 integrating APS and merchant units into a single economic analysis using

"PROSYM" and the "EMSS" database. The vendor of this data may require us to obtain a confidentiality agreement if ACC Staff wishes to review the results. These simulations confirm my recommendation herein to compete for APS' older gas and oil units.

Q. TO GIVE THIS DISCUSSION EVEN MORE PERSPECTIVE, PLEASE INDICATE THE PHYSICAL CAPABILITY OF THE HARQUAHALA GENERATING FACILITY.

A. Harquahala is a nominal 1,092 MW facility. Below is its production capability at various capacity factors:

90%	8,609,000 MWh
75%	7,174,000 MWh
50%	4,783,000 MWh

In other words, the Harquahala facility, *alone* is capable at supplying the entire APS unmet need plus economy purchases through 2006 and represents multiples of what APS purchased from Pinnacle West in 2001 and 2002. If one includes the other parties in this case that have finished or nearly finished facilities, it becomes apparent that group is capable of supplying many multiples of the total APS unmet quantity plus economy purchases. Then, if you add other bidders that are no doubt going to appear, the competition for APS' gas and oil units will be very significant.

1.C CAPABILITY OF PURCHASE POWER CONTRACTS

Q. WHAT IS YOUR ANALYSIS OF THE APS EXISTING PURCHASED POWER CONTRACTS?

A. This question brings me to the next component of my re-calculation in Exhibit TB-2. Only very recently did APS identify that Pinnacle West had four short-term purchased power supply contracts that it desires to assign to APS customers which would have the effect of reducing APS' unmet needs in 2003. According to APS, these are Pinnacle West's "hedging" contracts with Constellation, Williams, and Morgan Stanley totaling 125 MW at 100% capacity factor for July through September 2003 (Staff DR 1, Q. MR 1.4) entered into by Pinnacle West. I believe Pinnacle West entered into these contracts as part of their unregulated trading and risk management activities (given the timeframe in which they were obtained). They are probably now above market contracts Pinnacle West wants to assign to APS retail customers, outside of the competitive procurement process. If allowed to do so, the net affect would be to transfer additional cost and risk to APS customers for the activities of Pinnacle West. In its data responses, APS defends the assignment of these contracts to APS but admits that they do not contain language that the contracts are dedicated to serve APS customers.

Q. HOW DO YOU RECOMMEND THESE CONTRACTS BE TREATED IN THIS PROCUREMENT?

A. They should remain at Pinnacle West. Each of these contracts were entered into after the competitive bidding rules and APS Settlement were concluded and they each contain initial delivery dates that are well after the established date for starting the procurement program, which date had been established long ago.

If these Pinnacle West contracts are beneficial to APS customers, Pinnacle West can bid them in the upcoming competition to serve APS load, but they should not have an

automatic pass through. If they are the best deals, then they will be selected in the competition. Thus, the 955 MW and 1,798,000 MWh of contracts identified by APS in Schedule PME-1 should be reduced by 125 MW and 374,000 MWh, respectively.

Q. WHAT ABOUT THE APS CONTRACTS WITH PACIFICORP AND THE SALT RIVER PROJECT?

A. The parties to Track B were informed of these contracts some time ago. Some new information is contained in APS data responses (Staff DR 1 Q. MR1.5) indicating that the SRP contract is dispatched based on APS economics. Hence, APS retail customers can benefit from a comparison of the cost of economy interchange to the cost of buying under the SRP contract be procured as economy interchange on an on-going competitive basis.

Thus, in Exhibit TB-2, I include a range of potential economy interchange purchases for 2003-2006. As a check on my calculations, I note that APS data responses indicated that from 1998-2001, APS purchased a low of 1,788,000 MWh in 1998 to a high of 2,162,000 MWh in 1999. The four-year average over this period of APS purchases of economy interchange is 1,946 MWh.

1.D RMR GENERATION

Q. HAVE YOU MADE AN ADJUSTMENT TO THE RMR GENERATION IN SCHEDULE PME-1?

A. Yes, I recommend that this reduction to unmet needs be eliminated from the formula to determine unmet needs. First, there is substantial uncertainty concerning actual and future import limits to serving APS customers. Second, subjecting the RMR quantities, if any, to

competition can serve to demonstrate the validity of the calculated RMR. And most importantly, thirdly, my earlier analysis identified and confirmed APS' own actual results and further plans to idle its gas and oil fleet in favor of Pinnacle West purchases for 2003 and 2004 and prior to the in-service date of West Phoenix 5. Even in APS Schedule PME-1, APS projects very little RMR requirement for 2003. Since the RMR requirement is a future and not a present issue, it must be scrutinized carefully.

1.E FORMULA FOR UNMET NEEDS

Q. PLEASE SUMMARIZE YOUR FORMULA TO DETERMINE APS UNMET NEEDS FOR THE MARCH 2003 PROCUREMENT.

A. The formula for the current procurement can be summarized as:

1. Appropriately include all APS customers in capacity and energy forecasts.
2. Dedicate all existing APS coal and nuclear units to serving APS needs and augment those units with economy interchange purchases as future economics suggest.
3. Subject all APS gas and oil units to economic competition via RFP now.
4. Do not assign Pinnacle West's 2003 purchase power contracts to APS.
5. Subject APS' purchases from SRP to competition from economy interchange.
6. Do not create a set aside for RMR.
7. Compute APS' shortfall, if any, in EPS supply and subject it to competition from economy interchange.

However, now having provided this specific formula, I believe that the above 7 items are likely to occur anyways if the ACC orders APS to employ the economic criteria set forth below in Section 3: Economic Criteria.

2. ECONOMY INTERCHANGE PURCHASES & PROTOCOL

Q. NOW THAT YOU HAVE COMPLETED YOUR RECALCULATIONS OF THE VOLUME OF THE INITIAL PROCUREMENT, WHAT IS HARQUAHALA'S POSITION ON THE APS PROPOSAL TO PURCHASE MOST OF THEIR NEEDS AS ECONOMY INTERCHANGE?

A. I believe that APS can responsibly seek to procure now the entire quantity displayed in Exhibit TB-2 on a long-term basis. The balance of their need can be procured as economy interchange later on. We see no apparent reason for APS to delay procuring the amounts in Exhibit TB-2 on a *sound economic* basis for capacity and energy within the carefully structured Track B process.

Q. DO YOU HAVE ANY OTHER REACTIONS TO APS' PROPOSAL TO PROCURE ECONOMY INTERCHANGE IN LARGE QUANTITIES?

A. Yes. Harquahala and the NEG are very familiar with this product and buy and sell it virtually every day throughout the U. S. Also, economy interchange is an important component of most utilities' energy sales and purchase portfolios.

Our policy position throughout this proceeding has been that APS should seek a *balanced* portfolio consisting of a variety of products of various durations. We have also repeatedly indicated how attractive the power market, like the home mortgage market, is

today and thus, that APS can lock in favorable long-term purchases now to the benefit of its retail customers.

Hence, we would anticipate APS to procure a portion of their unmet needs as economy interchange, but not anywhere close to the large magnitudes they are now proposing. I have included a range of possible economy purchases in Exhibit TB-2. It is appropriate for utilities, like APS, to rely on economy purchases for reasonable uncertainties in the load forecast, uncertainties in the energy forecast for supply by the Environmental Portfolio Standard (the EPS is 170,000 MWh in 2007), and especially for on-going economic comparison of the economics of the SRP contract with the market, and to augment variations in their coal and nuclear generation. For example, APS' data responses indicated major outages at its Palo Verde facilities in the fall of 2003, 2005 and 2007 that will require them to replace the lost output. A portion of this reduction can be satisfied by economy interchange.

But, there is simply no basis for delaying the competition between APS' high heat rate and the merchants' low heat rate facilities for the simple reason that they cannot beat a new merchant producer using today's most modern equipment.

However, if the ACC is inclined to accept APS' proposal to rely very heavily on economy interchange in this procurement, we feel compelled to point out the following about their economy interchange proposal:

1. The APS economy interchange proposal maximizes the likelihood of price volatility due to its reliance on the very short-term market. If there has been any lesson learned, it should be that an over reliance on the short-term market puts retail customers at risk.

Such heavy reliance undermines this Track B process. Its ironic to me that Mr. Carlson, in his testimony, on one hand laments the lack of time remaining between completion of the March 2003 contracts and the start of contracts for the third quarter of 2003, but on the other hand, APS proposes to acquire so much economy interchange which is normally procured only days if not hours before delivery.

2. The APS proposal results in the vast majority of the procurement occurring outside of the current process. In fact, APS' witness, Mr. Carlson, expresses agreement with ACC staff that economy purchases can be made much as they are today. First, this likely mischaracterizes ACC Staff's position insofar as Staff had not received APS' proposal before their report was issued. Second, APS would procure outside of the reach of the independent monitor and away from the light of this process and it allows APS to purchase large amounts of energy from Pinnacle West generation under less than arms length procedures and without oversight. Thirdly, a number of the typical practices today for procuring economy interchange are not competitively friendly and favoritism is frequent. While, we are appreciative that APS has begun a dialogue on how its process for procuring economy interchange can be improved, they have not made any specific commitments to do so in this proceeding. Lastly, their proposal undermines ACC Staff's support for long-term contracts in circumstances of especially strong economics (using Staff's price to beat) for the simple reason that people will be bidding on a very limited range of products for a very limited duration.

3. The APS economy interchange proposal limits the competition to fuel prices. Other categories of future costs of APS existing units should factor into the competition. For

example, their capital budgets. Such budgets include the costs of environmental programs. So, through their proposal APS has merely attempted to overly narrow the areas of this already limited competition.

4. The APS proposal needlessly extends the drama of much of the competition into the future. As noted earlier herein, the process of reducing the output of APS' older gas and oil units is already well underway and cannot be reversed since the heat rates of the merchants' new technologies, including those of Pinnacle West, are dramatically lower than these older units. It will be many years hence when the power market is once again briefly limited in supply that these units will operate on a temporary basis. There is no need to pretend and plan on operating, for example, Ocotillo at full physical capability when it will be displaced year after year by the new units. APS can, with confidence, go to the market now to purchase on a multi-year basis the output from such new units. And the small balance it can purchase from the economy interchange market.

5. Because economy interchange purchases are of short duration, the APS proposal may falsely keep APS and Pinnacle West's hopes alive that the Track B program is temporary. The sooner APS can accept that this program is here to stay, as the Public Service Company of Colorado has done, the sooner its retail customers can benefit to the fullest extent.

6. The APS proposal is substantially different from its own earlier proposal for a descending clock auction and will result in most of the procurement occurring outside of the process Staff and the other parties have worked so hard to achieve. Even APS

acknowledges this. If APS cannot complete their auction process, it's better to go forward with a large RFP now than wait.

7. Economy interchange purchases are typically made very close to the date of initial delivery. In today's depressed energy market, a plant such as Harquahala may not be operating in a quick response mode unless it has a firm "anchor" contract to plan on. Thus, there is a greater chance plants such as ours will be off-line and cold when the call comes from APS for bids on economy interchange. This makes APS' attempted assignment of the 3 wholesale contracts to Pinnacle West even more valuable. They provide Red Hawk an "anchor tenant," thereby giving that unit an advantage in supplying economy interchange.

For all the above reasons, we conclude it is inadvisable for the Track B procurement to obtain anywhere close to the volume of economy interchange as APS proposes. The ACC can rectify this error by articulating economic criteria in its Track B order.

Q. WHEN APS PROCURES ECONOMY INTERCHANGE, SHOULD IT BE IN A COMPETITIVE MANNER?

A. Yes, for several reasons. First, its important the ACC Staff eliminates the incentive for APS to escape the official March 2003 procurement process and to over-rely on economy purchases. The ACC can help accomplish this by establishing a simple protocol for purchasing economy interchange. It would be a good start if APS filed its preferred draft protocol in this Track B hearing for review and comment by the parties since APS already appears to be using a more sophisticated method for some of its economy purchases. Such a protocol would result in APS publicly posting its needs, APS quickly receiving

competitive offers from all qualified suppliers, APS implementing appropriate conduct vis-à-vis its affiliate and ACC Staff periodically reviewing reports summarizing transactions. I would be eager to review and comment on a draft protocol.

3. ECONOMIC CRITERIA FOR TRACK B

Q. WHAT IS THE ECONOMIC CRITERIA YOU ARE RECOMMENDING TO THE ACC FOR USE IN TRACK B UNMET ENERGY NEEDS?

A. Rather than planning on running all units, including the older ones, at full throttle year after year regardless of the high cost, we are recommending a criteria that will enable APS to properly plan and implement how decisions regarding the relative economics of various power supply options are undertaken.

We propose the "minimize net present value of rate impacts" criteria.

The Colorado competitive procurement Rules (4 Code of Colorado Regulations 723-3, Rules 3610(f) employ this criteria:

> "In selecting the final resource plan, the utility's objective shall be to minimize the net present value of rate impacts, consistent with reliability considerations and development risks."
>
> "Net present value of rate impact means the current worth of the average annual rates associated with a particular resource portfolio, expressed in dollars per kilowatt-hour in the year the plan is filed. The net present value of rate impact for a particular resource portfolio is first calculated by discounting the total annual revenue requirement by the appropriate discount rate. The discounted revenue requirement is then divided by the total utility kilowatt-hour requirement for that year and averaged across the years of the planning period."

Its very important to note that the "portfolio" referred to in Colorado includes the utility's existing generation and purchase power contracts. Hence, the economic comparisons

between existing and new resources in Colorado are direct and transparent and this is exactly what I am proposing be adopted in Arizona.

I propose the ACC adopt this criteria in the Track B proceeding with only slight modification. In Colorado, the "plan" is the final portfolio. However, for Arizona, I recommend the word "plan" be changed to "contracts" and the word "planning" be changed to "contracting."

We believe that if the ACC embraces the criteria of minimizing net present value of revenue requirements, then it will naturally set in motion revisions to Schedule PME-1 that will produce results much closer to what I, in Exhibit TB-2, and ACC Staff have already calculated as being economic. Thus, by imposing economic comparison as described herein, the ACC Staff can cause APS to increase its *initial* procurement to levels commensurate with what APS had planned to purchase from Pinnacle West. And this can be accomplished without the ACC "taking over" the process and dictating specific products and timing. APS, once armed with the proposed economic criteria, will still have significant discretion in the March 2003 procurement. And lastly, and most important, this criteria directly embraces ACC Staff's primary goal of achieving consumer benefits from the Track B process.

In conclusion, we hope the Track B Order will direct APS to comply with the economic criteria stated herein and will submit a plan in January 2003 that seeks an initial procurement for quantities presented in Exhibit TB-2.

4. ACC STAFF TRACK B REPORT OF 10-25-02

Q. IN YOUR OPINION, DOES THE ACC STAFF TRACK B REPORT SET FORTH THE CRITICAL PARAMETERS NECESSARY FOR A SUCCESSFUL SOLICITATION AND ACCURATELY CONVEY THE AREAS OF CONSENSUS ACHIEVED IN THE WORKSHOPS PRECEDING THE REPORTS ISSUANCE?

A. Yes. I am grateful for the Staff's hard work and support of the Track B process leading to the issuance of this Report. It is detailed and provides subsequent opportunities for input into the process by all parties throughout the procurement process. Staff has clearly listened to all the participants, including the merchants, in preparing this report. I have only very few points to offer.

First, as compared to this Report, my testimony herein encourages the Staff to further strengthen the language in the Track B Order to include economic criteria that will better lead to the attainment of Staff's goals stated in the Introduction of the report (e.g., cost savings for ratepayers and economic benefits to consumers).

My testimony also asks that Staff look at 4 purchased power contracts that were entered into by APS' affiliate prior to the September 1, 2002 cut off date recommended in the Report, in part, because I am not sure the ACC approved those contracts and, if they were approved, do the issues presented herein cause reconsideration for the purposes of this solicitation.

Next, on page 21, line 19, APS is allowed to wait until 14 days before bids are due to indicate whether or not bidders have pre-qualified. My employer would prefer advance

notice of at least 30 days if possible. It appears this is easily doable given that the pre-qualification process starts when the prospective list of bidders is prepared.

I am appreciative that Staff has encouraged APS to consider differing means of providing risk mitigation.

Also, Staff's recommended use of a single fuel forecast to evaluate each fuel type is very helpful and can reduce the likelihood of manipulation to favor an affiliate.

As regards price to beat, my employer is content with that information **not** being specifically disclosed as to its amount. We are comfortable merely learning as to compliance with the price to beat. However, if the price to beat is disclosed to APS, then I recommend it be disclosed to all at the same time.

Q. HAVE YOU REVIEWED THE STAFF'S CALCULATION OF APS CONTESTABLE CAPACITY AND ENERGY PRESENTED IN THE REPORT?

A. Yes. Staff's calculations and my calculations presented in Exhibit TB-1 are about the same with mine being a little higher in total. In Exhibit TB-2, I separated my total unmet need into that to be sought in the March 2003 procurement and that to be sought by APS as economy interchange on an on-going basis.

My calculations demonstrate that my total unmet needs calculation relies upon economic comparisons of merchant bids and APS gas and oil units' dispatch cost. Thus, I support revising criteria that require a solicitation in 2003 for energy and capacity that "cannot be **economically** supplied from generation assets already included in the utility's rate base."

5. OTHER

Q. ON PAGE 7, STARTING ON LINE 10, APS WITNESS MR CARLSON BEGINS TO DESCRIBE THE PRODUCTS APS WOULD SEEK IN ITS RFP. ARE THEY SEEKING ONLY STANDARD WHOLESALE PRODUCTS?

A. No. Mr. Carlson describes purchasing 7-days a week. For the 16 hours he lists, the standard product is 6-days a week. While we would ideally like to sell power every day of the week, the selection of a non-standard product will have several consequences. First, it will make it more difficult for ACC Staff to accurately establish a "price to beat" since forecast data on standard products is more readily available. Second, it will reduce the competition to only those willing to offer a non-standard product.

Its possible that Mr. Carlson meant 6 days and not 7 days in his testimony because on page 8, line 1 of his testimony, he discusses "6 x 16" power, where the 6 means the number of days in a week. On line 7 of that same page, he says, "...the market is thinner than for the more standard 6 x 16 product."

So, it would be helpful if APS could clarify their position on this matter.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit TB-1

THOMAS BRODERICK
STATEMENT OF QUALIFICATIONS

2001-present	PG&E National Energy Group
	Thomas Broderick is Director External Relations, West Region for PG&E National Energy Group. He is responsible for regulatory, legislative and community relations. His current efforts are concentrated in Arizona, Colorado, and Louisiana where the Company has power plant projects and competitive bidding is planned or underway.
1999 - 2001	U.S. State Department /USAID, Kiev, Ukraine and Washington, D.C.
	• Senior Energy Advisor
1997 - 1998	PG&E Energy Services Corporation, Scottsdale, Arizona
	• Energy Consultant
1984 - 1996	Arizona Public Service Company
	• Planning Manager • Supervisor, Load Forecasts • Supervisor, Regulatory Affairs • Economist, Regulatory Affairs
1982 - 1984	Miller Brewing Company, Milwaukee
	• Analyst, Marketing Research
1981	Illinois Health Finance Regulatory Authority, State of Illinois, Chicago
	• Economist
1981	Masters, Economics, University of Wisconsin - Madison
1979	Bachelors, Economics, Arizona State University - Tempe

Exhibit TB-2

RESTATEMENT OF APS SCHEDULE PME-1

MW	2003	2004	2005	2006
Total APS customer load[2]				6,036
				6,336
				6,582
				6,835
+ 15% reserve margin	598	602	602	606
- Capability of coal and nuclear	2,798	2,798	2,798	2,798
- Capability of purchase contracts	830[3]	837	844	852
- Planned renewable under EPS	9	17	23	29
= Net unmet needs	**2,997**	**3,286**	**3,519**	**3,762**

Energy (GWh)	2003	2004	2005	2006
Total APS customer energy[2]				28,115
				29,462
				30,620
				31,799
- Capability of coal and nuclear	21,011	21,011	21,011	21,011
- Capability of purchase contracts	1,424[3]	1,672	1,986	2,044

[2] Includes 313 MW and 1,621 GWh in addition to APS Schedule PME-1.
[3] Includes a reduction of 125 MW and 374 GWh as compared to APS Schedule PME-1.

- Planned renewable under EPS	41	85	114	142
= Net unmet needs	**5,639**	**6,694**	**7,509**	**8,602**

Note: From 1998-2001, APS purchased, on average, 1,946 GWh of economy interchange. Thus, in addition to the net unmet energy needs above, APS should, at its discretion, continue to make similar economy interchange purchases when economic to do so to augment or displace their coal and nuclear units, their SRP purchase power contract and the shortfall, if any, in EPS supply.

THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING.	DOCKET NO. E-00000-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606	DOCKET NO. E-01345-01-0822
IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY	DOCKET NO. E-01933A-98-0471

ERRATA TO EXHIBIT TB-2 ATTACHED TO DIRECT

TESTIMONY OF THOMAS BRODERICK

ON BEHALF OF HARQUAHALA GENERATING COMPANY, LLC

Attached is a new Exhibit TB-2 , Restatement of APS Schedule PME-1, filed with the Direct Testimony of Tom Broderick, dated November 12, 2002, in replacement of the old exhibit at Page 29.

DATED this 12th day of November, 2002.

RESPECTFULLY SUBMITTED this 12th day of November, 2002

QUARLES & BRADY STREICH LANG LLP
Renaissance One
Two North Central Avenue
Phoenix, AZ 85004-2391

By _____
Roger K. Ferland
602.229.5607
Attorneys for Harquahala Generating Company, LLC

ORIGINAL and **21 COPIES** filed November 12, 2002, with:

Docket Control
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, AZ 85007

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Phoenix, AZ 85007

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E-01933A-02-0069; and E-01933A-98-0471

By Sarah Menne

Exhibit TB-2

RESTATEMENT OF APS SCHEDULE PME-1

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[1] Includes 313 MW and 1,621 GWh in addition to APS Schedule PME-1.
[2] Includes a reduction of 125 MW and 374 GWh as compared to APS Schedule PME-1.

EXHIBIT
H-2
Admitted

			Gas ($/MMBtu) Price Assumptions									
			$ 2.00	$ 2.50	$ 3.00	$ 3.50	$ 4.00	$ 4.50	$ 5.00	$ 5.50	$ 6.00	
	Heat Rate	VOM	**DISPATCH COST ONLY:**									
	14000	4	$ 32	$ 39	$ 46	$ 53	$ 60	$ 67	$ 74	$ 81	$ 88	
Capacity		1										
Factor	**54%**											
	Heat Rate	Fixed Cost	**CURRENT MARKET RANGES:**									
	7000	$ 85	$ 33	$ 36	$ 40	$ 43	$ 47	$ 50	$ 54	$ 57	$ 61	

NOTE: 1) Annual fixed cost of $85 equals a month fixed cost of $7.08.
2) Annual fixed cost of $65 equals a monthly fixed cost of $5.

EXHIBIT
H-3

8. Please indicate which forecast contained in the following forecast of purchases by APS of PWEC dedicated generation, as presented in a handout from Tom Mumaw at an ACC workshop:

a. for 2003, 1,700 Mw and 5,728,434 Mwh;

b. for 2004, 1,700 Mw and 6,170,100.

Response:

The APS purchases of PWEC dedicated generation referenced above were calculated as part of the April 2002 forecast and assumed the pricing model of the proposed PPA.

9. Please provide the forecast of APS purchases from PWEC for the years 2005 through 2012 from the forecast referenced in Data Request 8 above. Please separate the total forecasts by year into forecast for the Red Hawk power plant and all other PWEC generation purchases by APS.

Response:

The following table provides the APS purchases of PWEC dedicated generation by year from the April 2002 forecast. See also Responses to Question Nos. 7 and 8.

	Red Hawk (GWH)	Other PWEC (GWH)	Total (GWH)
2005	5,023	2,194	7,217
2006	5,131	2,289	7,420
2007	4,957	4,855	9,812
2008-2012	Data not available.		

LAW

1 & 2

EXHIBIT
LAW 1-2
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	Docket No. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-22-1606.	Docket No. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	Docket No. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	Docket No. E-01933A-02-0069

DIRECT TESTIMONY OF

DAVID BERRY

LAND AND WATER FUND OF THE ROCKIES

November 12, 2002

Direct Testimony of David Berry

Land and Water Fund of the Rockies

Docket No. E-00000A-02-0051 et al.

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Proposed Steps to Commission Adoption of an Environmental Risk Management Policy	DB-3

Introduction

Q. Please state your name and business address.

A. My name is David Berry. My business address is Post Office Box 1064, Scottsdale, Arizona 85252-1064.

Q. By whom are you employed and in what capacity?

A. I am Senior Policy Advisor with the Land and Water Fund of the Rockies (LAW Fund).

Q. Please describe the LAW Fund.

A. The LAW Fund is a regional environmental law and policy center serving the Rocky Mountain and Desert Southwest states, headquartered in Boulder, Colorado. The LAW Fund's Energy Project promotes the development of clean energy power production technologies, energy efficiency, renewable resources, and other measures that help to minimize the environmental impacts of meeting the demand for energy services in an economically and politically acceptable fashion. The LAW Fund has been involved in proceedings before the Commission for about ten years.

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

A. I am requesting that the Commission set up processes to incorporate demand side management and environmental risk management in future competitive solicitations. In addition, I am proposing several implementation measures for the initial competitive solicitation process.

Q. What are your professional qualifications related to these matters?

A. A summary of my qualifications is provided in Exhibit DB-1.

Demand Side Management

Q. What is Demand Side Management (DSM)?

A. The Office of Energy Efficiency and Renewable Energy of the U.S. Department of Energy defines DSM as "...actions taken on the customer's side of the meter to change the amount or timing of energy consumption. Utility DSM programs offer a variety of measures that can reduce energy consumption and consumer energy expenses."

Q. What is the public interest in DSM?

A. Cost effective DSM is a resource which can help meet the demand for electric energy services at lower cost than conventional generation resources. The public interest in DSM is to ensure that consumers' electric energy service bills are as low as possible. If cost effective DSM measures are not pursued, consumers will pay more for electric energy services than necessary. In addition, because DSM displaces electricity and generally has a stable cost, it helps consumers and utilities avoid fluctuations in the price of electricity and natural gas used to generate electricity. Further, DSM may reduce or eliminate the need for more transmission or distribution capacity, may avoid transmission constraints, and can reduce the environmental impacts of electricity consumption, including compliance costs associated with future environmental regulation.

Q. Has the Commission expressed support for DSM?

A. Yes. The Recommended Decision on Springerville Units 3 and 4 (which the Commission adopted in relevant part at its October 29, 2002 Open Meeting) states that "We encourage TEP and all Arizona utilities to practice energy efficiency and to implement energy efficiency measures when feasible and cost effective, not only as a means of pollution control, but also as a means of cost containment, both of which we support." Track B provides a means for the Commission to act on that support.

Q. What evidence is there that DSM achieves savings in kW and kWh?

A. There have been numerous studies and DSM programs that conclude that DSM measures can reliably reduce power and energy consumption and that indicate how such reductions can be achieved.[1]

Q. Are Arizona utilities currently conducting large scale DSM programs?

A. Apparently not. In response A4 to Harquahala Generating Company's first set of data requests, Arizona Public Service Company (APS) reported that it did not include any DSM in its forecasts. In response to question A3, APS stated that no DSM funding was authorized after 1999. In response to the same questions, Tucson Electric Power Company (TEP) provided a forecast of 6 to 7 MW of DSM per year but no MWh savings due to its Guarantee Home Program. (TEP did not explain the absence of energy savings). However, huge opportunities for cost effective DSM remain.[2]

A. How can DSM fit into the Commission's Track B process?

A. Track B is concerned with developing a competitive procurement process for APS and TEP to obtain power to serve their ratepayers. Cost effective DSM would be a greater benefit for ratepayers than some purchases of electricity from the wholesale

[1] Among these studies are the following: Pacific Northwest Laboratory, *Industrial Demand Side Management: A Status Report*, prepared for the Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, May 1995, Report No. PNL-10567. Arizona Corporation Commission, Staff Reports on Resource Planning, 1990, 1993, and 1996. Charles Goldman, Joseph Eto, and Galen Barbose, "California Customer Load Reductions during the Electricity Crisis: Did They Help to Keep the Lights On?" Lawrence Berkeley National Laboratory, LBNL-49733, May 2002. Connecticut Energy Conservation Management Board, *Report of the Energy Conservation Management Board*, Year 2001 Programs and Operations, 2002. Kim Clark and David Berry, "House Characteristics and the Effectiveness of Energy Conservation Measures," *Journal of the American Planning Association*, Summer 1995: 386-396. Kim Clark and David Berry, "Targeting Residential Conservation Measures," *Home Energy*, September/October 1994: 14-15. Howard Geller, "Utility Energy Efficiency Programs and Systems Benefit Charges in the Southwest," Southwest Energy Efficiency Project, 2002. Marilyn Brown et al. *National Impacts of the Weatherization Assistance Program in Single-Family and Small Multifamily Dwellings*, Oak Ridge National Laboratory ORNL/CON-326, 1993. E. Gregory McPherson, "Evaluating the Cost Effectiveness of Shade Trees for Demand-Side Management," *The Electricity Journal*, November 1993: 57-65.

[2] See Southwest Energy Efficiency Project (SWEEP), *The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest*, Boulder, CO: 2002.

market. As Track B has developed, DSM resources could be bid, but the emerging competitive solicitation process is not conducive to acquiring DSM in lieu of more expensive conventional generation. For instance, DSM is generally a long term resource while the utilities may seek only short term supply contracts. DSM, with its higher up-front costs and longer life spans, may not be readily comparable to short term power purchases. In addition, the performance-related risks of DSM are very different than the performance-related risks of conventional power supplies and need to be managed differently. Utilities have focused on managing the risks of power purchases. The LAW Fund proposes that the Commission adopt a policy to ensure that cost effective DSM resources are actively sought and acquired.

Q. What should the major features of the Commission's DSM policy be?

A. The DSM policy should include the following features:

- A resource acquisition process separate from competitive solicitations for conventional generation. The separate process would be more attractive to vendors of DSM than would an all-source bidding process.
- Target levels of cost effective DSM kW and kWh savings, considering the costs of DSM and the (avoidable) costs of conventional generation resources.
- DSM implementation time tables for APS and TEP.

Q. How can DSM resources be considered without delaying the Commission's schedule for starting competitive solicitations in Track B?

A. The Commission desires to implement competitive solicitations for wholesale power acquisitions quickly, but setting up effective DSM programs will take time. The LAW Fund does not wish to slow down the initial competitive solicitations undertaken by utilities as a result of Track B. Therefore, I propose that the Commission set up a separate process for developing its DSM policy which would be in place in time for the second and subsequent rounds of competitive solicitations.

Q. Why should the Commission address DSM policy now if that policy would not become effective until after the first round of competitive solicitations?

A. Developing a DSM policy will take time. Staff, utilities, and others need to update their knowledge of DSM, DSM programs in other jurisdictions should be reviewed, costs of DSM programs need to be considered, target levels of DSM (kW and kWh savings) must be established considering avoided costs associated with conventional resources, and program delivery methods must be examined. The DSM policy analysis should start as soon as possible, i.e., in early 2003. The Commission might need about a year to sort through the issues, resulting in an Order by the spring or summer of 2004. Specific utility programs will then have to be developed and reviewed by the Commission. If this process is completed in 2005, it will then be time to address the second cycle of competitive solicitations. That second cycle will require considerable attention from utilities, Staff, and other parties. It would be too burdensome to develop a DSM policy and new competitive solicitation guidelines for conventional resources at the same time. Further, the results of the DSM analysis would be needed as inputs into the competitive solicitation process for conventional resources. Therefore, I recommend that the Commission use the current proceeding to formally start the process of workshops and hearings necessary to implement a DSM policy.

Q. What is your recommendation for how the Commission should proceed so that DSM proposals can be developed and brought to the Commission for its consideration?

A. The Commission should direct Staff to conduct workshops and then request a hearing. Exhibit DB-2 sets forth a process.

Environmental Risk Management

Q. What is the public interest in the environmental aspects of utility resource acquisitions?

A. The public interest in environmental aspects of utility resource acquisitions stems from: a) Commissioners' previous statements on environmental matters; b) the recovery, through rates, of the costs of meeting environmental targets and requirements, including consideration of the allocation of risk of recovering future costs from ratepayers, power suppliers, and utility shareholders; and c) the environmental externalities (such as pollution) of power production imposed on society and the ecology of the State.

Q. What have Commissioners stated regarding environmental matters?

A. In a letter to parties to the present docket, dated July 18, 2002, Commissioner Spitzer wrote, "... the end state of this proposal is a future in which the wholesale electric market is competitive fair, and in which modern, efficient and clean generation replaces aged and highly polluting plants...." (p. 3). Decision No. 65154, regarding Track A, states that, through the competitive solicitation process in track B, "APS and TEP may decide to retire or displace inefficient, uneconomic, environmentally undesirable plants" (p. 23, note 8).

Q. Please illustrate the implications of environmental issues for ratepayers.

A. I will use the example of climate change. With growing evidence that the earth's climate is being altered by emissions of carbon dioxide and other greenhouse gases, including recent recognition of climate change by the White House, it is increasingly likely that the United States will act to stop worsening this situation. Resource acquisition decisions that do not take into account the potential future regulation of carbon dioxide emissions run the risk that the wrong resource choices will be made. The wrong resource choices could include those which have high carbon dioxide emissions causing the utility, power plant owners, and perhaps ratepayers, to pay

more to offset carbon dioxide emissions than the difference in the costs between those resources (without carbon offsets) and alternative resources with lower carbon dioxide emissions. If Arizona utilities lock into generation resources with high carbon dioxide emission rates and the costs of complying with future carbon dioxide regulation are passed on to consumers, the competitive solicitation process could be leading to needlessly high electric rates.

Second, the Commission could approach climate change as a question of good public policy quite apart from whether the federal government will impose carbon regulations. The current scientific consensus on climate change is that climate change could impose large costs on agriculture, businesses, and consumers as they try to adapt to changes in precipitation, temperature, and other weather patterns. The ecological impacts could also be significant. In a report prepared at the request of the Bush Administration, the National Research Council stated that the "U.S. National Assessment makes a strong case that ecosystems are the most vulnerable to the projected rate and magnitude of climate change, in part because the available adaptation options are very limited. Significant climate change will cause disruptions to many U.S. ecosystems, including wetlands, forests, grasslands, rivers, and lakes."[3] The Commission could explicitly address whether the resource choices of the utilities under its jurisdiction are contributing to greater climatic variability and how to foster resource acquisition decisions that are less destructive of the environment.

Utilities may reduce the effect of power generation on climate change by engaging in DSM, fuel or resource substitution, including greater use of renewable resources, sequestration of carbon dioxide and other greenhouse gases, improved heat rates at power plants, and purchase of tradable carbon credits. Each of these responses imposes a cost that might raise a utility's average costs and show up in rate increases.

[3] National Research Council, *Climate Change Science: An Analysis of Some Key Questions*, Washington, D.C.: National Academy Press, p. 20. The reference to the U.S. National Assessment is to: U.S. National Assessment, U.S. Global Change Research Program, "Climate Change Impacts on the United States: The Potential Consequences of Climate Variability and Change," 2001, Cambridge University Press.

1 DSM responses would, in general, lower ratepayers' energy service bills. The other
2 responses would, in general, tend to raise utility costs. Carbon offset or reduction
3 costs could range from around a few dollars per metric ton of carbon to over $100 per
4 metric ton of carbon.[4] To put these numbers in perspective, a carbon removal or
5 offset cost of $40 per metric ton of carbon ($9.74 per U.S. ton of carbon dioxide)
6 would add about $0.0086 per kWh to the cost of producing electricity at a coal plant
7 and about $0.0038 per kWh to the cost of producing electricity at a natural gas fired
8 combined cycle plant.[5] Rate impacts would be similar, depending on rate treatment
9 by the Commission.
10
11 Q. How can Track B serve as a vehicle for achieving environmental improvements?
12 A. Competitive solicitations arising from Track B will accomplish environmental
13 improvements only by happenstance unless environmental issues are directly
14 addressed by the Commission. In the absence of managing environmental risks,
15 Arizona faces the potential of locking in generation from more carbon-intensive
16 generation resources or dirtier power plants or power plants consuming large volumes
17 of water. The potential impact of not considering these issues at the time of resource
18 acquisition is higher costs in the long run.

---

[4] See, for example: Tellus Institute, *The American Way to the Kyoto Protocol*, prepared for the World Wildlife Find, 2001. Andrew Plantinga, Thomas Mauldin, and Douglas Miller, "An Econometric Analysis of the Costs of Sequestering Carbon in Forests," *American Journal of Agricultural Economics*, November 1999: 812-824. Richard Newell and Robert Stavins, "Climate Change and Forest Sinks: Factors Affecting the Costs of Carbon Sequestration," *Journal of Environmental Economics and Management*, 2000: 211-235. Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*, 2000. Charles Kolstad and Michael Toman, "The Economics of Climate Policy," Resources for the Future Discussion Paper 00-40REV, 2001. Natsource, *Assessment of Private Sector Anticipatory Response to Greenhouse Gas Market Development*, prepared for Environment Canada, 2002. World Resources Institute, Forest and Land-Use Change Carbon Sequestration Projects," www.wri.org/climate/sequester.html.

[5] The assumptions are as follows for a coal plant: a 400 MW coal plant, 190 pounds of carbon dioxide per MMBtu of fuel, a heat rate of 9,253 Btu per kWh, a 90 percent capacity factor, 3.67 pounds of carbon dioxide per pound of carbon, 2240 pounds per metric ton. The assumptions for a gas-fired combined cycle plant are as follows: a 400 MW plant, 117 pounds of carbon dioxide per MMBtu of fuel, a heat rate of 6,639 Btu per kWh, a 70 percent capacity factor, 3.67 pounds of carbon dioxide per pound of carbon, 2240 pounds per metric ton.

Costs are sometimes expressed in dollars per ton of carbon dioxide. As noted above, there are 3.67 pounds of carbon dioxide per pound of carbon.

Q. Which environmental issues does the LAW Fund believe merit the greatest attention in making resource decisions?

A. There are numerous environmental impacts of generating and transmitting electricity. The process I propose (described below) should include as one of its topics the determination of which environmental issues to address. The LAW Fund believes that the following are important: a) air emissions of carbon dioxide, carbon monoxide, sulfur oxides, nitrogen oxides, mercury, and particulates; and b) water usage. The analysis should look at the resources acquired through the competitive solicitation and the utility's entire portfolio. An additional topic to be considered is the extent to which some of these issues are already adequately addressed in existing regulations and in the power plant and line siting review process where the Commission has put more stringent requirements on some new power plants. I also recommend that the Commission order that climate change be included in the final list of environmental impacts to be considered because it is an important issue that has not received the attention it deserves.

Q. How can the Commission's Track B competitive solicitation process take into account environmental issues?

A. The competitive solicitation process adopted by the Commission should explicitly require APS and TEP to take into account the environmental implications of their resource choices, to prudently manage these risks, and to explicitly consider the allocation of risks among ratepayers, power suppliers, and the utility. The solicitation process should also take into account actions by utilities (and their power suppliers) to reduce or offset adverse environmental impacts and it should avoid penalizing utilities and their power suppliers for taking such actions.

Q. How can environmental risk management be considered without delaying the Commission's schedule for starting competitive solicitations in Track B?

A. Recognizing that the Commission desires to implement competitive solicitations for wholesale power acquisitions quickly, and that setting up a workable environmental risk management policy will take time, the LAW Fund does not wish to slow down the initial competitive solicitations undertaken by utilities as a result of Track B. Therefore, the LAW Fund proposes that the Commission set up a process now for developing its environmental risk management policy which would then be applied to the second and subsequent rounds of competitive solicitations.

Q. Why should the Commission address environmental risk management policy now if that policy would not become effective until after the first round of competitive solicitations?

A. As with DSM, developing an environmental risk management policy will take time. Staff, utilities, and others should review environmental issues and invent options for managing environmental risks. The parties might need about a year to analyze the issues and present recommendations to the Commission, resulting in a Commission Order several weeks later. Specific utility programs will then have to be developed and reviewed by the Commission. By then, it will be time to address the second cycle of competitive solicitations. That second cycle will require considerable attention from utilities, Staff, and other parties to deal with conventional solicitation issues. It would be too burdensome to develop an environmental risk management policy and new competitive solicitation guidelines at the same time. Further, requirements for environmental risk management are inputs into competitive solicitations and should be known before conventional resources are acquired. Therefore, I recommend that the Commission use the current proceeding to formally start the process of workshops and hearings necessary to implement an environmental risk management policy.

Q. Do you have any suggestions on how the Commission should direct Staff to proceed so that environmental risk management proposals can be developed and brought to the Commission for its consideration?

A. Yes. Exhibit DB-3 sets forth a process.

Comments on Staff's Report: Public Participation

Q. In Staff's Report, dated October 26, 2002, Staff recommends several points of review of utility information. Do you have any recommendations regarding these reviews?

A. Yes. Staff has recommended review of certain pieces of information but does not permit interested parties such as the LAW Fund access to this information. In particular:

- On page 8 of the Staff report, Staff states, "Bidders will have the opportunity to review non-restricted information used by the utility in preparation for the solicitation, as well as draft solicitation materials, before the solicitation is released. Bidders may provide comments to the Staff and the Independent Monitor regarding the materials at any time before the bidders' conference." Similarly, on page 9, Staff states, "Bidders will be invited to review non-proprietary materials produced by the utility and to address comments or inquiries to the utility, Staff or the Independent Monitor regarding those materials at any time between the release of reports, plans or drafts and the conclusion of the bidders' conference." I recommend that bidders **and other interested parties** be allowed to review and comment on these materials. Expanding the review to include other parties will allow additional comments that could benefit consumers, utilities, or bidders. For example, interested parties may identify provisions in the draft solicitation that needlessly restrict creative bids or dissuade potential bidders. As a second example, a draft solicitation might impede certain technologies from bidding which could otherwise provide resources at lower cost or with less environmental impact. A wider ranging review might catch such problems.
- On page 14, Staff states that "The load forecast, resource plan and needs assessment will be reviewed with the Staff and the Independent Monitor." I do not understand why this information can't be provided to all interested parties.

- On page 17, Staff states that "It will be the responsibility of the utility to prepare draft solicitation materials and to discuss these drafts with the Staff and the Independent Monitor prior to distributing them in draft form to potential bidders." Consistent with the above recommendation, I recommend that the term "potential bidders" be replaced with "potential bidders and other interested parties."
- On pages 20 and 21, Staff states that "Each utility shall schedule one or more bidders' conferences to answer questions posed by potential bidders and to take comments regarding the adequacy and quality of the information provided to bidders. All bidders' conferences must be completed at least 10 days before the release of the final bid package." I recommend that all interested parties be allowed to attend the bidders' conferences and be allowed to ask questions.

Comments on Staff's Report: Environmental Information

Q. In light of Commissioners' concerns about environmental aspects of resource decisions, are there ways in which the competitive solicitation process can provide useful information on environmental impacts, beyond the environmental risk management process proposed above?

A. Yes. As proposed by Staff, the monitor is to provide a report to the Commission on the solicitation process (pp. 11 and 26) and Staff is to review the utilities' power supply portfolios (p. 27). The LAW Fund believes that these reports and reviews would benefit from inclusion of the air emissions (carbon dioxide, carbon monoxide, sulfur oxides, nitrogen oxides, mercury, particulates, and perhaps other emissions) and the water usage of the resources acquired and of the utilities' entire portfolios. Such information would be instructive for the Commission to evaluate whether the competitive solicitation process is resulting in improved environmental performance. This information should be provided for the Spring 2003 competitive solicitation and subsequent solicitations.

Comments on Staff's Report: Price Risk

Q. Does Staff's proposed review process (pages 22 and 23) adequately address price volatility and price risk?

A. No. A major lesson of electricity markets in the past few years is that prices can suddenly jump way up or way down. Unfortunately, price risk and price volatility are not given adequate attention by Staff. On page 22, Staff states that utilities are to use a single fuel price forecast. While this may reduce bias in reviewing alternative proposals, it also overlooks price volatility. A range of prices ought to be used. On page 23, Staff lists various evaluation criteria, but neglects explicit consideration of price volatility. Applying Staff's criteria, two bids with an expected price of $0.04 per kWh would be ranked equally, even if one bid exposed the utility to wide price fluctuations and the other bid collared price variations or otherwise hedged price risk. The LAW Fund recommends that price risk and management of that price risk be explicitly included in the evaluation criteria and that utilities be required to address price risk in their evaluations for any proposals that allow price to vary.

Response to Staff's Position on DSM and Environmental Risk Management

Q. Staff states (page 39) that DSM and environmental risk mitigation should not be addressed by the Commission in this proceeding and that the Commission need not decide at this time whether a separate proceeding is necessary to examine these issues. Do you agree?

A. No. It is in the public interest to reduce the costs of meeting the demand for electric energy services through DSM and it is in the public interest to address environmental aspects of resource acquisitions. As explained above, DSM requirements and environmental risk management should be inputs into the next round of competitive solicitations. Staff's proposal does not allow for adequate time to develop the DSM

and environmental risk management policies so that APS and TEP can incorporate them into their next round of solicitations.

Q. Does this conclude your direct testimony?

A. Yes.

Qualifications of David Berry

Education:

B.A. Syracuse University (Geography)
M.A. University of Pennsylvania (Regional Science)
Ph.D. University of Pennsylvania (Regional Science)

Employment History:

- Land and Water Fund of the Rockies, Senior Policy Advisor (2001 - present)
- Navigant Consulting, Inc., Senior Engagement Manager (1997-2001)
- Arizona Corporation Commission, Chief Economist and Chief, Economics and Research (1985 – 1996)
- Boston University, Department of Urban Affairs and Planning, Lecturer (1981-1985)
- Abt Associates, Inc., Senior Analyst (1979-1985)
- University of Illinois, Department of Urban and Regional Planning, Visiting Assistant Professor (1977-1979)
- University of Pennsylvania, Regional Science Department, Lecturer (1974 –1977)
- Regional Science Research Institute, Research Associate (1972-1977)
- U.S. Army (1969-1971)

Testimony and Public Comment:

- Before the Maine Land Use Regulation Commission
- Before the Arizona Corporation Commission
- Before the New Mexico Public Regulation Commission

Publications in:

- *Ecological Economics*
- *Public Management*
- *Journal of the American Planning Association*
- *Business Economics*
- *Solar Today*
- *NRRI Quarterly Bulletin*
- *The Electricity Journal*
- *Journal of Economic Issues*
- *Public Utilities Fortnightly*
- *Journal of Environmental Management*
- *Professional Geographer*
- *Energy Policy*
- *Water Spectrum*
- *Geographical Perspectives*
- *Strategic Planning for Energy and the Environment*
- *National Tax Journal*
- *Policy Sciences*
- *Natural Resources Journal*
- *Water International*
- *Growth and Change*
- *Home Energy*
- *American Journal of Economics and Sociology*
- Chapters in books and proceedings

Proposed Steps to Commission Adoption of a DSM Policy

1. **Educational Workshop on DSM:** Staff invites outside experts on DSM measures and programs to make presentations and answer questions about DSM. Staff should solicit names of possible speakers from interested parties. Arizona utilities should be invited to make presentations on their DSM programs. It may also be desirable to also invite a speaker from an organization that provides DSM services. This may be a two day workshop.

2. **Workshop on Determining the Amount of DSM to Pursue:** Utilities, Staff, and other interested parties present and discuss their analyses on the amount of feasible, cost effective DSM, costs of DSM measures, suggested target levels of DSM and associated resource acquisition schedules, and programs to implement the suggested target levels of DSM. Implementation issues should include how DSM program are to be carried out – e.g., by the utility, by program administrators selected by the utility, by a third party selected by the Commission, etc. This workshop could run for two or three days.

3. **Workshop to Reach Agreement on DSM Program Features, Where Possible:** The parties to the second workshop may be able to reach agreement on some important DSM program features while disagreeing on other features. To assist the Commission, the parties should identify areas of agreement.

4. **Workshop to Develop DSM Acquisition Process:** Similar to the Track B workshops on competitive solicitation, utilities, Staff, and interested parties should discuss the parameters of a separate solicitation process for acquiring DSM resources and seek to reach consensus, to the extent possible, on that process.

5. **Hearing on DSM Policy**: Utilities, Staff, and interested parties would present testimony on DSM proposals for Commission consideration. Topics addressed in the hearing would include the amount and types of DSM to be pursued in the service areas of APS and TEP, and mechanisms for implementing DSM programs.

Proposed Steps to Commission Adoption of an Environmental Risk Management Policy

1. **Educational Workshop**: Staff invites outside experts on environmental aspects of power generation, including climate change, to make presentations and answer questions. Staff should solicit names of possible speakers from interested parties.

2. **Brainstorming Workshop on Policies to Manage Environmental Risks:** Staff or a facilitator working for Staff would coordinate a discussion among utilities, independent power producers, other interested parties, and one or more experts from the first workshop to determine which environmental issues should be addressed (e.g., sulfur oxide emissions, nitrous oxide emissions, mercury emissions, water consumption) in addition to climate change/carbon dioxide emissions, and to invent and critique options for managing the risks of environmental impacts of power generation. Examples of options include: a) applying adders reflecting the cost of complying with future regulations to the cost of each resource to identify resources with the lowest total (conventional plus environmental) cost (adders are not actually paid to the supplier); b) reducing emissions through DSM, fuel substitution, and improved heat rates at power plants, for example; c) offsetting emissions; and d) explicit allocation of environmental risks among utilities, power suppliers, and ratepayers. The workshop is, of course, expected to expand and modify this illustrative list.

3. **Workshop to Reach Agreement, Where Possible, on Environmental Risk Management:** As a result of the second workshop, parties may be able to agree on some aspects of an environmental risk management policy. Staff would facilitate consensus building.

4. **Hearing on Environmental Risk Management:** Utilities, Staff, and interested parties would present testimony on environmental risk management proposals for Commission consideration. Hearing topics could include environmental performance targets for utility resource portfolios, costs of emission reductions and offsets, mechanisms to meet performance standards, and specific programs for achieving target emission reductions or offsets and for meeting water consumption goals.

EXHIBIT
Number LAW-2
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	Docket No. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-22-1606.	Docket No. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	Docket No. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	Docket No. E-01933A-02-0069

REPLY TESTIMONY OF

DAVID BERRY

LAND AND WATER FUND OF THE ROCKIES

November 18, 2002

Reply Testimony of David Berry

Land and Water Fund of the Rockies

Docket No. E-00000A-02-0051 et al.

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Introduction

Q. Please state your name and state whom you represent.

A. My name is David Berry. I represent the Land and Water Fund of the Rockies (LAW Fund) in this matter.

Q. Did you file direct testimony in this docket?

A. Yes. I filed direct testimony on November 12, 2002.

Q. What is the purpose of your reply testimony?

A. I would like to respond to Harquahala Generating Company's (HGC's) proposal that the Commission adopt a criterion that the competitive solicitation process seek to minimize the net present value of rate impacts. I would also like to address several points in the Residential Utility Consumer Office's (RUCO's) testimony.

HGC's Proposed Rate Impact Criterion

Q. What is HGC's proposed economic criterion?

A. On pages 23 and 24 of his testimony, Thomas Broderick recommends that the Commission adopt as the criterion for competitive solicitations the minimization of the net present value of rate impacts. The rate impacts are to be computed by dividing discounted total annual revenue requirements "by the total utility kilowatt-hour requirement for that year and averaged across the years of the planning period." All resources, including a utility's existing generation and purchased power contracts are to be included.

Q. Does Mr. Broderick's proposal raise any concerns?

A. Yes. I appreciate Mr. Broderick's desire to place a decision framework around the competitive solicitation process that will result in benefits for ratepayers. However, the choice of a criterion or criteria must be made with care. There are two problems

with the rate impact test and the revenue requirements analysis that goes into the rate impact test:

a. A necessary condition for a test based solely upon utility revenue requirements to be valid is that all environmental impacts be internalized so that all the costs of those impacts appear in the revenue requirements. If some environmental impacts are not internalized by the utility, a focus on revenue requirements will ignore the ecological, public health, aesthetic, and other environmental costs associated with power production. That is, any costs which can be put upon consumers or the environment and that are not reflected in utility revenue requirements will be ignored. Sweeping environmental costs of power generation under the rug is not in the public interest. In addition, as I pointed out in my direct testimony, some environmental impacts of electricity generation carry significant risks of increased costs to ratepayers attributable to future environmental regulatory requirements. An analysis of utility revenue requirements that does not account for these risks could lead to increased costs for ratepayers in the long run.

b. Translating revenue requirements (dollars) into rate impacts (dollars per kWh) introduces a significant distortion into the decision criterion. Cost effective demand side management (DSM) will reduce kWh sales. Consumers will benefit from cost effective DSM because the total cost of meeting their demand for electric energy services will decrease. The rate impact test will report that electricity rates will go up because the utility's sunk costs will be spread over lower kWh sales, *ceteris paribus*. But, relying on the rate impact test would be misleading because it would falsely indicate that cost effective DSM is a bad investment for society. The rate impact test gives misleading information about DSM because it incorporates irrelevant costs into the analysis and does not provide a comprehensive comparison of costs of alternatives in the proper units. The irrelevant costs are the sunk costs of the utility such as past investments in existing power plants. These costs cannot be undone. The relevant costs for resource acquisition are incremental costs, i.e., costs that will be incurred going

forward. The proper comparison of alternatives involves the incremental costs incurred by society to implement each alternative. For example, one should compare the incremental costs of resource mixes containing only generation and resource mixes containing generation and various levels of DSM. The mix with the lowest costs for society is the preferred option, holding constant all other factors, such as exposure to price volatility or environmental risk. The proper unit of analysis is dollars, not dollars per kWh: consumers pay their bills with dollars and utilities purchase resources with dollars.

Response to the Residential Utility Consumer Office

Q. Dr. Rosen, on behalf of RUCO, recommends that the Commission employ a test using the present value of revenue requirements to determine whether a resource acquisition plan is the best plan (pp. 6, 7, 8, 25). Dr. Rosen also implies that the Commission previously employed such a test in its Resource Planning Rules (e.g., p. 25). Do you have any comments on Dr. Rosen's approach?

A. Yes. I agree with Dr. Rosen that it is necessary to look at resource acquisitions in a comprehensive and systematic manner. But, as stated above with respect to Mr. Broderick's testimony, the revenue requirements test is valid only under special circumstances. I would also like to correct the history of cost tests used in Arizona. The Commission did not adopt a revenue requirements test as the criterion for selecting the best resource plan. Decision 57589, regarding the first cycle of resource planning, states that the resource planning rules "were adopted by the Commission for the purpose of minimizing the total cost of providing electric energy services by improving long range planning" (p. 4). That decision also states that "the primary test should be the Total Societal Test with consideration given to environmental concerns" (p. 10). A.A.C. R14-2-703(F) states that utilities are to select the plan which "will tend to minimize the present value of the total cost of meeting the demand for electric energy services." Total cost is defined in the rule as all capital, operating, maintenance, fuel, and decommissioning costs incurred in the provision or

conservation of electric energy services borne by end users, utilities, or others, including any adverse environmental effects.

Q. Dr. Rosen recognizes the importance of demand side management in lowering the cost of meeting the demand for electric energy services. How does his proposal for DSM compare with the LAW Fund's proposal?

A. On page 33, Dr. Rosen recommends that the formal solicitation process be delayed to allow time for developing a more inclusive bidding process. On page 28, he recommends that the regulated utility be required to bid into the resource mix, at regulated cost of service rates, DSM sufficient to reduce its peak load by 2 percent each year, with the expectation that about half of that would be selected as cost effective. I agree with Dr. Rosen that DSM should not be overlooked in minimizing the costs of meeting the demand for electric energy services. Our proposals are similar in that the LAW Fund recommends that DSM resources be acquired and that the cost effectiveness of DSM resources be evaluated against the avoidable costs of supply side resources. We differ in that the LAW Fund did not propose delaying or modifying the first cycle of competitive solicitations. In addition, the LAW Fund proposed that the Commission determine the parameters of DSM programs after workshops and a hearing.

Recommendations

Q. Do you have any recommendations based on the above review?

A. Yes. I recommend that the Commission not require that the present value of rate impacts or revenue requirements be used to determine decisively which portfolio of resources to acquire. The present value of rate impacts, in particular, should be avoided because it improperly evaluates the benefits of DSM. The relevant costs for resource acquisition are incremental costs, i.e., costs that will be incurred going forward. The proper comparison of alternatives involves the incremental costs

incurred by society to implement each alternative, including consideration of environmental costs and risk.

The LAW Fund does not wish to delay the first round competitive solicitations, and it will take time for the Commission to develop an appropriate policy on integrating environmental costs and risks into the solicitation process. I therefore recommended in my direct testimony that the Commission establish a separate proceeding on environmental risk management in preparation for the second and subsequent cycles of competitive solicitation. I suggest that the Commission address the issue of integrating environmental costs and risks into the decision criteria for resource evaluation in that separate proceeding.

Q. Does this conclude your reply testimony?

A. Yes.

PANDA

1 – 4

EXHIBIT
P-1
Admitted

1.34 Does APS contend that the APS full requirements contract with El Paso allows APS to designate non-APS owned generating facilities as points of delivery?

a. If yes, does APS contend that it can designate an unaffiliated merchant generator as a delivery point under the full requirements contract with El Paso so long as APS is acquiring the electrical output of the facility for its native load needs?

b. Does APS contend that the full requirements contract with El Paso allows APS, or its agent, to designate PWEC or other generation affiliated with APS as a delivery point under the full requirements contract so long as APS is acquiring the electrical output of the affiliated facility for its native load needs?

RESPONSE:

APS has previously objected to these questions as they do not seek information relevant to Track B nor are they reasonably calculated to lead to the discovery of admissible evidence. FERC-jurisdictional gas supply contracts between El Paso Natural Gas Company and APS and its affiliates are not relevant to competitive procurement in Track B. Such matters are appropriately addressed at FERC, where Panda is already litigating over these contracts. APS further objects to the extent that the questions call for confidential, trade secret, and competitively-sensitive information.

Subject to the objection, yes. APS believes that the TSA allows it to use gas capacity through a tolling arrangement with any generator.

EXHIBIT
P-2
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING ELECTRIC RESTRUCTURING ISSUES.	)	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	)	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	)	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	)	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	)	DOCKET NO. E-01933A-98-0471

TESTIMONY OF
CRAIG R. ROACH, Ph.D.

ON BEHALF OF
PANDA GILA RIVER, L.P.

November 12, 2002

BOSTON PACIFIC COMPANY, INC.

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C. APS has understated its unmet capacity needs by using a double standard for reserves, overstated its RMR needs, and failed to correct its persistent underestimation of peak load. 17

D. The best approach for APS' ratepayers is to solicit the majority of unmet needs through asset-backed, dispatchable unit bids that would sell under traditional pay-for-performance PPAs. The remainder of unmet needs would be met with seasonal call options with pre-established energy prices. 22

IV. I AGREE WITH MUCH OF WHAT I SEE IN THE STAFF REPORT, BUT I WOULD LIKE TO SEE THREE OF STAFF'S PROPOSALS BE MORE FULLY SPECIFIED. 28

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1 **I. INTRODUCTION AND PURPOSE OF TESTIMONY**

2

3 Q. Please state your name, position, and business address?

4 A. My name is Craig R. Roach. I am a Partner with Boston Pacific Company, Inc.

5 My business address is 1100 New York Avenue, NW, Suite 490 East,

6 Washington, DC 20005.

7

8 Q. Are you the same Craig R. Roach who testified in both the Track A and Variance

9 proceedings on behalf of Panda Gila River, L.P.?

10 A. Yes.

11

12 Q. Did you participate in the Track B workshops sponsored by Staff?

13 A. Yes, along with business representatives and counsel of Panda Gila River, L.P., I

14 participated in each of the Track B workshops.

15

16 Q. What is the purpose of your Testimony?

17 A. The purpose of my Testimony is to respond to (a) Arizona Public Service

18 Company's (APS') needs assessment and procurement proposal as presented in

19 two testimonies dated November 4, 2002,[1] and (b) the Staff's Report on Track B

20 dated October 25, 2002 (the "Staff Report").[2]

21

[1] Direct Testimonies of Peter M. Ewen and Thomas J. Carlson, Docket No. E-00000A-02-0051, et al., November 4, 2002.

[2] Staff Report on Track B: Competitive Solicitation, Docket No. E-00000A-02-0051 et al., October 25, 2002.

II. SUMMARY OF TESTIMONY

A. APS' needs assessment and procurement proposals

Q. Can you summarize your overall opinion of APS' needs assessment and procurement proposal?

A. I am greatly disappointed with APS' needs assessment and procurement proposal. APS' proposal is more an attempt to undermine the competitive solicitation required by the Track A Order, than it is an attempt to implement it.

To start, APS' needs assessment significantly understates its unmet needs. The Commission's Track A Order required APS to solicit competitive proposals for "at a minimum" the capacity and energy that APS could not produce from its existing assets.[3]

In its proposal, however, APS has artificially minimized the amount of energy to be solicited by defining its "unmet energy needs" as the amount of energy it would need if it ran its existing assets at full output *regardless of cost*. Clearly, by ignoring the cost of its own power plants, APS overstates the amount of energy it should procure from its own high-cost units and, thereby, underestimates the amount of energy it would need from new suppliers.

[3] Decision No. 65154, Docket No. E-00000A-02-0051, September 10, 2002 ("Track A Order") at page 30 Finding of Fact 36.

1 Q. Do you believe APS should forecast its unmet energy needs without regard to
2 what it costs to supply energy from its own assets?
3 A. No, of course not. Nor could the Commission have intended this since APS'
4 interpretation would violate one of the most basic requirements for any utility:
5 meet your ratepayer's needs *at reasonable cost*.
6
7 Q. What is your opinion of APS' estimate of unmet capacity need?
8 A. I have three concerns. I believe APS has understated its unmet capacity needs by
9 (a) calculating its 15% reserve margin on just APS capacity rather than on peak
10 load as is traditionally done; (b) excluding the non-APS RMR units (Pinnacle
11 West's new West Phoenix units) from unmet needs; and (c) not correcting for its
12 persistent under forecasting of peak load.
13
14 Q. What is the concern with excluding non-APS RMR generation from unmet needs?
15 A. APS attempts to shield Pinnacle West's new West Phoenix units from area-wide
16 competition. APS' premise for this shielding is that these non-APS units will be
17 needed in certain hours for reliability must run service. However, by APS' own
18 estimates, even these non-APS units would be needed at most for 159 hours for
19 RMR service though the year 2006; in 2003, RMR service is required in only 6
20 hours.[4] These few hours are not sufficient to justify excluding these units, in their
21 entirety, from unmet capacity needs and, thereby, shielding its Affiliate's units
22 from area-wide competition year-round.
23

[4] (Exhibit No.___(CRR-3)).

Q. How does APS' estimate of its unmet energy and capacity needs compare to those from Staff and to those you would recommend?

A. Table One below compares the three estimates of unmet needs for both capacity and energy in 2006. As you can see, my estimate and those from Staff are reasonably close. APS' estimate of unmet energy needs is a fraction of our estimates; APS' estimate of unmet capacity needs is also significantly lower--indeed, it is 1,119 MW lower than Staff's.

TABLE ONE

THREE ALTERNATIVE CALCULATIONS
OF APS' UNMET NEEDS
IN 2006

	CAPACITY	ENERGY
APS[a]	1,779MW	1,469GWH
STAFF[b]	2,898MW	9,754GWH
PANDA[c]	2,644MW	8,801GWH

[a]Exhibit No.___(CRR-2) reproducing APS Schedule PME-1
[b]Staff Report page 7, energy reflects 38% capacity factor
[c]Uses Staff's 38% capacity factor for energy

Q. Aside from your concerns with APS' needs assessment, do you have any concerns with its procurement proposal?

A. Since APS' estimate of unmet needs is intentionally low, it naturally chose the wrong products to procure. Thus, APS proposes to *solicit capacity* from competitive power suppliers through its RFP, but it *will not solicit much actual energy (electric generation)* from those same suppliers at the time of the RFP.

1 Q. Does APS say it intends to get all the energy from its existing assets?

2 A. No. APS does not propose to get the energy it needs from running its existing
3 assets at their physical maximums, as APS assumed in the calculation of its unmet
4 energy needs. APS must have seen just how expensive that would be for its
5 ratepayers. Rather, APS proposes to solicit energy later (most likely in real time
6 or monthly) from the Western spot market. I will refer to this as APS "economy
7 energy proposal."[5]

8

9 Q. What do you think of APS' economy energy proposal?

10 A. APS' economy energy purchases are the element of APS' procurement proposal
11 that is potentially most harmful to APS' ratepayers. This is because APS'
12 proposal puts its ratepayers at risk in the volatile spot markets of the West. If we
13 learned anything from the California Crisis, it is that overexposure to spot markets
14 is dangerous to consumers. For this reason alone, APS' economy energy proposal
15 must be rejected at the outset.

16

17 Q. Please summarize your recommendations regarding APS' needs and assessment
18 and procurement proposal?

19 A. I recommend that the Commission reject APS' estimates of its unmet energy and
20 capacity needs as well as APS' product definition. Instead, for 2006, APS should
21 solicit 1,891 MW of asset-backed, dispatchable unit sales under traditional pay-
22 for-performance PPAs. The remainder of unmet capacity needs in 2006 should be
23 solicited as seasonal call options. The unit sales offers should assume non-APS

[5] Carlson Direct at page 4, page 12 to 14.

RMR units will be required to run in RMR hours, and this non-APS RMR service will be contested in a separate solicitation.

B. The Staff Report

Q. Can you summarize your overall assessment of Staff's Report?

A. I agree with much of what I see in the Staff Report. For example, the Staff requires that the solicitation be monitored by an independent third party (the "Independent Monitor"). Also, as I showed earlier, my estimate of APS' "unmet needs" is very close to that presented in the Staff Report.

Q. Are there areas of the Staff Report that you would like to see changed?

A. Yes. There are four key areas in which the findings should be more clearly specified: Specifically, I call for (a) APS responses to comments by interested parties; (b) adjustment in the manner in which Staff develops its "Price to Beat;" (c) a requirement that the Independent Monitor concur in the selection of winning bidders or the solicitation does not get certified by the Commission as being prudent; and (d) allowing the Independent Monitor to ask the Commission to stop the solicitation process if APS fails to act in good faith.

III. ONCE AGAIN APS HAS MADE A PROPOSAL THAT OBVIOUSLY IS NOT IN THE BEST INTEREST OF APS' RATEPAYERS.

A. APS has consistently made proposals that benefit its shareholders at the expense of its ratepayers.

Q. You say you are disappointed in APS's propsal, why?

A. Staff and its consultants did a good job attempting to get consensus through a series of workshops, and demanding that the process work to benefit Arizona ratepayers. My client, Panda Gila River, L.P. went to considerable effort and expense to participate in those workshops in good faith, as well as in the Track A and Variance proceedings. In sharp contrast, APS' testifying witnesses did not participate in any of the three workshops held prior to submitting testimony. Moreover, over the past year, APS has put forth a string of proposals that benefit its shareholders at the expense of its ratepayers. Its most recent testimony is more of the same.

Q. You mentioned a "string of proposals" over the past year by APS. What specific proposals do you have in mind?

A. I have three proposals in mind. On October 18, 2001, APS proposed that its ratepayers take on the burden of a 29-year power purchase agreement (PPA) with its Affiliate, Pinnacle West.[6] This Affiliate PPA was a high-cost offer that

[6] Request of Arizona Public Service Company for a Partial Variance to A.A.C. R14-2-1606 (B) and for Approval of a Purchase Power Agreement, Docket No. E-01345A-01-0822, October 18, 2001.

1 afforded none of the risk protection or reliability guarantees offered in the
2 standard pay-for-performance PPA from competitive power suppliers.[7]
3
4 On July 11, 2002, in a letter from Chairman Post to the Commission, Pinnacle
5 West suggested that the merchant plants built by Pinnacle West (Redhawk and
6 new West Phoenix) be put into APS' rate base at full cost.[8] Again, this was a full-
7 cost, cost-plus deal despite the fact that Arizona now has a glut of merchant
8 capacity built by others, which means that APS' ratepayers could get a better deal.
9
10 On September 16, 2002, APS proposed that it would loan $500 million to its
11 Affiliate because Pinnacle West could not stand on its own.[9] A proposal it has
12 now advanced again with an "emergency" request to create a $125 million credit
13 fund for Pinnacle West. In my view, this might be the most blatant attempt to
14 benefit shareholders at the expense of ratepayers since the ratepayers get
15 absolutely nothing in exchange for shouldering the debt burden of Pinnacle
16 West's unregulated investments.
17
18 Q. What is the point you are making by citing these three proposals?
19 A. My point is that APS has consistently acted to benefit it Pinnacle West Capital
20 Corp.'s shareholders at the expense of its ratepayer.
21
22 Q. Why is this important?

[7] See Direct Testimony of Craig R. Roach, Docket No. E-00000A-02-0051, March 29, 2002.
[8] Letter by Chairman William J. Post to the Arizona Corporation Commission, July 11, 2002.
[9] Application of Arizona Public Service Company, Docket No. E-01345A-02-0707, September 16, 2002.

1 A. It is important for two reasons. First, the procurement mechanism proposed by
2 Staff is based on an assumption that the utility is operating in the best interest of
3 ratepayers in making its choices. As I describe above, that has not been the case
4 here. This lays the framework for the second point, which is it demonstrates the
5 affiliate bias inherent in APS' actions and demands that APS be denied the
6 discretion Staff proposes for purchasing utilities.
7
8 **B. APS' most recent proposal will also harm ratepayers. APS understated**
9 **its unmet energy needs to justify its economy energy proposal, and that**
10 **proposal will leave its ratepayers at the mercy of the volatile Western spot**
11 **market.**
12
13 Q. Let's return to your concern about APS' economy energy proposal. Please
14 summarize your concern.
15 A. The Commission's Track A Order required that "upon implementation of the
16 outcome of Track B, APS shall acquire, at a minimum, any required power that
17 cannot be produced from its own existing assets, through the competitive
18 procurement process as developed in the Track B proceeding. The minimum
19 amount of power, the timing, and the form of procurement shall be determined in
20 the Track B proceeding."[10] The "economy energy" proposal artificially
21 minimized the amount of energy it should solicit through the Track B process by
22 using a calculation of the maximum output its assets could physically produce

[10] Decision No. 65154, 4th ordering paragraph.

1 *regardless of cost*. The Commission clearly did not limit the solicitation in this
2 manner.
3
4 Based on this faulty calculation of unmet energy needs, APS proposes to conduct
5 a competitive solicitation and to contract for capacity, but, rather than
6 simultaneously locking in fixed-formula pricing for energy production from those
7 same power plants, APS proposes to buy its unmet energy needs (the electricity
8 actually generated) through what it calls "short-term and economy energy"
9 purchases.[11] APS' economy energy proposal would subject its ratepayers to the
10 mercy of the spot market for much of their energy needs. Indeed, APS' own
11 forecast shows that economy energy would account for 23% of total energy needs
12 in 2006.[12] If there is any lesson from the California Crisis it is that
13 overdependence on spot market purchases is dangerous for ratepayers.
14
15 Q. Could APS' dependence on the Western spot market prove to be even greater
16 were its proposal accepted?
17 A. Yes. APS' own testimony shows that it consistently underestimates energy needs.
18 When the forecast horizon is four years, as it is today for 2006, on average, APS
19 underestimates its energy needs by 7.4%.[13] If APS' forecast for 2006 has the
20 usual underestimation, economy energy sales could account for 28% of all
21 ratepayer energy needs in that year.
22

[11] Carlson Direct at pages 12 to 14.
[12] (Exhibit___(CRR-4)) and (Exhibit___(CRR-2)) reproducing APS Schedules PME-13 and PME-1).
[13] (Exhibit No.___(CRR-5)).

1 Q. Does APS have an alternative to these spot purchases?

2 A. Under its proposal, the only apparent alternative to spot purchases is additional
3 generation from APS' existing assets. However, based on APS' own workpapers
4 additional energy from existing assets is expensive as compared to what might be
5 secured through a winning bid from a new combined cycle plant.[14] In Schedule
6 PME-13 from APS' Testimony, the third column from the left shows the
7 economy energy prices APS is projecting on average.[15] For 2006, for example,
8 the forecast is $40.53/MWH. Since APS projects it would buy 23% of its needs
9 through economy energy instead of generating additional energy from existing
10 assets, we can assume this additional energy has incremental costs greater than
11 $40.53/MWH on average, although we do not know how much greater.
12
13 Q. Why do you say energy from a winning bid would be cheaper?
14 A. I say this based on some simple calculations. The fourth column from the left of
15 APS' Schedule PME-13 provides APS' forecast of natural gas prices.[16] In 2006,
16 that price is $3.35/MMBtu. Assume a combined cycle plant wins the capacity
17 solicitation, and assume further it has a heat rate of 8,000 Btu/kwh (HHV). With
18 that heat rate, and the APS gas price of $3.35/MMBtu, the plant's energy price
19 bid could be as low as $26.80/MWH, which is 34% lower than APS' projected
20 average economy energy price of $40.53/MWH in 2006.[17]
21

[14] (Exhibit No.___(CRR- 4)).
[15] Exhibit No.___(CRR-4)).
[16] Ibid.
[17] This example is meant as an illustration, and therefore does not include Variable O&M and transmission losses.

1 Q. What is the point you are making with this calculation?

2 A. The point is that, using APS' own projections, there is the potential for
3 considerable cost savings to its ratepayers from soliciting energy bids from the
4 same combined cycle plants from which capacity bids will be solicited. The most
5 important point, however, is that APS ratepayers, Commission Staff and the
6 Independent Monitor would be deprived of knowing whether this better deal is
7 available because APS will not have asked.

8

9 Q. What approach do you recommend in place of APS' economy energy proposal?

10 A. Obviously, the approach that is in the best interest of APS' ratepayer is to attempt
11 to get the best of both worlds, and the way to do that is to have a majority of the
12 solicited capacity procured through dispatchable unit sales. If Redhawk and new
13 West Phoenix had been put in rate base, their capacity and energy, in effect,
14 would have been sold under an asset-backed, dispatchable unit sales agreement.
15 Indeed, all rate-based power plants are, in effect asset-backed, dispatchable unit
16 sales agreements, although, in ratebase they do not offer the consumer risk
17 protection and availability guarantees of a pay-for-performance unit sales
18 agreement.

19

20 Dispatchable unit sales agreements with competitive power suppliers secure the
21 best of both worlds for APS' ratepayers because, while they assure sufficient
22 capacity to keep the lights on, they can also pre-set to various extents the price at
23 which energy will be generated thus protecting consumers from high-end spot

1 prices. At the same time, because they are dispatchable, if spot energy prices are
2 low, APS can buy spot energy instead of running these units at full tilt.
3
4 Q. Are there other reasons to recommend asset-backed dispatchable unit sales?
5 A. Yes. Asset-backed, dispatchable unit sales are better for APS' ratepayers at this
6 point in time for two other reasons. First, there is a glut of power plant capacity
7 in Arizona and allowing those power plants to compete head-to-head will get the
8 best bargain for ratepayers. Head-to-head competition is best in the context of
9 unit sales. Second, unit sales are the best way to secure asset-backed deals where
10 the Staff and the Commission can go out and "kick the tires." In the Staff's
11 request that all bidders agree to site visits I detect a real interest in such "steel in
12 the ground" proposals.
13
14 Q. How would you contrast your asset-backed, dispatchable unit sales to APS'
15 proposal?
16 A. In sharp contrast to the traditional unit sales proposal, APS would solicit bids for
17 capacity and then buy energy in the spot market. Even putting aside the inherent
18 spot market risk of its economy energy purchases, I think the Commission should
19 question the capacity products APS proposes to solicit. APS proposes to solicit
20 (a) capacity-only; (b) capacity plus minimum energy; and (c) call option capacity.
21 I do not see that APS has much experience with these products. At the moment,
22 through data requests we see only four contracts for a total of 125 MW of summer

1 purchases in 2003, of both capacity and associated energy.[18] I do not doubt that
2 all three of these capacity products could be beneficial in the right circumstances.
3 However, I do not see the need to (or the prudence of a) jump from (a) 125 MW
4 of straightforward peak purchases to (b) 1,700 MW of the more complex, new
5 products.
6
7 Q. Do you believe APS is aware of the potential benefits of asset-backed,
8 dispatchable unit power sales?
9 A. Yes. APS must be aware of the potential ratepayer benefits of asset-backed,
10 dispatchable unit power sales from new combined cycle plants. It endorsed those
11 benefits every time it claimed Pinnacle West's Redhawk and new West Phoenix
12 units were the best deal for APS' ratepayers.
13
14 Q. Did APS previously reveal its economy energy proposal and capacity RFP?
15 A. No, at least not to me or other workshop participants. I was intensely involved in
16 all of Staff's workshops and I had no indications of APS' scheme.
17
18 Q. Did you previously reveal your asset-backed, dispatchable unit sales approach?
19 A. Yes, absolutely. On Panda's behalf, I promoted this approach during Staff's
20 workshops by presenting several versions of Panda Gila River's "Strawdog"
21 proposal. I have attached the last version of Panda Gila River's Strawdog, which

[18] APS Response to Staff's First Set of Data Requests MR 1.4 (Exhibit No.___(CRR-6)).

was presented to the Commission on August 28th (please note that this proposal has not been updated since that time).[19]

Q. Why did APS propose this now?

A. I cannot know APS' intent, but I can only deduce that APS hopes its proposal will subvert the solicitation. I suspect that, with the economy energy plan, APS hoped to purchase from its Affiliate's Redhawk plant at spot market prices. I believe all bidders would have this same suspicion.

Q. Are there other facts that fuel this suspicion?

A. Yes. I will mention two. First, in the Staff's August 13/14 Workshop, when APS believed its Affiliate's combined cycle Merchant plants (Redhawk and new West Phoenix) might be put into rate base, APS presented a table showing that those plants (with 1,700 MW of capacity) would generate 6,170 GWH of energy and, therefore, would have a 41% capacity factor in the year 2004.[20] But once APS realized that a competitive supplier could own the combined cycle power plants from which energy will be procured, APS began using a capacity factor of about 6% for approximately the same amount of capacity (1,634 MW), which means these power plants will generate just 840 GWH in 2004.[21] Thus, with this one forecasting gimmick, APS has wiped out more than 86% of its unmet energy need.

[19] (Exhibit No.___(CRR-7)).
[20] (Exhibit No.___(CRR-1)).
[21] (Exhibit No.___(CRR-2) reproducing APS Schedule PME-1).

Second, in a similar vein, the Commission will recall APS' proposed Affiliate PPA in which 4,720 MW of divested assets (including all existing APS units plus Redhawk and new West Phoenix) were offered and committed to produce 21,090 GWH of energy. Contrast that with APS' current claim that just its existing assets could be used to produce up to 29,931 GWH.[22] APS is claiming that, with 15% less power plant capacity (4,001 MW of capacity vs 4,720 MW), it intends to produce up to 42% more energy than it offered in the Affiliate PPA.

Q. Are there specific anti-competitive tactics that bidders will anticipate?

A. Yes. For example, assume APS issues a capacity-only RFP in which only a capacity price is allowed. If Pinnacle West knows it will be favored in the economy energy purchases it can bid an artificially lower capacity price. It could artificially lower its capacity price bid because (a) it can anticipate spot prices sometimes embedding a fixed cost contribution (an implicit capacity payment) and/or (b) it can be assured its start-up costs and minimum load energy costs will be covered so these costs need not be reflected in the capacity price Pinnacle West bids.

Q. You mentioned an "implicit capacity price" in spot prices. Does that mean that ratepayers could pay twice for capacity?

A. Yes. It is a possibility, but not a certainty, that APS ratepayers could pay twice for capacity under APS' economy energy proposal.

[22] (Exhibit No. ___ (CRR-2)).

1 **C. APS has understated its unmet capacity needs by using a double standard**
2 **for reserves, overstated its RMR needs, and failed to correct its persistent**
3 **underestimation of peak load.**
4
5 Q Let's turn now to your concern about APS underestimating its unmet capacity
6 needs. Please summarize your concerns.
7 A. I have three concerns. I believe APS has understated its unmet capacity needs by
8 (a) calculating its 15% reserve margin on just APS capacity rather than on peak
9 load as is traditionally done; (b) excluding the non-APS RMR units (most likely
10 Pinnacle West's new West Phoenix units) from unmet needs; and (c) not
11 correcting for its persistent under forecasting of peak load.
12
13 Q. How did APS justify its approach to calculating reserves?
14 A. APS justifies calculating a 15% reserve margin on just APS capacity by stating
15 that all competitive power suppliers would be expected to bring their own
16 reserves. It is true that competitive power suppliers may bring their own reserves
17 – they do so with my Firm LD unit sales, as well as with my call option product.
18 However, this does not suggest that unmet capacity needs be calculated without
19 reserves, rather, it necessitates a change in how we measure the products that
20 meet those needs. Put simply, 100 MW of APS existing capacity or 100 MW of
21 my unit contingent capacity fills 100 MW of Standard Offer capacity needs (when
22 that need is calculated to include reserves). However, 100 MW of Firm LD unit
23 sales or 100 MW of call options fills 115 MW of Standard Offer needs.

1 Q. Why is your approach better?

2 A. The approach outlined herein is better for two reasons. First, unlike APS'
3 approach, it does not hide the fact that the products which bring reserves are
4 higher quality products. That is, it does not hide the fact that these premium
5 products from competitive power suppliers are more valuable than APS' own
6 assets.
7
8 Second, it is better because it allows the power plants that provide reserves to be
9 determined by economics. For example, in a world of all unit-contingent sales
10 (the same as in the world of standard utility-owned plants), the plants that provide
11 reserves are higher-cost plants. So if we brought on several new, low-energy cost
12 combined cycle plants, this could mean that APS' higher cost plants are pushed
13 into the role of providing reserves. Even more broadly, my approach will let
14 economics dictate whether products that include reserves are more economical
15 than products that do not.
16
17 Q. What is the impact of calculating reserves on total peak load?

18 A. Calculating unmet needs with a 15% reserve margin on peak load, not just on
19 APS' owned generating assets, increases the amount of unmet needs. In 2006, for
20 example, this one change would increase APS' unmet capacity needs from 1,779
21 MW to 2,161 MW, or by 21%.
22
23 Q. Has APS ever used your method?

A. Yes. Indeed, when APS thought that its Affiliate's merchant plant would not have to compete, it calculated its reserves on peak load just as I propose here, although APS used a 12% reserve margin at the time.[23]

Q. Let's turn to your second concern about APS' calculation of unmet capacity needs. How does APS justify excluding Pinnacle West's new West Phoenix units?

A. APS attempts to shield its Affiliate's new West Phoenix units from area-wide competition by declaring those units to be essential reliability must run (RMR) units year-round despite the fact that its own forecasts show them to be needed for very limited hours in all years through 2006. APS refers to these as non-APS RMR needs and the hours of RMR service are shown in Table Two below.

TABLE TWO

NON-APS RMR NEEDS
2003 Through 2006

Year	Capacity Need	Number of RMR Hours
2003	29	6
2004	184	19
2005	338	57
2006	493	159

SOURCE: Exhibit No.___(CRR-3) reproducing APS' workpaper at page 76.

[23] (Exhibit No.___(CRR-1)).

1 Q. Is it necessary to exclude Pinnacle West's new West Phoenix units from unmet
2 capacity needs and, thereby, to shield those units from area-wide competition?
3 A. No, not at all. A much better approach is to simply carve out the few hours in
4 which these units actually provide RMR service, require those units to run in
5 those hours at a price no higher than the protocol price established in APS'
6 OATT, and then allow full area-wide competition for all the other hours of the
7 year. This is consistent with the Staff Report, which allows capacity to be
8 excluded from unmet needs for RMR service *during RMR hours*.
9
10 Q. Could the carved out RMR hours be subject to competition separately?
11 A. Yes. As APS suggested, competition for Pinnacle West's new West Phoenix
12 units during RMR hours should be allowed from other in-area (in-Valley) plants
13 or by plants that could deliver to the Valley via non-APS transmission lines.[24]
14
15 Q. Let's turn to your third concern. What is your point about APS' forecast errors?
16 A. My concern is that APS' own workpapers show it has consistently under-
17 forecasted peak load, especially when the forecast is four years out, as it would be
18 here. Table Three below reveals that forecasts (a) have been too low and (b) the
19 forecast errors increase as the forecast horizon is extended.
20
21
22
23

[24] Carlson Direct at page 10 lines 5 to 9.

TABLE THREE

APS UNDER FORECASTS PEAK LOAD
(Percent Error for Peak Demand)

Forecast Horizon

Forecast Date	1 year	2 years	3 years	4 years
Jan-92	6.77%	15.45%	16.75%	17.94%
Feb-93	15.23%	16.56%	19.05%	18.33%
Oct-93	13.74%	16.59%	20.27%	
Feb-94	16.59%	20.27%	18.67%	28.54%
Oct-94	15.31%	16.59%	15.20%	
Jun-95	16.59%	15.20%	22.87%	15.87%
Oct-95	14.23%	12.83%	21.98%	
May-96	12.83%	21.98%	16.86%	26.24%
Oct-96	9.56%	18.06%	12.88%	
Feb-97	18.84%	13.60%	22.35%	22.91%
Oct-97	13.01%	5.81%	13.41%	
Feb-98	5.81%	13.41%	14.04%	13.07%
Oct-98	3.29%	10.96%	11.23%	
Apr-99	9.36%	9.47%	9.04%	
Oct-99	8.54%	8.12%	7.13%	
Apr-00	6.08%	3.68%		
Oct-00	3.78%	1.82%		
Apr-01	-0.09%			
Oct-01	3.44%			
Average	10.15%	12.97%	16.11%	20.42%

*Note that positive numbers indicate the amount that was under forecast. For example, in January 1992 the forecast predicted a demand that was 6.77% lower than actual demand in 1993.
SOURCE: Ewen Direct at PME-7.

Q. What would it mean if APS' forecast presented in its recent Testimony suffered the same forecast error as shown in the past?

A. The effect would be a dramatic increase in unmet capacity needs. For example, in 2006, the unmet capacity need would have to be increased to reflect a 20.42% under estimate of peak load. By my calculations, and correcting for my other two concerns, that would increase 2006 unmet capacity need from APS' estimate of 1,779 MW to 4,176 MW, which is more than a doubling.

Q. Do you recommend that APS' estimate of unmet needs be corrected for this forecast error?

A. No, not in terms of raising the forecast. I just wanted to make the Commission aware of it. However, the Commission should find that persistent under forecasting, as compared to errors in both directions, is indicative of either poor forecasting or forecasting gimmicks. Moreover, the Commission should put APS on notice that, if its under forecasting leads to greater expense or lower reliability for its ratepayers, APS will be subject to a finding of imprudence. And, further, that when an under forecast is discovered, any additional need must be competitively procured under the Track A Order.

D. The best approach for APS' ratepayers is to solicit the majority of unmet needs through asset-backed, dispatchable unit bids that would sell under traditional pay-for-performance PPAs. The remainder of unmet needs would be met with seasonal call options with pre-established energy prices.

Q. How should the Commission require APS to amend its calculation of unmet capacity needs?

A. APS must be required to recalculate unmet needs with a 15% reserve margin on peak load, and without excluding non-APS RMR capacity. That would change the calculation of unmet capacity need as shown below in Table Four.

TABLE FOUR

CORRECTED UNMET NEEDS
WITH FULL 15% RESERVE AND NO NON-APS RMR
EXCLUSION

Capacity	2003	2004	2005	2006
Total Standard Offer Load	5,723	6,023	6,269	6,522
+15 % Reserve Margin	858	903	940	978
APS Units	(3,927)	(3,953)	(3,949)	(3,975)
Purchase Contracts	(955)	(837)	(844)	(852)
EPS	(9)	(17)	(23)	(29)
Net Unmet Needs	1,690	2,119	2,393	2,644

Includes 15 % Reserve Margin on Total Standard Offer Load, and does not exclude Non-APS RMR generation from Unmet needs.

Q. Should the Commission require changes in APS' procurement plan?

A. Yes. Because the initial solicitation is so important in setting the stage for success in future solicitations, the Commission should set some boundaries.

Q. What boundaries do you have in mind?

1 A. The majority of the unmet needs must be met by asset-backed, dispatchable unit
2 sales with traditional pay-for-performance PPAs. The amount of capacity
3 solicited for unit sales would be equal to that intended to be met by Pinnacle
4 West's Redhawk and new West Phoenix units; this is a total of 1,644 MW plus
5 15% reserves for a solicitation total of 1,891 MW in 2006. The logic here is
6 obvious: APS had argued that these units were needed now and, had they been put
7 in rate base, they would have been treated akin to unit power sales.
8
9 Q. What reliability offers would be required?
10 A. Two reliability offers would be accepted. The first would be a unit contingent
11 offer with an Availability Guarantee of 95%. The second would be an offer of
12 firm power that would include a 100% Availability Guarantee and the
13 requirement to pay for replacement capacity and energy if the 100% guarantee is
14 not met; this offer is also called "Firm LD" because it is made firm with its
15 liquidated damages provision.
16
17 Q. What pricing structure should be set for these unit sales?
18 A. With respect to pricing, the RFP for unit sales would allow bidders to offer up to
19 five components of price:
20
21 • A Capacity Price stated in $/kw-year for each year of the contract term, or
22 initial-year stated and then indexed to inflation; payments of the Capacity Price
23 must be tied to the Availability Guarantee;

- An Energy Price that is either a fixed price ($/MWH) stated for each year or stated as a guaranteed heat rate and a fuel price tied to some publicly available fuel price index; a gas tolling offer is also allowable in which the heat rate is guaranteed, but APS provides the gas;
- A Fixed Operation & Maintenance (FO&M) Price in $/kw-year for each year of the contract length, or an initial-year price indexed to inflation; payments of this price, too, must be tied to the Availability Guarantee;
- A Variable Operation & Maintenance (VO&M) Price ($/MWh) stated for each year or an initial-year price indexed to inflation; and
- A Start Price in dollars per start stated for each year or indexed.

Q. How would APS determine the amount of energy it would procure from this capacity?

A. These unit sales offers would be dispatchable within specified limits such as minimum load and ramp rates, based on the offered energy price plus variable operation and maintenance price and transmission losses. This is no different from how APS "procures" power today from its own power plants. So a supplier's offered prices would determine how much energy it would sell.

Q. Does your approach mean that APS could not buy from the Western spot market?

A. No, not at all. My proposal allows APS to get the best deal for ratepayers by taking the cheapest energy, whether it was from these contracts or the spot market, whatever is best for ratepayers. Dispatchability would allow APS to take

1 advantage of the spot market if and when it was to the benefit of ratepayers, but
2 the guaranteed energy from these PPAs would give the risk protection inherent in
3 a pre-set, fixed-formula energy price. In this way, APS' ratepayers would get the
4 best of both worlds.
5
6 Q. How would the remainder of unmet capacity needs be met?
7 A. The remainder of the unmet needs (753 MW in 2006) can be met with seasonal
8 call options. The call option gives APS the right (but not the obligation) to call on
9 the bidder during the summer months (June, July, August and September). APS
10 could structure this product to be callable for either 16 peak hours in a day or just
11 in 6 super-peak hours. All of the calls are under day-ahead scheduling. Once
12 called to run, the unit would be guaranteed to run for the full 16 or 6 hours
13 depending upon the product. This call option product would also be Firm LD;
14 that is, it would guarantee 100% availability backed by liquidated damages.
15
16 Q. What pricing structure would be used for the call options?
17 A. Pricing would be in the form of a two part-price: (a) a call option payment paid at
18 the start of each year (or monthly) in $/kw and (b) a strike price paid when called
19 that can be fixed ($/MWh) or fixed-formula (guaranteed heat rate tied to a fuel
20 index).
21
22 Q. Must APS stick with the amount in your unit sale/call option split regardless of
23 the bids it receives?

1 A. No. APS should always act in the best interests of its ratepayers. If one type of
2 bid is clearly superior in terms of price, risk and reliability, then APS should
3 procure more of it. This would be determined jointly by APS, Staff, and the
4 Independent Monitor as part of the Bid Evaluation Team.
5
6 Q. How would non-APS RMR service be reflected in the RFP?
7 A. The RFP for unit sales would take account of the expected RMR service of the
8 non-APS RMR units, whether that is the new West Phoenix units or competing
9 units. Specifically, non-APS RMR units would be required to be available for
10 RMR service in RMR hours and would be paid no higher than the Arizona
11 protocol price for load pocket pricing. My understanding is that APS' OATT
12 requires a price set to variable costs plus a share of fixed costs – the share of fixed
13 costs would bet set at the share of total hours of operation which are attributed to
14 RMR service. In the non-RMR RFP, bids from competing suppliers would be
15 accepted for all the remaining non-RMR hours in the year.
16
17 Q. Would you endorse APS' call for a separate RFP for RMR service?
18 A. Yes. The RMR hours can be contestable too, with APS running a separate RFP
19 for RMR service. Bids would be accepted from: (a) in-Valley generation; (b) out-
20 of-Valley generation that has non-APS firm transmission service to the Valley
21 during RMR hours; and (c) out-of-Valley generation that offers to finance new
22 transmission capacity to the Valley. For purposes of the RMR RFP, APS must

offer to re-start and run mothballed generation (e.g., old West Phoenix 4 and 6) at a bidder's expense.

Q. Are there any boundaries the Commission should set with respect to the term of PPAs?

A. Yes. APS states that it will not consider offers with longer than a four-year term. In contrast, Staff's Report gives APS the discretion to seek contracts with options to extend if that would be in the ratepayers' best interests.[25] With APS' approach, many contracts will expire in about 2006. I think this is risky for APS' ratepayers since the capacity glut should be absorbed by then. The Commission should put APS on notice that, if it fails to implement Staff's option to extend, and prices spike in 2006, APS will be at risk for a finding by the Commission of imprudence.

IV. I AGREE WITH MUCH OF WHAT I SEE IN THE STAFF REPORT, BUT I WOULD LIKE TO SEE THREE OF STAFF'S PROPOSALS BE MORE FULLY SPECIFIED.

Q. What is your overall assessment of the Staff Report?

A. I agree with much of what I see in the Staff Report. There are three areas in which I would like to see the Report be more specific.

[25] Staff Report at page 25 lines 15 to 16.

1 Q. What are your areas of agreement with the Staff?

2 A. There are several, I will mention five.

3

4 First, I agree with Staff that "[c]ompetition can help to obtain the best deal for

5 ratepayers,"[26] and believe that my proposal has several positive aspects which are

6 meant to ensure competition will work to the benefit of Arizona ratepayers.

7 Futhermore, I agree with Staff's goal of creating an equitable and transparent

8 process that "facilitate[s] a manageable transition to a competitive wholesale

9 power market that provides economic benefits to customers in Arizona...".[27]

10

11 Second, and most notably, I agree with Staff's analysis of APS' unmet needs for

12 capacity and energy, particularly the approximately 38% load factor Staff used to

13 calculate the energy portion.[28]

14

15 Third, I concur with Staff that the unmet needs for each of the next four years

16 should be the minimum amount that is included in the 2003 solicitation.[29]

17

18 Fourth, in many respects its proposal achieves Staff's stated purpose of ensuring a

19 fair and equitable solicitation. Specifically, the Staff is right to endorse a bid

20 evaluation format that compares bids using an equivalent annual annuity

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[26] Staff Report at page 1 line 6.
[27] Id at page 1 lines 8 to 9.
[28] Id. at page 7.
[29] Id. at page 35 lines 7 to 8.

1 method.[30] I also agree with Staff that APS must be required to provide ancillary
2 services to all bidders if it provides them to any generating asset not included in
3 rate base.[31] And I agree that APS should make transmission access on its system
4 available to all bidders in an unbiased fashion.[32]
5
6 Fifth, I support Staff's proposal for a solicitation website, which monitors all
7 contact between the utility and bidders, as a positive step in ensuring that there is
8 no bias toward Pinnacle West.[33]
9
10 Q. Are there areas of the Staff Report that you would like to see changed?
11 A. Yes. There are three areas in which the findings should be deepened.
12
13 First, I appreciate Staff recognizing the importance of allowing Intervenors to
14 have specific opportunities to comment on each step of the solicitation process
15 through written comments provided to APS, Staff, and the Independent Monitor.
16 However, equally important, APS must be required to respond to these comments
17 in writing within seven days.
18
19 Second, the Staff's price to beat estimate must focus on the question ratepayers
20 care about most: will my monthly bills increase over time with the winning bids?
21 To that end, it would be best if Staff compared the winning bids in any solicitation

[30] Id. at page 23 lines 8 to 11.
[31] Id. at page 16 lines 7 to 11.
[32] Id. at page 5 lines 6 to 9.
[33] Id. at pages 19 to 21.

to the unbundled generation cost of APS' existing power resources as adjusted for fuel costs and inflation. If Staff chooses to also incorporate a forecast of spot market purchases in its price to beat, it should reflect the consumer risk of such a dependence on spot purchases; one way to reflect this risk is to use a Black and Scholes calculation to estimate what would be charged to lock into the forecast used by Staff.

Third, while Staff assures the third-party Independent Monitor access to all the information used by APS to solicit and choose among bids, it fails to give the Independent Monitor any means of leverage. Specifically, while APS must allow the Independent Monitor access, there is no pressure on APS to work to win the Independent Monitor's concurrence on both its process and, more importantly, its choice of winning bids. I recommend that the Independent Monitor's Report to the Commission, which is required by Staff, include a headline statement by the Monitor on whether he or she concurs with the ultimate selection of winners. Moreover, that concurrence or lack thereof should be given considerable weight in the Commission's approval or disapproval of the purchase contracts, which result from the solicitation. In addition, the Independent Monitor should have the right to ask the Commission to stop the solicitation process if APS acts in bad faith.

V. RECOMMENDATIONS

Q. What are your recommendations based on your Testimony?

A. I have five recommendations with respect to APS based on my Testimony:

First, the Commission must reject APS' estimate of its unmet energy needs because its economy energy proposal puts its ratepayers at risk in the volatile Western spot market. Instead, consistent with its approach when promoting its Affiliate's Redhawk and new West Phoenix units, APS must estimate this need assuming new, dispatchable combined cycle plants will fill its capacity need.

Second, the Commission must reject APS' estimate of unmet capacity needs because (a) it fails to calculate the 15% reserve on total peak load as it has done in the past and as is traditional; and (b) it shields Pinnacle West's new West Phoenix units from area-wide competition by excluding them from unmet capacity needs based on limited RMR service. The Commission should also take note that APS consistently under forecasts peak load by more than 20% when looking out four years, as would be the case here, and that APS is liable for ratepayers harm due to its under forecasting.

Third, the Commission must reject APS' product definition, which I see as an attempt to undermine, rather than implement, the competitive solicitation required by the Commission's Track A Order. Instead, for 2006, APS should solicit 1,891

1 MW of asset-backed, dispatchable units sales offers under traditional pay-for-
2 performance PPAs with both unit contingent and Firm LD options allowed. The
3 remaining 753 MW of unmet capacity need in 2006 should be solicited as
4 seasonal call options that are Firm LD.
5
6 Fourth, for the unit sales RFP, bidders should assume that non-APS RMR units
7 will be required to run in RMR hours under the Arizona protocol and that
8 competition will be for all non-RMR hours of the year.
9
10 Fifth, a separate RFP for non-APS RMR service can be held. To support this
11 RFP, APS must offer to re-start mothballed in-Valley units fully at a bidder's
12 expense.
13
14 Q. Do you have any recommendations with respect to the Staff Report?
15 A. The Commission should generally accept Staff's Report. I would recommend that
16 it deepen the Staff's recommendation in three areas.
17
18 • First, APS must be required to respond in writing to comments by interested
19 parties in seven days.
20 • Second, Staff's price to beat should compare unbundled generation rates today
21 with the rates resulting from winning bids. If Staff adds wholesale spot prices
22 to its price to beat, it must reflect the consumer risk of relying on spot
23 purchases.

- Third, the Independent Monitor must be asked to announce whether he or she concurs with APS' process and selection of winning bids. And, that announcement must be given considerable weight in the Commission's approval or pass through of winning contracts to ratepayers. The Independent Monitor must also have the right to ask the Commission to stop the solicitation process if APS acts in good faith.

Q. Does this conclude your Testimony?

A. Yes.

Exhibit No. ___ (CRR-1)

APS LOAD AND RESOURCE FORECAST FROM AUGUST 13/14, 2002 WORKSHOP

APS Load and Resource Forecast
2003-2004

	Units	2003	2004
APS Retail Peak Load [1]	MW	6,647	7,019
APS Existing Generation [2]	MW	4,697	4,730
PWEC Dedicated Generation [3]	MW	1,700	1,700
Purchases	MW	251	589
APS Retail Load	MWH	26,404,986	27,733,094
APS Existing Generation [2]	MWH	20,669,120	21,543,806
PWEC Dedicated Generation [3]	MWH	5,728,434	6,170,100
Purchases	MWH	7,432	19,188

[1] Includes 12% Reserves

[2] Generation, Long-term Contracts and Renewable Energy

[3] West Phoenix CC Units 4 & 5, Saguaro CT Unit 3, and Redhawk CC Units 1 & 2

The data presented in this summary is estimated planning data for internal APS planning purposes only. Actual APS load and requirements will depend on numerous variables, such as weather, actual load and demand growth, and plant outages, which are not necessarily included in the figures above. Accordingly, this data is provided for discussion purposes only and APS makes no representations or warranties as to its ultimate accuracy.

Exhibit No. ___ (CRR-2)

APS LOAD AND RESOURCE FORECAST
FROM DIRECT TESTIMONY OF PETE EWEN,
SCHEDULE PME-1

SCHEDULE PME-1
APS Projected Unmet Capacity and Energy Needs
2003 - 2012

Capacity (MW)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Total standard offer load [1]	5,723	6,023	6,269	6,522	6,787	7,064	7,357	7,667	7,914	8,127
+ 15% reserve margin [2]	598	602	602	606	606	609	609	609	609	609
- Physical capability of APS units [3]	(3,927)	(3,953)	(3,949)	(3,975)	(3,975)	(4,001)	(4,001)	(4,001)	(4,001)	(4,001)
- Full capability of purchase contracts [4]	(955)	(837)	(844)	(852)	(860)	(868)	(876)	(884)	(893)	(902)
- RMR generation from non-APS units [5]	(29)	(184)	(338)	(493)	(647)	(802)	(956)	(1,111)	(1,265)	(1,426)
- Planned renewable energy supply under EPS [6]	(9)	(17)	(23)	(29)	(34)	(46)	(56)	(70)	(79)	(89)
= Net unmet reliability needs [7]	1,401	1,634	1,717	1,779	1,877	1,956	2,077	2,210	2,285	2,318

Energy (GWH)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Total standard offer load [1]	26,494	27,841	28,999	30,178	31,388	32,670	33,983	35,305	36,425	37,531
- Physical capability of APS units [3]	(24,016)	(25,242)	(25,663)	(26,496)	(26,941)	(28,179)	(28,707)	(29,182)	(29,567)	(29,931)
- Full capability of purchase contracts [4]	(1,798)	(1,672)	(1,986)	(2,044)	(2,281)	(2,140)	(2,358)	(2,551)	(2,719)	(2,870)
- RMR generation from non-APS units [5]	(0)	(2)	(8)	(27)	(72)	(141)	(248)	(398)	(540)	(705)
- Planned renewable energy supply under EPS [6]	(41)	(85)	(114)	(142)	(154)	(197)	(221)	(267)	(290)	(312)
= Net unmet reliability needs [7]	639	840	1,228	1,469	1,940	2,013	2,449	2,907	3,309	3,713

[1] Standard offer load includes all retail customer energy and coincident peak demands plus APS wholesale contracts served by APS resources from Oct 2002 budget projections. Under Staff's proposal, this calculation would be updated prior to any actual procurement.

[2] Reserve margin is calculated on APS generation and known contingent purchases only.

[3] Includes the production from all rate-based APS generation units subject to standard planned and forced outage assumptions.

[4] Includes firm purchase contracts entered into prior to September 1, 2002.

[5] RMR generation assumes a Valley import limit of 3,535 MW, 660 MW of local APS generation, and 110 MW of required reserves. To the extent that bidders can demonstrate higher import capability or import capability is increased, RMR would be reduced, all else remaining the same. The present import limit of 3,535 MW assumes timely completion of the Southwest Valley line and also uses its most recent (and higher) capacity rating.

[6] Includes solar and renewable resource additions planned each year under current funding levels. To the extent the Commission approves higher funding levels, capacity and energy under EPS will increase.

[7] Energy figures do not include economy purchases, which as noted in Schedule PME-13 would add some 3,700 gwh in 2003 (and more in subsequent years) assuming present forecasts of gas and power costs.

Exhibit No. ___ (CRR-3)

APS METRO PHOENIX RELIABILITY MUST RUN ESTIMATES FROM PAGE 76 OF PETE EWEN'S WORKPAPERS

APS Metro Phoenix Reliability Must Run Estimates
2003 - 2012

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Capacity Need (MW)										
Metro Phoenix Peak Demand	4,114	4,269	4,423	4,578	4,732	4,887	5,041	5,196	5,350	5,511
Transmission Import Limit	3,535	3,535	3,535	3,535	3,535	3,535	3,535	3,535	3,535	3,535
RMR Need	579	734	888	1,043	1,197	1,352	1,506	1,661	1,815	1,976
APS Resources	660	660	660	660	660	660	660	660	660	660
APS Reserves	110	110	110	110	110	110	110	110	110	110
Unmet Need	29	184	338	493	647	802	956	1,111	1,265	1,426
Energy Need (GWH)										
Total Energy	37	92	172	291	445	633	862	1,124	1,366	1,628
APS Supplied	37	90	165	263	373	492	614	727	826	923
Unmet Need	0	2	8	27	72	141	248	398	540	705
RMR Hours										
Total	210	455	640	862	1,099	1,293	1,511	1,723	1,909	2,103
APS Supplied	210	455	640	862	1,099	1,293	1,511	1,723	1,909	2,103
Unmet Need	6	19	57	159	313	510	737	944	1,114	1,282
RMR Capacity Factor										
APS Supplied	0.8%	1.9%	3.4%	5.5%	7.7%	10.2%	12.7%	15.1%	17.1%	19.2%
Unmet Need	0.1%	0.1%	0.3%	0.6%	1.3%	2.0%	3.0%	4.1%	4.9%	5.6%
Total	0.7%	1.4%	2.2%	3.2%	4.2%	5.3%	6.5%	7.7%	8.6%	9.4%

Exhibit No. ___ (CRR-4)

APS ECONOMY ENERGY PURCHASES
FROM DIRECT TESTIMONY OF PETE EWEN,
SCHEDULE PME-13

SCHEDULE PME-13
POTENTIAL ECONOMY ENERGY PURCHASES

	With Current Market Prices			Electric Prices 10% Higher		Electric Prices 10% Lower	
Year	Economic Purchase Amount (GWH)	Average Palo Verde On-Peak Electric Price ($/MWH) [1]	Average San Juan Basin Natural Gas Price ($/MMBTU) [1]	Economic Purchase Amount (GWH)	Percent Change	Economic Purchase Amount (GWH)	Percent Change
2003	3,705	39.42	3.60	3,122	-15.7%	4,418	19.2%
2004	4,033	40.13	3.50	3,465	-14.1%	4,699	16.5%
2005	6,695	40.25	3.36	5,795	-13.4%	7,673	14.6%
2006	6,948	40.53	3.35	6,032	-13.2%	8,025	15.5%
2007	8,320	40.77	3.38	7,341	-11.8%	9,296	11.7%
2008	6,785	41.79	3.46	6,095	-10.2%	7,591	11.9%
2009	7,964	42.83	3.55	7,274	-8.7%	8,787	10.3%
2010	9,136	43.90	3.64	8,427	-7.8%	9,911	8.5%
2011	10,167	45.00	3.73	9,428	-7.3%	10,951	7.7%
2012	11,099	46.13	3.82	10,300	-7.2%	11,871	7.0%

[1] Power and natural gas prices were determined from market quotes through 2007 and escalated by 2.5% per year thereafter.

Exhibit No. ___ (CRR-5)

APS UNDER FORECASTS ENERGY NEEDS
(PERCENT ERROR FOR ENERGY DEMAND)

APS UNDER FORECASTS ENERGY NEEDS
(Percent Error for Energy Demand)

	Forecast Horizon		
Forecast Date	2 years	3 years	4 years
Jan-92	1.71%	-0.70%	2.95%
Feb-93	-0.07%	5.83%	8.87%
Oct-93	0.16%	7.50%	
Feb-94	5.82%	12.95%	13.07%
Oct-94	5.82%	12.95%	
Jun-95	5.24%	5.85%	7.51%
Oct-95	2.29%	2.54%	
May-96	2.46%	2.59%	6.49%
Oct-96	1.12%	0.73%	
Feb-97	1.19%	4.98%	5.49%
Oct-97	-0.46%	2.65%	
Feb-98	2.65%	3.33%	
Oct-98	3.15%	3.49%	
Apr-99	3.49%		
Oct-99	5.61%		
Apr-00			
Oct-00			
Average	2.68%	4.98%	7.40%

*Note that positive numbers indicate the amount that was underforecast. For example, the January 1992 forecasted a demand which was 2.95% lower than the actual demand for energy in 1996.

Exhibit No. ___ (CRR-6)

APS' FIRST SET OF DATA RESPONSES TO STAFF
DATED OCTOBER 15, 2002
MR 1.4

STAFF'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE IN DOCKET NO's. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630 AND E-01933A-02-0069 (TRACK B)
October 15, 2002

MR 1.4 Please list each contract under which APS obtains capacity and energy to serve its retail load. For each contract listed, please specify the contract's capacity and energy or load factor and the date it was entered into.

RESPONSE:

PacifiCorp Diversity Exchange
480 MW on-peak capacity limited to maximum 40% capacity factor May 15-Sep 15 each year. The contract was entered into September 1990.

Salt River Project Territorial Agreement
350 MW capacity for delivery January-December each year. This amount increases per a formula by 7 or 8 Mw per year. Energy is distpatchable and varies as a function of APS economics and to meet the needs of APS system reliability. The annual capacity factor has ranged from 31% to 59% in the 2000-2002 time frame. The contract was entered into in 1955 and was most recently amended in 1998.

Constellation Power (entered into March 2000)
25 MW on-peak capacity with 100% capacity factor during on-peak period for delivery July 2003 - September 2003

Williams Energy Marketing and Trading (entered into March 2000)
25 MW on-peak capacity with 100% capacity factor during on-peak period for delivery July 2003 - September 2003

Morgan Stanley Capital Group (entered into March 2000)
50 MW on-peak capacity with 100% capacity factor during on-peak period for delivery July 2003 - September 2003

Morgan Stanley Capital Group (entered into November 2001)
25 MW on-peak capacity with 100% capacity factor during on-peak period for delivery July 2003 - September 2003

NOTE: APS also has a QF agreement with Abitibi, but it is not for firm capacity or energy and thus has been excluded from APS resources for Track B purposes.

Exhibit No. ___ (CRR-7)

PANDA GILA RIVER, L.P.
REVISED STRAWDOG PROPOSAL
DATED AUGUST 28, 2002

TRACK B PROCEEDING

REVISED STRAWDOG PROPOSAL FOR COMPETITIVE PROCUREMENT BY APS

Presented by
Craig R. Roach, Ph.D
Boston Pacific Company, Inc.

On Behalf of
Panda Gila River, L.P.

REVISED

August 28, 2002

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VII. BROADER ISSUES

I. STARTING POINT AND SUMMARY FOR THE REVISED PROPOSAL

A. The starting point for this strawdog proposal lies in three central points in the ALJ's recommended order on Track A issues. (Although the Commission spoke this week to the ALJ's Order, we do not have final written guidance to reflect herein.)

- First, APS must competitively procure power that it cannot produce from its existing generation assets ("unmet needs"). It is assumed that APS will want to replace its older, less efficient and environmentally unfriendly plants so that its "existing" generation will decline over time.

- Second, the Track A proceeding is not the appropriate forum to justify the transfer of APS' Merchant units (Redhawk and the new West Phoenix) from Pinnacle West to APS.

- And third, divestiture should be delayed until at least 2004.

II. THRESHOLD QUESTIONS

A. What is the format of the competitive solicitation?

- The competitive solicitation will be a three-phase Request for Proposals (RFPs) for all unmet needs.

B. What products are offered in the solicitation?

- The RFPs will solicit asset-backed offers only for capacity and energy. This includes unit sales and system sales.

C. What is the structure of the final contract to be signed in the solicitation?

- The final contract to be signed will be a standard pay-for-performance contract.

D. How will APS and its affiliates be treated in the solicitation?

- PWEC or any other APS affiliate must bid under the same rules as any other bidder and must be held to its bid if it wins.

- Under no circumstances will power from APS' Redhawk and new West Phoenix units be sold to APS, for other than an interim period, except as a result of competitive solicitation.

E. Who will evaluate the bids in the RFP?

- If the utility or its affiliate bids, a Bid Evaluation Team will be formed. The Team will include the Commission Staff plus a Third-Party Evaluator chosen by the Commission. APS will be the other member of the team.

F. How will transmission expansion costs be reflected in the bid evaluation?

- Emerging FERC policy will guide how transmission costs are reflected in the Bid Evaluation. This policy is that (a) each power project must pay for its transmission *interconnection* cost and those costs are presumed to be reflected in its bid; and (b) transmission *integration* costs (system upgrades) will be rolled into transmission rates, but the power projects driving the need for those upgrades will finance the system upgrades (i.e., they will pay for them upfront and then receive credits for transmission service once service begins). Transmission expansion costs will be treated in the bid evaluation process in a non-discriminatory manner.

G. Who will sell power until other winning bids in the RFPs come on-line?

- If a winning bidder is not immediately on-line to supply power, the Bid Evaluation Team should initiate bilateral negotiations with the three next-best bidders that are already on-line and ready to supply power on an interim basis.

III. TIMING AND SCALE OF THE THREE-PHASE RFPS

A. The proposed RFP will be conducted in three phases.

- The Phase 1 RFP will be issued in Fall 2002;
- The Phase 2 RFP will be issued in Spring 2004; and
- The Phase 3 RFP will be issued in Spring 2007.
- The timing and scale is such that, by the end of Phase 3 in 2010, APS' Standard Offer load will be 100% competitively procured.

B. The amount of power to be solicited in Phase 1 is 2,513 MW. This is the estimate of year 2005 peak load that APS cannot serve with its existing generation. Bids are accepted for power plants with in-service dates up to May 2005. Estimates of load growth and existing generation are shown in Table One. The amount of power solicited will be higher if APS retires its older, less-efficient, environmentally challenged units.

- Phase 2 will solicit between 2,981 MW and 5,494 MW. The 2,981 MW reflects the estimate of load growth from 2005 to 2007 (581 MW) plus the load served by 2,400 MW of APS' existing generation assets, which will be divested at this time. The 5,494 MW reflects the fact that, if only three-year PPA terms are accepted, some or all of the load from the first RFP (2,513 MW) must be re-bid. Bids are then accepted for power plants with in-service dates of up to May 2007.

- Phase 3 will solicit between 3,473 MW and 8,967. The 3,473 MW reflects the estimate of load growth from 2007 to 2010 (1,028 MW) plus the load served by the remaining 2,445 MW of APS' existing generation assets, which will be divested at this time. The 8,967 MW reflects the fact that, if only three-year PPA terms are accepted, some or all of the load from the Phase 2 RFP (5,494 MW) must be re-bid. Bids are accepted for power plants with in-service dates of up to May 2010.

IV. MODEL PPA

A. The RFP will include a model PPA to be used as a template for all bids. This PPA will detail all the required and/or preferred price and non-price terms. The goal is to streamline the bid evaluation process by settling most contract issues upfront.

B. Length of Contracts

In order to reach a compromise, we have suggested that the Phase 1 RFP solicit shorter term contracts (three-years) with an option to extend the contract for an additional five-years. However, because we believe there is significant consumer benefit to long-term contracts we believe that the issue should be revisited and that Phase 2 should entertain longer term contracts.

- For Phase 1, the contract term submitted by a bidder will be for three years. In addition, the bidder may choose to submit an option price to extend the contract life for an additional five years. APS may either pay the option price, and in three years extend the contract, or ignore the option price and take the contract as a three year deal.

- We realize the Staff is reluctant to commit ratepayers to longer-term contracts, however, once the benefits of competitive solicitation have been demonstrated in Phase 1, the Commission may endorse longer-term contracts for the Phase 2 and 3 RFPs. In this event, APS will file with the Commission their portfolio-term preferences for approval (e.g. APS prefers 60% of the RFP capacity procured under 10-year terms, 20% under 5-year and 20% under 15-year). This preference will be made public as part of the RFP process.

C. Structure of Price Bids

1. Capacity Price

- Stated in $/kw-year for each year of the contract term; or, initial-year stated and then indexed to inflation.

- The capacity price must be tied to an availability guarantee.

2. Availability Guarantee

- The capacity price would be paid in full if, and only if, the facility was available for service 95% of the time, on average, over the previous 12 months. If it was available for less than 95% of the time, capacity payments would be reduced proportionally and the seller is responsible for the replacement cost of power. If the performance fell below 50% availability, no capacity payment would be made.

- If availability was above 95%, then the supplier would receive a proportional bonus for each percentage point above 95%.

- A guaranteed megawatt output will be stated.

3. Energy Price

- The energy price will either be a fixed price ($/MWH) stated for each year; or,

- Stated as a guaranteed heat rate and a fuel price tied to some publicly available fuel price index.

- Gas tolling offers are acceptable and, in this case, a guaranteed heat rate must be offered.

4. Fixed Operation & Maintenance (FO&M) Cost

- An explicit fixed cost in terms of $/kw-year for each year of the contract length, or an initial-year price indexed to inflation.

- FO&M will also be tied to the Availability Guarantee.

5. Variable Operation & Maintenance (VO&M) Cost

- VO&M will be a fixed price in terms of $/MWH stated for each year or an initial-year price indexed to inflation.

- Start Price: The cost in $/start can be fixed or tied to a publicly available index.

D. Non-Price Terms

1. Dispatchability: Each generation asset is dispatchable based on its energy price plus VO&M plus transmission losses. Each bid must submit the necessary parameters for dispatch such as:

- Minimum load level,
- Ramp rates,
- Minimum run times, and
- Start-up times.

2. No Regulatory-Out Clause

- The RFP itself will be the prudence review, and, therefore there is no need for an ongoing prudence review of the contract. Since there is no risk of a disallowance, there is no need for a regulatory-out clause.

3. *Force Majeure* will be defined using the industry standards for events out of the control of the parties.

4. Security Deposit

- Construction Period Security Deposit shall be in the form of a Letter Of Credit (or an acceptable substitute) for $30,000/MW and be applicable from the date that the winning bidder(s) sign the PPAs until the in-service date of the asset.

- Operation Period Security Deposit shall be in the form of a Letter of Credit (or an acceptable substitute) for $30,000/MW and be applicable for the entire term of the contract.

5. Construction Milestones

- If a bidder's asset is not on-line, it must contractually guarantee to meet milestones, including milestones such as the completion of permitting, financial close, and equipment delivery.

6. Liquidated Damages

- A bidder is liable for the replacement cost of power in the event of (a) early contract termination, (b) under-performance, or (c) failure to meet in-service date.

- The Construction or Operation Period Security Deposits are the source of payment and set the limit for replacement costs.

7. Creditworthiness: Prospective bidders may submit bids only if they meet one of the following creditworthiness standards:

- Bond rating of the company is investment grade;
- The asset to be bid has been financed;
- The asset has an investment grade guarantor; or
- Both Construction and Operation Period Security Deposits are increased to $100,000/MW.

V. BID EVALUATION IN THE RFP

A. A Bid Evaluation Team will be created to ensure fair treatment for all bids.

- The Team will consist of APS, the Commission Staff, and an Independent Third-Party Evaluator chosen by the Commission.

B. The bid evaluation will be in two stages. The first consisting solely of an assessment of generation costs, and the second taking into account possible transmission system upgrade costs.

C. To compare the contracts with unequal lives (i.e. a three-year contract as compared to a three-year contract with an option for five-year extension) the bid evaluation should follow the annuity method detailed in Attachment One.

VI. OTHER ISSUES

A. Confidentiality: All bids are confidential, including those from PWEC. The PPAs from winning bids will be made public upon contract signature.

B. Dispute Resolution: Each bidder is entitled to a post-bid meeting with the Bid Evaluation Team if it is omitted from the short-list, or it is not a winner after being on the short-list. If a grievance remains, losing bidders (a) will agree to arbitration on matters concerning the evaluation of its bid or (b) can appeal to the Commission for serious breaches of procedure only. The entire RFP must be re-opened if procedural breaches are found.

C. Demand-Side Bids: Demand-side bids will be accepted if they can demonstrate that they are effective alternatives to peaking capacity.

D. Bid Fee: A non-refundable $10,000 fee per bidder (covering up to three bid alternatives) will be assessed to defray the cost of the Third-Party Evaluator.

VII. BROADER ISSUES

A. Consistency with FERC's Standard Market Design (SMD) Notice of Proposed Rulemaking (NOPR) with respect to long-term power sales contracts.

The Strawdog Proposal is consistent with the SMD NOPR[1] in the sense that both encourage generation and transmission investment through a preference for longer-term contracts. FERC's clear expectation is that bilateral contracts are used to serve most of the retail load, noting that these contracts account for 85% of the load in the Eastern ISOs.[2] FERC states that a mitigated spot market does not give sufficient incentive to invest.[3] Through its Resource Adequacy requirement, and the use of a longer-term planning horizon within that requirement, FERC says it is encouraging infrastructure investment by promoting longer-term contracts.[4] FERC proposes a forward looking Resource Adequacy requirement, possibly in the 3-year to 5-year range, but will allow the final choice to be made in different regional planning efforts.[5] FERC is also clear that the Resource Adequacy requirement is asset-backed, meaning that the generation assets used to meet the requirement must be specified.[6] FERC does ask for comments on allowing the requirement to be met with offers backed by liquidated damages, but with unspecified generation sources.[7]

FERC also accommodates longer-term contracts by allowing for longer-term transmission rights. FERC speaks of "life of the facility" rights being earned by a customer who pays for network upgrades; these rights are even exempt from the auction requirement four years hence.[8] These lifetime rights can go to merchant transmission

[1] See Notice of Proposed Rulemaking, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design in Docket No. RM01-12-000 (July 2002).
[2] Id. at page 6 and page 10 of Appendix E.
[3] Id. at page 253.
[4] Id. at page 276.
[5] Id. at page 277.
[6] Id. at page 272 and page 273.
[7] Id. at page 273.
[8] Id. at page 6 of Appendix F.

builders, too.[9] FERC wants to allow transmission rights to match the terms of longer term power sales contracts, specifically asking for comments on whether contract terms for transmission rights should be required to match the planning horizon of the Resource Requirement.[10]

B. The Strawdog Proposal calls for unit contingent bids because PWEC's Redhawk and new West Phoenix units are unit contingent.

The Strawdog calls for unit-contingent bids because that is how PWEC's merchant units (Redhawk and new West Phoenix) are accepted by APS; PWEC's units should not have an artificial competitive advantage over competitors. Put simply, this means that PWEC's units do not supply their own operating reserves, but, rather, are backed up by the reserve margin constituted by APS' portfolio of power plants. There is no reason to treat merchant plants developed by competitive power producers differently than merchants developed by an APS affiliate. Moreover, since Arizona ratepayers are already paying for those APS reserves, the unit contingent sale offers the lowest cost to consumers.

We would entertain a 100% availability guarantee if all merchant suppliers, including PWEC, had to meet the requirement. That is, APS could not use its portfolio of assets to back up PWEC's merchant units at Redhawk and new West Phoenix. In addition, we would recommend that the 100% availability requirement be met by membership in the Southwest Reserve Sharing Group (SRSG).[11] An alternative would be that the requirement could be met by a purchase of ancillary services from APS at FERC-approved tariff rates.

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[9] Id. at page 10.

[10] Id. at page 140.

[11] Our understanding is that the SRSG currently has 11 members. The calculation of the contingency reserve requirement for each member is in two parts. The first part results in the percentage share (the Reserve Responsibility Ratio) of the regional reserve requirement for which an entity is responsible. (It is that entity's percentage share of the sum of 25% of each entity's firm load plus its most severe single contingency). The second part sets the actual megawatt contingency reserve requirement for each entity. (This is equal to an entity's reserve responsibility ratio times the region's most severe single contingency.)

TABLE ONE

Proportion of Load Served by Existing APS Resources and Competitive Procurement

Year	Forecasted Peak Summer Load Plus 12% Reserve Margin*	Existing APS Resources (MW)**	% Served by APS Existing Resources	MW Available for Competitive Procurement	
				RFP	
				Minimum	Maximum
2002	6,204	4,845	78%		
2003	6,647	4,845	73%	2,513	2,513
2004	7,019	4,845	69%	↓	↓
2005	7,358	4,845	66%	2,981	5,494
2006	7,628	↓	↓	↓	↓
2007	7,939	2,445	31%	3,473	8,967
2008	8,262	↓	↓	↓	↓
2009	8,604				
2010	8,967	0	0%	All Load	All Load

Load forecast was taken from APS' FERC Form 714, dated 5/22/02; the 12% Reserve Margin was added. The 12 % appears to be what APS currently utilizes. If APS uses a higher planning Reserve Margin, then these numbers would increase. APS informs us that this load only includes retail load. We propose that wholesale load that cannot be served by APS' Existing Resources also be put out for bid.

**Includes all current rate-base plants and contracts with SRP and Pacificorp. Does not include new West Phoenix units and Redhawk 1 and 2. If Ocotillo and West Phoenix are shut down, APS' existing resources decreases by 433 MW (Ocotillo 325, Old West Phoenix 108 MW).

ATTACHMENT ONE

BID EVALUATION IN THE RFP

A. A Bid Evaluation Team will be created to ensure fair treatment for all bids.

- The Team will consist of APS, the Commission Staff, and an Independent Third-Party Evaluator chosen by the Commission.

B. The bid evaluation will be in two stages. The first consisting solely of an assessment of generation costs, and the second taking into account transmission costs.

C. Stage One: Generation Cost Bid Evaluation

1. The initial generation cost bid evaluation will be done across a range of uniform capacity factors. The Team will specify the uniform capacity factors to be used (e.g.10%, 20%, and so on) and each bid will yield a price at each capacity factor (a screening curve).

2. In addition to specifying the uniform capacity factors, the Team will specify all other assumptions for evaluation such as natural gas prices or other fuel costs, and inflation.

3. With the uniform capacity factor evaluation, the costs will be represented as an annuity cost per MWH. The steps are as follows:

- The annual costs for each price component (capacity, energy, VO&M, FO&M and starts) will be projected over the proposed term of the offer, at each of the uniform capacity factors.

- The present value of these projected costs will be determined using APS' after-tax weighted cost of capital as the discount rate.

- A cost annuity will be calculated for the bid over the proposed term. To be clear, if a 3-year offer is made, a 3-year annuity would be calculated. An annuity is used to allow the comparison of bids with unequal lives.

- To adjust for unequal bid sizes, the annuities would be divided by the MWH of the bid as dictated by each uniform capacity factor.

- The Team will rank the annuities per MWH and choose the lowest-cost bids sufficient to meet the megawatt level solicited (e.g. 2,513 MW for the Phase 1 RFP).

4. If the Team is satisfied with the uniform capacity factor evaluation, it need not go further in the generation cost evaluation. If however, the Team wants an additional analysis, it is entirely appropriate to add a production simulation based-bid evaluation.

   - Capacity factors for each bid would be determined through production simulation.

   - Bid comparison would be done on the basis of the cumulative present value of the revenue requirement adjusted for difference in contract term and project size.

D. Stage Two: The Bid Evaluation Team will next take account of the costs of transmission system upgrades.

1. The winning bidders based on generation costs, as a group, will be called the Minimum Generation Cost Portfolio (MGC Portfolio).

2. Transmission modeling will be used to determine the system upgrade costs, if any, associated with the MGC Portfolio. System upgrades will be made to assure reliability criteria are met.

3. Transmission system upgrades will be translated into transmission rates and, if transmission rates do not rise by more than 5%, these system upgrade costs are considered reasonable and the MGC Portfolio is the winning Portfolio.

4. If the 5% transmission rate impact is exceeded, another portfolio of generation bids will be created. This will be called the Second-Best Generation Portfolio. (SBG Portfolio). The SBG Portfolio will include higher-cost generation bids that are expected to require lower transmission system upgrades. Transmission modeling will be used to determine the system upgrade costs of the SBG Portfolio.

5. The costs of the MGC and SBG Portfolio now would be compared with the transmission costs included. The annuity cost of transmission upgrades would be added to the annuity cost of the generation bids. The lower cost Portfolio would win.

6. All bids in the winning portfolio are considered responsible for and must offer to finance a *pro rata* share of the transmission system

upgrades in their region. An exception occurs when a bidder has secured firm transmission service already over non-APS transmission facilities.

E. Load-Pocket Location

- A separate analysis for load-pocket location for generation is required to determine if, and only if, system reliability requires load-pocket location for physical needs regardless of transmission capability.

- If a load pocket is a result of insufficient transmission capability, it is an economic decision captured in the transmission cost analysis detailed above. That is, if the cost of (a) generation outside the Valley plus the cost of required system upgrades is more expensive than (b) the cost of in-Valley generation, then in-Valley generation will win the RFP without any locational preference. There is no need for a location preference if the reason for the load-pocket is insufficient transmission capability.

- APS must allow bidders to co-locate facilities with APS, as possible, on its existing in-Valley sites.

- If APS mothballs or retires in-Valley units, it will include in the RFP a price at which out-of-Valley bidders may call on these units when transmission constraints are binding.

F. Non-Price Factors

- Although many non-price factors are made comparable by the Model PPA, the value of non-price factors in bid evaluation must be made clear in the RFP evaluation process beforehand.

- For example, some value can be assigned to having completed construction or being in an advanced stage of construction.

EXHIBIT
P-3
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING ELECTRIC RESTRUCTURING ISSUES.	)	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	)	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	)	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	)	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	)	DOCKET NO. E-01933A-98-0471

TESTIMONY OF
CRAIG R. ROACH, Ph.D.

ON BEHALF OF
PANDA GILA RIVER, L.P.

November 18, 2002

BOSTON PACIFIC COMPANY, INC.

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1 **I. INTRODUCTION AND PURPOSE OF TESTIMONY**

2

3 Q. Please state your name, position, and business address?

4 A. My name is Craig R. Roach. I am a Partner with Boston Pacific Company, Inc.

5 My business address is 1100 New York Avenue, NW, Suite 490 East,

6 Washington, DC 20005.

7

8 Q. Are you the same Craig R. Roach who submitted Direct Testimony in this

9 proceeding on November 12, 2002 on behalf of Panda Gila River, L.P.?

10 A. Yes.

11

12 Q. What is the purpose of your Rebuttal Testimony?

13 A. The purpose of my Testimony is to respond to certain portions of the Direct

14 Testimony of (a) Mr. Steven Wheeler on behalf of Arizona Public Service

15 Company (APS), including his reliance on APS' revised Code of Conduct; (b) Dr.

16 Richard Rosen on behalf of the Arizona Residential Utility Consumer Office

17 (RUCO); and (c) Mr. Thomas Broderick on behalf of Harquahala Generating

18 Company, LLC.

19

20

21 **II. SUMMARY OF TESTIMONY**

22

23 Q. Can you summarize your overall opinion of Mr. Wheeler's Testimony?

1 A. While there are certain aspects of Mr. Wheeler's testimony with which I can
2 agree, his testimony does not resolve my concerns about APS' needs assessment
3 and procurement proposal. In addition, the proposed APS Code of Conduct
4 referenced by Mr. Wheeler does little to alleviate my concerns about APS running
5 a biased solicitation.
6
7 I do agree, however, with Mr. Wheeler that the Commission's oversight and
8 review of the competitive solicitation constitutes a prudence review.
9
10 Q. Can you summarize your overall assessment of Mr. Rosen's Testimony?
11 A. Dr. Rosen proposes a return to the Integrated Resource Planning/Least Cost
12 Planning (IRP/LCP) of the 1980's and 1990's, which I believe is entirely
13 unnecessary. Staff and other interested parties in this proceeding are focused on
14 assuring that the competitive solicitation will get the best deal for Arizona
15 ratepayers, and the solicitation process, in every respect, is aimed at achieving the
16 least cost for them.
17
18 Q. What is your overall opinion of Mr. Broderick's Testimony?
19 A. I share Mr. Broderick's concerns in many respects. Most notably, I agree that
20 APS has underestimated its unmet needs for this solicitation, and that its economy
21 energy proposal puts ratepayers at risk in a volatile Western spot market.
22
23

III. APS' NEW TESTIMONY DOES NOT RESOLVE ANY OF MY CONCERNS ABOUT ITS NEEDS ASSESSMENT OR PROCUREMENT PROPOSAL.

A. APS' proposed Code of Conduct does little to alleviate my concerns about APS running a competitive solicitation without bias toward its Affiliate.

Q. Do you agree with the Staff's goals that Mr. Wheeler endorsed in his testimony?

A. Yes. I think we can all agree with the general goals that Staff laid out and that APS has endorsed in its testimony.[1] Most importantly, I agree that all of us must assure an equitable, transparent and open competitive solicitation. However, APS' proposed Code of Conduct gives me no comfort about APS running an unbiased competitive solicitation that will achieve these goals.

Q. Are there any specific details in the Code of Conduct that concern you with respect to the competitive solicitation?

A. Yes, there are a number. First, the proposed Code of Conduct does not keep the Affiliate from participating in the solicitation. In fact, APS' witness, Mr. Wheeler, states that both APS and Pinnacle West employees may conduct the solicitation.[2] I find this troublesome given APS' prior actions, the obvious bias toward its affiliate in the proposed PPA and in its Track B needs assessment and

[1] Direct Testimony of Steven Wheeler, Docket No. E-00000A-02-051, at page 3 lines 9 to 13, (November 12, 2002) ("Wheeler Direct").

1 procurement proposal, and the fact that Pinnacle West entities will be bidding in
2 the solicitation. The only way to ensure a fair and competitive solicitation is to
3 keep the two entities completely separate during the solicitation process.
4
5 Q. What else concerns you about Mr. Wheeler's reliance on the Code of Conduct?
6 A. As presented to the Commission, the Code does not guarantee that APS will treat
7 other merchant generation developers the same as it treats its merchant generation
8 affiliate.
9
10 Q. Can you give examples of differing treatment that could result from an inadequate
11 Code of Conduct and that would have an impact on the competitive solicitation
12 being developed in this Track B process?
13 A. Yes, two examples come to mind. First, there is no guarantee in the Code of
14 Conduct that APS will give merchant generation developers the same treatment as
15 APS' merchant affiliate when it comes to things like the arrangements for test
16 energy or other activities prefatory to commercial operation. Distinguishing
17 between generation sources on items such as test energy can have significant
18 economic ramifications.
19
20 My second example relates to APS' rights under its Full Requirements natural gas
21 contract with El Paso. The specific allocation of the rights under that contract is
22 the subject of a current FERC proceeding.[3] Of relevance to this proceeding,

---

[2] Id., at page 9 line 24 to page 10 line 2.
[3] El Paso Natural Gas Company, et. al., Docket No. RP00-336-005.

however, is the fact that APS is of the opinion that it can assign that capacity to any merchant generator through a tolling arrangement.[4] Of course, APS did not mention this opinion in any of the Track B workshops or its testimony and it would appear that APS intended to simply allow its merchant affiliate to claim rights under the agreement.

We believe the Code of Conduct must ensure the comparable treatment of all merchants, including APS' merchant affiliate, during the Track B solicitation and also throughout the normal course of operations.

Q. Are there other items in the Code of Conduct that give you concern?

A. Yes. The proposed Code of Conduct contains several definitions of terms which seem inappropriate and could be used to favor an affiliate.

First, the Code of Conduct defines an "Arm's Length Transaction" as "a transaction between or among parties, each of whom acts in its own interest and where the final decision is not made by a single individual."[5] By not explicitly excluding affiliates, APS misses the essence of the term "Arm's Length." A company simply cannot be at arms length with itself. Affiliated entities, like APS and Pinnacle West, have common interests by definition. For this reason, if given discretion, APS will not take actions that go against its parent, Pinnacle West.

[4] Panda Gila River L.P.'s First Set of Data Requests to Arizona Public Service Company, Docket No. E-0000A-02-0051, Supplemental Data Request 1.34.

1 Second, APS has defined "Shared Services" as services between affiliates that
2 include "energy risk management" and "system dispatch."[6] Given APS' economy
3 energy proposal, it is concerning that system dispatch decision-making and
4 information is openly shared. Since system dispatch determines which units are
5 run based upon the cost of the unit, the Affiliate would have access to the costs of
6 APS' own units, as well as to those of the winning bidders of this solicitation. I
7 participated in the procedural conference where APS argued that the cost
8 information which would be needed by APS to run system dispatch was so
9 important and proprietary that even the outside lawyers and consultants for a
10 potential bidder should not have access to it for fear they would pass it on to
11 personnel preparing the bid. Now, in sharp contrast, Pinnacle West would have
12 immediate, routine access to this information through its role in dispatch.
13 Similarly, risk management is integral in the selection of products, and it appears
14 Pinnacle West would be dictating the means and the ends of risk management.
15 Pinnacle West, thereby, could define products which bias a solicitation toward its
16 resources.
17
18 Third, the definition of "Extraordinary Circumstances"[7] seems inappropriate. Of
19 course, in an emergency, APS should use whatever means are necessary to
20 resolve the problem and to ensure system reliability. However, it should be noted
21 that any contract APS signs as part of this solicitation should include an

[5] APS Code of Conduct, at page 1.
[6] Id., at page 3.
[7] APS Code of Conduct, at page 2.

emergency service clause and, thus, in emergency situations all generators would be treated equally, i.e., subject to the same protocols.

Q. Are there any other sections of the Code that require clarification?

A. Yes. There are several other areas that raise concerns and I believe should be clarified, such as (a) Section II. Applicability of Code of Conduct;[8] (b) Section IX. Separation Requirements;[9] and (c) Section XII. Financing Arrangements.[10] The fact that the Policies and Procedures are not provided here also raises concern.

B. I disagree with APS' implication that the 2003 solicitation will not be intensely competitive, and with APS' request that it alone be given Staff's price to beat.

Q. Does APS express concerns with the Staff Report?

A. Yes. Mr. Wheeler is concerned about the Track B timeline.

Q. What is APS' concern with the Track B timeline?

A. Mr. Wheeler is concerned that the Staff's timeline is problematic and states, "[m]any otherwise interested bidders may have already sold forward their

[8] Id., at page 3.
[9] Id., at page 6.
[10] Id., at page 8.

1 capacity for 2003 by this time, or market prices may have turned unexpectedly
2 higher."[11]
3
4 Q. Do you agree with Mr. Wheeler's concern?
5 A. No. I see little reason for concern given the glut of power plant capacity (by the
6 end of 2003 this will amount to about 6,500 MW, not including Pinnacle West's
7 assets) that is under construction in APS' service territory. My client alone could
8 fill the full unmet need in 2003, and, with so many other generators in the area,
9 including Pinnacle West's Redhawk and new West Phoenix units (for 1,644
10 MW), there will surely be intense competition at the time of Staff's proposed
11 solicitation. Mr. Wheeler is also forgetting that the risk of losing capacity and
12 energy sales for four years to another competitor will likely keep price bids
13 competitive in 2003.
14
15 Q. Does APS have other concerns with the Staff Report?
16 A. Yes. Mr. Wheeler is concerned with the viability of Staff's price to beat and
17 wants Staff to show APS its price to beat.[12]
18
19 Q. Should the price to beat be disclosed to APS?
20 A. No. This information should be disclosed uniformly; that is, either all parties
21 receive the information or none do. While, I can sympathize with some of the
22 concerns raised about the calculation of the price to beat, the possibility that APS'

[11] Wheeler Direct, at page 6 lines 2 to 3.
[12] Wheeler Direct, at page 8 lines 7 to 24.

Affiliate would obtain this information is too great and would unfairly bias the solicitation.

C. I do agree that the Commission's oversight and review of the solicitation constitutes a prudence review, but only for the short duration of the contracts.

Q. Is there any aspect of APS' testimony with which you agree?

A. Yes. While I disagree with much of APS' testimony, there is, one area of agreement. I agree with Mr. Wheeler that the Commission's oversight and review of the competitive solicitation constitutes a prudence review.[13]

Q. How is prudence determined?

A. Generally, an action is deemed prudent if it was arrived at using a reasonable decision-making process given the facts known, and knowable, at the time of the decision.

Q. Why would the Commission's approval of the solicitation process constitute a prudence review?

A. When the Commission approves the process used by APS in soliciting its unmet needs, it will have effectively determined that the process constituted reasonable decision-making. Further, given that prudence can only be judged with the facts known or knowable at the time of the decision, the Commission would not benefit

1 from waiting and reviewing the contracts at a later date; that is, hindsight cannot
2 be used to judge prudence.
3
4 Q. What information should the Commission use in weighing the prudence of the
5 contracts?
6 A. While the Commission should use all known or knowable information at the time
7 of its decision, as I proposed in my Direct Testimony, the Commission should
8 give great weight to the Independent Monitor's report when making its prudence
9 determination. Specifically, the Independent Monitor's report should contain a
10 specific approval or disapproval of the process undertaken and the final contracts
11 awarded. If the Independent Monitor disapproves of the outcome, the
12 Commission should be reluctant to rule that the outcome was prudent.
13
14 Q. Can you give the Commission perspective on judging the prudence of the
15 contracts at this time?
16 A. Yes. For perspective, note that because these contracts are for a short duration,
17 the burden of judging prudence is far less dramatic for the Commission than
18 judging the prudence of a 29-year contract, as was the case with the Affiliate
19 PPA. In addition, the Commission should be reassured with a pay-per-
20 performance PPA obtained through a competitive solicitation because it would
21 have three important elements: (1) a set termination date; (2) penalties for failure
22 to perform; and (3) fixed or fixed-formula prices.
23

[13] Id., at page 6 line 25 to page 7 line 5.

1

2 **IV. DR. ROSEN'S PROPOSED RETURN TO THE INTEGRATED**

3 **RESOURCE PLANNING/LEAST COST PLANNING (IRP/LCP) OF THE**

4 **1980'S AND 1990'S IS ENTIRELY UNNECESSARY. STAFF IS CLEARLY**

5 **FOCUSED ON ASSURING THE COMPETITIVE SOLICITATION WILL**

6 **GET THE BEST DEAL FOR ARIZONA RATEPAYERS, AND THE**

7 **SOLICITATION PROCESS, IN EVERY RESPECT, IS AIMED AT**

8 **ACHIEVING THE LEAST COST FOR THEM.**

9

10 Q. Was RUCO's witness Dr. Rosen present at any of the Staff sponsored workshops

11 on Track B?

12 A. No he was not.

13

14 Q. Did RUCO make its position on the competitive procurement process clear during

15 those sessions?

16 A. Unfortunately no.

17

18 Q. Can you summarize the thrust of Dr. Rosen's testimony?

19 A. Yes. Dr. Rosen wants the competitive solicitation to be done in the context of the

20 Integrated Resource Planning/Least Cost Planning (IRP/LCP) regime of the 1980s

21 and 1990s.[14] Indeed, Dr. Rosen recommends that least cost planning should be

[14] Direct Testimony of Richard Rosen, Docket No. E-00000A-02-051, at page 8 lines 9 to 12, (November 12, 2002) ("Rosen Direct").

the "most important organizing principle around which the entire Track B process must be structured."[15]

Q. Do you agree?

A. No. It is not necessary to return to IRP/LCP. Dr. Rosen's testimony should be rejected in this regard.

Q. Do you agree that IRP/LCP is the only way to protect ratepayers?

A. No, not at all. Staff made it clear throughout the workshops that its number one goal in the development and implementation of a solicitation process was to ensure ratepayer benefit.

Q. What evidence does Dr. Rosen offer to support his suggested return to IRP/LCP?

A. Dr. Rosen provides no evidence, *per se*, but he appears to rely on three points: (a) a concern about using the right capacity factors; (b) the need for a Regulated Proxy bid; and (c) the alleged failure to consider both generation and transmission investments.

A. Getting capacity factors right does not require a return to IRP/LCP.

Q. Please comment on Dr. Rosen's first point.

A. First, Dr. Rosen drives most of his proposal with a concern over getting the capacity factors right for comparison of the various bids.[16] This is a legitimate

[15] Rosen Direct, at page 13 lines 13 to 15.

analytic concern. However, given that the bids will come primarily from new combined cycle plants, I just do not see that this is a major analytic hurdle. A head-to-head comparison, based on a single capacity factor, can take us a long way towards the right answer. Moreover, the screening curve approach that I discussed in the Workshops and in Panda Gila River's Strawdog is a good way to compare the bids at multiple capacity factors to see it there is any difference among bidders. If additional analysis is still required, production simulation modeling can be used to sort through a short list of bids. This is all routine and does not require a return to elaborate IRP/LCP techniques, nor should it be allowed to slow this solicitation.

B. Dr. Rosen's proposed Regulated Proxy bid is not needed.

Q. What is Dr. Rosen's second point in support of returning to IRP/LCP?

A. Dr. Rosen argues that APS needs to develop a bid on a "regulated cost-of-service basis."[17] He refers to this as a "proxy." I will refer to this as his "Regulated Proxy."

Q. Do you agree?

A. No. Dr. Rosen's Regulated Proxy bid is not necessary. Cost-plus offers simply do not provide the same risk protections and reliability guarantees that are standard in pay-for-performance PPAs. Moreover, the costs of a cost-plus

[16] Id., at page 10 line 19 to page 11 line 19.
[17] Rosen Direct, at page 8 line 23.

1 regulated asset are often understated and never guaranteed. This makes a cost-
2 plus offer difficult to compare, and more importantly, simply inferior.
3
4 Q. Do you think the Commission would agree?
5 A. Yes. For the future, the old-line, cost-plus way is "out" and pay-per-performance
6 PPAs are "in" because they offer a better deal to consumers in terms of price, risk
7 and reliability. I see the Track A Order endorsing this with its requirement that
8 APS competitively procure capacity and energy that it cannot produce from its
9 existing assets.[18] Even APS does not propose a procurement for cost-plus
10 products.
11
12 Q. Is there a real-world bid that could be used instead of Dr. Rosen's Regulatory
13 Proxy?
14 A. Yes. APS maintained that it is the Affiliate's Redhawk and new West Phoenix
15 units that were built to serve APS' standard offer load. Bids from these already-
16 built plants are the appropriate basis of comparison to other bids; not a
17 hypothetical, new cost-plus unit.
18
19 **C. Contrary to Dr. Rosen's assertion, Staff's three-phased evaluation**
20 **clearly includes a consideration of both transmission and generation**
21 **investment.**
22
23 Q. What is Dr. Rosen's third point in support of going back to IRP/LCP?

A. His third point is his assertion that Staff's proposal fails to consider both generation and transmission.[19]

Q. Is Dr. Rosen right?

A. No. Dr. Rosen is wrong to suggest that Staff fails to outline a procedure in which both generation and transmission investment are considered. Indeed, the process Dr. Rosen outlined for doing this is exactly what Staff is suggesting in its three-phase approach. Staff states:

> "The first should be to rank order the bids by price using valuation methods that equalize volumetric and or duration differences on a price basis . . . Phase Two should, to the extent not determined during pre-qualification, evaluate deliverability using the network transmission assessment previously provided to the Staff and the Independent Monitor. . . If a bid imposes delivery costs on the utility, the bid price as evaluated should be adjusted to reflect those costs and a new rank order established. . . During Phase Three all other factors not previously considered are to be evaluated. These include evaluations of creditworthiness, experience and proposed exceptions to model contract terms and/or conditions."[20]

Clearly, Phase Two is an assessment of transmission expansion costs, if any, with the generation bids.

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[18] Decision No. 65154, Docket No. E-00000A-02-0051, at Finding Of Fact 36, (September 10, 2002).
[19] Rosen Direct, at page 22 line 13 to 17.
[20] Staff Report on Track B: Competitive Solicitation, Docket No. E-00000A-02-0051, at page 23 line 5 to 25, (October 25, 2002).

1 **V. I SHARE SEVERAL CONCERNS OVER APS' ESTIMATION OF UNMET**
2 **NEEDS WITH HARQUAHALA GENERATING COMPANY, LLC'S**
3 **WITNESS, TOM BRODERICK.**
4
5 Q. Can you please explain the areas in which you agree with Mr. Broderick?
6 A. Yes, there are five areas. First, I agree with Mr. Broderick that APS' forecasts
7 reflect "a persistent under forecasting as opposed to frequent alternating back and
8 forth in accuracy."[21] As stated in my Direct Testimony, if APS' under forecasting
9 leads to greater expense or lower reliability for its ratepayers, APS should be
10 subject to a finding of imprudence. In addition, when an under forecast is
11 discovered the additional capacity and energy must be competitively procured
12 under the Track A Order.
13
14 Second, I argue that APS has significantly underestimated its unmet energy needs.
15 Mr. Broderick offers supporting evidence that, when APS was intending to
16 purchase from Pinnacle West, it reduced the generation of APS' older gas and oil
17 units.[22] In addition, he found that APS' planned purchases from Pinnacle West
18 were substantially higher than its unmet needs calculations.[23] Similarly, my
19 testimony discusses the difference between the power APS would have procured
20 from its Affiliate PPA versus its current estimate of unmet needs.
21

[21] Direct Testimony of Thomas Broderick, Docket No. E-00000A-02-051, at page 9 lines 4 to 5, (November 12, 2002) ("Broderick Direct").
[22] Broderick Testimony, at page 11 line 19 to page 12 line 15.
[23] Id., at page 12 line 16 to page 13 line 4.

Third, I agree with Mr. Broderick's point that RMR generation should be eliminated from the determination of unmet needs.[24]

Fourth, I share Mr. Broderick's concern over APS' economy energy proposal, and like him, believe that it will unnecessarily subject consumers to the risks of a volatile spot market.[25]

Finally, I agree that Staff should require that APS calculate unmet needs based on the energy and capacity that "cannot be **economically** supplied from generation assets already included in the utility's rate base."[26] This, of course, increases unmet energy needs, but also, as Mr. Broderick suggests, may justify retirement of APS' older oil and gas units. This, in turn, would increase APS' unmet capacity needs.

VI. RECOMMENDATIONS

Q. What are your recommendations based on your Testimony?

A. I have two recommendations with respect to APS. First, I recommend that the Commission provide support for a detailed review of APS' proposed Code of Conduct. At a minimum, the Commission should require that (a) APS exclude its Affiliate from any participation in conducting the solicitation; and (b) APS treat

[24] Id., at page 16 line 23 to page 17 line 7.
[25] Id., at page 19 lines 23 to 25.

1 all Merchants comparably at all times and on all transactions including, but not
2 limited to, test energy and the allocation of Full Requirements natural gas. The
3 Commission should also require APS to redefine the terms "Arm's Length,"
4 "Shared Services," and "Extraordinary Circumstances."
5
6 Second, I recommend that the Commission reject Mr. Wheeler's suggestion that
7 APS be provided with Staff's price to beat.
8
9 Q. Do you have additional recommendations?
10 A. Yes. I have two others.
11
12 I also recommend that the Commission consider its review of the solicitation
13 process and the resulting contracts as representing a prudence review if approved
14 by the independent monitor.
15
16 Finally, I recommend that the Commission reject Dr. Rosen's proposal that we go
17 back to an Integrated Resource Planning/Least Cost Planning framework. This is
18 unnecessary because Staff's solicitation process is clearly focused on getting the
19 best deal for the consumer.
20
21 Q. Does this conclude your Testimony?
22 A. Yes.
23

[26] Broderick Direct, at page 26 lines 23 to 24.

Exhibit No.__ (Panda-4)

EXHIBIT
P-4
Admitted

TABLE A
2006 RATEPAYER COSTS

APS Procurement Proposal	Capacity Costs	Energy Costs	Total Costs
Q.3 Capacity plus economy energy	$30 million[1]	$341million[2]	$371 million
Asset Backed Dispatchable Unit-Contingent	$96 million[3]	$197 million[4]	$293 million

[1] Rebuttal Testimony of Mr. Calrson page 16 Line 18. ($5/kw-month times 2,000 MW times 3 months)
[2] Schedule PME-13 and PME-1. Pay the economy energy price for 2006 of $40.53 for 8,417 GWh (6,948 GWh of Economy energy and 1,469 GWh of Unmet Needs)
[3] Rebuttal Testimony of Mr. Calrson Page 16 line 18. ($4/kw-month times 2,000 MW times 12 months)
[4] Schedule PME-13, PME-1, and Rebuttal Testimony of Mr. Carlson page 16 line 19. Using a 7,000 Btu/kwh heat rate times $3.35/Mmbtu= $23.35/MWh for 8,417 GWh

TABLE B
2003 RATEPAYER COSTS

APS Procurement Proposal	Capacity Costs	Energy Costs	Total Costs
Q.3 Capacity plus economy energy	$30 million[1]	$171 million[2]	$201 million
Asset Backed Dispatchable Unit-Contingent	$96 million [3]	$109 million[4]	$205 million

[1] Rebuttal Testimony of Mr. Calrson page 16 Line 18. ($5/kw-month times 2,000 MW times 3 months)
[2] Schedule PME-13 and PME-1. Pay the economy energy price for 2003 of $39.42 for 4,344 GWh (3,705 GWh of Economy energy and 639 GWh of Unmet Needs)
[3] Rebuttal Testimony of Mr. Calrson Page 16 line 18. ($4/kw-month times 2,000 MW times 12 months)
[4] Schedule PME-13, PME-1, and Rebuttal Testimony of Mr. Carlson page 16 line 19. Using a 7,000 Btu/kwh heat rate times $3.6/Mmbtu = $25.2/MWh for 4,344 GWh

RELIANT

1 - 2

EXHIBIT
Reliant
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

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DIRECT TESTIMONY OF CURTIS L. KEBLER

On Behalf of

RELIANT RESOURCES, INC. ("RELIANT")

NOVEMBER 12, 2002

LAW OFFICES
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Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Curtis L. Kebler. My business address is 8996 Etiwanda Avenue, Rancho Cucamonga, California 91739-9662. I am Director, Asset Commercialization, West Region for Reliant Resources, Inc. ("Reliant").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND EXPERIENCE.

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

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION?

A. I offered testimony on behalf of Reliant Resources, Inc. in the Arizona Public Service Company ("APS") Request for Variance matter and in the Track A matter, both of which are a part of this consolidated Docket.

I. SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN TRACK B?

A. First, Reliant thanks Staff and all the parties to Track B for their efforts and participation in the various workshops conducted to establish a competitive solicitation process for the initial solicitation to be conducted in March of 2003. Staff is to be commended for the *Staff Report on Track B: Competitive Solicitation* issued October 25, 2002 ("Staff Report"). My testimony focuses on areas where Reliant believes the general competitive solicitation process outlined in the Staff Report and the specific processes outlined by Arizona

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Public Service Company ("APS") and Tucson Electric Power Company ("TEP") should be modified for the initial competitive solicitation to be conducted next year.

In particular, I will discuss:

1. Why it is inappropriate for both APS and TEP to rely exclusively on a Request For Proposal ("RFP") process, without use of an auction process during the initial solicitation;
2. Why prompt Commission prudence evaluation of awarded contracts is important to provide the level of regulatory certainty needed to allow the competitive solicitation process to minimize costs and maximize economic efficiency;
3. Why the "price to beat" concept is unnecessary where the utility adequately defines the product to be solicited and is unworkable where the product is not defined;
4. Why the Affiliated Code of Conduct needs some additional clarification; and
5. Why the utility's dispatch methodology, the structure and proposed treatment of ancillary services in the solicitation process, and the treatment of Reliability Must Run (RMR) all raise additional concerns

I have also included an edited redline version of that portion of the Staff Report dealing with the description of the Texas competitive electricity market (page 49) to correct certain factual misstatements. Finally, Reliant agrees with the Staff Report's assessment that it is not necessary to discuss or resolve Least

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Cost Planning, Demand Side Management and Environmental Risk Mitigation in this proceeding.

II. A SIGNIFICANT PORTION OF THE UNMET NEEDS SHOULD BE ACQUIRED THROUGH AUCTION

Q. THE DIRECT TESTIMONY OF BOTH APS AND TEP INDICATE THAT THEY INTEND TO INITIALLY RELY EXCLUSIVELY ON RFPS TO SOLICIT BIDS. DOES RELIANT SUPPORT THE USE OF RFPS AS THE EXCLUSIVE INITIAL SOLICITATION PROCEDURE?

A. No. While Reliant recognizes the RFP solicitation process is an appropriate method for securing a portion of the unmet needs of APS and TEP, Reliant supports the use of an auction process to secure a significant portion (at least a third) of those unmet needs in the initial solicitation, as well as for economy and short-term energy purchases. Reliant believes an auction process achieves Staff's goal of a transparent process that results in cost savings for ratepayers.[1] An auction process can be readily developed that is equitable and auditable, yet flexible and is easily understood by all participants.[2] Auctions are particularly well suited for soliciting products that are easily standardized or are already part of a liquid wholesale market. The types of products described by both APS and TEP, such as the 25 MW blocks of capacity and capacity with minimum energy purchases during specific time periods, the call options, and the economy and short-term energy purchases as described by Mr. Carlson on behalf of APS, are the types of products that can be readily standardized.

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[1] Staff Report at p. 1, l. 4.

[2] Criteria established by Staff for an acceptable competitive solicitation process in the Staff Report at p. 1, ll. 8-14.

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Q. PLEASE FURTHER EXPLAIN WHY AN AUCTION SHOULD BE UTILIZED FOR A SIGNIFICANT PORTION OF THE COMPETITIVE SOLICITATION.

A. First, a properly devised auction will accomplish the goals I mentioned above and discussed at pages 1 and 3 of the Staff Report, including the facilitation of an open, transparent, and fair solicitation. Second, suppliers will typically compete on price. All other facets of the product will be determined by a standard contract. This will provide the Commission and Staff greater ease in determining the prudency and reasonableness of the contracts. In turn, Arizona's consumers can be assured that the prices are efficient and the lowest available for those products. Finally, the auction provides Staff an indicator of what actual market prices exist at the time of the solicitation. This is possible because the suppliers are only competing on one variable. By way of contrast, a less-standard RFP product can result in many subjective and deal-specific criteria that may make it difficult to compare options. With an auction, all of that subjective measurement is standardized and consolidated with only price changing among and between the various participants. This transparency should further ease the Commission's prudency review of the competitive solicitation products and provide the Commission and Staff a potential benchmark for determining the prudency of non-standard solicitation products. Finally, it is important that the auction process be utilized in this initial solicitation to allow the Commission to examine the pros and cons of the auction process against the RFP process.

Q. DID APS PROPOSE USING AN AUCTION PROCESS IN THEIR NOVEMBER 4, 2002 FILING IN THIS DOCKET?

A. No, but APS witness Thomas Carlson did suggest an auction process similar to the proposal APS made in their July 1, 2002 filing was actively being considered for a solicitation in 2004.

Q. COULD APS UTILIZE AN AUCTION PROCESS FOR THEIR FIRST SOLICITATION?

A. Reliant believes APS could very easily use an auction process for a significant portion of their initial solicitation. This is particularly evident when one considers the standard nature of the products for which APS is proposing to solicit contracts. Each of these products—capacity, capacity plus energy, and physical call options—are very good candidates for a standard auction process. As both the Commission and Staff have mentioned in previous hearings and workshops, there is a surplus of wholesale generation available in Arizona's market today. An open, transparent, and fair solicitation promotes the utilization of this surplus wholesale generation for the benefit of Arizona's consumers. By allowing firms to compete head-to-head as suppliers of these products, the Commission can rest assured that the results will represent the best possible price for consumers.

Q. APS CLAIMS THERE IS INSUFFICIENT TIME TO INSTITUTE AN AUCTION PROCESS FOR THIS FIRST SOLICITATION. DO YOU AGREE?

A. No. APS' testimony stated that the short time frame for the solicitation does not allow for the development of the appropriate software and controls for an

automated auction. However, there are alternatives available that can accomplish the same results. As an example, a manual process with sealed bids submitted and posted in an open meeting can be immediately used. Other auction styles are available that can result in very similar outcomes. An open auction has an advantage over the RFP process since there is no additional negotiation. For example, in a RFP process with unit-backed capacity many substantive contract terms beyond price still must be negotiated after the initial selection. These include scheduling rights, maintenance schedules, availability guarantees, heat rate guarantees, and capacity guarantees, just to name a few. Not only can it take weeks or even months to resolve these issues, the ultimate resolution can change the cost and value of the product to Arizona's consumers. An auction process avoids these difficulties by standardizing a portion of the requirements up front, just as APS has suggested doing on a short-term basis, and thereby ensures Arizona's consumers receive the truly competitively priced product.

Q. WOULD AN OPEN, TRANSPARENT, AND FAIR AUCTION BE APPROPRIATE FOR APS' PROPOSED ECONOMY AND SHORT-TERM ENERGY PURCHASES?

A. Yes. The development of a simple but transparent auction for APS' proposed economy and short-term energy purchases has several benefits. First, an open and transparent process ensures that competition determines an efficient price for the product solicited. Secondly, the efficient pricing outcome should assist both the Commission and APS in any prudency review of the proposed economy energy purchases. APS would have the assurance that it was

procuring the most efficient price available from the market. Finally, an open, transparent, and fair auction for economy and short-term energy purchases will mitigate concerns regarding the dispatch of utility affiliate generating assets over other regional suppliers that I discuss later in my testimony.

Q. PLEASE DESCRIBE A METHOD BY WHICH APS MIGHT USE AN AUCTION FOR ECONOMY AND SHORT-TERM ENERGY PURCHASES?

A. A relatively simple method would utilize a "bid stack" for the supply of day-ahead, month-ahead, or 45-day-ahead economy energy purchases. The utility could utilize a standard contract for the product it wishes to procure through economy energy. The utility would then accept sealed or electronic bids. Bids received would be reviewed by utility staff members certified as not having contact with persons involved in the bid development of the utility affiliate, except for the submission of the bid. The use of a standard contract allows suppliers to bid only just one variable: price. Thus, the bids are stacked and ranked by price, with the lowest bids selected, in merit order, to supply the economy energy needs of the utility.

Q. WOULD THE INDEPENDENT MONITOR NEED TO BE INVOLVED IN EVERY TRANSACTION WHERE APS PROCURES ECONOMY OR SHORT-TERM ENERGY?

A. Not necessarily. Once an open, transparent, and fair auction process is in place, where only price determines the winner, any improper behavior should be readily identifiable. Therefore, the Independent Monitor's function can be limited to periodic review.

Q. DID TEP PROPOSE AN AUCTION PROCESS IN THEIR NOVEMBER 4, 2002 FILING IN THIS DOCKET?

A. No. According to the testimony of David Hutchens, TEP will use a RFP to procure fixed price firm on-peak energy, fixed price firm super-peak energy, index-priced unit contingent capacity and energy, and non-spin ancillary service capacity. For the same reasons discussed above, TEP could utilize an auction process for their first solicitation.

Q. ARE YOU SUGGESTING THAT APS AND TEP RELY SOLELY ON AN AUCTION PROCESS TO PROCURE THEIR UNMET NEEDS?

A. Not necessarily. A significant portion of the utilities' unmet needs should be obtained through an auction process. To the extent that the utilities in Arizona need products that are easily standardized or are already part of a liquid wholesale generation market, an auction is a reasonable method of obtaining the product through robust competition. If the utility is in need of a specialized product, especially one that cannot be standardized, then it is appropriate to look to other methods of procurement, such as a RFP. Ultimately, the Commission should expect that a balanced utility portfolio will reflect multiple product types procured through the most appropriate means for those products.

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III. THE COMMISSION SHOULD PROVIDE PROMPT PRUDENCY REVIEW

Q. UNDER STAFF'S PROPOSAL, DOES THE COMMISSION HAVE A ROLE IN THE APPROVAL OF THE CONTRACTS SIGNED AS A RESULT OF THE COMPETITIVE SOLICITATION?

A. Yes. However, under Staff's proposal the timing of the Commission's review, both as to the manner in which the solicitations were conducted and the appropriateness of the power supplies purchased, is totally discretionary.[3] The undetermined timeline in the prudency review creates significant and unnecessary risk for the utility, the suppliers, and Arizona's consumers.

Q. DESCRIBE THE UNCERTAINTY CREATED BY THE UNDETERMINED TIMELINE FOR PRUDENCY REVIEW.

A. Without a definitive schedule for determining the prudence of the wholesale suppliers' contracts: 1) utilities will not know whether they can recover the costs of the suppliers' contract; 2) utilities are likely to include "regulatory out" clauses in their competitive solicitation contracts; taking away the parties' certainty regarding the contract, including the term thereof; and 3) ultimately, these uncertainties are translated into higher solicitation prices borne by Arizona's utilities and greater risks for Arizona's consumers. Suppliers' bids are impacted when the review and approval of contracts is lengthy. Providing the parties involved in the competitive solicitation with certainty of the

[3] Report at p. 4, l. 26 through p. 5, l. 2. Staff does suggest that the Commission should "review the contracts entered into as a result of the solicitation at such time as the utility seeks to recover the associated costs from customers". Staff Report at p. 36, ll. 20-22. As discussed in my testimony, such a delay in obtaining Commission prudency review increases costs and is unnecessary.

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outcome in a timely manner will assure the most efficient outcome and the best possible prices for Arizona's consumers.

Q. HOW CAN THIS UNCERTAINTY BE MITIGATED?

A. The Commission and Staff can mitigate the uncertainty by determining the prudency of any competitive solicitation product within a time frame dependent on the solicitation method being used by the utility. Where the Independent Monitor finds an auction process is transparent and fairly conducted, Staff's certification of the results as reasonable and prudent and the Commission acceptance or rejection of Staff's certification should be completed within five (5) business days. Where the Independent Monitor makes the same findings for any Request for Proposal ("RFP") process, Staff's certification of the result as reasonable and prudent and the Commission acceptance or rejection of Staff's certification should be completed within thirty (30) days, recognizing the potential for non-standard contracts in a RFP solicitation.

Q. DOES THE PARTICIPATION OF AN INDEPENDENT MONITOR PROVIDE ADDITIONAL CERTAINTY TO AN OPEN, TRANSPARENT, AND FAIR OUTCOME?

A. Yes. The participation of the Independent Monitor and its role as described in the Staff Report enhances the Commission's ability to determine the prudency of the competitive solicitation contracts in a timely manner. Staff has done a commendable job in augmenting the role of the Independent Monitor to ensure an open, transparent, and fair outcome. Certainty in the outcome is further provided by the Independent Monitor's ability to petition the Commission for

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suspension or termination of a solicitation, which it deems to be flawed and the Commission's ability to order such changes as it deems necessary to promote effectiveness, reasonableness and fairness[4] at any point in the solicitation process.

IV. THE "PRICE TO BEAT" IS UNNECESSARY FOR STANDARDIZED PRODUCTS (THE SUBJECT OF MOST AUCTIONS) AND PROBABLY UNWORKABLE FOR NON-STANDARDIZED PRODUCTS (USUALLY SECURED THROUGH RFPS)

Q. WHAT IS THE PURPOSE OF THE "PRICE TO BEAT" ACCORDING TO THE STAFF REPORT?

A. Staff developed the price to beat concept "to provide certainty of Staff support for cost recovery as an alternative to an expedited review process."[5]

Q. SHOULD THE "PRICE TO BEAT" AS PROPOSED IN THE STAFF REPORT PROVIDE ANY CAUSE FOR CONCERN?

A. Yes. As proposed, the price to beat could artificially cap the market price based upon forecasts regardless of whether they reflect actual market conditions or the characteristics inherent in the products available through competitive solicitation. The use of a price to beat creates a time lag for any potential change in the market from the time of the price forecast to the time of the ultimate procurement. These changes could significantly alter the outcome

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[4] Staff Report at p. 12, ll. 5-9. As a result, the Staff's Report provision for post-solicitation remedies after notice and hearing, such as disallowing the recovery of cost of power incurred pursuant to contracts entered as a result of an inequitable solicitation (Staff Report at p. 12, ll. 10-16) is unnecessary.

[5] Staff Report at p. 35, ll. 22-27.

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of the solicitation compared to Staff's expectations. These changes could, in the eyes of Staff, create an "unsuccessful" solicitation despite the fact that the outcome is representative of current market conditions.

Q. WHAT OTHER DIFFICULTIES DOES THE USE OF A "PRICE TO BEAT" CREATE?

A. Determining the price to beat is administratively difficult. The Staff Report states that Staff and Independent Monitor will establish a price to beat for "each product solicited for each utility."[6] Based upon the proposals of APS and TEP, this will mean the determination of at least 6 different prices to beat; this number can be further multiplied by however many different term lengths are included in the procurements. The task of determining multiple prices to beat is not only onerous, but is further complicated by the difficulty in comparing the price to beat for the procurement of any non-standard product. There is no clear method of comparing a non-standard product to a price forecast.

Q. CAN EFFICIENT PRICES BE PROVIDED TO CONSUMERS WITHOUT A "PRICE TO BEAT"?

A. Yes. By focusing on a transparent solicitation process, whether an auction for standard products or properly designed RFPs for non-standard products, the Commission and Staff can be assured that the solicitation outcome itself represents an efficient price under current market conditions and should provide the lowest price to Arizona's consumers for the products solicited.

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[6] Staff Report at p. 24, ll. 27-28.

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Q. ARE THERE OTHER REASONS STAFF SHOULD FEEL COMFORTABLE WITH THE OUTCOME OF A COMPETITIVE SOLICITATION WITHOUT USING A "PRICE TO BEAT"?

A. Yes. As I mentioned previously, the Independent Monitor plays a significant role throughout the procurement process to ensure that whatever solicitation process is implemented creates an open, transparent, and fair solicitation to supply the utilities' unmet needs. Certainty provided by the Independent Monitor's participation, combined with the Commission's prompt prudency review, renders a price to beat unnecessary.

V. AN AFFILIATE CODE OF CONDUCT NEEDS TO PROTECT AGAINST AFFILIATE CONTACT THROUGHOUT THE SOLICITATION DEVELOPMENT PROCESS AND IN SHORT-TERM ENERGY TRANSACTIONS

Q. DOES RELIANT BELIEVE AN AFFILIATE CODE OF CONDUCT IS NECESSARY FOR THE COMPETITIVE SOLICITATION?

A. Yes. To the extent an affiliate of any Arizona utility wants to participate in the utility's competitive solicitation, including economy and short-term energy transactions, clearly defined firewalls should be in place to protect the competitive process. As I have mentioned previously, a transparent and fair process that leads to an efficient market outcome is in the best interest of Arizona's consumers.

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Q. DOES RELIANT HAVE ANY SUGGESTIONS TO STRENGTHEN THE CODE OF CONDUCT AS CURRENTLY PROPOSED?

A. Yes. The Staff Report provides a workable template for a Code of Conduct in the competitive solicitation. Reliant suggests that additional consideration be given to the exposure and role of utility employees who work on its procurement. The deadline of January 1, 2003 for the utility to establish its "procurement team" suggested in the Staff Report ignores the substantial work that is already being performed by the utilities employees in preparation of the solicitation. Reliant submits that the Code of Conduct must require the utility demonstrate that those who worked on the procurement, including its development, execution, and review, did not have any improper contact with any utility affiliate that is participating in the competitive solicitation. Members of the procurement team should be required to attest that they have no knowledge of the products or offers of any affiliate participating in the competitive solicitation. This will provide greater assurance to all participants that no party has an unfair advantage throughout the solicitation. As discussed later, Reliant is also concerned that short term energy purchases could be conducted to favor an affiliate. The Code of Conduct must insure that the bid stack, dispatch and procurement decisions are made on a non-discriminatory basis and that the affiliate's employees are not provided access to information or decision makers that would provide the affiliate an unfair competitive advantage to the affiliate.

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VI. OTHER TROUBLESOME ASPECTS OF APS' PROPOSAL

Q. YOU PREVIOUSLY DISCUSSED THE LACK OF AN AUCTION PROCESS IN APS' SOLICITATION PROPOSAL. ARE THERE OTHER ASPECTS OF APS' PROPOSAL THAT CONCERN YOU?

A. Yes. The utility's dispatch methodology, the structure and proposed treatment of ancillary services in the solicitation process, and the treatment of Reliability Must Run (RMR) all raise additional concerns.

Q. DESCRIBE YOUR CONCERN REGARDING APS' DISPATCH METHODOLOGY.

A. APS' reliance on economy and short-term energy purchases brings into question how it plans to dispatch the assets under its control and those available to APS from the market. It is in the best interest of Arizona's consumers that the dispatch of energy be done on a non-discriminatory economic basis. APS has not specified whether APS or one of its affiliates will be making the dispatch decisions in APS' control area. Reliant submits that the Commission should ensure that until a Regional Transmission Organization ("RTO") is in place, an affiliate of APS is not the control area operator and that all dispatched units be treated in a non-discriminatory manner.

Q. DESCRIBE YOUR CONCERN REGARDING THE LACK OF AN ANCILLARY SERVICES MARKET IN APS' PROPOSAL.

A. The Staff Report states "bidders will provide all ancillary services required to support their bids."[7] APS' proposal does not mention this provision or how it

[7] Staff Report at p. 16, l. 8.

plans to address it. Arizona's current market structure does not provide for a competitive ancillary services market. Furthermore, many standard products do not include ancillary services in addition to the standard product. Ultimately, ancillary services would need to become an unbundled control area product to create a market for these services. Otherwise, the suppliers in the region must rely on the control area operator for ancillary services. While Reliant strongly supports the development of a competitive ancillary services market, it is premature for Staff to expect suppliers to provide "all ancillary services required to support their bid" when no market for such services currently exists.

Q. DESCRIBE YOUR CONCERNS REGARDING THE TREATMENT OF RMR UNITS AND FORECASTS.

A. Reliant has two concerns regarding the status of RMR in this proceeding. First, based upon the testimony of Peter Ewen, APS will not be able to provide a determination of RMR hours until well after a decision in the Track B process is rendered. This means that the actual amount of capacity and energy available for procurement will not be known until after the Commission has made a decision in this proceeding. To resolve this uncertainty, APS should be required to provide an estimate of its RMR hours in this proceeding and be required to justify any changes it later proposes for the actual solicitation.

Q. WHAT IS YOUR SECOND CONCERN REGARDING THE TREATMENT OF RMR IN APS' PROPOSAL?

A. The testimony of Thomas Carlson states that capacity or energy for RMR not supplied by APS could be solicited separately from the original unmet needs

solicitation. It may be less expensive for a unit that is already supplying capacity and energy to provide the RMR services as long as they meet all the technical requirements. By removing this element from the standardized solicitation proposal, APS is ignoring an option to provide less expensive services from a competitive supplier for the benefit of Arizona's consumers.

VII. DETERMINATION OF UNMET NEEDS

Q. DOES RELIANT HAVE A POSITION REGARDING THE AMOUNT OF UNMET NEEDS INCLUDED IN THE UTILITIES' INITIAL COMPETITIVE WHOLESALE GENERATION SOLICITATION?

A. Reliant has not, at this time, undertaken an independent analysis of the level of unmet needs quantified by APS and TEP in their November 4, 2002 filings, in this Track B proceeding. It is Reliant's understanding that the direct testimony of other parties to this proceeding will address the amount of unmet needs included in the utilities' initial competitive wholesale generation solicitations. Reliant reserves its right to comment on the utilities amount of unmet needs subject to competitive wholesale generation solicitation after reviewing the parties' testimony submitted on November 12, 2002.

VIII. TECHNICAL CORRECTIONS TO THE STAFF REPORT'S DESCRIPTION OF THE TEXAS RESTRUCTURING PROCESS

Q. DO YOU PROPOSE ANY TECHNICAL CHANGES TO THE STAFF REPORT?

A. Yes. Appendix B contains an edited redline version of that portion of the Staff Report dealing with the description of the Texas restructuring process.

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Appendix B clarifies and corrects certain factual information about that process.

IX. CONCLUSION

Q. PLEASE SUMMARIZE RELIANT'S CONCLUSIONS AND RECOMMENDATIONS FOR THE INITIAL COMPETITIVE SOLICITATION.

A. Reliant believes the utilities should utilize an open and transparent process to ensure a fair solicitation that results in a balanced portfolio served by efficient market-based results. The Commission should urge the utilities to use an auction process for a significant portion of their solicitation where standard products are being procured. For the initial solicitation, Reliant recommends not less than a third of the unmet needs be acquired through an auction process. Furthermore, the Commission must recognize the importance of certainty and timeliness in the approval process of the competitive solicitation award contracts. By applying the recommendations included in this testimony, the Commission can facilitate a robust wholesale electricity market in Arizona that provides the benefits of competition the state's electricity consumers.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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APPENDIX A

STATEMENT OF QUALIFICATIONS

Curtis Kebler is Director, Asset Commercialization West Region for Reliant Resources, Inc. Reliant is a competitive provider of electricity and energy services to wholesale and retail customers in the U.S. and Western Europe. Mr. Kebler is responsible for representing Reliant's commercial interests on a broad range of technical and policy issues before various regulatory, legislative, and industry organizations in the Western U.S. He coordinates and implements the company's policies relating to restructured western region electricity markets and Regional Transmission Organizations, and oversees the performance of research and analysis and the development of studies and reports on western energy markets.

Mr. Kebler has more than 15 years experience in the energy industry and has broad knowledge of the structure, operation and performance of California's natural gas and electric power markets. From 1985 to 1997, Mr. Kebler worked for Southern California Edison Company in a variety of positions and was actively involved in the restructuring of California's natural gas industry and following that the restructuring of the state's electricity industry. From 1997 to 1999, Mr. Kebler worked for the California Power Exchange and was actively involved in all aspects of the start-up and initial operation of that corporation.

Mr. Kebler has a Bachelor of Science degree in nuclear engineering from the University of California. He is a member of the Board of Directors of the Independent Energy Producers Association and the Western Power Trading Forum and serves as Reliant's representative on numerous industry associations and committees.

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APPENDIX B

Texas

Background

Restructuring legislation was enacted in 1999 in Texas ~~to restructure the Texas electric industry~~ allowing retail competition~~. The bill required retail competition~~ to begin by January 2002. Under retail competition in Texas, default service for residential and small commercial consumers, ("Price to Beat" or "PTB" service) and Provider of Last Resort ("POLR") service are two separate services provided by separate Retail Electric Providers ("REPs"). PTB service is provided by the affiliate of the incumbent utility – the Affiliated Retail Electric Provider ("AREP") – for customers who elect PTB service or those customers who have had their service disconnected due to non-payment. The provider of POLR service is chosen via a competitive bid process or lottery. POLR service is intended primarily as a temporary service for those customers whose REP has exited the market.

Texas retail electricity ~~R~~rates were~~are~~ frozen from 1999 to the end of 2001~~or 3 years~~, and then a 6 percent reduction ~~will~~ is ~~be~~ required for PTB ~~residential and small commercial~~ consumers. This ~~will remain the~~ "price to beat" remains for five years after retail competition begins and may be adjusted up to twice a year to reflect significant changes in the market price of natural gas and purchased energy to serve retail customers.~~or until utilities lose 40 percent of their consumers to competition.~~ The AREP can provide competitive service to residential and small commercial customers the earlier of January 2005 or when it loses 40 percent of residential and/or small commercial customers to other REPs.

Utilities were required to ~~must~~ unbundle into 3 separate categories ~~, using separate companies or affiliate companies, the~~ generation, ~~the~~ distribution and transmission, and the retail electric provider – using separate companies or affiliate companies. Power

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generation companies are ~~Utilities will be~~ limited to owning and controlling not more than 20 percent of installed generation capacity located in or capable of delivering to ~~in~~ their region (ERCOT).

~~The PUC adopted rules for the provider of last resort for when competition began in early 2002. The provider of last resort is required to provide to consumers no longer served by their provider of choice service at a fixed price. A competitive bidding process will designate the last resort providers for each consumer class. Bidding was completed by June 1, 2001.~~

During 2001, generation affiliates of the utilities in Texas began the process of auctioning part of their generating capacity as described below. ~~The auction is designed to increase the pool of available power for new retail suppliers entering the market, prevent market power, and promote competition in electricity markets.~~

Wholesale solicitation

As part of the restructuring of the Texas electricity market, generation affiliates of the utilities in Texas are required to ~~acquire~~ sell at auction entitlements to at least 15% of their installed generation capacity until the AREP loses 40% of their residential and small commercial consumers to competitive REPs or 2007, whichever occurs first. ~~requirement through auction~~. The purpose of the auction is to promote competitiveness in the wholesale market through increased availability of generation and increased liquidity. The AREP is not allowed to purchase capacity in this auction. ~~The utility has the responsibility to procure the necessary capacity and energy, adhering to the rules established by ERCOT. Capacity in addition to the mandated capacity auction is procured through solicitation and secured by bilateral contracts.~~

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EXHIBIT
Reliant-2
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING ELECTRIC RESTRUCTURING ISSUES	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES	DOCKET NO. E-01933A-02-0069

REBUTTAL TESTIMONY OF CURTIS L. KEBLER

On Behalf of

RELIANT RESOURCES, INC. ("RELIANT")

NOVEMBER 18, 2002

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Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Curtis L. Kebler. My business address is 8996 Etiwanda Avenue, Rancho Cucamonga, California 91739-9662. I am Director, Asset Commercialization, West Region for Reliant Resources, Inc. ("Reliant").

Q. ARE YOU THE SAME CURTIS L. KEBLER THAT OFFERED DIRECT TESTIMONY IN THIS DOCKET ON NOVEMBER 12, 2002?

A. Yes.

I. SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN TRACK B?

A. I will be responding to the testimony from Mr. Wheeler of Arizona Public Service Company ("APS"), Mr. Hutchens of Tucson Electric Power Company ("TEP"), Dr. Rosen for Residential Utility Consumer Office ("RUCO"), Mr. E. Douglas Mitchell of Sempra Energy Resources ("Sempra") and Dr. Roach for Panda Gila River, L.P. ("Panda") as it pertains to the following:

1. Commission approval of the Track B procurement and assurance of cost recovery;
2. The "price to beat;"
3. Refinement of the role of Staff and the Independent Monitor; and
4. The regional and integrated resource evaluation methodologies suggested by RUCO and Sempra.

I will also briefly address the revised Code of Conduct filed by APS on November 12, 2002.

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II. COMMISSION REVIEW AND APPROVAL OF THE SELECTED CONTRACTS

Q. DO YOU AGREE WITH THE CONCERN EXPRESSED BY MR. WHEELER AND MR. HUTCHENS REGARDING THE ABSENCE OF PROMPT ARIZONA CORPORATION COMMISSION ("COMMISSION") ACCEPTANCE OF THE RESULTS OF THE POWER PROCUREMENT PROCESS?

A. Yes. Both Mr. Wheeler[1] and Mr. Hutchens[2] express the same concern set forth in my direct testimony – the lack of timely Commission approval of the contracts selected through the solicitation process injects an unnecessary element of regulatory risk into the economic transaction that will be reflected in increased costs. Mr. Wheeler correctly observes that the structure of the solicitation and the oversight of Staff and the Independent Monitor, provides a high degree of confidence that the stated goals have been achieved in an equitable and prudent manner and should permit the Commission to promptly approve the selection decision.

III. THE "PRICE TO BEAT" IS UNNECESSARY

Q. DO ANY OF THE OTHER WITNESSES EXPRESS CONCERNS REGARDING THE "PRICE TO BEAT" ADVOCATED BY STAFF?

A. Both Mr. Wheeler and Dr. Rosen express concern regarding the practical difficulties Staff will face in establishing the price to beat,[3] while Mr. Hutchens states that the price to beat may deter long-term contracts by requiring an

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1 Wheeler, Direct at pages 4-7.
2 Hutchens, Direct at pages 10-11.
3 Wheeler, Direct at page 4, lines 12-16, page 9, lines 1-11; Dr. Rosen, Direct at page 14, lines 12-20.

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additional discount to the price to beat.[4] My direct testimony explains how the price to beat contributes to the uncertainty of the entire process and that the methodology for its development and application is unknown and not understood. Therefore, use of a price to beat in the evaluation process only confuses the prudence issue due to the difficulty in making accurate comparisons of all the varying products and the timeliness of its development and its ultimate application.

When the solicitation is structured in an open, transparent and equitable manner, then the winning bid represents ***the*** "price to beat." There is no need for comparison with a hypothetical price to beat because the best price for that particular product available in the market at that particular time has been obtained by competitive solicitation.

Q. IF A "PRICE TO BEAT" IS RETAINED AS PART OF THE SOLICITATION PROCESS, DO YOU AGREE WITH MR. WHEELER THAT IT SHOULD BE REVEALED ONLY TO THE UTLITY?

A. No. First, for the reasons stated above and in my direct testimony, Reliant believes the price to beat concept is unnecessary. If the price to beat concept is adopted by the Commission, Reliant urges that it be used only as a reference point for evaluating the bids selected by the utility. Therefore, Reliant agrees with the Staff Report that it is not necessary to disclose the actual price to beat as part of the competitive solicitation process. Reliant does, however, recommend Staff be required to disclose the general methodology used to

[4] Hutchens, Direct at page 9, lines 8-10.

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determine the price to beat in the context of the products subject to competitive solicitation. Furthermore, the utility should not be the only party apprised of the price to beat as suggested by Mr. Wheeler.[5] Whatever is revealed about the price to beat should be revealed to all participants. This is the only way to ensure a level playing field is maintained for the current, as well as future competitive solicitations.

Q. DOES RELIANT AGREE WITH DR. ROACH'S SUGGESTION AT PAGE 34 OF HIS TESTIMONY THAT THE INDEPENDENT MONITOR SHOULD ANNOUNCE WHETHER HE OR SHE CONCURS WITH APS' PROCESS AND SELECTION OF THE WINNING BIDS AND THAT THE COMMISSION SHOULD GIVE SUCH ANNOUNCEMENT CONSIDERABLE WEIGHT IN ITS PRUDENCE REVIEW?

A. Yes, and Reliant believes the Staff Report already comports with Dr. Roach's suggestion. The Staff Report requires the utility to submit a detailed report to the Commission within two weeks of the selection of winning bids. The utility's report must detail both the process employed to conduct the solicitation and explain the basis for selecting the winning bid. The Staff Report requires the Independent Monitor to submit two reports. The first report is due within 3 days of the selection of winning bid identifying the winning bids and outlining any deficiencies noted in the solicitation process. A second report is due from the Independent Monitor within 14 days of the selection of the winning bid. This report must describe the process employed by the utility and evaluate the utilities' conformity with the process

[5] Wheeler, Direct at page 8, lines 9-10.

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requirements. The report must state if the Independent Monitor finds the utility unfairly or erroneously conducted the solicitation and detail the basis for the Independent Monitor's belief that the selection process was flawed. Reliant believes the Commission should require the Independent Monitor's reports to contain whatever information the Commission deems necessary to aid it in the prompt review of the solicitation. We agree with Dr. Roach that, as an opinion of an independent professional selected by Staff, the Independent Monitor's reports are entitled to considerable weight by the Commission. As I stated in my direct testimony, a five-day time frame is appropriate for auctions because the standardization of product minimizes the subjectivity involved in the final selection process.

IV. BIDDERS MUST BE ABLE TO REPORT DIRECTLY TO THE INDEPENDENT MONITOR

Q. MR. WHEELER SUGGESTS[6] THAT THE STAFF REPORT CONTEMPLATES NUMEROUS OPPORTUNITIES FOR THE BIDDERS TO ATTEMPT TO NEGOTIATE "AROUND" THE UTILITY TO INFLUENCE THE PROCESS OR SUGGEST NEW PROCUREMENT PROTOCOLS. DO YOU AGREE WITH THESE CONCERNS?

A. No. The Staff Report merely allows any participant in the process to provide information to the Independent Monitor. The Independent Monitor determines whether the information warrants any action. Bidders should not be prohibited from reporting concerns directly to the Independent Monitor, whenever they deem such a direct report is appropriate. Reliant does agree that a meeting

[6] Wheeler, Direct at page 4, lines 18-21.

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should be held with all affected parties, including the utility, before the Independent Monitor takes any action on a concern reported by a bidder or the utility. Reliant further emphasizes that it is better to resolve as many issues as possible prior to the release of the final bid solicitation material so as to narrow the field of open items to be dealt with after the bid.

Q. DOES THE USE OF AN AUCTION PROCESS ALSO ASSIST IN NARROWING THE NUMBER OF OPEN ITEMS TO BE DEALT WITH AFTER THE BID?

A. Yes. An auction process alleviates all of these concerns. For standard products that are determined to be appropriate for the needs of utilities, an auction is a transparent, equitable and neutral method of securing those products. By involving Staff and the Independent Monitor ahead of time in the product definition it removes the regulatory risk and the associated premium. When the auction is concluded and the only variable among the participants that has changed is the price, Staff, the Independent Monitor, the Commission and the ratepayers of Arizona are assured the lowest price for a product agreed upon beforehand.

V. INTEGRATED RESOURCE PLANNING AND REGIONAL MODELS

Q. MUST AN INTEGRATED RESOURCE PLAN OR A REGIONAL MODEL BE EMPLOYED TO EVALUATE THE IMPACT OF THE CONTRACTS SELECTED THROUGH THE CURRENT COMPETITIVE SOLICITATION PROCESS?

A. No. Reliant believes the methodologies suggested by RUCO and Sempra are unnecessary for the current competitive solicitation process scheduled for

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March of 2003. The Staff Report recognizes that the wholesale competitive solicitation process is part of the overall resource planning for the utility.[7] The Staff Report already requires each utility to provide Staff and the Independent Monitor its current 10-year load and energy forecast and resource plan. The utility must meet with Staff and the Independent Monitor and justify the adequacy of its resources committed to serve expected loads and the reliability of the resources planned to serve that load. Based upon the utility's load and energy forecast and its resource plan, the utility must develop a needs assessment identifying specific capacity and energy needs and such other services and/or facilities as may be needed over the term of the load forecast. The load forecast, resource plan and needs assessment are reviewed with Staff and the Independent Monitor.

The Third Procedural Order recognized that the "utilities' needs assessments and procurement proposals are issues central to the solicitation process . . . [and required the parties to present] facts to support such a determination . . . prior to the hearing."[8] The Administrative Law Judge emphasized that the "parties have been participating in workshops on the development of a solicitation process since May of this year, and should be on notice that such assessments and proposals are required. The provision of data supporting a parties' position on these issues should therefore not be problematic."[9]

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7 Staff Report at page 13, line 24 through page 14, line 17.
8 Third P.O. at page 7, lines 17-20.
9 Id. at lines 20-23.

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The parties have had six months to advocate methodologies in workshops. The Commission put the parties on notice in its Track A decision that a determination would be made in Track B as to the level of unmet needs for APS and TEP to be used in the initial competitive solicitation process. Clearly, this proceeding is intended to quantify the unmet need and the process to be used in the initial competitive solicitation.

APS, TEP, Harquahala Generating Company, L.L.C. ("HGC") and Panda each have presented evidence supporting a specific needs assessment. The evidence presented by the parties provides the factual basis for the Commission to make a decision for this initial solicitation.

VI. CODE OF CONDUCT

Q. DOES THE REVISED CODE OF CONDUCT FILED BY APS ON NOVEMEBER 12, 2002 ADDRESS THE CONCERN YOU RAISED IN YOUR DIRECT TESTIMONY REGARDING DISPATCH FUNCTIONS?

A. APS' revised Code of Conduct appears to permit APS to improperly share Confidential Information with APS Competitive Electric Affiliates (i.e., APS affiliates offering competitive retail or wholesale services), to the extent they are providing Shared Services, including "energy risk management" and "system dispatch." In particular, Section IX.C of the revised Code of Conduct (which generally prohibits the joint employment of employees) states: "Contracts for services accounted for in conformance with Section X of this Code of Conduct shall not constitute prohibited joint employment if measures are taken to prevent the transfer of Confidential Information between APS and a Competitive Electric Affiliate." Section X.C permits APS to provide Shared

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Services to its Competitive Electric Affiliates and Sections X.D permits APS to acquire Shared Services from Pinnacle West. Importantly, the definition of Confidential Information excludes "information necessary for a Competitive Electric Affiliate to provide or receive Shared Services". Shared Services includes such things as "energy risk management," "system dispatch" and "contract management."

Q. WHAT IS THE PROBLEM WITH THE FOREGOING LANGUAGE?

A. APS and Pinnacle West have integrated economic dispatching and purchasing of generation supplies and therefore the information crosses corporate boundaries. This undermines the competitive solicitation process. The language referred to above would allow a "Competitive Electric Affiliate" or Pinnacle West Energy Corporation ("PWEC") to be exempt from the prohibition of the sharing of Confidential Information when it involves system dispatching, energy risk management or contract management issues. This means that corporate firewalls put into place to maintain confidentiality can be set aside when purchasing Shared Services, including system dispatch or making energy purchasing decisions. In fact, the Shared Service provision appears to allow whoever at APS is in control of system dispatching to share Confidential Information with persons at PWEC, even though PWEC is competing in the marketplace with other generators.

Q. DO YOU HAVE A PROPOSAL TO REMEDY THIS SITUATION?

A. Yes. In addition to prohibiting PWEC personnel from making the short-term economy transactions and energy dispatch decisions for APS, the definition of

Shared Services should be changed to delete reference to "energy risk management," "system dispatch" and "contract management."

Q. DOES APS' REVISED CODE OF CONDUCT ENSURE THAT AN APS EMPLOYEE ASSIGNED TO ANY PORTION OF THE PROCUREMENT PROCESS HAS NOT HAD ANY IMPROPER CONDUCT WITH AN APS AFFILIATE?

A. APS has indicated that personnel and their responsibilities are being shifted between APS and PWEC. For this reason, I recommend that any APS employee who works on the competitive procurement, including its development, execution and review, be required to attest that they have no knowledge of the products or offers of any APS affiliate participating in the competitive solicitation. In addition, they should attest that they have provided no information, not generally available to all entities participating in the competitive solicitation process, to an employee of an APS affiliate or to an employee performing Shared Services with an APS affiliate regarding APS' procurement process.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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RUCO

1 & 2

EXHIBIT
RUCO-1
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES	))))	Docket No. E-00000A-02-0051 ET.AL.

DIRECT TESTIMONY

OF

DR. RICHARD A. ROSEN

On Behalf of the Arizona
Residential Utility Consumer Office

Tellus Institute
11 Arlington Street
Boston, MA 02116-3411
Tel: 617/266-5400

TESTIMONY ON TRACK B ISSUES

NOVEMBER 12, 2002

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dr. Richard A. Rosen. My business address is Tellus Institute, 11 Arlington Street, Boston, MA 02116-3411.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a B.S. in Physics and Philosophy from MIT, a M.S. in Physics from Columbia University, and a Ph.D. in physics from Columbia University. Currently I am a senior research director at Tellus Institute, as well as executive vice-president and secretary/treasurer of the Institute. I am also the manager of the Institute's Electricity Program.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF TELLUS INSTITUTE.

A. Tellus Institute is a non-profit organization specializing in energy, natural resources, and environmental research. Within Tellus Institute, the Electricity Program focuses on energy and utility research areas which include demand forecasting, conservation program analysis, electric utility dispatch and reliability modeling, least-cost utility planning and integrated resource planning, avoided cost analysis, financial analysis, cost of service and rate design, non-utility generation issues, bidding systems, incentive regulation, cost of capital analysis, and utility industry restructuring.

Q. PLEASE ELABORATE ON YOUR EXPERIENCE WITH ELECTRIC UTILITY SYSTEM SUPPLY PLANNING.

A. As past director of the Energy Group and manager of the Electricity Program, I have had wide experience assessing utility system supply options on both a service area and a regional basis. These assessments have encompassed all types of generation plant, transmission plant, purchases of capacity and energy, fuel purchases and contracting, central station district heating and decentralized cogeneration plants, and alternative sources of energy such as wind, biomass, and solar energy connected to electricity grids. These assessments have dealt with the technical, economic, environmental, regulatory, and financial aspects of supply planning, including the relationships between supply planning, load forecasting, rate design, and revenue requirements. I have also reviewed the prudence of many past supply-planning decisions by utilities.

Q. PLEASE PROVIDE A FEW ADDITIONAL DETAILS OF YOUR EXPERIENCE IN THE AREA OF UTILITY PLANNING.

A. Power supply system modeling and integrated resource planning has been a major focus of my activities for the past 22 years. My research and testimony in this area began in 1980, and I have testified in numerous cases involving generation planning and the integration of demand and supply technologies on a least-cost basis. For example, I submitted extensive generation planning testimony in the 1980 CAPCO Investigation in Pennsylvania in Case No. I-79070315, and in the 1981 Limerick Investigation as well (Case No. I-80100341). In early 1982, I prepared a major report for the Alabama Attorney General's Office entitled "Long-Range Capacity Expansion Analysis for Alabama Power Company and the Southern Company System," and I filed testimony in Docket No. 18337 before

the Alabama Public Service Commission. In addition, I testified on the excess capacity issue regarding Susquehanna Unit 1 in the 1983 Pennsylvania Power and Light Co. Rate Case (No. R-822169). In 1987, I testified before the Federal Energy Regulatory Commission ("FERC") on NEPOOL's Performance Incentive Program on behalf of the Maine Public Utilities Commission in Docket No. ER-86-694-001. In 1989, I testified before the Pennsylvania Public Utility Commission on excess capacity and ratemaking treatment regarding Philadelphia Electric Co.'s Limerick 2 nuclear unit. This work was performed on behalf of the Pennsylvania Office of Consumer Advocate in Docket No. R-891364. I also testified in Vermont in Docket No. 5330 on the cost-effectiveness of the proposed purchased power contract between the Vermont utilities and Hydro-Quebec. In the 1980s, I testified in several cases involving the planning and construction of the Palo Verde nuclear units, before the Arizona Corporation Commission ("Commission" or ACC), as well as before FERC.

Finally, in January 1998, I testified before this Commission on behalf of the Residential Utility Consumer Office ("RUCO") in Docket No. U-0000-94-165 regarding public policy recommendations on key issues related to calculation, sharing, and recovery of stranded costs; and presentation of the "retail generation service" methodology for computing stranded costs. In September 1998, in Docket No. E-01933A-98-0471, I was the author of comments to the Commission entitled "Analysis and Recommendations of Residential Utility Consumer Office Regarding the Tucson Electric Power Company's Stranded Cost Filing." In November 1998, I filed testimony before the Commission in Docket Nos. E-

01933A-98-0471; E-01933A-97-0772; E-01345A-98-0473; E-01345A-97-0773; and U-00000C-94-165 on various filings related to the unbundled service tariffs, stranded cost recovery proposal for Arizona Public Service and Tucson Electric Power Company, and various other aspects of their restructuring proposals. I filed testimony before the Commission in Docket No. RE-00000C-94-0165 in July 1999 on the status of settlement discussions between RUCO and Citizens Utilities Company-Arizona Electric Division ("CUC-AED"), and summary concerns about CUC-AED's stranded cost recovery plans. In February 2002, I filed testimony before the Commission in Docket No. E-01032C-00-0751 on Citizens Communications Company's Purchased Power and Fuel Adjustment Clause and its wholesale power supply contract with Arizona Public Service. Earlier this year I also testified before the ACC regarding Track A issues in this docket.

Due to my extensive regulatory experience supporting the public interest, as outlined above, in 1988 I was chosen to serve a three-year term on the Research Advisory Committee of the National Regulatory Research Institute, an appointment made by the public utility commissioners serving on the NRRI Board of Directors. In addition, I have been the project manager on contract research that the Tellus Institute has performed for the U.S. Department of Energy, the U.S. Environmental Protection Agency, the U.S. Department of Justice, the National Association of Regulatory Utility Commissioners (NARUC), the New England Conference of Public Utility Commissioners, the New England

1 Governors Conference, and the National Council on Competition in the Electric
2 Industry.
3 In the last six years, I have spent most of my time analyzing electric utility
4 restructuring issues. As early as 1996, I testified before the New Hampshire
5 Public Utilities Commission on issues affecting the design of the state's pilot
6 programs (Docket No. 96-150), and I testified before the New York Public
7 Service Commission on stranded costs, market structures, and other issues related
8 to ConEd's, NYSEG's, and RG&E's restructuring plans. I also have worked on or
9 testified on other restructuring issues in Nevada, New Mexico, New Jersey,
10 Illinois, Missouri, Colorado, Pennsylvania, Maryland, Maine, Rhode Island, and
11 Michigan. Exhibit___(RAR-1) provides a copy of my resume.
12 Q. PLEASE SUMMARIZE YOUR TESTIMONY.
13 A. In reviewing the Staff Report on Track B issues that was distributed on October
14 25, 2002, I have come to five major interrelated conclusions:
15 1. The Staff does not provide an adequate approach to determining which
16 competitive bids for power should be selected by a distribution utility
17 in order to ensure that the resulting electricity prices are reasonable.
18 The Staff did not recognize that resource bids need to be evaluated in
19 groups or portfolios, and they cannot be evaluated individually. Yet,
20 there is no need to "reinvent the wheel", namely to try to develop a
21 new methodology for bid selection, when a methodology for this
22 purpose has already previously been used in Arizona and in many

other places throughout the world. (See, for example, the suspended Arizona IRP rules.)

2. There is only one reasonable way in which these competitive bids should be evaluated with respect to price, and that is to utilize a standard least-cost planning methodology. Each utility would have to take this approach anyway if it wanted to ensure that its selection methodology was prudent. The "bottom-line" for least cost planning is to minimize the present value of revenue requirements over a pre-specified planning period. This process will yield reasonable electric rates.

3. Demand-side management (DSM) program bids should be allowed from third parties, and a wide variety of DSM bids to serve all customer classes should be required from each distribution utility in amounts up to an incremental 2 percent of annual peak load in each year. If about 2 percent of the peak load is bid to be met by DSM, perhaps DSM programs of various types that will meet about 1 percent of the load will actually be chosen as more cost-effective than new generation resources. This will help guarantee that the lowest cost resources available to ratepayers will actually be evaluated as part of the competitive solicitation process.

4. Each distribution utility should be required to provide bids for peaking, cycling, and baseload power resources on a regulated basis in their own solicitation process in order to provide a "competitive price

baseline" against which unregulated market bids can be compared. Only if this is done can ratepayers be assured that they will end up paying reasonable rates as a result of this new competitive solicitation process. Only bids for new generation from highly responsible and financially capable entities should be considered in this process.

5. Once an appropriate least-cost planning process is established and correctly utilized for the purpose of evaluating resource bids, this process should automatically establish a presumption that the distribution utility, which utilized the process, carried out prudent planning for the resource portfolio selected.

Q. HOW DOES THE NEED FOR A LEAST-COST PLANNING PROCESS AND METHODOLOGY AS THE BASIC CONCEPTUAL FRAMEWORK FOR THIS COMPETITIVE SOLICITATION PROCESS HELP EXPLAIN WHAT IS MISSING IN THE BID EVALUATION METHODOLOGY OUTLINED IN THE STAFF REPORT?

A. Least-cost planning makes it clear that all resources — generation, transmission, and DSM — have to be evaluated simultaneously, as a package. Because each type of technology is different, because each bid will have a different ratio of fixed to variable costs, and because the capacity factor of each type of technology bid will depend to some extent on the mix of other technologies that co-exist with it, the mathematics of determining the least cost *portfolio,* or mix of technologies, is complex. The total present value of revenue requirements (PVRR) for all possible, technologically compatible resource portfolios have to be compared to

the PVRR for all other such portfolios over the relevant planning period. No *single* resource bid or technology can be evaluated *by itself*, without reference to the cost and technical characteristics of *every other resource bid* that might be part of the least-cost portfolio. This basic concept was entirely missing from the Staff Report, which instead suggested that individual bids could be rank ordered in some absolute manner.

Q. WHAT DO YOU RECOMMEND TO THE ARIZONA CORPORATION COMMISSION AT THIS TIME?

A. The Arizona Corporation Commission (ACC) should:

1. Establish the entire competitive solicitation process within a Least Cost Planning rubric, as described in section III below, and as previously contained in the suspended Arizona IRP rules. This would not change the overall process described by the Staff in its October 25, 2002 report significantly, but it would significantly change the key details of how the price evaluation process for bids would need to be done. As described below, a least-cost planning framework allows the evaluation of all types of electric power products and contract durations at one time, on a self-consistent basis. A least-cost planning process would also allow DSM investments to be evaluated on a consistent economic basis along with new power supplies and new transmission investments.
2. The Commission should also require the utilities involved in a competitive solicitation process to prepare their own bids for "proxy" power plants on a regulated cost-of-service basis in parallel with their solicitation of third

party bids, in order to have a set of resources available on a "fall-back" basis. The Commission might have to order the construction of some of these new power plants on a regulated basis if doing so turns out to be lower in cost than a portfolio of competing bids offered by the independent power market. Arizona ratepayers should not be required to pay more for power as the result of a competitive solicitation process than they could pay under a continuation of traditional rate regulation. To do so would both indicate that the independent power market was not really sufficiently competitive at this time in history, and it would also provide a signal from Arizona's regulators that they were unwilling to hold the unregulated power market to a reasonable competitive standard in order to try to make it more competitive.

3. The Commission should not rush the establishment of an appropriate least-cost planning process. One approach, of course, would be to revive the existing Arizona IRP rules that were suspended in 1999. If such a process cannot be in place to select resource bids for the summer of 2003, those resources could be selected in a more *ad hoc* manner by each distribution utility, to which the usually prudent planning standards would apply. The final bid evaluation process could be used to select resources for 2004-2007, if the summer of 2003 cannot be included.

II. CRITIQUE OF STAFF REPORT

Q. WHAT IS THE MAJOR PROBLEM THAT YOU FIND WITH THE STAFF REPORT OF OCTOBER 25, 2002?

A. The major problem with the Staff Report is that it does not provide a logically consistent and coherent methodology for evaluating the bids solicited from the independent power producer (IPP) market. In particular, leaving non-price factors aside, it does not provide a coherent and workable methodology for evaluating bids based on their impact on utility costs, and, therefore, on the revenue requirements paid by ratepayers.

In particular, the Staff Report proposes a list of bid evaluation criteria on page 18. Of the eight categories listed there, only one, "delivered prices", directly affects ratepayer costs. The other bid evaluation criteria listed are basically non-cost items that must be satisfied sufficiently for the respective bids to be seriously considered at all. In fact, appropriately so, the Staff also lists several of these evaluation criteria on page 21 as "pre-qualification" factors. Thus, to first approximation, these other criteria can be segregated from the price or cost factors that are part of each bid.

Q. HOW DOES THE STAFF PROPOSE THAT THE PRICE OR COST FACTORS BE TAKEN INTO ACCOUNT IN DETERMINING THE WINNING BIDS?

A. The Staff describes their price evaluation methodology on pages 23-25 of the Report. They propose that the bids be evaluated in three "phases". The first phase "should be to rank order the bids by price using valuation methods that

equalize volumetric and or duration differences on a price basis." This aspect of Staff's proposal seems to be describing a way to derive a dollar per kWh figure for each bid. A key assumption needed to do this is to know the capacity factor for each product in each year into the future. This fact will prove crucial in determining what an adequate price evaluation methodology would be.

Q. WHY WOULD ONE NEED TO KNOW THE CAPACITY FACTOR FOR EACH BID TO DETERMINE A DOLLAR PER MWH COST FOR EACH BID?

A. Typically, each bid for power would consist of a fixed cost component and a variable cost component, though it is possible for some bids, particularly baseload bids, to just be bid on a total dollars per MWH basis. If a bid does have a fixed cost component, it would likely be on a dollar per kW of capacity basis. In order to convert a dollar per kW bid into a dollar per kWh bid basis, one needs to know how many kWh each kW of capacity would generate in a year. That number is closely related to the capacity factor of the power plant being bid with a certain minimum capacity factor assumed. The dollars per kWh representing the fixed costs assuming a specific capacity factor, and the dollars per kWh representing variable costs in the bid, would be added together to get a <u>total</u> dollar per kWh result. However, this result would only be valid for the capacity factor assumed. A higher capacity factor would lead to a lower total cost per kWh, and *vice versa*.

Q. WHAT ARE THE SECOND AND THIRD PHASES OF THE BID EVALUATION PROCESS AS PROPOSED BY STAFF?

A. Phase two involves evaluation of deliverability, and Phase three involves evaluation of other factors, such as creditworthiness, experience and exceptions to

1 model contract terms. These phases of the bid evaluation process are non-price
2 related phases, and, thus, are not relevant to my critique of Staff's price evaluation
3 process.

4 Q. DOES STAFF PROVIDE ANY OTHER ASPECTS OF A METHODOLOGY
5 FOR DETERMINING THE WINNING BIDS BASED ON PRICE?

6 A. No. Unfortunately, Staff provides no additional guidance for the utilities subject
7 to this competitive solicitation process, yet it insists (correctly) that the results
8 produce "reasonable rates" as required by law. Related, but somewhat separate
9 from this issue, Staff says on page 16 under "Identification of Products" for which
10 prices will be bid that "the utility will specifically define the capacity and energy
11 sought on a time-differentiated basis..." However, the Staff does not provide any
12 details on how this would be done. For example, it does not state that a
13 generation dispatch model would need to be run to develop this information, and,
14 if so, how.

15 Q. DOES THE STAFF SUPPORT THE IDEA OF FRAMING THE BID
16 SELECTION PROCESS WITHIN THE CONTEXT OF LEAST COST
17 PLANNING?

18 A. No, the Staff explicitly rejects adopting a least-cost planning framework for the
19 competitive solicitation process on page 39 of the Report. In fact, it does not even
20 want least-cost planning to be an issue in this docket, which seems like a rather
21 extreme position to take given that least-cost planning has traditionally been the
22 way in which utilities have selected new generation resources to either construct,
23 or for which to contract.

Q. DID THE ADMINISTRATIVE LAW JUDGE IN THIS DOCKET DISAGREE WITH STAFF ON THIS POINT?

A. Yes. In addressing RUCO's concern about assuring the lowest reasonable rates to ratepayers as a result of the solicitation process as expressed at a Track B workshop, the ALJ in this docket explicitly stated on page 5 of the Third Procedural Order on Track B Issues that she would not exclude the least cost planning issue from this case. However, in the process of doing so, the ALJ said, "RUCO believes that the Least Cost Planning framework can fit *within* [emphasis added] the Track B solicitation issues." This is not quite what RUCO meant to say. RUCO maintains that least-cost planning can fit within the Track B issues, and, therefore, least-cost planning should be included. RUCO meant to say that least-cost planning is absolutely central to the entire Track B solicitation process; it is **not** peripheral. In contrast, least-cost planning should be the single-most important organizing principle around which the entire Track B process must be structured.

Q. DID STAFF PROPOSE A KIND OF A "SAFE HARBOR" FOR BID PRICES <u>INSTEAD OF AN EXPLICIT SELECTION CRITERION FOR BIDS</u>?

A. Yes. Instead of establishing a traditional least cost planning-based selection process for generation bids, the Staff has proposed to establish a kind of "safe harbor" for bids based on their price. In order to accomplish this, Staff has proposed to calculate something they call the "prices to beat" for the products solicited for each utility. (Page 24-25) "The 'prices to beat' established by the Staff will be used for the purpose of determining whether the Staff will

recommend without further analysis a finding that prices contained in any contract meeting the conditions outlined below are reasonable." (Page 25) If the contract bid price exceeds the relevant price to beat, then staff will perform some unspecified analysis and make findings about the "prudence, reasonableness and used and usefulness" of the contract price. (Page 25) Thus, this new concept of a "price to beat" appears to become a safe harbor with respect to further scrutiny by the Staff if a utility chooses such a product as part of its final resource portfolio. Of course, I assume that any other party to the relevant ACC case would still be free to challenge the reasonableness of the contract price, even if it is lower than the "price to beat" as computed by the Staff. However, Staff should confirm whether or not this is correct.

Q. DOES THE STAFF EXPLAIN WHAT METHODOLOGY WOULD BE USED TO COMPUTE THIS "PRICE TO BEAT"?

A. No. Unfortunately, Staff provides no statement at all in their Report as to how this very critical "price to beat" would be calculated. However, the text of their report gives me the feeling that there would be a single number computed for each proposed contract for each product. But I cannot discern how this would be done from the Report. In addition, in answer to RUCO data request 1.3, Staff states that it "does not intend to make the methodology it will use to calculate the price to beat public."

Q. EVEN THOUGH YOU DO NOT KNOW HOW THE "PRICE TO BEAT" WOULD BE CALCULATED, IS THERE ANY POSSIBLE METHODOLOGY THAT WOULD RESULT IN A SINGLE NUMBER FOR EACH PRODUCT

THAT COULD BE USED TO YIELD REASONABLE OVERALL RETAIL RATES FOR A DISTRIBUTION UTILITY INVOLVED IN THE PROPOSED SOLICITATION PROCESS?

A. No. There is no possible mathematical methodology of which I am aware that could possibly produce a single number for each product bid, and lead to the outcome of reasonable rates. The reason for this apparent impossibility is that the bids for each product are likely to be in the form of a separate fixed and variable cost component, unless the capacity factor of operation is already specified, as explained above. Thus, at least two separate numbers, not one bid price, will likely characterize each bid. The two separate numbers could only be combined into one total price once the capacity factor of a product (power plant) is specified. Yet, except, perhaps, for baseload power plants running full-out at their maximum possible capacity factor, neither the bidders nor the Staff will know what the capacity factor for each product is likely to be in any given future year. Thus, Staff could not compute a single bid price number such as a total cost per kWh from the bid data alone.

Q. HOW COULD THE STAFF COMPUTE A CAPACITY FACTOR FOR EACH PRODUCT BID IF IT WANTED TO DO SO?

A. If the Staff wanted to compute a capacity factor for each product bid, it would have to use a generation dispatch model to do so for each year covered by the bid. However, in order to get meaningful results for each capacity factor, the model would have to be run with enough total capacity of different products and bids to fully meet the load plus reserves, in each year. In fact, the resulting capacity

factors would only be meaningful if enough new capacity is added to the existing capacity to meet the total load plus the required reserve margin. A complicating issue is, though, that the capacity factor of each bid will change depending on which other bids or products are included in the total new capacity added. Thus, the capacity factor for any given bid or product in any given year will, in general, depend on the mix of all the other products or bids included to make up enough capacity to meet the total load plus required reserves.

Q. HOW, THEN, WOULD THE STAFF KNOW WHICH OTHER BIDS SHOULD BE INCLUDED IN A DISPATCH MODEL RUN IN ORDER TO COMPUTE THE CAPACITY FACTOR FOR ANY SPECIFIC BID?

A. There would be no way for the Staff to know which set of other bids to include in running a dispatch model in order to determine the correct capacity factor for any given bid in order to compute a "price to beat", or any other single price number, for each bid. (Note that while the Staff proposes to compute the "price to beat", the utility will actually be selecting the resource bids that it believes should be included in its resource mix for the future.)

Q. HOW CAN WE GET AROUND THIS APPARENT "CHICKEN AND EGG" PROBLEM THAT ARISES WHEN ONE ATTEMPTS TO COMPUTE A "PRICE TO BEAT", SO THAT THE BEST SET OF BIDS CAN BE SELECTED IN ORDER TO RESULT IN THE LOWEST REASONABLE RATES?

A. This Staff idea of trying to develop a single number to describe the price of each bid does inevitably degenerate into a hopeless spiral. To be clear, it is a "chicken and egg" type of situation because one cannot know which comes first, the

capacity factor of a particular product, or the mix of other products or bids. But there is a simple, logical way out of this loop. Least-cost planning was developed precisely to solve this mathematical problem. The problem arises when one has a set of existing generation resources, and when one then wants to minimize the overall cost of adding new generation resources to the total system. The mathematical problem that we need to solve is to simultaneously find the cost minimizing mix of new generation resources or bids that should be selected out of a much larger set of offered bids, given the variable production costs of operating the current mix of generating units.

To slightly oversimplify, each existing resource is characterized by a variable cost to operate in each year. Each new resource or bid is characterized by a fixed and variable cost component, if we add it to the system in the future. Existing resources have no fixed costs for the purpose of this calculation because they have already been included in ratebase. Thus, the mathematical problem is to compute the total cost of all combinations of new and old resources so that one can find the mix that minimizes the total cost. That combination of new resources is called the least cost plan, or the least cost mix of new resources.

Q. IS THERE ANY OTHER WAY OF EVALUATING BIDS WITH RESPECT TO PRICE IN ORDER TO END UP WITH REASONABLE RATES?

A. No. This is not a new issue. Every state and every utility has had to deal with least cost planning in the past, either implicitly or explicitly. In the past, Arizona defined in its Integrated Resource Planning Rules (IRP Rules) R14-2-701-704 (portions of the IRP Rules were suspended in 1999) how prudent planning for

new resources should be done. Those Rules provided that new resources should be determined on a least-cost planning basis subject to various policy constraints that the ACC may determine. Section R14-2-703F of the IRP Rule states that the resulting plan should "tend to minimize the present value of the total cost of meeting the demand for electric energy services." Though portions of the IRP Rules have been suspended, the process they establish is a good way to accomplish the goal of selecting those resources that would imply the lowest reasonable electric rates.

Q. ON PAGE 39 OF THE STAFF REPORT IT IS STATED THAT THE BID SELECTION PROCESS PROPOSED BY STAFF "IS COMPREHENSIVE AND BASED ON SUCCESSFUL MODELS FROM OTHER JURISDICTIONS" AS MODIFIED BY THE UNIQUE CIRCUMSTANCES IN ARIZONA. DO YOU AGREE?

A. No. I do not agree that the process proposed by Staff is modeled on successful models from other states. For example, there is no state in the US that uses a "price to beat" in the sense that the ACC Staff seem to mean. The term "price to beat" has often been used in other states simply to mean the generation component of unbundled retail rates once retail competition has been established. Yet, that is not what staff means by its use of the term "price to beat."

Secondly, at the fairly general level of discussion thus far in my testimony, there is nothing unique about circumstances in Arizona that would fundamentally affect what planning process should be used. In fact, as the Staff discusses in some detail beginning on page 43 of the Staff Report, several other states use

1 competitive solicitation processes to determine how the load of each distribution
2 utility will be met at the lowest reasonable rates.
3 Q. DO OTHER STATES USE LEAST COST PLANNING PROCESSES TO
4 SELECT THEIR GENERATION BIDS?
5 A. Yes. Whether or not states that rely on the competitive generation market
6 currently call their resource selection process a "least-cost" process, or not, the
7 process is always a "least cost" process in some fundamental sense. It is quite
8 surprising that the Staff's description of the resource selection process in the eight
9 states discussed on pages 43-49 of their report does not make this clear. For
10 example, the situation of Colorado is almost identical to the situation currently
11 found in Arizona (utilities are acquiring power for retail customers on the
12 wholesale market.) Yet, under the current integrated resource planning (IRP)
13 rules in effect in Colorado, the utilities perform least cost planning by minimizing
14 the present value of revenue requirements subject to various constraints, over a
15 fairly long planning period, e.g., 20 years, or more. I know this because I testified
16 in the last IRP case held for Public Service Company of Colorado.
17 Furthermore, in the 1980s and early 1990s, the term integrated resource
18 planning and least-cost planning were almost synonymous, and these formal
19 planning processes were used by public utilities commissions in many, if not
20 most, states throughout the US. For example, the state of Florida uses a planning
21 process that determines "whether the proposed plant is the most cost-effective
22 alternative available", as Staff states on page 44. Here "cost-effective" is just
23 another way of saying "least-cost".

1 Q. WHAT DO THE OTHER SIX STATES, DISCUSSED BY STAFF, THAT
2 HAVE ALREADY ADOPTED RETAIL COMPETITION DO TO SELECT
3 NEW RESOURCES FOR THEIR STANDARD OFFER CUSTOMERS?
4 A. Basically, each of these other states either leaves the resource selection process up
5 to the distribution utilities because standard offer rates are capped, or the state
6 PUCs oversee a competitive solicitation process for all, or slices, of the system
7 load. But this second group of processes is also explicitly a least cost process, in
8 the sense that the average cost of power selected is minimized, even though there
9 are price caps. Clearly, the distribution utilities want to pay as little as possible
10 for generation at the wholesale level. However, the situation is not the same in
11 Arizona currently. The Commission has decided to have the competitive
12 solicitation process not be for the total load or for a slice of the entire system load.
13 Instead, the Commission has determined that the competitive solicitation process
14 should be for new resources needed over and above the amount of power that
15 each utility's current resources can provide. Thus, as noted above, the current
16 situation in Arizona is most similar to that of Colorado, among the eight states
17 discussed in the Staff Report. Of course, the current situation in Arizona is also
18 fairly similar to the current planning situation faced by most utilities that have not
19 moved to retail competition, and many states still have least-cost planning or IRP
20 processes in place for those utilities to follow. In fact, I am currently directly
21 involved in the IRP processes that are on going in both Utah and Wisconsin. In
22 particular, PacifiCorp, Arizona's neighboring utility to the north, has just
23 completed a draft IRP report that I am reviewing. I can assure the ACC that

PacifiCorp follows least-cost planning principles by stressing the resource mix that has the lowest present value of revenue requirements over a planning period for its selection process.

Q. IN CONCLUSION, DOES THE STAFF REPORT PROVIDE AN ADEQUATE DESCRIPTION OF A METHODOLOGY THAT COULD BE USED BY ARIZONA UTILITIES TO CARRY OUT THE ACC'S MANDATE FOR A COMPETITIVE RESOURCE SOLICITATION PROCESS?

A. No, it does not. The Staff Report does not describe any logical and complete methodology at all for this purpose. The Track B solicitation process must be reconfigured to be consistent with traditional least-cost planning practices, as described in the next section.

III. A LEAST-COST PLANNING PROCESS FOR ARIZONA

Q. HOW SHOULD THE COMPETITIVE SOLICITATION PROCESS IN ARIZONA BE STRUCTURED?

A. The competitive solicitation process should be structured in a way to assure that Arizona ratepayers will end up paying the reasonably lowest electric rates that are feasible given the various physical, policy, and legal constraints faced by each distribution utility. In theory, all three basic types of electricity "resources" should be included in the process, namely generation, transmission, and demand-side investments in more efficient end-use equipment (DSM). If any one of these key types of resources is excluded, then electric rates will be higher than is reasonable.

For example, the Staff Report primarily focused on the need to evaluate generation bids from the wholesale generation market, with agreement that DSM bids would also be allowed. However, the Staff Report did not describe how new transmission investments would be evaluated in relationship to the generation or DSM bids. Because Arizona has several significant "load pockets" or load centers that are highly transmission constrained in many hours of the year, new transmission investments to relieve some of these constraints should be evaluated on a self-consistent basis with the generation and DSM bids. It is possible, if unlikely, that new baseload resources built outside a load pocket, plus a new transmission line into the load pocket from these resources, would be lower in cost than generation bids received from units built within the load pocket.

Similarly, it is possible that new DSM investments could significantly defer the construction of new generation or transmission construction in some areas within Arizona. Thus, I believe that it is important to take time now to set up a comprehensive and appropriate planning process for Arizona utilities, similar to the one that had been followed in the past, rather than rush to create a process that would tend to increase electric rates above a reasonable level.

Another key ingredient of an appropriate planning process for Arizona utilities would be for the regulated utilities themselves to bid to supply new generation, transmission, and DSM on a regulated cost-of-service basis. If these regulated costs for service from the three basically different kinds of resources are not included in the mix of options that could be chosen, there will be no "competitive baseline" against which to measure the economics of bids from the unregulated wholesale market. If the unregulated market bids can beat the regulated cost-of-service bids, then the wholesale market will have proven that it can be competitive, in the sense of being lower in cost and more efficient than regulated utilities. However, if the regulated cost-of-service bids are lower than the market-based bids, then Arizona ratepayers ought to be able to continue to benefit from the ability of vertically integrated utilities to provide electricity at a lower price. The "bottom-line" is that an appropriate Track B competitive solicitation process for Arizona could be similar to the suspended Arizona IRP rules.

1 Q. IS IT LIKELY, OR EVEN POSSIBLE, THAT MARKET-BASED BIDS FOR
2 GENERATION COULD BEAT REGULATED COST-OF-SERVICE BIDS AT
3 THE PRESENT TIME?
4 A. It certainly is possible that at the current time market-based bids for wholesale
5 electric power could beat regulated bids for the same types of products. This is
6 because the IPP industry is particularly stressed financially at the current time, so
7 there may be some very good, fairly long-term contracts for power available now.
8 In fact, this next year, during which Arizona's competitive solicitation will be
9 held, may be a very good time in which to lock up some low cost, long-term
10 purchased power contracts. On the other hand, it may also be a good time for
11 Arizona's utilities to buy one or more power plants currently under construction
12 in or near Arizona on a "fire-sale" basis, at a regulated cost of capital. Whatever
13 the lowest cost way of providing wholesale electricity to Arizona's electric
14 ratepayers is, that is the approach that should be relied on, assuming system
15 reliability and other factors are maintained at sufficiently high levels.
16 On the other hand, if wholesale market participants believe that the current
17 financial crisis will be short lived, they may hold out for fairly high prices, unless
18 they know that they are going to have to compete against regulated cost-of-service
19 prices for new generation. This might happen because once the financial crisis in
20 the IPP industry is mitigated, investors in that industry may demand much higher
21 returns on their capital investments than regulated utilities would receive. Thus,
22 in the long run there is a strong likelihood that the cost of IPP generation may be
23 significantly above the cost of generation provided on a regulated cost-of-service

basis. This is why it is very important to provide ratepayers with a competitive baseline, or ceiling on the price that they will have to pay, as a result of the competitive solicitation process established in Arizona. The regulated alternative to the wholesale market must be preserved as an option as part of this solicitation process, or ratepayers will overpay for electricity and Arizona's economy will suffer as a consequence.

Q. HOW SHOULD THE CONCEPT OF "LEAST-COST" BE INTERPRETED AS PART OF LEAST-COST PLANNING?

A. The concept of "least-cost" has almost always been interpreted to mean the lowest present value of revenue requirements (PVRR) over a given planning period. This was true in the suspended IRP rules for Arizona. (See rule R14-2-703F.) An appropriate planning period should be at least 20 years long. A 30-year planning period might even be better because it corresponds more closely to the operational lifetime of new power plants. Of course, to compute the present value of revenue requirements over time requires the use of a discount rate. Typically, the discount rate used is the utility after-tax cost of capital, since that reflects the time value of money to utility stockholders. Alternatively, the Commission could decide to use a ratepayer discount rate, which would typically be higher than the after-tax cost of capital to a utility. The Commission may also want to consider adopting part or all of the Colorado PUC's IRP rules, which are currently undergoing revision, to define this least-cost planning process. (See the PUC website for details under Docket No. 02R-137E.)

1 Q. WHY DOES THE PLANNING PERIOD HAVE TO BE AS LONG AS 20
2 YEARS, IF MOST COMPETITIVE GENERATION MARKET BIDS ARE
3 ANTIPATED TO BE OF MUCH SHORTER DURATION? THE STAFF
4 REPORT DID NOT EVEN MENTION THE NEED FOR A LONG PLANNING
5 PERIOD TO EVALUATE WHOLESALE MARKET BIDS.
6 A. The planning period needs to be at least 20 years in order to capture the long-run
7 trade-offs between fixed and variable costs which represent the different kinds of
8 new generation or DSM resources that could be purchased. If the planning period
9 were only a few years, then the lower capital investments per kilowatt, such as
10 new peaking units, would probably appear least cost in the short run even though
11 they might be very expensive for ratepayers in the long run. Thus, the use of a
12 planning period that is too short would tend to bias the results of a least-cost
13 planning analysis. The use of a longer planning period allows low cost short-term
14 contracts to be selected as part of a least-cost plan, but would not preclude
15 investments or contracts that might be more expensive in the short-run but have a
16 lower in cost when averaged (in present value terms) over the entire planning
17 period.
18 When a least cost planning exercise is run using a computerized
19 optimization model, as is necessary, proxy new plants also need to be included for
20 the long run, namely for later in the planning period when the new resource bids
21 would no longer be sufficient to fully meet the load growth that is projected for
22 the relevant region. For example, if the currently planned competitive solicitation
23 is structured in a way to select resources that will meet existing load plus load

growth for the next four years, as Staff proposes, then the resource bids might be from anywhere from 1 year to 30 years in duration. The duration of the proposed contracts is not important, so long as a mechanism is in place to fairly evaluate the bids relative to each other independent of their duration. This is why the proxy plants noted above are necessary as "filler" resources. There would need to be a proxy peaking unit, cycling unit, and baseload unit that could, in theory, come on-line in any year of the planning period, as soon as it could be constructed. By a "proxy" plant, a realistic alternative, I mean a set of plants that could be actually sited where needed, at the cost assumed, to serve the loads of Arizona utilities. The computer model used in least cost planning would then select the lowest cost combination of contract bids and proxy plants over the entire planning period. The costs of the proxy plants should represent the costs for constructing and operating those types of units on a regulated basis, since those costs would provide a maximum or ceiling price on what would have to be paid for that "product" or type of power plant. These proxy plant costs would be determined by the regulated utility's bids for those types of units on a regulated cost-of-service basis required as part of their solicitation process. If, over the next four years, enough of the wholesale market bids were selected by the model as being part of the least cost plan to satisfy their total load, then contracts for those bids would be signed, and no proxy plants would need to be constructed on a regulated basis. If, however, the optimization model selected some bids and some proxy plants, then both types of actions would need to occur. The same optimization model could also be used to select cost-effective DSM resources.

1 Q. WHAT SHOULD BE DONE TO PREVENT A SITUATION WHEREBY THE
2 MARKET PARTICIPANTS DID NOT BID ALL REASONABLY COST-
3 EFFECTIVE DSM MEASURES INTO THE SOLICITATION PROCESS?
4 A. It is important to structure the solicitation process in a way that insures that the
5 end result (the least-cost plan) will include a significant amount of cost-effective
6 DSM. If the plan actually implemented did not reflect a significant fraction of all
7 possible cost-effective DSM over the next few years, then not only would electric
8 rates be higher than necessary in the long run, but the environmental impacts of
9 power plant and transmission line siting, and plant operations would also be
10 greater than necessary. To ensure that sufficient amounts of cost-effective DSM
11 will be bid into the proposed solicitation process, the Commission should require
12 the regulated utility to also bid DSM programs on a regulated cost-of-service
13 basis, just as they would submit bids for generation resources. The types of DSM
14 programs bid should be broad in variety, and should be programs for all customer
15 classes, particularly programs for low-income residents. Load management as
16 well as energy conservation programs should be bid. The types of DSM programs
17 bid might include fairly expensive DSM programs that may or may not turn out to
18 be cost-effective, which means that they may not be part of the least-cost plan
19 chosen. As a guideline for utilities in a high growth region like Arizona, each
20 distribution utility involved in a competitive solicitation process should bid
21 incremental or new DSM programs that would reduce its peak load each year by
22 up to 2 percent on a successive basis. This should provide enough new DSM
23 program options to choose from each year in order to yield a reasonable least cost

plan over the long run. Perhaps about 1 percent per year in DSM caused load reductions would actually be shown to be cost-effective.

Q. IN ITS ANSWERS TO INTERROGATORIES, ARIZONA PUBLIC SERVICE STATED THAT IT COULD PROBABLY PURCHASE A SIGNIFICANT AMOUNT OF ECONOMY PURCHASES OVER THE NEXT FOUR YEARS TO REPLACE SOME GENERATION FROM ITS CURRENT GENERATING UNITS. HOW SHOULD POSSIBLE ECONOMY PURCHASES BE DEALT WITH IN THIS SOLICITATION PROCESS?

A. Again, the Staff Report did not deal with the issue of how economy purchases should be dealt with as part of the solicitation process. How to treat economy purchases is a potential issue in a competitive solicitation process because economy purchases are different from other purchases that could be made from the wholesale generation market on a longer-term bilateral contract basis. In APS response MR 1.5, which is part of Appendix II to the Staff Report, APS stated that it "expects to procure a certain amount of economy energy in each of these years [2003-2007] depending solely on the actual energy cost of APS resources compared with market prices for power." Then, APS provides an estimate of how much economy energy might be available in each year.

Q. PLEASE DEFINE WHAT "ECONOMY ENERGY" IS, AND EXPLAIN WHY THIS RAISES A NEW ISSUE THAT IS RELEVANT TO THE SOLICITATION PROCESS.

A. Economy energy is power purchased from the regional utility grid on a fairly short-run, basis at a lower price than it would cost to operate its marginal

generating units. Because economy energy is purchased on an "as available" basis that cannot be planned for very far ahead of time, a utility cannot rely on economy energy to meet its peak demand requirements. In fact, economy energy is least likely to be available during times of peak demand. However, the benefit of economy energy is its low price when it is available.

The reason why a utility's ability to buy economy energy raises an interesting issue is that because economy energy can save the utility money. The mere existence of a competitive solicitation process should not preclude spontaneous purchases of economy energy when it is available. On the other hand, since a utility cannot plan on economy purchases being available on a firm basis, the existence of economy energy should <u>not</u> subtract from the energy requirements that a utility would have based on the availability of its own generating resources. Thus, APS' figures for their energy requirements that appear on their attachment to MR 1.5 should still be valid even taking their projections of the availability of economy energy into account. The Commission should recognize the benefits that purchases of economy energy have for all ratepayers, and the competitive solicitation process should not ban such purchases outside of that process.

Q. DOES THIS MEAN THAT THE COMPETITIVE SOLICITATION PROCESS CAN COMPLETELY IGNORE THE POSSIBILITY OF ECONOMY ENERGY PURCHASES IN THE FUTURE BECAUSE THEY WILL HAVE NO IMPACT ON THE PROCESS?

A. No. The possibility of making significant amounts of economy purchases can influence the mix of new resources that would be part of a least-cost plan. By

reducing the cost of the energy component, or the variable cost component, of rates to customers, the existence of economy energy tends to make new baseload resources less cost effective relative to other types of resources. This is because economy energy tends to substitute for new baseload resources to some extent by making the energy component of electric production somewhat cheaper. Thus, realistic assumptions about the availability of economy energy in each year should be included when running a least-cost planning optimization model. Because economy energy can more likely substitute for baseload resources, but not likely for peaking resources, the availability of economy energy will tend to shift the least-cost mix of new resources towards new peaking resources and away from new baseload resources.

Q. CAN A LEAST-COST PLANNING MODEL INCLUDE THE ANALYSIS OF THE ECONOMICS OF NEW TRANSMISSION INVESTMENTS SIMULTANEOUSLY WITH THE ECONOMICS OF NEW GENERATION AND DSM INVESTMENTS? IF NOT, HOW SHOULD THIS EVALUATION BE HANDLED AS PART OF THE COMPETITIVE SOLICITATION PROCESS IN ARIZONA?

A. The commercially available least-cost optimization models of which I am aware are not sophisticated enough to evaluate the economics of new transmission along with new generation and DSM. Thus, Arizona utilities should utilize an iterative process between running a least-cost optimization model for evaluating only the generation and DSM bids, and analyzing the economics of new transmission separately.

In order to make this assessment, the optimization model could first be run with no new transmission lines assumed. Then, if the generation bids that turn out to be part of the least-cost plan can all be accommodated sufficiently (i.e. transmitted to the load centers) without any new transmission lines being built, the bid evaluation process would be complete. On the other hand, if a generation bid that is initially part of the least cost plan would require new transmission to serve native load, then the costs of building that new transmission would need to be included in the total PVRR of that scenario. If the total PVRR of that scenario were less than the total costs of all other mixes of generation and DSM bids that do not require new transmission, then building this transmission line would be part of a least-cost plan. However, if another mix of generation and DSM bids has a lower PVRR than the total cost of the scenario that includes new transmission, then no new transmission is needed, and that alternative mix of generation bids should be selected. (Note that being part of a least-cost plan defines the word "need" in this context.) Again, this process is not new. It is how prudent utility planning has usually been done in the past.

Q. GIVEN THE NEED TO STRUCTURE BID EVALUATIONS AROUND A LEAST-COST PLANNING CONCEPTUAL FRAMEWORK, WHAT DO YOU RECOMMEND FOR THE SCHEDULE OF THE RESULTING TRACK B LEAST-COST PLANNING PROCESS?

A. Unfortunately, even if one could rely on bids from the wholesale power market for 100 percent of the new resource to be evaluated (which one cannot), the appropriate Track B bid evaluation process is somewhat more complicated than

1 Staff suggests. Thus, somewhat more time than Staff has allowed for in their
2 proposed schedule will be required to re-design a reasonable process. Because of
3 this unavoidable situation, I recommend that the competitive solicitation process
4 not be used to provide energy and capacity for the summer of 2003. I recommend
5 that the distribution utilities use a more *ad hoc,* but prudent, planning process in
6 order to cover their needs for next summer. The more formal competitive
7 solicitation process could begin for resources required for 2004-2006 at one time,
8 once the process has been properly structure.

9 Obviously, if developing the details for a proper least-cost planning
10 process can be done in time to acquire resources for the summer of 2003, then, of
11 course, that period could be included. But it is far more important to get the
12 solicitation process structured properly for the long run, than to rush the process
13 through to completion too quickly. Too much ratepayer money is at stake in the
14 long run to not get the details of the solicitation process right for the current Track
15 B process. My recommendation might also imply that the distribution utilities
16 should focus on acquiring fairly short-term firm power contracts to cover their
17 needs through 2003, unless an obviously super-good deal comes their way on a
18 longer-term basis. Of course, least cost planning would also have to be used by
19 the utility to evaluate such a long-term bid.

20 Q. SHOULD A LEAST-COST PLANNING PROCESS, IF DONE CORRECTLY,
21 HAVE ANY IMPLICATIONS FOR THE PRUDENCE OF THE RESULTING
22 INVESTMENT COMMITMENTS ON THE PART OF THE REGULATED
23 UTILITIES INVOLVED?

1 A. Yes. Any contract or build order for new resources that results from the
2 Commission's review and approval of an appropriate least-cost planning process
3 should convey to the regulated utilities the presumption of prudence (this is the
4 case in Colorado). After all, what is determined in the least-cost planning process
5 is the same thing the utilities need to demonstrate in a later review of planning
6 prudence for cost recovery purposes. Presumably, there would be two kinds of
7 prudence issues raised in any cost recovery review. The first would be the
8 prudence of planning. Clearly, this would be covered by the initial bid evaluation
9 process if my recommendations are adopted, so it would not be fair for the
10 Commission to second guess the initial planning process. The second prudence
11 issue would whether the utility acted prudently based on whatever information
12 became available after the initial planning process was completed, both to
13 implement the least-cost plan and to adjust the plan if required due to this new
14 information. This second prudence issue should be reserved for the final cost
15 recovery hearing, but the first issue should not be reopened.
16 Q. IN LIGHT OF THE LIKELIHOOD THAT THE TYPE OF LEAST-COST
17 PLANNING PROCESS THAT YOU RECOMMEND CAN NOT BE CARRIED
18 OUT FOR RESOURCES FOR THE SUMMER OF 2003, HOW SHOULD
19 THESE TWO PRUDENCY ISSUES BE ADDRESSED FOR THOSE
20 RESOURCES?
21 A. If the resources needed for the summer of 2003 cannot be evaluated as part of the
22 final least-cost solicitation process developed, then both types of prudence issues
23 would need to be reviewed as part of the Commission's cost recovery hearings for

1 those resources, unless no contracts for those resources extended beyond July 1,
2 2004 for APS and January 1, 2005 for TEP. The prudence issues may not need to
3 be addressed by the Commission at all if none of these contracts extend beyond
4 those dates, because the retail rates for these two utilities are frozen during those
5 time periods, and thus it will be in the interest of those utilities' stockholders to
6 minimize wholesale power costs until new retail rates are set by the Commission
7 to come into effect after those dates.
8 Q. COULD THE COMMISSION JUST LIFT THE SUSPENSION OF THE
9 EXISTING IRP RULES IN ARIZONA IN ORDER TO BEGIN TO REDEFINE
10 AN APPROPRIATE LEAST-COST PLANNING PROCESS FOR USE AS A
11 COMPETITIVE SOLICITATION PROCESS?
12 A. Yes, the Commission could lift the 1999 suspension of the existing IRP rules in
13 order to provide a basis for a least-cost competitive solicitation process for use
14 next year. However, I would suggest that the old rules be reviewed for any
15 revisions that may be desirable under the current circumstances. In particular, the
16 old rules should be reviewed to make sure that they fully allow for any potential
17 benefits from the competitive wholesale generation market to be captured for
18 Arizona's ratepayers. However, section R14-2-703D of the old rules did include
19 the need to evaluate potential purchased power contracts as part of doing least-
20 cost planning, so not much modification to the old rules may be required.
21

IV. CRITIQUE OF APS AND TEP TESTIMONY

Q. PLEASE SUMMARIZE MR. CARLSON'S TESTIMONY AS TO HOW APS PLANS TO CARRY OUT ITS TRACK B SOLICITATION PROCESS.

A. Mr. Carlson calls for a "multi-layered procurement effort". APS would issue an RFP to solicit bids for three specific "products", i.e. types of electric generation. Unfortunately, APS is prejudging the entire bid selection process, and is proposing to limit the types of products solicited to peaking products only. Thus, APS is not proposing to solicit any cycling or baseload products, even if there might be some very low cost products of this type available for the short-run or long-run. The reason why APS is only proposing to solicit peaking products appears to be because the load factor of their unmet reliability needs is very low, like a peaking product. While APS' plan may correctly yield a least cost outcome, it also might not. For example, it could be the case that in the current financially stressed generation market, some baseload products would be available that could provide both capacity for peak demand, and would also save enough in energy costs from some of APS' existing generators to be even more economically desirable than a peaking product.

Furthermore, it is very important to point out that APS does not explicitly support a long-run least cost planning approach to evaluating its Track B resource bids. In fact, APS is not planning to solicit any products for the long run, so it would not even be able to determine if long-run products offer a better deal for

ratepayers than short-run products. Mr. Carlson states that APS will only select bids for up to four years in duration. (Page 9)

Q. DOES APS' RELUCTANCE TO SOLICIT BASELOAD AND CYCLING PRODUCTS ILLUSTRATE ANOTHER CONCEPTUAL PROBLEM WITH THE SOLICITATION METHODOLOGY PROPOSED IN THE STAFF REPORT?

A. Yes, APS seems to just be following the Staff methodology in bidding out only the unmet amounts of capacity and energy that its own generating units cannot provide. This is what they call their "unmet reliability needs". This is the right approach to take for bidding capacity, but there is no good reason to limit the amount of energy bid out to the amount of energy that cannot be generated by the company's own generating assets. Soliciting bids for generating capacity is more fundamental, because once a utility has enough capacity, the dispatch of that capacity, which yields the amount of energy needed from each generating unit, will be determined by the variable cost for each MW of capacity and the demand in each hour. Thus, bids should be solicited for all types of capacity - low, medium, and high cost capacity, with low, medium, and high variable costs.

The least-cost planning process, through the use of a dispatch model, will determine how much energy should come from each kind of capacity. Again, it may be cheaper, as indicated above, for some of the energy that could have been produced by a utility's generating units, to be displaced by lower variable cost capacity that would be bid into a well-constructed solicitation process. Whatever solicitation process is used, the bids solicited by each distribution utility should

not be limited with respect to the total amount of energy requested. The amount of energy that it is optimal to take each year from each capacity option offered will automatically be determined as an outcome of the least cost planning process, if one is used.

Q. WHAT DOES MR. CARLSON SAY ABOUT HOW APS WILL DETERMINE THE PORTFOLIO OF RESOURCES THAT WILL RESULT FROM THE TRACK B PROCESS?

A. Mr. Carlson is not at all clear as to what methodology APS will use to select its final resource portfolio as a result of the Track B process. On page 16 of his testimony, Mr. Carlson states "there is no magic formula, and if there were, I would not disclose it to potential suppliers in this public forum." "You study the market (both present and future), weigh credit considerations, evaluate regulatory risk, and factor in the inherent uncertainty of any load forecast." (Page 16) While I do appreciate the desire of APS to be able too exercise sound business judgment as part of the Track B process, APS also needs to understand that judgment alone is not a prudent way of selecting a final resource portfolio. This is why formal least-cost planning or IRP methodologies were developed by the utility industry, and why Arizona had IRP rules in force in the past. A systematic resource selection methodology is required to yield reasonable electric rates. The Commission cannot allow APS, or any other utility, to just use their judgment in this unspecified way. To do so would not represent prudent planning.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE BID EVALUATION PROCESS THAT MR. HUTCHENS PROPOSES FOR TEP?

A. Yes, I do. On the whole, TEP's proposed approach for their bid evaluation process is much better than APS' proposed approach. On page 4 of his testimony, Mr. Hutchens acknowledges that the amount of energy that might be acquired as a result of the bid evaluation process could be greater than the amount of energy included in the "contestable load," which is the energy that could not be produced by the company's generating assets. In addition, on page 10, Mr. Hutchens states that TEP will perform "a least cost analysis of the bids." It is only after that least-cost analysis is completed that TEP will determine how much of the capacity and energy from each bid to purchase. This is the correct logical sequence for carrying out a bid evaluation process.

However, one concern that I have with the TEP process is that TEP still seems to be significantly limiting the types of generation products that they will solicit. These products are listed on lines 7-10 of Mr. Hutchens' testimony. While the range of products listed here appears to be somewhat broader than the range of products that APS has proposed soliciting, there should be no limitations placed on the types of products that either TEP or APS should solicit. I believe that Arizona's utilities should solicit all the potentially favorable types of electric generating capacity and products that the wholesale market will offer, and then determine the most cost-effective types of bids to accept during the least-cost planning process. By definition, if any types of bids are prematurely excluded, the resulting least-cost portfolio will not have as low a cost as it might otherwise have had. It is also not clear from Mr. Hutchen's testimony what range of durations over which TEP will solicit bids. But, again, I urge the Commission to

1 require that all distribution utilities seek a full range of durations for bids, because
2 there may be some good long-term bargains available now that could help these
3 utilities meet their load growth over a longer period than just 2003-2006. By
4 comparing the bids received from the wholesale market to cost-of-service based
5 bids for new utility-owned generation resources that I believe the Commission
6 should require from the regulated utilities themselves in the context of a least-cost
7 planning process, the utilities will be able to determine if it is a good time to make
8 some longer term purchases.
9 Q. DO YOU AGREE WITH TEP THAT THEY SHOULD BE ABLE TO
10 INCLUDE THE TWO COMBUSTION TURBINES COMPLETED IN THE
11 SUMMER OF 2001 TOTALING 95 MW IN THEIR LIST OF EXISTING
12 ASSETS?
13 A. Yes, I do. I cannot understand why it would not be appropriate to include these
14 two relatively new units in TEP's list of existing generating resources for the
15 purpose of determining TEP's remaining capacity needs to be bid out. This is
16 especially true since TEP constructed these generating units within their regulated
17 utility affiliate.
18 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?
19 A. Yes, it does.

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Experience

1998-2001	Director of Energy Group, Tellus Institute
1997-present	Manager of Electricity Group, Tellus Institute.
1993-1997	Director of Energy Group, Tellus Institute.
1991-present	Director of Planning, Tellus Institute.
1977-present	Energy Group. Responsibility for a broad range of research on integrated resource planning energy conservation; electric generation planning issues; and modeling studies of long-range energy demand, utility system reliability, energy demand curtailment, and environmental externalities and energy planning.
1978-1980	Consultant to Brookhaven National Laboratory.
1979	Consultant to the National Academy of Sciences, Puerto Rico Energy Study Committee.
1976-1978	Assistant Physicist, Economic Analysis Division, National Center for the Analysis of Energy Systems, Brookhaven National Laboratory.
1974-1976	National Research Council - National Academy of Sciences Resident Research Fellow, Goddard Institute for Space Studies, New York.
1973	Instructor, Putney - Antioch Graduate School.

Testimony

Agency	Case or Docket No.	Date	Topic
Public Service Commission of Wisconsin	05-CE-117, 05-CE-130, 05-AE-109 (Tellus 02-070)	August 2002	Review components of Phase I of proposed Power The Future investment plan; recommend changes in assumptions and methodology to improve WEPCO's Application for both Phase I and Phase II
		September 2002	Surrebuttal testimony in above dockets
Arizona Corporation Commission	E-00000A-02-0051 (Tellus 02-072)	May 2002	Market Power in the Context of Deregulated Electricity Markets
Arizona Corporation Commission	E-04345A 01-0822 (Tellus 01-199)	March 2002	Arizona Public Service Company's Request for a Variance of Certain Requirements of A.A.C. R14-2-1606
Arizona Corporation Commission	E-01032C-00-0751 (Tellus 00-172)	February 2002	Citizens Communications Company wholesale purchased power costs
United States District Court for the Southern District of Ohio – Eastern Division	C2-9901181 (Tellus 00-205)	November 2001	Evaluation of whether Ohio Edison should have forecasted that 11 activities undertaken at W.H. Sammis plant would cause net emissions increases exceeding the allowable Clean Air Act thresholds for SO_2, NO_X, and PM_{10} at the time the activities occurred
		August 2000	Supplemental Expert Testimony in above docket.
Colorado Public Utilities Commission	00A-600E (Tellus 00-204)	March 2001	Review of evidence filed by Public Service Company of Colorado in support of a proposed transmission line and high voltage DC converter between Lamar, CO and Holcomb, KS
Wisconsin Public Service Commission	05-CE-113 (Tellus	Nov. 2000	Review and critique of Application supporting construction of Arrowhead-

	99-207)		Weston transmission line
		Dec. 2000	Sur-rebuttal Testimony in above docket
Colorado Public Utilities Commission	99A-549E Phase I (Tellus 00-128)	Nov. 2000	Review of the adequacy of PSCo's selection of the electric generation resource bids that it has chosen for its final IRP plan
Colorado Public Utilities Commission	00A-007E (Tellus 00-021)	March 2000	Review of methodologies on which PSCo's summer peak demand and sales forecasts are based, and recommendations how its load forecasting could, and should, be improved
New Hampshire Public Utilities Commission	DE99-099 (Tellus 99-136)	Dec. 1999	Discussion of the Transition Service Energy Charges that might be applied in New Hampshire
New Hampshire Public Utilities Commission	DE 99-099 (Tellus 99-136)	Nov. 1999	Non-rate design aspects of the proposed Settlement Agreement between PSNH and the State of New Hampshire
Delaware Public Service Commission	99-457 (Tellus 99-145)	Nov. 1999	Analysis of the stranded cost-related issues in the Delaware Electric Cooperative, Inc.'s filing and sponsoring of an estimate of stranded costs for the DEC
		Dec. 1999	Rebuttal testimony
Federal Energy Regulatory Commission	EC97-56-000 ER97-4669-000 (Tellus 97-230)	Sept. 1999	Description of, and results of, an independent analysis of market power performed to demonstrate potential impact on regional electricity prices of proposed KCPL/Western Resources merger, and to illustrate several key aspects of how market power analysis for a merger should be done
Arizona Corporation Commission	RE-00000C-94-0165 (Tellus 98-147)	July 1999	The status of settlement discussions between Residential Utility Consumer Office (RUCO) and Citizens Utilities Company-Arizona Electric Division, and summary of concerns about CUC-AED's stranded cost recovery plans

Public Utilities Commission of New Hampshire	DR 96-150 (Tellus 98-237)	June 1999	Clarification of the regulatory policy implications of the New Hampshire Supreme Court decision of December 23, 1998, as it applies to the future recovery of stranded costs in the rates that the PUC will set for Public Service of New Hampshire
Missouri Public Service Commission	Case No. EM-97-515 (Tellus 97-230)	April 1999	Review and critique of the analyses of market power specific to the proposed merger of Kansas City Power & Light Company and Western Resources, performed by Dr. Robert Spann on behalf of the Applicants. Also a description of, and the results of, an independent analysis of market power performed in order to demonstrate the potential impact on regional electricity prices of the proposed merger.
Arizona Corporation Commission	E-01933A-98-0471; E-01933A-97-0772; E-01345A-98-0473 E-01345A-97-0773 and U-00000C-94-165. (Tellus 98-147)	November 1998	Analysis of various filings related to the unbundled service tariffs, stranded cost recovery proposals for Arizona Public Service and Tucson Electric Power Company, and various other aspects of their restructuring proposals
New Mexico Public Utility Commission	2867/2868 (Tellus 98-195)	November 1998	Application of Residential Electric Incorporated for a CCN to provide electric service and its request that Public Service of New Mexico offer transmission, distribution, and customer-related services, at unbundled rates
Public Utilities Commission of Nevada	98-7023 (Tellus 98-111)	November 1998	Analysis of stranded generation costs of Sierra Pacific Power Co. and the Nevada Power Co.; analysis of conditions under which competitive wholesale power markets could be created in Nevada, particularly given the severe transmission constraints in the state
Maine Public Utility Commission	97-580 (Tellus 98-007)	May 1998	Central Maine Power's proposed Standby rates and related policy issues
		August	Surrebuttal testimony in above docket

		1998	
Maine Public Utility Commission	97-580 (Tellus 98-007)	April 1998	Alternative estimate of value of stranded costs of Central Maine Power Company based on three changes to their methodology, and alternative estimate of CMP's non-utility generation stranded costs arising from the Regional Waste Systems purchased power contract
New Hampshire Public Utilities Commission	DR 98-012 (Tellus 98-019)	April 1998	Proposed Offer of Settlement in the Granite State Electric Company restructuring docket
New Mexico Public Utility Commission	2761 (Tellus 97-135)	April 1998	Investigation of the potential of using market pricing for the unbundled generation portion of rates in a way that will allow Public Service Company of New Mexico to realize the fair market value of its generation plant over the long run, beginning with the test year 1996
New Hampshire Public Utilities Commission	DE97-251 (Tellus 98-019)	March 1998	Evaluation of whether or not the proposed transfer of the generating assets and purchased power agreements of the New England Power Company to USGenNE is in the public interest for the citizens of New Hampshire
Arizona Corporation Commission	U-0000-94-165 (Tellus 97-289)	Jan. 1998	Public policy recommendations on key issues related to calculation, sharing, and recovery of stranded costs; presentation of "retail generation service" methodology for computing stranded costs
		Feb. 1998	Sur-Rebuttal testimony in above docket
New Jersey Office of Administrative Law	BPU EO9707-0465 OAL PUC-7309-97 BPU EO9707-0464 OAL PUC-7310-97 Tellus (97-203/A4)	Jan. 1998	The importance of pricing retail generation services for use in the appropriate methodology for making stranded cost calculations (Rockland Electric Company)

		March 1998	Sur-rebuttal Testimony in above docket
New Jersey Office of Administrative Law	BPU E097070 456 OAL PUC 7311-97 (Tellus 97-203/A6)	Nov. 1997	Importance of pricing retail generation services for use in the appropriate methodology for making stranded cost calculations (Atlantic City Electric)
New Jersey Office of Administrative Law	BPU EO9707 0459 OAL PUC-7308-97 BPU E09707 0458 OAL PUC-7307-97 (Tellus 97-203/A3)	Nov. 1997	Pricing of retail generation services relative to the appropriate methodology for making stranded cost calculations (Jersey Central Power & Light dba GPU Energy)
New Jersey Office of Administrative Law	BPU E09707 0462 OAL PUC-7347-97 BPU EO9707 0461 OAL PUC-7348-97 (Tellus 97-203/A1)	Nov. 1997	Pricing of retail generation services relative to the appropriate methodology for making stranded cost calculations (Public Service Electric & Gas Company)
		Jan. 1998	Sur-rebuttal testimony in above dockets
Public Utility Commission of Texas	473-96-2285 and 16705 Tellus 97-046)	Sept. 1997	Competitive issues
Michigan Public Service Commission	U-11283 (Tellus 97-093)	May 1997	Recommendations on key policy issues related to determining the appropriate division between transmission and local distribution facilities, and the appropriate cost allocations, as required under FERC Order No. 888 using FERC's seven-point test

Michigan Public Service Commission	U-11337 (Tellus 97-093)	May 1997	Recommendations on key policy issues related to determining the appropriate division between transmission and local distribution facilities, and the appropriate cost allocations, as required under FERC Order No. 888 using FERC's seven-point test
New York Public Service Commission	96-E-0898 (Tellus 97-009)	May 1997	Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of Rochester Gas and Electric Corp., and public policy recommendations on key issues related to market structure, market power, and the likelihood of RG&E's proposed retail access program actually leading to competition
New York Public Service Commission	96-E-0897 (Tellus 97-009)	April 1997	Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of Consolidated Edison Company of New York, Inc., and public policy recommendations related to market structure and market power
New York Public Service Commission	96-E-0891 (Tellus 97-009)	February 1997	Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of New York State Electric and Gas Company, and public policy recommendations on key issues related to market structure and market power
Missouri Public Service Commission	EM-96-149 (Tellus 96-214)	Nov. 1996	Various issues related to market power
Federal Energy Regulatory Commission	EC96-10-000 (Tellus 96-050F)	Sept. 1996	Review of the joint application of Baltimore Gas & Electric Company and Potomac Electric Power Company for approval of their proposed merger and organization
Maryland Public Service Commission	8725 (Tellus 96-050)	July 1996	Review of the joint application of BGE and PEPCO for approval of their proposed merger and reorganization
Illinois Commerce	95-0551	March	Review of joint application of Central

Commission	(Tellus 95-302)	1996	Illinois PSC, CIPSCO Incorporated, and Union Electric Company for approval of their proposed merger and reorganization
Vermont Public Service Board	5724 (Tellus 94-064)	July 1994	Review of Central Vermont Public Service's planning for its power supply resources over the past 5 years and its management of its resource portfolio
Illinois Commerce Commission	94-0065 (Tellus 94-112A)	June 1994	Assessment of the extent to which Byron 2, Braidwood 1 and Braidwood 2 nuclear units may be considered used and useful for ratemaking purposes by Commonwealth Edison, and recommendation of an appropriate ratemaking treatment of the units based on this assessment
		July 1994	Rebuttal Testimony in above docket
Kansas Corporation Commission	180,056-U	February 1994	Oral Testimony (no written testimony) on establishment of IRP rules for electric and gas utilities
Public Utilities Commission of Hawaii	7257 (Tellus 93-144A3)	December 1993	Critique of HECO IRP plan. Recommendations re: better and simpler approach to taking environmental externalities into account in integrated resource planning
Arkansas Public Service Commission	93-132-U (Tellus 93-148)	November 1993	Review application of Arkansas Electric Cooperative Corporation (AECC) for a certificate of public convenience and necessity for the construction, ownership, operation, and maintenance of a hydro-electric generating facility at Dam No. 2 ("H.S. #2") on the Arkansas River
		January 1994	Sur-Rebuttal Testimony in above docket
Public Utilities Commission of Georgia	4152-U (Tellus 93-100)	August 1993	Review of ratemaking aspects of the Clean Air Act Compliance plans of Georgia Power Company and Savannah Electric and Power Company

Pennsylvania Public Utility Commission	A-110300 F. 051 (Tellus 92-026)	July 1993	Critique of certain aspects of the Joint Applicants' filing with respect to whether the Joint Applicants have satisfied the requirements of the Pennsylvania PUC's siting regulation
Public Utilities Commission of Ohio	91-635-EL-FOR 92-312-EL-FOR 92-1172-EL-FOR (Tellus 92-165)	April 1993	Comments and recommendations re: Cincinnati Gas & Electric Company's integrated resource plan submitted in the Company's 1992 Electric Long Term Forecast Report
Georgia Public Service Commission	4133-U, 4136-U (Tellus 92-078)	October 1992	Review of the need for new capacity on the Georgia Power Company, Savannah Electric & Power Company, and Southern Company system over the next three years, 1992-1995
Public Utilities Commission of Ohio	92-708-EL-FOR 92-1123-EL-FOR (Tellus 92-041A)	September 1992	Comment on Centerior Energy Corporation's integrated resource plan and Clean Air Act compliance plan submitted in the Company's Long Term Forecast Report; specific recommendations for action on behalf of the Company to improve components of its resource and Clean Air Act compliance planning process
Public Service Commission of the State of Georgia	4131-U, 4136-U (Tellus 91-266)	June 1992	Adequacy of the 1992 Integrated Resource Plans of Georgia Power Company (GPC) and Savannah Electric Power Company (SEPCO)
U.S. Bankruptcy Court - Manchester, NH	BK-91-11336 Chapter 11	March 1992	Adequacy of bankruptcy plan filed by New Hampshire Electric Cooperative, Inc.
Public Utilities Commission of Ohio	91-410-EL-AIR (Tellus 91-082)	December 1991	Ratemaking treatment of Cincinnati Gas & Electric Company's 39.63% share in the Zimmer plant under the jurisdiction of the Public Utilities Commission of Ohio (PUCO)

Public Utilities Commission of Ohio	92-418-EL-AIR (Tellus 91-091)	December 1991	Ratemaking treatment of Columbus Southern Power Company's 24.20% share in the Zimmer plant under the jurisdiction of the Public Utilities Commission of Ohio (PUCO)
Maine Public Utilities Commission	89-193, 89-194, 89-195 (ESRG 89-189B & 90-039)	August 1990	Review of Bangor Hydro-Electric Company's solicitation of bids with a request for proposals dated July 24, 1989, and its approach to the evaluation of the respondents' bids.
New Hampshire Public Utilities Commission	DF 89-085 (ESRG 90-051)	July 1990	Assessment of Eastern Utilities Associates' Plan to acquire UNITIL Corporation: Issues Affecting NH Consumers
		September 1990	Supplemental Testimony in above docket.
Florida Public Service Commission	891345-EI (ESRG 90-017)	April 1990	Rate base treatment of Gulf Power Company's 63-MW ownership share of the Scherer 3 generating unit.
Michigan Public Service Commission	U-9458 (ESRG 89-158)	February 1990	Implications of excess capacity on the Indiana Michigan system for the costs that should be included in the Company's 1990 PSCR plan.
Vermont Public Service Board	5330 (ESRG 89-078)	December 1989	Presentation of results of ESRG Study: *The Role of Hydro-Quebec Power in a Least-Cost Energy Resource Plan for Vermont.*
		February 1990	Further Testimony in above Docket
		February 1990	Surrebuttal Testimony in above Docket
Pennsylvania Public Utility Commission	R-891364 (ESRG 89-90A)	October 1989	Recommendations regarding the proper ratemaking treatment for PECo's Limerick 2 nuclear unit.
Florida Public Service Commission	881167-EI (ESRG 89-034)	May 1989	Ratebase Treatment of Gulf Power Scherer 3 Capacity

Federal Energy Regulatory Commission	ER88-630-000 (ESRG 88-153)	April 1989	Pass Through of Performance Incentive Program Charges by New England Power Company
Public Service Commission of the District of Columbia	Formal Case No. 877 (ESRG 88-128D)	February 1989	Evaluation of the Need and Justification for 210 MW CTs at Benning Road Site Proposed by PEPCO
	(ESRG 88-128E)	March 1989	Rebuttal Testimony
Michigan Public Service Commission	U-8871 (ESRG 88-32)	April 1988	Review of the Appropriate Avoided Costs for the CPCo System
	(ESRG 88-32A)	August 1988	Rebuttal Testimony
Maine Public Utilities Commission	87-268 (ESRG 30A)	April 1988	Review Related to the Staff's Evaluation of the Desirability of the Purchase of Power from Hydro Quebec Proposed by Central Maine Power
	87-268 (ESRG 87-30A1)	August 1988	Supplemental Testimony
Pennsylvania Public Utility Commission	M-870111, G-870087 G-870088 (ESRG 88-01)	February 1988	Review of Pennsylvania Power Company's Requested Recovery of Purchased Power Costs
Pennsylvania Public Utility Commission	R-870732 (ESRG 87-80)	November 1987	Investigation into Pennsylvania Power Company's Share of Perry 1 Nuclear Unit and Assessment of Physical Excess Capacity. Direct and Rebuttal Testimony.
Michigan Public Service Commission	U-7830 (ESRG 85-35E)	December 1987	Review of the Application of Consumers Power Company to Recover Its Midland Investment
Pennsylvania Public Utility Commission	R-870651 (ESRG 87-50D)	October 1987	Investigation into Whether Perry 1 and Beaver Valley 2 Capacity Is Economically Used and Useful on the Duquesne System.

Federal Energy Regulatory Commission	ER-86-694-001	September 1987	Analysis of NEPOOL's PIP Program on Behalf of Maine Public Utilities Commission
Maine Public Utilities Commission	86-85	June 1987	Investigation of Reasonableness of Rates
		August 1987	Surrebuttal
Maryland Public Service Commission	7972	February 1987	Investigation by the Commission of the Justness and Reasonableness of the Rates of Potomac Electric Power Company
Arizona Corporation Commission	U-1345-85-367 (Tellus 86-42B)	February 1987	Concerning the Prudence of Palo Verde Investment
Michigan Public Service Commission	U-8578 (Tellus 86-055A)	January 1987	Power Supply Cost Recovery Plan for Detroit Edison
Michigan Public Service Commission	U-8585	January 1987	Power Supply Cost Recovery Plan for Upper Peninsula Power Company
Pennsylvania Public Utility Commission	R-860378 (Tellus 85-083A)	September 1986	Economics of Duquesne Light Company's Share of Perry 1
		November 1986	Surrebuttal
Pennsylvania Public Utility Commission	R-850267 (Tellus 85-083B)	September 1986	Economics of Penn Power's Share of Perry 1
		November 1986	Surrebuttal
		March 1987	Supplemental

Michigan Public Service Commission	U-8348	July 1986	Palisades Performance Standards
Michigan Public Service Commission	U-8291	April 1986	Power Supply Cost Recovery Plan for Detroit Edison
Michigan Public Service Commission	U-8286	February 1986	Power Supply Cost Recovery Plan for Consumers Power
Michigan Public Service Commission	U-8297	January 1986	Power Supply Cost Recovery Plan for Upper Peninsula Power Company
Michigan Public Service Commission	U-8285	January 1986	Power Supply Cost Recovery Plan for Indiana & Michigan Company
Division of Public Utilities, Dept. of Business Regulation	85-2011-01 85-999-08	January 1986	Construction of a Transmission Line and Transmission Facilities in Southwestern Utah
New York Public Service Commission	28252	October 1985	Shoreham - Rate Moderation
		January 1986	Surrebuttal
Missouri Public Service Commission	ER-85-128 EO-85-185 EO-85-224 (Tellus 83-089)	June 1985	Wolf Creek Excess Capacity and the Prudency of Company Planning
Federal Energy Regulatory Commission	ER-84-560-000 (Tellus 85-019)	April 1985	Callaway Excess Capacity and a Review of Union Electric Planning
State Corporation Commission of the State of Kansas	120-924-U 142-098-U 142-099-U 142-100-U	April 1985	General Investigation by the Commission of the Projected Costs and Related Matters of the Wolf Creek Nuclear Generation Facility at Burlington, Kansas
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EXHIBIT
RUCO-2
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES	))))	Docket No. E-00000A-02-0051 ET AL.

REBUTTAL TESTIMONY

OF

DR. RICHARD A. ROSEN

On Behalf of the Arizona
Residential Utility Consumer Office

Tellus Institute
11 Arlington Street
Boston, MA 02116-3411
Tel: 617/266-5400

REBUTTAL TESTIMONY ON TRACK B ISSUES

NOVEMBER 18, 2002

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dr. Richard A. Rosen. My business address is Tellus Institute, 11 Arlington Street, Boston, MA 02116-3411.

Q. ARE YOU THE SAME DR. RICHARD A. ROSEN WHO FILED DIRECT TESTIMONY ON TRACK B ISSUES?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is primarily to show how IRP and least-cost planning principles can help the Arizona Corporation Commission (ACC) to sort out the various proposals for the Track B process made by several other witnesses in the Track B portion of the docket. These principles will allow the Commission to determine which of these proposals make sense because they are consistent with least-cost planning, as compared to those proposals that do not make sense because they conflict with least-cost planning. I will comment on the direct testimony of Mr. Broderick, Mr. Kebler, Mr. Roach and Mr. Mitchell.

Q. WHAT IS YOUR GENERAL REACTION TO MR. MITCHELL'S DIRECT TESTIMONY?

A. I generally agree with everything that Mr. Mitchell says in his direct testimony on Track B. I particularly agree with the description on page 6 of his testimony as to how a least-cost planning process should be carried out. He makes the same key point that I made in my direct testimony, namely that "the only feasible way to

evaluate the complex interactions between power opportunities associated with these bids is to simulate the entire electrical system using computer programs designed for this task." He also agrees with me on page 8 of his testimony that the utilities should not limit their solicitations to a small group of specific products that appear to be needed, especially not to the ones the utilities list in their November 4, 2002 testimony. Finally, if APS does not have a dispatch model that can "capture the impact of transmission constraints in the simulation process" for modeling the dispatch of the company's power plants, as Mr. Mitchell states on page 10, then APS will need to obtain better software for carrying out that task. An adequate Track B evaluation process should model the full transmission system of both APS and TEP, including load pockets and RMR units.

Q. MR. BRODERICK RECOMMENDS THAT THE TRACK B PROCESS UTILIZE THE NEW ECONOMIC CRITERIA FOR LEAST-COST PLANNING ADOPTED BY THE COLORADO PUC. DO YOU AGREE?

A. No. While I advocate a least-cost planning process, Colorado's new criterion is not quite the correct criterion, for a simple reason. The new economic criterion established by the PUC minimizes the net present value of "rate impacts," which means rates. This compares to the traditional least-cost planning criterion which minimizes the net present value of revenue requirements, not rates. The difference is that rate impacts are equal to revenue requirements divided by the total retail sales. Thus, the new Colorado criterion is an unweighted calculation, namely the rates are not weighted by the amount of power bought at each rate

level. Colorado's unweighted calculation does not consider any growth in demand, and as a result, the new Colorado criterion does not minimize the total cost of a given resource portfolio to society, as the traditional criterion does. Yet, this latter criterion is the one that makes more sense for use by any public utilities commission. The traditional least-cost planning criterion minimizes the present value of the total electric bills to customers for a given utility over the relevant planning period.

Q. MR. BRODERICK AND SEVERAL OTHER WITNESSES RECALCULATE APS' UNMET NEED FOR POWER IN EACH YEAR, AND THEY ESTIMATE BOTH A NET CAPACITY REQUIREMENT AND A NET ENERGY REQUIREMENT. DOES IT MAKE SENSE TO SPECIFY THE NET NEED IN TERMS OF BOTH OF THESE QUANTITIES?

A. No. As I discussed in my direct testimony, it is the net needed amount of capacity that is of primary importance. This capacity could be supplied by additional generation or by DSM. The amount of energy that this capacity produces in each future year will depend on the complete portfolio of resources within which it is evaluated. The same type of capacity product might generate very different amounts of energy in two different portfolios. Therefore, the "unmet need" assessment should not include any statement about the amount of energy that is needed. The amount of energy "needed" from each resource in each year will be a natural result of the least-cost planning process, and will be determined by running an appropriate dispatch model. This is true for both existing resources and new resources, and existing transmission system constraints will strongly

1 influence these dispatch results for both new and existing generation resources,
2 depending upon where they are located.
3 Q. SEVERAL WITNESSES SUCH AS MR. BRODERICK HAVE INDICATED
4 THAT THERE IS A NEED FOR AN ADJUSTMENT TO THE NET NEED
5 CALCULATION FOR THE RMR UNITS OF THE UTILITY SYSTEM. IS
6 THIS TRUE?
7 A. The answer to this question depends on the dispatch modeling approach used. If
8 the least-cost planning model used to determine the least-cost portfolio includes
9 all reasonable detail on the transmission constraints that lead to load pockets in
10 certain hours of the year, then such a model will be able to determine the capacity
11 and energy needs to serve RMR requirements and the more general system
12 generation needs simultaneously. This implies that a separate calculation or
13 adjustment for RMR needs will not have to be made.
14 Q. MR. BRODERICK ALSO SUGGESTS ON PAGE 17 OF HIS TESTIMONY
15 THAT THE TRACK B PROCESS SHOULD SUBJECT ALL OF APS' GAS
16 AND OIL UNITS TO ECONOMIC COMPETITION. DO YOU AGREE?
17 A. Yes, I agree with Mr. Broderick on this proposal in the sense that a proper least-
18 cost planning process will automatically subject all of APS' generating units to
19 competition in every hour of the year. Whatever the least-cost combination of
20 capacity and/or energy from market bids is that can economically substitute for
21 the capacity and/or energy of any APS (or TEP) generating plant will do so.
22 Again, the information as to which utility units will need to run more or less than
23 they have in the past will be automatically provided as the outcome of the

1 dispatch of the least-cost resource portfolio. As Mr. Roach states on page 25 of
2 his testimony, if the capacity chosen as part of the least-cost plan is dispatchable,
3 then "a supplier's offered prices would determine how much energy it would
4 sell." However, this also implies that Mr. Roach is contradicting himself when,
5 on page 29, he accepts the Staff's assumed load factor (really a capacity factor) of
6 38 percent when computing APS' unmet energy need. No specific capacity factor
7 can be *assumed* for this purpose, and, therefore, Mr. Roach's calculation of the
8 unmet energy need for APS is not correct.
9 Q. ON PAGE 9 OF HIS TESTIMONY, MR. ROACH IS CONCERNED THAT
10 APS' PROPOSAL TO PURCHASE ECONOMY ENERGY OUTSIDE THE
11 CONTEXT OF THE TRACK B PROCESS WILL EXPOSE ITS RATEPAYERS
12 TO "RISK IN THE VOLATILE SPOT MARKETS OF THE WEST." DO YOU
13 AGREE?
14 A. No. As long as both APS and TEP acquire a least-cost portfolio of resources that
15 includes sufficient generating *capacity* to cover their annual peak demand plus
16 their required reserve margin, then they will also be able to generate a sufficient
17 amount of energy from this portfolio to cover their energy requirements. This
18 conclusion follows from the fact that having enough capacity to cover their
19 required reserve margin means that their energy needs are also covered to a very
20 high degree of reliability. (This is true by definition. A required reserve margin is
21 determined by making sure that any unmet energy needs are extremely small.)
22 In addition, the projected costs of spot market energy would also be
23 included in the inputs to the least-cost planning model. Therefore, once the least-

cost portfolio is determined, that portfolio will already take into account a "least-cost" level of reliance on the spot market. If, however, cheaper energy than assumed in the inputs to the planning analysis turns out to be available for purchase on a spontaneous basis in the future, then APS is simply proposing to purchase that cheaper energy at that time in order to save ratepayers money. This is quite reasonable, and will not expose ratepayers to any significant risk, since their costs will never be higher than those implied by the initial least-cost plan. That plan can only be improved by purchasing economy energy on an "as available" basis.

Q. MR. KEBLER STATES ON PAGES 2-3 OF HIS TESTIMONY THAT IT IS NOT NECESSARY "TO DISCUSS OR RESOLVE LEAST COST PLANNING, DEMAND SIDE MANAGEMENT AND ENVIRONMENTAL RISK MITIGATION IN THIS PROCEEDING." DO YOU AGREE?

A. No, I do not agree with this statement by Mr. Kebler. All three of the issues he mentions need to be addressed simultaneously in the context of IRP. If any one of these issues is omitted, then electric rates to consumers will be unnecessarily high in the long run. Furthermore, one of the reasons that Mr. Kebler gives for maintaining this position is his claim that the Track B process could rely on an auction process to select winning bids for standardized generation products. However, this can not work. The problem with this proposal is that an auction process could never determine *how much* (how many MWs of capacity) of each standardized product would be part of a least-cost portfolio. Such an auction could only determine which bids for a certain standardized product would be the

lowest price bids of that type. These lowest price bids for each standardized product would, then, be the ones that should be included in the least-cost optimization process. The higher-priced bids for those standardized products could be omitted from the least-cost planning process as long as there were enough of the lower-priced bids. Thus, there is no auction process that could *directly* determine which standardized products, and how much of each standardized product, it would be prudent for a utility to purchase in each year.

Q. SEVERAL WITNESSES INCLUDING MR. KEBLER URGE THAT THE COMMISSION SHOULD PROVIDE A PROMPT PRUDENCY REVIEW FOR THE BIDS ACCEPTED DURING THE TRACK B PROCESS, PRESUMABLY TO HELP ENSURE THAT THE GENERATORS GET PAID. WHAT IS YOUR REACTION TO THAT TESTIMONY?

A. First, if a utility signs a purchased power contract with an independent power producer, the generator will get paid whether or not the utility gets to recover those costs from ratepayers, so I do not understand why the potential bidders are stressing this point so strongly. Secondly, a prudent selection process may take at least 6-8 weeks, plus time for Commission approval through an adjudicated hearing process, so the bidders will just have to be patient for the portfolio to be approved by the Commission until the purchased power contracts can be finalized, as appropriate. Thirdly, if, and only if, a least-cost planning process is properly implemented to select the final portfolio of bids for each utility, should that process be deemed to convey a significant degree of prudence on each individual contract signed as a result of that process.

The type of prudence conveyed by the portfolio selection process would be "planning prudence." Each utility would still need to carry out the contract negotiation process, and related implementation tasks needed for the final signing of all contracts, prudently, in order for the utility to have been determined to have acted prudently with respect to all key Track B issues by the Commission. This would include the prudent implementation of all DSM programs selected as part of the least-cost portfolio, as well as the signing of any purchased power contracts. It would also include the construction of any new generation facilities by the utility on a cost-of-service basis, if such a bid was selected as part of the least-cost planning process. I have also discussed this issue in my direct testimony.

Q. MR. KEBLER HAS SAID ON PAGE 13 OF HIS DIRECT TESTIMONY THAT THE PARTICIPATION OF THE INDEPENDENT MONITOR IN THE SOLICITATION PROCESS SHOULD CONVEY A SIGNIFICANT DEGREE OF PRUDENCE ON THE SELECTION PROCESS, GIVEN THAT IT DOES NOT MAKE SENSE TO USE THE STAFF'S PROPOSED "PRICE TO BEAT" APPROACH. DO YOU AGREE?

A. No, I do not agree. The Independent Monitor can certainly help assure that the selection process for the final portfolio is carried out properly, but, to repeat, only if that selection process is a least-cost planning/IRP process can planning prudence be conveyed to the end results.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Sempra

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EXHIBIT
Sempra-1
Admitted

BEFORE THE

ARIZONA CORPORATION COMMISSION

DIRECT TESTIMONY OF E. DOUGLAS MITCHELL

On Behalf of Sempra Energy Resources

Docket No. E-00000A-02-0051, et al.

November 12, 2002

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is E. Douglas Mitchell, and the business address is 101 Ash Street, San Diego, CA 92110. I am a Regulatory Policy Manager at Sempra Energy Global Enterprises.

Q. WHAT IS YOUR EDUCATIONAL AND RELEVANT PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science degree in electrical engineering from the University of Florida in 1970 and a Masters of Engineering from the University of South Florida in 1974. In my current position, I am responsible for regulatory policy issues and coordination associated with the non-utility businesses of Sempra Energy. This includes representing Sempra Energy Resources in proceedings such as this one.

I have previously worked for San Diego Gas & Electric Company for over twenty years, primarily in the Generation Planning Department. During my tenure at SDG&E, I conducted a number of competitive solicitations for a combination of short-range and longer-range power purchases extremely similar to the one now being considered by the Arizona Corporation Commission ("ACC")

for implementation by Arizona Public Service ("APS") and Tucson Electric Power ("TEP").

I have previously testified before the California Public Utilities Commission in numerous situations including solicitations associated with its Biennial Resource Plan Update, a State Legislative Committee on resource planning issues, the California Energy Commission on planning and policy issues, and the California Superior Court on appropriate resource selection methods.

Q. **WHAT WAS THE OUTCOME OF THOSE SOLICITATIONS ON THE ELECTRIC RATES OF SDG&E CUSTOMERS?**

A. SDG&E began this series of power purchase solicitations beginning in the early 1980s. Just prior to implementing these solicitations, SDG&E had the second highest electric rates in the nation. After nine years of these competitive solicitations, SDG&E enjoyed the lowest Investor-Owned Utility ("IOU") electric rates in the state for three years in a row. This low-cost position was achieved even though the other two state IOUs owned large, low-cost hydro facilities while SDG&E did not.

Q. **HOW WAS SDG&E ABLE TO ACHIEVE SUCH SIGNIFICANT BENEFITS FROM ITS COMPETITIVE SOLICITATIONS?**

A. These solicitations were conducted during a period that could best be described as a "buyers market". The auction process used to solicit interested sellers stimulated the marketplace and forced sellers to either provide very competitive prices or see their power plants sit idle.

Q. **DOES IT APPEAR THAT A "BUYERS MARKET" IS NOW AVAILABLE FOR ARIZONA UTILITIES?**

A. There are many indicators that would suggest this is the case. One indicator is simply the number of interested merchant plant providers actively participating in this proceeding. Another indicator is that spot market clearing prices for electric products in Western markets have remained at very competitive levels for some time now. The competitive solicitations conducted this past month in neighboring California also show a strong interest by merchant power providers to serve load in the region. While the results of these solicitations are protected by confidentiality restrictions, it is known that Southern California Edison ("SCE") is requesting approval of a number of pending contracts that were judged favorable. San Diego Gas & Electric ("SDG&E") also experienced a robust interest in their solicitation

and is also requesting approval a number of pending contracts judged to be favorable.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. To encourage the ACC to immediately proceed with the adoption and implementation of the Staff's recommendations for a competitive procurement process designed to comply with the Commission's Decision No. 65154 in Track "A" of this proceeding. The current timing for this solicitation is excellent and the expected results should provide substantial rate benefits for the Standard Offer electricity customers in Arizona. Additionally, a proposed improvement to the auction process is offered to help assure the best possible results for the ratepayers.

II. SUMMARY

Q. **WOULD YOU PLEASE SUMMARIZE YOUR DIRECT TESTIMONY?**

A. The IOUs should immediately begin a comprehensive RFP solicitation for power purchases on the schedule presented in Staff's October 25, 2002 Report on Track B: Competitive Solicitation (page 29). The amount of capacity committed through this solicitation should be a minimum of its forecasted unmet need for at least the next three years and the maximum level of capacity should

be limited only by economic considerations. In other words, the utilities should expand their proposed solicitations to include the competitive procurement of energy when it is available on the open market at a price lower than the utilities cost to generate its own power.

III. THE SOLICITATION PROCESS

Q. HOW SHOULD THE SOLICITATION PROCESS BE STRUCTURED?

A. The first two steps identified in the Staff Report appear to be appropriate and consistent with ensuring a viable and effective auction. These two steps are: (1) Pre-solicitation, and (2) Solicitation Preparation. The third step, however, does not go far enough in specifying what is needed to produce optimum results. However, modifying the third step to produce optimum results, requires a longer time for implementation of the solicitation.

Q. WHAT ADDITIONAL SPECIFICATION IS NEEDED FOR THIS THIRD STEP AND HOW LONG WILL THIS ADDITIONAL ACTIVITY TAKE?

A. The additional specification is needed in the "evaluate prices". (Task ID number 23 page 29 of Staff Report) The one and only way to determine the value of an auction bid is to evaluate it within the context of the fully integrated generation operating system. This includes the dual considerations of: (1) providing reliable power, and

(2) achieving the lowest cost possible. The only feasible way to evaluate the complex interactions between power opportunities associated with these bids is to simulate the entire electrical system using computer programs designed for this task. These programs can simulate hour-by-hour system load requirements, the operating characteristics of each of the generating units and power purchases, known operating procedures and requirements, as well as the cost and availability of economy energy purchases while simultaneously considering any transmission constraints associated with delivery of this power. If the utility is unable or unwilling to perform this analysis, there is a vendor(s) that can immediately provide this service and also provide the information needed to model the entire western grid from a recently updated database.

Q. WHAT IS A GOOD WAY TO EFFICIENTLY PERFORM AN ANALYSIS OF THIS TYPE?

A. After the proposals are received at the close of the solicitation period, the offers should be pre-screened and sorted into similar groups. (e.g., baseload offers in one group, dispatchable peaking resources in another, etc.) Within each group a rank ordering should be established from the best offers on down. When this grouping and

ranking is complete, the better of the bids in each group (or more likely a combination of bids in each group) can be incrementally tested in combination with the existing generating units (this combination is referred to as a "scenario") in a way that the minimum reserve requirements are satisfied.

The offers obtained in this solicitation are likely to be plentiful, and will permit a number of combinations and permutations of the better bids to satisfy reserve requirements. When a reasonable number of combinations of bids are prepared (e.g., three or four scenarios), these scenarios should be simulated with the aid of a detailed production costing model to determine the scenario that produces the minimum total revenue requirements. When this single best scenario is determined, the additional considerations associated with those items identified in the Risk Management Section (Section IV of this testimony) can be analyzed.

Q. **HOW MUCH TIME SHOULD BE ALLOCATED TO PERFORM THESE DETAILED PRODUCTION COSTING SIMULATIONS?**

A. With a group of four or five professionals familiar with computer modeling and knowledge of the operational and planning needs of an electric utility, experience has

shown that this task can be completed in approximately six weeks.

Q. CAN A REASONABLE SUBSTITUTE FOR THE DETAILED PRODUCTION COSTING SIMULATIONS BE MADE BY LIMITING THE RFP SOLICITATIONS TO SPECIFIC PRODUCTS THAT APPEAR TO BE NEEDED BASED UPON AN "UNMET NEED" ANALYSIS?

A. In my professional opinion, no. The goal of the RFP solicitation stated in the first paragraph of the Staff Report is to achieve cost savings for ratepayers. I believe this goal cannot be met without a complete and detailed examination of the complex interactions inherent in a generating system operating within an interconnected utility grid.

Limiting the proposal only to some pre-determined "unmet need" exposes customers to potentially higher prices because it looks at procuring only what the utility is unable to provide physically (i.e., through its own generating units) without regard to the combination of resources that yields the optimum results.

For example, while the utilities focus the need for peaking-type resources in their expansion plans, it is nevertheless important to observe that bid proposals have the potential to replace some higher-prices generators in their current portfolio mix. A detailed review of these

opportunities could uncover a baseload or mid-range proposal that provides net benefits to ratepayers.

Q. **WOULD YOU PLEASE PROVIDE AN EXAMPLE IN WHICH AN OUTCOME FROM AN "UNMET NEED" ANALYSIS WOULD LIKELY LEAD TO AN INCORRECT RESULT?**

A. Yes, one example would be the issues surrounding quantities and prices of economy energy deliveries. A proper analysis of these transfers is dependent on three conditions: (1) knowledge of the system decremental cost of the receiving utility ("buyer"), (2) the quantity available and the offering price of the sending utility ("seller"), and (3) sufficient unused transmission transfer capacity must be available to accommodate the transaction. Lack of knowledge of any one of these components could lead to incorrect conclusions.

Q. **COULD AN INCORRECT CONCLUSION IN THIS AREA BE SIGNIFICANTLY DETRIMENTAL TO THE RATEPAYERS IN THE STATE?**

A. Yes. Given the stated intention of the two Arizona utilities to increase their reliance on the receipt of economy energy, indeed incorrect conclusions could be significantly detrimental. The numbers provided by APS in Mr. Ewen's testimony from Schedule PME-13 (and at the workshop on November 6, 2002) show that the company is

projecting the dependence on economy energy to grow from 14% of total Standard Offer load in 2003 to 30% in 2013. At this same workshop, APS stated that the computer model used by the company could not capture the impact of transmission constraints in the simulation process. Therefore, APS appears to be counting on a source of energy for almost one third of its needs, but does not know if this power can actually flow into the system.

Q. **DO YOU HAVE SIMILAR CONCERNS OVER RESTRICTING THE SOLICITATION TO ONLY THE THREE PROPOSED BASIC PRODUCTS?**

A. Yes, only three basic products (i.e., capacity only, capacity plus some minimum level of energy, and physical "call" options) were proposed for solicitation, based upon this same "unmet need" analysis. A more comprehensive analysis that considered insights about projected utility operations over the planning horizon would show that many types of energy products should be considered.

Q. **BASED UPON YOUR EXPERIENCE, WHAT TYPES OF PRODUCTS SHOULD BE REQUESTED OF BIDDERS?**

A. There should be no restrictions on energy products, other than perhaps on minimum quantities. Attempts to place rigid requirements on bidders have the potential to simply limit the number of good offers that might otherwise be

submitted. Experience also shows that bidders often ignore these proposed restrictions anyway and submit bids on their own terms and conditions. Solicitations that propose a contract that follows well-known industry protocols, such as the EEI Master Agreement or the WSPP Standard Contract will likely help remove any risk premium that might otherwise be placed in the bid price to compensate for uncertainty in this area.

V. RISK MANAGEMENT

Q. **WHAT IS THE BEST WAY TO EVALUATE BOTH PRICE RISK UNCERTAINTY AND PRICE VOLATILITY CONSIDERATIONS?**

A. Setting specific risk tolerance levels on both price risk and price volatility is clearly the responsibility of the individual utilities with guidance from their regulators. The Staff Report, for instances, offers the guidance that a solicitation process needs to be designed in such as way to ensure that "benefits occur instead of pitfalls." However, I would like to comment on the methods used to evaluate these risks, and on what utilities generally consider prudent.

The starting point for these evaluations is the lowest cost scenario obtained from evaluating the best combination of bids (referred to as the Base Case scenario). This is the scenario that is subjected to

additional risk scrutiny. A typical price risk analysis is simply the straightforward observation of the tenure of the resources in the portfolio. The optimum results produce a mix of resource commitments that are half long-term (five years or more) and the other half are a mix of shorter term (less than five years) and spot market purchases. Such a blend of resources will allow price level stability in times of high spot prices, and provide opportunities to reduce costs if spot market prices are lower.

A price volatility analysis is usually performed as a sensitivity evaluation to the base case scenario. Price considerations that are known to be volatile (e.g., natural gas prices) are tested over a range of potential price levels extremes. Evaluating the variances in total system costs provides a basis to determine the sensitivity of the base case scenario to price volatility considerations. If the base case is deemed to be overly sensitive to a particular price-related attribute, it should be modified to alleviate this undesirable characteristic. Changes of this type should be made at the discretion of the utility and allowing this leeway should be part of the bid selection process.

Q. GIVEN THIS METHOD OF RISK EVALUATION AND MITIGATION, WOULD A STRATEGY OF RELYING EXCLUSIVELY ON MARKET EXCHANGES SUCH AS THE ICE OR BLOOMBERG OFFER A REASONABLE SUBSTITUTE FOR AN RFP SOLICITATION?

A. The exclusive use of a market exchange would contribute toward both greater price sensitivity risk and greater exposure to price volatility. Neither of these outcomes is desirable.

Market exchanges maintain liquid transaction opportunities in short-term energy products only. A total reliance on this short-term procurement method would therefore eliminate any stability associated with longer-term resource commitments at known pre-determined prices. If the Arizona utilities ascribe to a target portfolio of 50% longer-term resources, this method of acquiring resources will ultimately lead to inappropriate acquisitions.

The price of energy products in virtually all these exchanges is closely tied to the prevailing price of natural gas. Natural gas-fired power plants represent the vast majority of resources "on the margin" that provide offers to sell power in these markets. Greater exposure to natural gas price volatility is undesirable, particularly when this strategy is coupled with a reliance on economy energy that, as indicated in the utility's work papers, is also tied to natural gas prices. This "double

whammy" exposure to gas prices, which are known to fluctuate, is not conducive to mitigating price volatility risk. In fact, such an approach is likely to lead to increased volatility and, ultimately, higher costs for consumers.

An additional consideration about the use of these exchanges is the lesson learned from the California experience. That lesson is that when supplies become tight, sellers will seek and obtain whatever prices the market will bear.

Despite some of these apparent drawbacks, exchanges clearly have an important place in the overall functioning of wholesale energy markets. Most utility planners, however, would not consider it prudent to rely entirely on them for all future generation expansion needs.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

TEP

1 - 3

EXHIBIT
TEP-1
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	Docket No. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. 4-14-2-1606	Docket No. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR	Docket No. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC POWER COMPETITION RULES COMPLIANCE DATES	Docket No. E-01933A-98-0471
ISSUES IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES	Docket No. E01933A-02-0069

TESTIMONY OF DAVID HUTCHENS

ON BEHALF OF

TUCSON ELECTRIC POWER COMPANY

RE: NEEDS ASSESSMENT AND PROCUREMENT PROPOSAL

NOVEMBER 4, 2002

Q: Please state your name and employment position.

A: My name is David Hutchens. I am Manager of Wholesale Marketing for Tucson Electric Power Company.

Q: What are your job responsibilities at Tucson Electric?

A: I oversee the Wholesale Marketing department functions including wholesale gas & electricity procurement, resource management, risk management, marketing, scheduling and trading.

Q: Did you participate in the Track B workshops?

A: Yes. I have represented TEP in every workshop.

Q: What is the purpose of your testimony?

A: Pursuant to the "Third Procedural Order on Track B Issues", in Docket E-00000A-02-0051 *et al.*, TEP must "file a needs assessment and procurement proposal, sufficient to inform the Commission in its determination of the minimum amount of power, the timing, and the form of procurement as required by Decision No. 65154, together with supporting testimony, by noon on November 4, 2002." This testimony will provide that information.

Q: How is your testimony structured?

A: It discusses three areas: (i) Track B Workshop Background; (ii) TEP's needs assessments and associated background information and assumptions; and (iii) TEP's draft procurement proposal.

Q: Please summarize your testimony.

A: TEP's Contestable Load for purposes of the upcoming competitive solicitation is set forth in Exhibit 1. This Contestable Load factors in TEP's wholesale load and all of TEP's existing reliability must-run generation units. In the upcoming solicitation, TEP intends to issue requests for bids on a variety of energy products and ancillary services and will use the process generally described in the Commission Staff's October 25, 2002 Report.

TRACK B WORKSHOP BACKGROUND

Q: What has been TEP's involvement in the Track B Workshops?

A: TEP has actively participated in every Track B workshop. TEP has provided, and will continue to provide, relevant information and data about TEP's resources, loads and needs assessments in a timely manner to facilitate the group's discussions and agreement.

Q: What were the conclusions of key issues to TEP that were addressed and resolved to TEP's satisfaction in the Track B Workshops?

A: TEP believed that several key TEP-related issues were addressed and resolved in the workshops. Those issues were: (i) all of TEP's generation as of September 1, 2002, whether owned or leased, would be included in TEP's resources for the purpose of calculating the "Contestable Load", including the two new Reliability Must-Run ("RMR") Combustion Turbines ("CTs") added in 2001 (DeMoss Petrie & North Loop #4); (ii) TEP's wholesale load would be included in TEP's forecasted needs; (iii) TEP's contestable load would be as set forth in Exhibit 1; and (iv) TEP could have its wholesale marketing department involved in the solicitation process because TEP did not intend to bid during that process.

Q: How were these issues apparently resolved?

A: The agreement on these issues was dependent on the inclusion of TEP's wholesale load in calculating the contestable load. In short, the amount of Contestable Load represents a settlement of all these issues. TEP had contended early in the workshop process that the procurement of "any required power that cannot be produced from its own existing assets through the competitive procurement process as developed in the Track B proceeding"[1] should still provide the utility's management the discretion to create a diverse and balanced portfolio of energy purchases. This portfolio would include differing term and price structures as well as differing products and procurement timing that met the utility's procurement and risk management needs. With this view in mind, TEP had offered to include its wholesale load in the procurement process since TEP would have nothing to

[1] ACC Decision No. 65154, p. 33.

bid in the procurement process if it only included the retail load. This view was based on the assumption that "existing assets", as contemplated by Decision 65154, included all of TEP's assets as of the date of that Decision (September 10, 2002). In the second Staff Draft Solicitation Proposal, Staff recommended that two of TEP's existing Combustion Turbines (95 MW in total) installed as RMR units prior to the summer of 2001 should not be included TEP's existing resources. TEP therefore argued that its FERC-approved, Market-Based Tariff wholesale contracts should not be part of the load to be covered by this procurement process. Through discussion and compromise with the other parties in the workshop, TEP agreed to include its wholesale load as long as the two combustion turbines were included in TEP's existing resources and TEP's wholesale marketing department could be involved in the solicitation process.

Q: What did the October 25, 2002 Staff Report reflect concerning these TEP issues?

A: The October 25, 2002 Staff Report has taken the opposite side on every issue mentioned above, with the exception that wholesale load is still included in TEP's forecasted needs. In particular, Staff recommends that: (i) TEP's new RMR CTs should not be included in TEP's existing assets,[2] (ii) TEP's contestable load amount should be higher,[3] and TEP's wholesale marketing department should be precluded from participating in the solicitation process.[4]

Q: What is TEP's position on the Track B Workshop issues in light of the Staff Report?

A: In TEP's "Track B List of Issues for Hearing" (filed on October 1, 2002),TEP listed the above issues as unresolved due to their negotiated settlement nature and interdependence. TEP did this to reserve the right to change its position on any of the above issues if any others were modified. TEP further believes that the apparent resolution of the issues at the workshops was the correct resolution. However, given the Staff Report, TEP believes that we may be back to "square one" in resolving TEP's contestable load.

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[2] October 25, 2002 Staff Report, p. 6.

[3] Id., p. 7.

[4] Id., p. 19.

Q: Did TEP list other issues as unresolved in its "Track B List of Issues for Hearing"?

A: No. Throughout the Track B hearings TEP has remained flexible and open-minded with solving the issues related to implementing the solicitation process in a fair and timely manner. TEP remains committed to the solicitation process timeline and working with Staff and the other parties collectively to address the remaining issues.

TEP'S NEEDS ASSESSMENT

Q: What is the purpose of the "Needs Assessment"?

A: The "Needs Assessment" is intended to determine the "contestable load" for TEP. That load is what TEP must acquire through the competitive solicitation process. Pursuant to Commission Decision No. 65154, "Contestable Load" is what TEP "shall acquire, at a minimum, any required power that cannot be produced from its own existing assets, through the competitive procurement process as developed in the Track B proceeding." The Needs Assessment determines a contestable load for both capacity and energy.

Q: Please provide an overview of TEP's Needs Assessment Methodology.

A: TEP's Needs Assessment does several things. First, it identifies TEP's generation assets and quantifies the capacity of each asset. This analysis includes generation plant and purchase contracts. It also provides a forecast of the power that will be available from those assets. Second, the Needs Assessment determines the forecasted load and energy demand that TEP will face. Third, the Needs Assessment calculates the actual contestable load, i.e., what portion of TEP's load that will not be met in the future by its existing assets.

Q: Please provide an overview of TEP's needs assessment.

A: Exhibit 3 provides a general graphical representation of TEP's Loads and Resources Needs Assessment for 2003-2006. The top line of the graph represents TEP's forecast load, including retail, operating reserves and wholesale. The solid background areas represent the anticipated capacity of TEP's existing assets. The area shown as "System Shortages" in the graphs represents amount of capacity on the peak hour of each month that cannot be met with existing assets. Each graph further lists the amount of energy (in

GWh) that cannot be met with existing assets.

DETERMINATION OF EXISTING ASSETS

Q: What did TEP consider to be its existing assets in this assessment?

A: For purposes of the needs assessment study, only existing TEP generation assets and firm purchase contracts where considered available to serve its load obligations. Exhibit 4 lists TEP's existing generation assets and their related capacities, based on TEP's ownership interest in the specific generation facility. This exhibit also shows the amount of existing asset capacity by month used in the Needs Assessment. TEP's only existing firm purchase contract that is included in its resources for this study is its 110 MW Southern California Edison Exchange Agreement which is also included in Exhibit 4.

Q: Why are the two newer CT plants included as existing generation assets?

A: First, as discussed in the previous section, the inclusion these two CTs added in 2001 (DeMoss Petrie and North Loop #4) were discussed with all the parties at the Track B workshops. The amount of contestable load for TEP was determined and enumerated with all the parties in the workshop with these CTs counted as existing assets.

Q: Besides the discussions with the other parties in the workshop as to the inclusion of the CTs in TEP's existing assets, is there any other evidence supporting their inclusion?

A: Yes. In ACC Decision 65154 (Track A), dated September 12, 2002 the Commission Ordered TEP to cancel any plans to divest interests in generation assets. It further ordered "TEP to acquire, at a minimum, any required power that cannot be produced from its own existing assets through the competitive procurement process as developed in the Track B proceeding." In the same order, the Commission specifically identified that "[f]or the purposes of the competitive procurement process, the PWEC generating assets that APS may seek to acquire from PWEC shall not be counted as APS assets in determining the amount, timing, and manner of the competitive procurement."[5]

[5] ACC Decision No. 65154, p. 30.

Q: How does the reference to PWEC's plants infer inclusion of TEP's new CTs?

A: It was clear that the Commission and other parties to the Track A proceedings defined "existing assets" as all assets currently owned (or leased) by the utility and was intent on only excluding assets that may be added later.

Q: What was Staff's view of transferring existing assets in the Track A proceedings?

A: As set forth in the Track A Decision, "Staff recommends that the Commission should not allow asset transfer until it is convinced that the transfer is in the public interest."[6] Staff further goes on to state that transfer of assets is not in the public interest and that "no reliability must-run ("RMR") should be divested" and that "if a utility chooses to retain its assets, the Staff believes that the Commission should apply cost of service principles when setting rates."[7] TEP's two newer CTs are RMR units within TEP's load pocket and, although they are not in TEP's current rate-base, the addition of those RMR units has been in TEP's resource plans for over 10 years.

Q: How were the two CTs treated in Track A?

A: TEP was precluded from transferring the CTs and therefore treated as "existing assets" with the same meaning as used in Decision No.65154 referencing the competitive procurement process.

FORECASTED LOAD AND ENERGY DEMAND

Q: Please discuss TEP's Load Forecast used in the Needs Assessment.

A: TEP used its June, 2002 energy and demand forecast compiled by its forecasting group. A monthly summary of demand and energy forecast for the years 2003 to 2006 is provided as Exhibit 5.

Q: Does this forecast include wholesale contracts?

A: Yes. As previously discussed, the needs assessment includes all of TEP's wholesale load.

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[6] Id., p.11.

[7] Id.

Q: Please describe TEP's wholesale contracts included in the load forecast.

A: TEP has three wholesale contracts that are included in the "Wholesale Load" line on the Exhibit 3 and in the load demand forecast calculations in Exhibit 5. All three are sales agreements under TEP's Market Based Sales Tariff and include 100 MW sale of capacity and energy to SRP, a full-requirements capacity and energy sale to Navajo Tribal Utility Authority and a 60 MW sale to Phelps Dodge Energy Services.

TEP'S CONTESTABLE LOAD

Q: Please summarize the contestable load results.

A: Exhibit 1 provides the TEP's Contestable Load for 2003 through 2006 as discussed in the Track B workshop process and calculated using the above described process. TEP believes that this is the appropriate contestable load to use for the solicitation process.

Q: Are these the same numbers supplied to the parties in the Track B workshops?

A: Yes. In fact, both Exhibits 1 and 3 hereto had been provided to Staff and the other parties at the Track B workshops. Exhibit 1 is simply a tabulation of the data from the Exhibit 3 graphs.

Q: Does the Staff's October 25, 2002 Report on Competitive Solicitation reflect the same Contested Load for TEP?

A: No. Staff has changed the amount of TEP's contestable load that the parties discussed in the Workshop.

Q: Did Staff recognize the apparent agreement of the parties on the amount of TEP's contestable load?

A: Apparently not. TEP was under the impression that the Contestable Load, as presented in Exhibit 1, was accepted by all parties participating in the workshop. In particular, Staff did not list TEP's unmet needs as an area of dispute on Staff's issue list submitted on October 1, 2002. On the other hand, Staff did list APS's unmet needs as an area of dispute.

Q: How did the Staff Report change TEP's contestable load?

A: Staff did not include the RMR CTs added in 2001, discussed more fully above, as existing assets in calculating the contestable load. Further, Staff used a 40% capacity factor on these two RMR CTs in calculating the contestable load.

Q: Is a 40% capacity factor for these CT's accurate?

A: No. This is several times higher than TEP's forecast capacity of these units.

Q: Has TEP looked at what its contestable load would be without including the two new CTs?

A: Yes. After reading Staff's report, TEP ran its needs assessment again excluding the two newer RMR CTs as existing assets. Exhibit 2 shows the resulting amount of contestable energy by year based on the same forecast and assumptions.

Q: Does the exclusion of the two CTs from existing assets preclude TEP from bidding that capacity into the Solicitation?

A: No. However, as was discussed at length in the workshops, it unnecessarily complicates the bidding process. TEP is a single economic entity that owns both of the CTs in question. There is no affiliate involved with those units and there will be no rate impact if the units are included in the solicitation because TEP's rates are frozen through 2008. In fact, because the CTs are RMR units located within TEP's load pocket, it makes their capacity impossible to replace with other assets in the solicitation process. In order for TEP to "bid" this capacity and energy to itself, TEP would be required to set up a separate group at TEP to perform the solicitation activities as currently prescribed by Staff's report. It therefore creates a complicated bidding process that has no benefit to any party and does not affect the solicitation outcome in any way.

Q: Why would TEP require a separate group to perform the solicitation?

A: Staff's current report requires that TEP's Wholesale Marketing department be excluded from the procurement process. This is an unnecessary operational hurdle for TEP given the fact that this is the group that manages TEP's load and resources and has the best ability to evaluate TEP's needs and assess the solicitation bids. If this requirement is

imposed, it would increase TEP's costs by creating a duplicate department that will basically be conducting many of the same analyses and tasks.

Q: What did the parties in the Track B workshops agree to with respect to TEP's Wholesale Marketing department participating in the solicitation process?

A: In discussing the amount of contestable load, it was expressly agreed that TEP's Wholesale Marketing department would be allowed to conduct the solicitation.

Q: Was this a contested issue in the workshops?

A: No. To the contrary, there was not a single objection to TEP's request that its Wholesale Marketing department conduct the solicitation.

Q: Will the amount of contestable load change prior to TEP's solicitation?

A: TEP continually updates its Load and Resource forecasts throughout the year as the many factors underlying such a forecast are subject to frequent change. The Contestable Load numbers discussed herein represent an initial estimate by TEP. These numbers may change somewhat during the pre-solicitation section of the overall solicitation process. As fully recognized and discussed in the workshops, each utility must determine its contestable load in the pre-solicitation process with input from Staff and other parties.

TEP'S PROCUREMENT PROPOSAL

Q: Please describe the nature of TEP's Contestable Load

A: The nature of TEP's Contestable Load drives the structure of TEP's procurement proposal. TEP's proposed Contestable Load has very low load factors as shown in Exhibit 1. This is due primarily to the extreme seasonal variation in retail energy consumption. Further, daily and even hourly variation in load is tied to weather and can be extreme. It is also impossible to predict future days when TEP will actually require power in excess of its existing resources. All of these factors will negatively affect the economics of serving this load through a single type of forward contract. For example, if capacity is purchased ahead of time to meet the estimated peak hour shortage, the incremental cost associated with supplying the required power will be astronomical. On the other hand, if on-peak blocks of firm energy are purchased to completely meet the

estimated peak shortage hour, the operational ramp characteristics would be unmanageable and less expensive TEP resources would be displaced in a majority of the hours. It is also imprudent to leave all of TEP's required power needs to the spot market as the prices and availability of power vary significantly.

Q: Please provide an overview of TEP's procurement proposal.

A: With the factors discussed above in mind, TEP will procure a combination of different energy products and ancillary services to meet the contestable load. Currently, TEP envisions requesting bids for fixed price firm on-peak energy, fixed price firm super-peak energy, index-priced unit contingent capacity and energy, and non-spin ancillary service capacity. While Exhibit 1 provides the estimated total contestable load, TEP will provide further details during the solicitation process as to the preferred timing, duration, and quantity of each product desired. The amount of each product contracted will vary by month and year and will be determined after a least cost analysis of the bids are complete. TEP will require all of the energy procured to be deliverable at specific locations, consistent with TEP delivery capabilities, as delineated in the RFP.

Q: Why has TEP chosen this mix of products?

A: In order to manage the risks of volatile gas and power markets, TEP has chosen a combination of fixed-price and variable-price products that can be hedged to provide a reasonably stable power supply cost to TEP and its customers. TEP has also chosen different products (on-peak, super-peak, capacity and energy, reserves) to satisfy system ramp and operational constraints as well as economic considerations. TEP may further consider, with input from Staff, leaving a small portion of the Contestable Load to be filled in the short-term and spot markets with non-affiliated third parties.

Q: What is the timing of TEP's planned procurement?

A: TEP is primarily focused on the 2003-2006 timeframe but may accept bids for longer term agreements. Per Staff's current proposed timeline, deliveries will start by June 1, 2003.

Exhibit 1

TEP CONTESTABLE LOAD

Exhibit 2

TEP'S CONTESTABLE LOAD WITHOUT TWO NEWEST RMR CTS

Exhibit 1. TEP Contestable Load

Includes Two Newest RMR CTs in TEP's Existing Assets

	2003	2004	2005	2006
Capacity (MW)	147	214	346	393
Energy (GWh)	14	14	57	58

Includes Firm Wholesale Contracts as Load

Exhibit 2. TEP's Contestable Load without Two Newest RMR CTs

	2003	2004	2005	2006
Energy (GWh)	50	46	120	104

Includes Firm Wholesale Contracts as Load

Exhibit 3

2003 TEP LOADS/RESOURCES PEAK DEMAND FORECAST

Exhibit 3
2003 TEP Loads/Resources Peak Demand Forecast

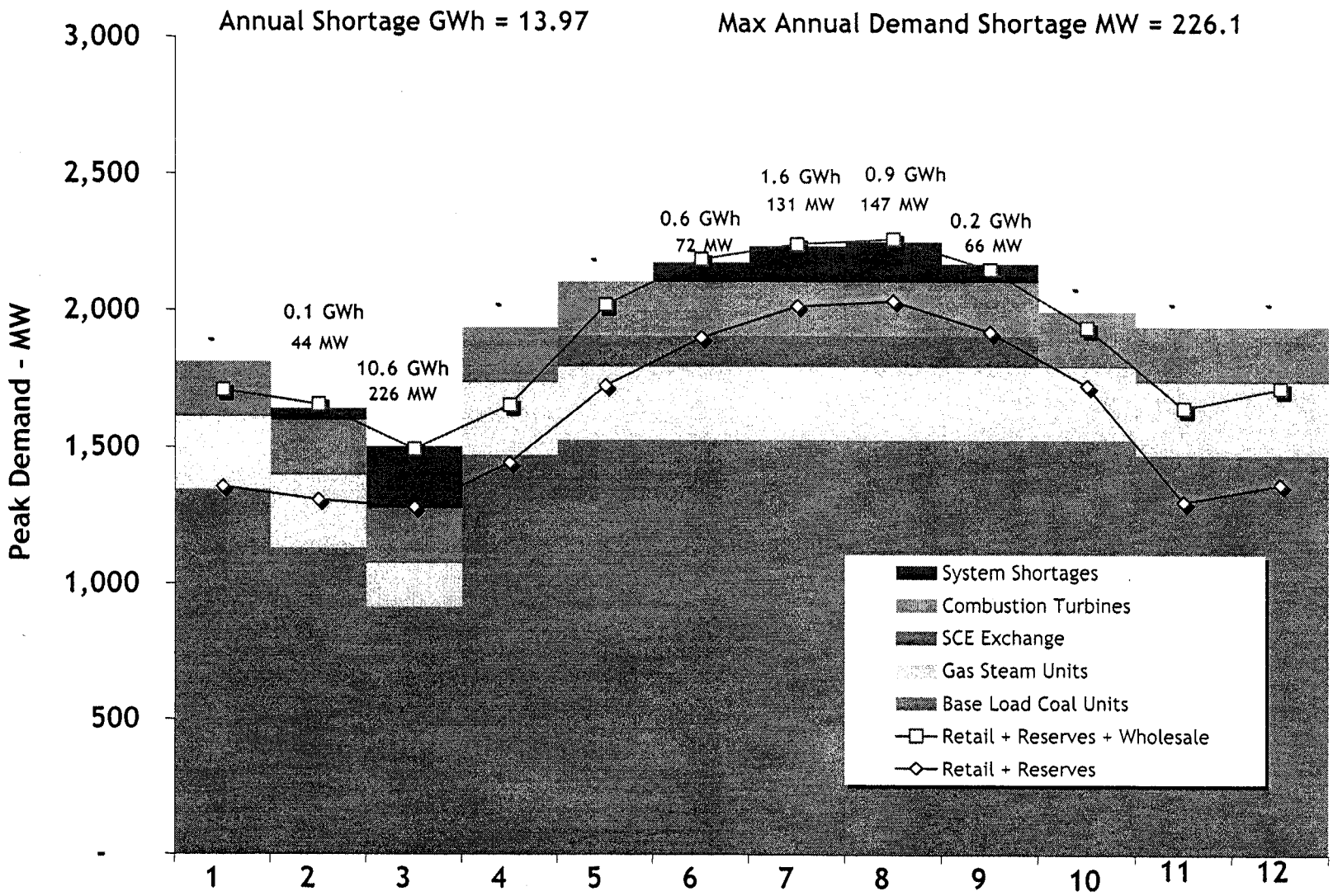

Exhibit 3 - page 2

2004 TEP Loads/Resources Peak Demand Forecast

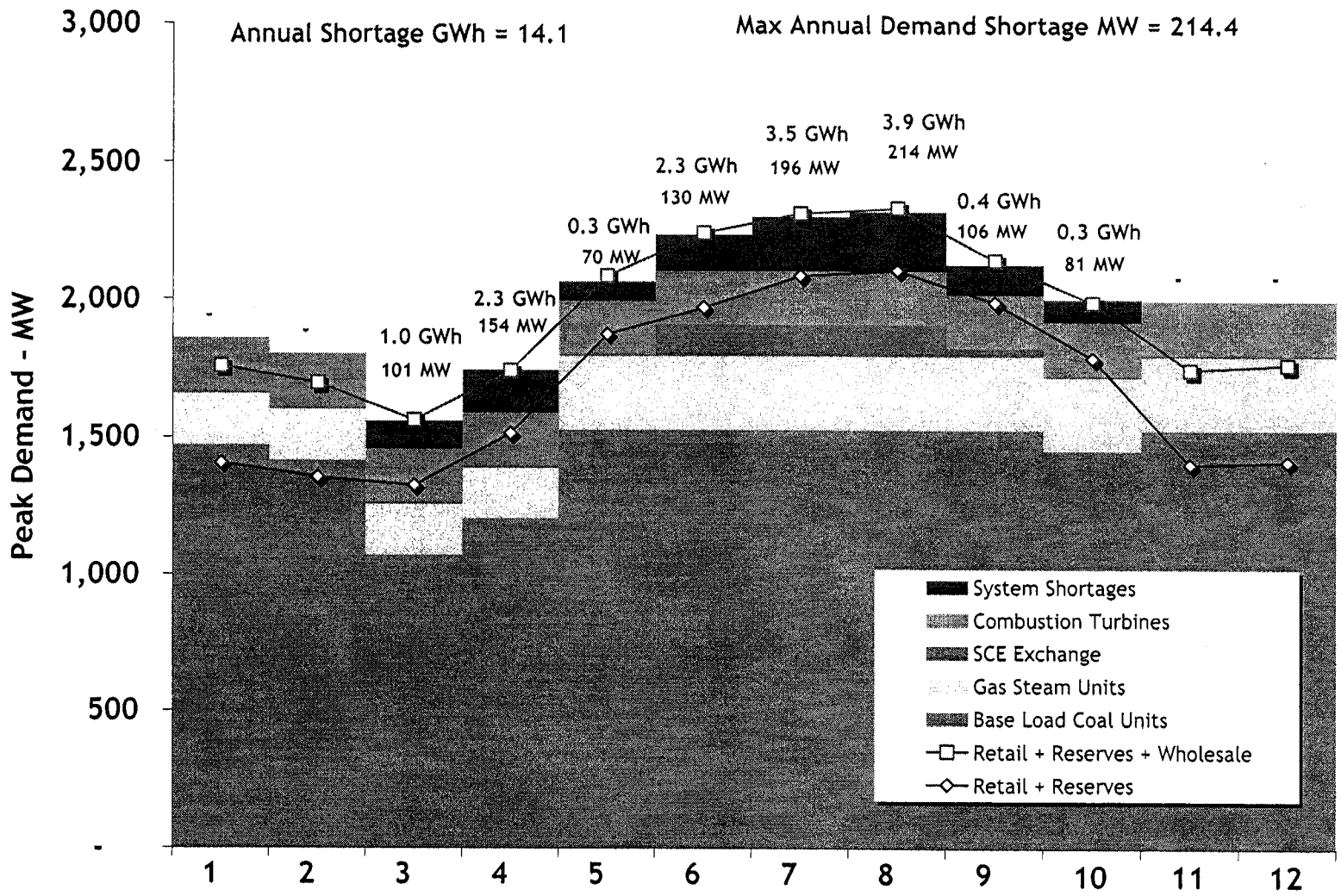

Exhibit 3 - page 3

2005 TEP Loads/Resources Peak Demand Forecast

Annual Shortage GWh = 57.1 Max Annual Demand Shortage MW = 345.6

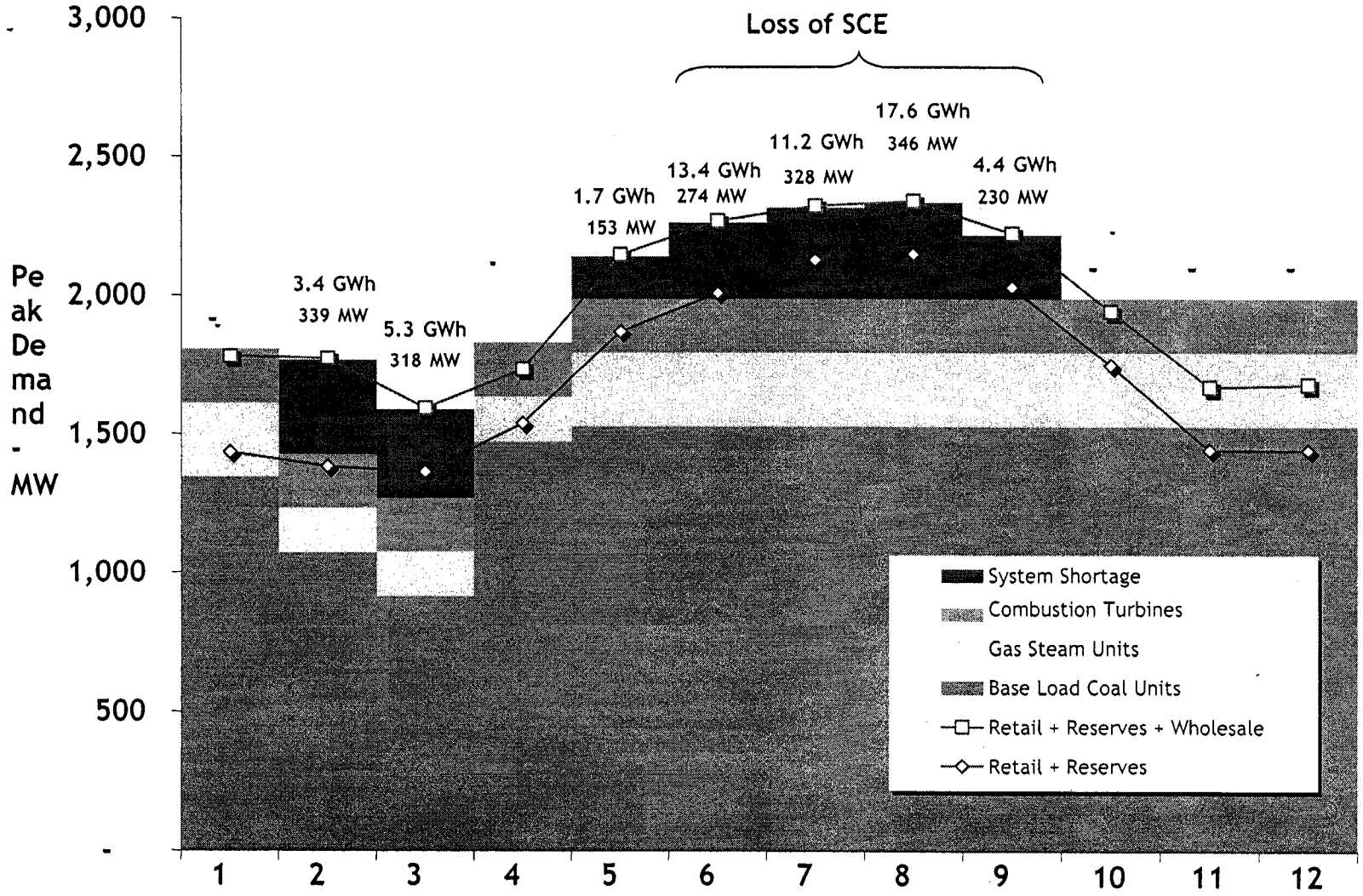

Exhibit 3 - page 4

2006 TEP Loads/Resources Peak Demand Forecast

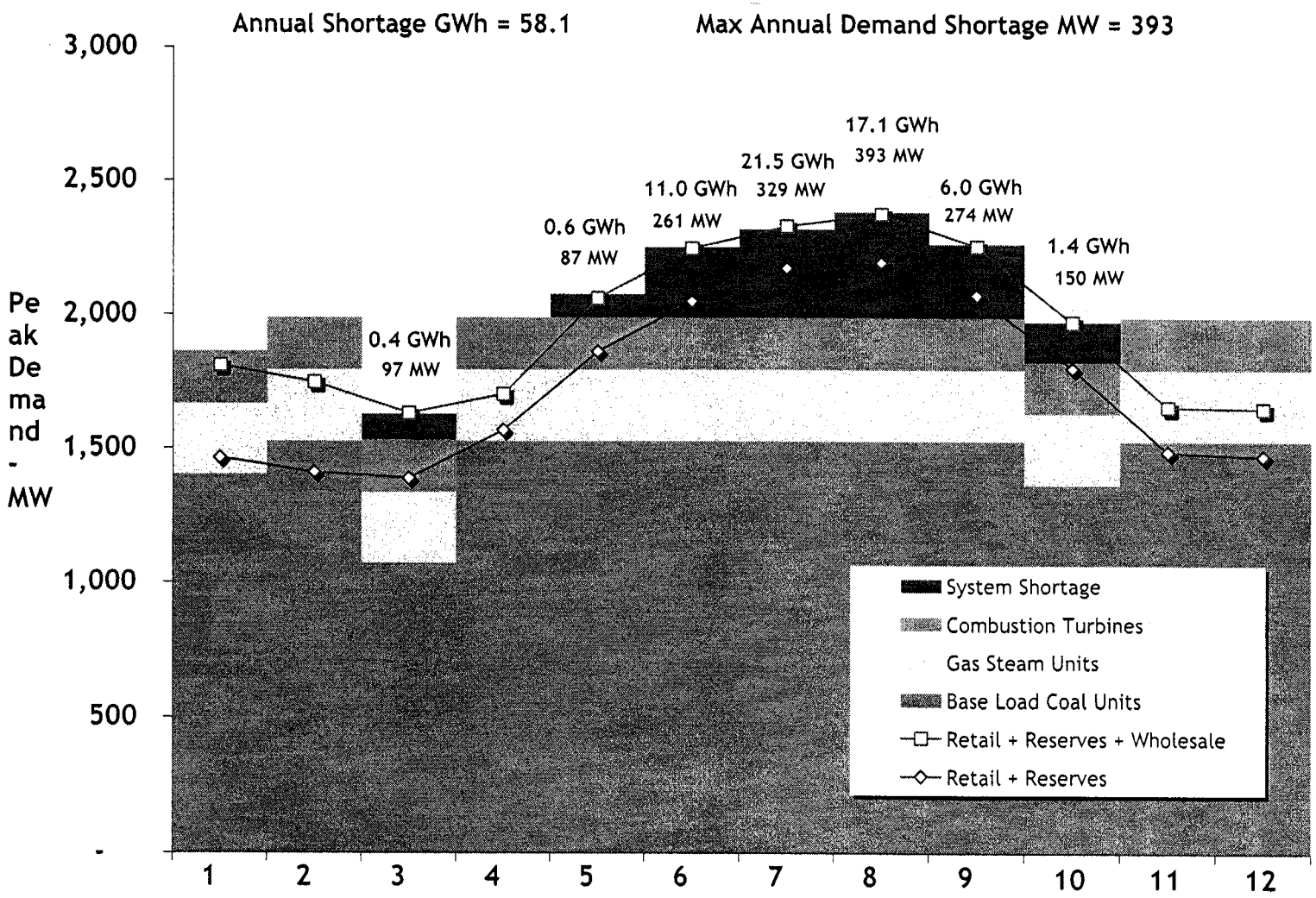

Exhibit 4

TEP RESOURCE INFORMATION

Exhibit 4. TEP Resource Information

2002 Generation Capacity	Capacity* (MW)	Unit Type
FOUR CORNERS 4	55.0	Coal Steam
FOUR CORNERS 5	55.0	Coal Steam
NAVAJO 1	56.3	Coal Steam
NAVAJO 2	56.3	Coal Steam
NAVAJO 3	56.3	Coal Steam
SAN JUAN 1	163.5	Coal Steam
SAN JUAN 2	158.0	Coal Steam
SPRINGERVILLE 1	400.0	Coal Steam
SPRINGERVILLE 2	400.0	Coal Steam
IRVINGTON 1	81.0	Gas Steam
IRVINGTON 2	80.5	Gas Steam
IRVINGTON 3	104.5	Gas Steam
IRVINGTON 4	125.0	Coal Steam
DEMOSS 1	67.5	Gas Turbine
NORTHLOOP CT 1	22.5	Gas Turbine
NORTHLOOP CT 2	22.1	Gas Turbine
NORTHLOOP CT 3	21.1	Gas Turbine
NORTHLOOP CT 4	18.9	Gas Turbine
IRVINGTON CT 1	21.5	Gas Turbine
IRVINGTON CT 2	22.1	Gas Turbine
Total Thermal Capacity	**1,987**	
SCE Exchange	110	Contract
Total Existing Capacity	**2,097**	

*Units based on operating capacities which account for spinning reserves and summer derations

2003 Peak Capacity	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Base Load Coal Units	1,344	1,130	911	1,469	1,525	1,525	1,525	1,525	1,525	1,525	1,470	1,470
Gas Steam Units	266	266	162	266	266	266	266	266	266	266	266	266
Combustion Turbines	196	196	196	196	196	196	196	196	196	196	196	196
Total Thermal	1,806	1,591	1,269	1,931	1,987	1,987	1,987	1,987	1,987	1,987	1,932	1,932
SCE					110	110	110	110	110			
Total Resources	1,806	1,591	1,269	1,931	2,097	2,097	2,097	2,097	2,097	1,987	1,932	1,932
2003 Unit Maintenance	(181)	(396)	(718)	(56)	(0)	(0)	(0)	(0)	(0)	(0)	(55)	(55)

2004 Peak Capacity	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Base Load Coal Units	1470	1414	1069	1200	1525	1525	1525	1525	1525	1361	1525	1525
Gas Steam Units	185	185	185	185	266	266	266	266	266	266	266	266
Combustion Turbines	196	196	196	196	196	196	196	196	196	196	196	196
Total Thermal	1851	1795	1450	1581	1987	1987	1987	1987	1987	1823	1987	1987
SCE					110	110	110	110	110			
Total Resources	1,851	1,795	1,450	1,581	2,097	2,097	2,097	2,097	2,097	1,823	1,987	1,987
2004 Unit Maintenance	(136)	(192)	(537)	(406)	(0)	(0)	(0)	(0)	(0)	(164)	(0)	(0)

2005 Peak Capacity	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Base Load Coal Units	1,344.00	1,069.00	911.00	1,470.25	1,525.25	1,525.25	1,525.25	1,525.25	1,525.25	1,525.25	1,525.25	1,525.25
Gas Steam Units	266.01	161.56	161.56	161.56	266.01	266.01	266.01	266.01	266.01	266.01	266.01	266.01
Combustion Turbines	195.57	195.57	195.57	195.57	195.57	195.57	195.57	195.57	195.57	195.57	195.57	195.57
Total Thermal	1806	1426	1268	1827	1987	1987	1987	1987	1987	1987	1987	1987
SCE												
Total Resources	1,806	1,426	1,268	1,827	1,987	1,987	1,987	1,987	1,987	1,987	1,987	1,987
2005 Unit Maintenance	(181)	(561)	(719)	(160)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)

2006 Peak Capacity	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Base Load Coal Units	1400.25	1525.25	1069	1525.25	1525.25	1525.25	1525.25	1525.25	1525.25	1361.75	1525.25	1525.25
Gas Steam Units	266.01	266.01	266.01	266.01	266.01	266.01	266.01	266.01	266.01	266.01	266.01	266.01
Combustion Turbines	195.57	195.57	195.57	195.57	195.57	195.57	195.57	195.57	195.57	195.57	195.57	195.57
Total Thermal	1862	1987	1531	1987	1987	1987	1987	1987	1987	1823	1987	1987
SCE												
Total Resources	1,862	1,987	1,531	1,987	1,987	1,987	1,987	1,987	1,987	1,823	1,987	1,987
2006 Unit Maintenance	(125)	(0)	(456)	(0)	(0)	(0)	(0)	(0)	(0)	(164)	(0)	(0)

Exhibit 5

TEP PEAK LOAD FORECAST DEMAND AND ENERGY

Exhibit 5. TEP Peak Load Forecast Demand and Energy

Monthly Peak Hour Demand (MW)

	2003	2004	2005	2006
JAN	1243	1286	1310	1335
FEB	1197	1238	1262	1286
MAR	1171	1211	1245	1266
APR	1329	1396	1416	1440
MAY	1608	1672	1706	1732
JUN	1767	1828	1864	1899
JUL	1880	1945	1982	2020
AUG	1890	1956	1993	2030
SEP	1789	1851	1886	1922
OCT	1601	1659	1631	1662
NOV	1187	1285	1307	1330
DEC	1248	1291	1316	1341
	1890	1956	1993	2030

Monthly Energy (GWh)

	2003	2004	2005	2006
JAN	661,188	694,640	728,308	766,668
FEB	576,735	614,267	627,459	647,917
MAR	617,950	645,161	667,976	715,979
APR	638,802	673,869	706,708	746,078
MAY	771,773	815,383	868,221	876,957
JUN	871,349	906,798	941,880	969,838
JUL	950,094	982,688	1,005,867	1,074,212
AUG	947,601	1,003,553	1,034,003	1,102,624
SEP	866,374	914,562	939,017	975,379
OCT	718,887	749,971	781,981	844,378
NOV	622,034	651,401	670,174	708,817
DEC	667,700	698,771	740,352	769,008
	8,910,485	9,351,063	9,711,946	10,197,855

Note: Includes Retail & Wholesale load

EXHIBIT
TEP-2
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	Docket No. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. 4-14-2-1606	Docket No. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR	Docket No. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC POWER COMPETITION RULES COMPLIANCE DATES	Docket No. E-01933A-98-0471
ISSUES IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES	Docket No. E01933A-02-0069

DIRECT TESTIMONY OF DAVID HUTCHENS

ON BEHALF OF

TUCSON ELECTRIC POWER COMPANY

RE: TRACK B ISSUES

NOVEMBER 12, 2002

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WITNESS BACKGROUND

Q: Please state your name and employment position.

A: My name is David Hutchens. I am Manager of Wholesale Marketing for Tucson Electric Power Company.

Q: What are your job responsibilities at Tucson Electric?

A: I oversee the Wholesale Marketing department functions, including wholesale gas and electricity procurement, resource management, risk management, marketing, scheduling and trading.

Q: What has been your involvement in the Track B proceedings?

A: I have represented TEP in every workshop and submitted testimony on TEP's needs assessment and procurement proposal.

Q: What is the purpose of your testimony?

A: Pursuant to the "Third Procedural Order on Track B Issues," in Docket E-00000A-02-0051 *et al.*, parties, including TEP, "shall file testimony and associated exhibits on the Track B issues identified by the parties" and a "response to the Staff Report" by 12:00 p.m. on November 12, 2002. This testimony will provide that information.

Q: How is your testimony structured?

A: It addresses five topics: (i) the unique circumstances concerning TEP's participation in the competitive solicitation process; (ii) comments on TEP's unresolved Track B issues; (iii) comments on Staff's Track B Report (dated October 25, 2002); (iv) TEP's comments on two Track B issues raised by other parties; and (v) TEP's key recommendations concerning modifications to the solicitation process outlined in the October 25 Staff Report.

SUMMARY

Q: Please summarize your testimony.

A: TEP's position on the proposed competitive solicitation process is driven by the unique circumstance that TEP believes deserve consideration in the solicitation process. The

two key facts underlying TEP's positions are: (i) TEP does not have any competitive affiliates that will participate in the solicitation process and (ii) the TEP retail service area faces significant transmission limitations that may affect TEP's competitive solicitation. However, although the Commission Staff's October 25, 2002 Report contains many valid conclusions that TEP fully supports, it fails to recognize TEP's unique position and places uneconomic and unnecessary requirements on TEP. Moreover, those detrimental requirements provide no benefit to other parties. TEP proposes two key modifications to Staff's solicitation proposal to remedy TEP's concerns: (i) allowing TEP's wholesale marketing department to conduct the competitive solicitation, thus avoiding the need to create a duplicate, parallel department and (ii) allowing TEP to include all TEP generation assets existing as of September 1, 2002 in the determination of TEP's Contestable Load, not just assets "included in rate base."

TEP'S UNIQUE CIRCUMSTANCES

Q: What was the overriding concern throughout the Track B workshops?

A: The majority of the workshop discussion centered around insuring that Pinnacle West would not be given any advantage over the other generators bidding into the solicitation process, particularly given that it appeared that the vast majority of available contestable load would be APS load. Thus, many of the proposed requirements that have been included in Staff's proposed solicitation process were designed to specifically address the issue of APS having an affiliate, Pinnacle West, with generation resources that would be bidding into the solicitation. However, several of those general requirements create an unnecessary burden on TEP given the difference between TEP and APS.

Q: What are the circumstances unique to TEP that should be noted in the development of the Competitive Solicitation Process?

A: There are three important, unique circumstances: (i) TEP has no affiliate involved in the marketing and trading of wholesale power; (ii) TEP has no generation affiliate that will be bidding into the 2003 solicitation; and (iii) TEP has different transmission concerns for delivery of energy to its load area.

Q: How does the absence of a TEP affiliate involved in the generation, marketing and trading of wholesale power bidding into the solicitation process affect the process design?

A: TEP understands that Decision No. 65154 seeks to increase the competitiveness of the wholesale electricity markets in Arizona by insuring all future needs are met through competitive processes. However, even without the proposed competitive solicitation process being developed in Track B, TEP currently procures all of its "required power that cannot be produced from its own existing assets"[1] from unaffiliated third parties in the wholesale market, as is now required by that Decision. Thus, TEP feels that it already meets the spirit of Decision No. 65154 pertaining to the procurement of power that cannot be produced from TEP's existing generation assets. It is only the requirement that TEP use a specific solicitation process to procure that "required power" that will create any change in TEP's resource management functions. To the extent the process is being designed to avoid unfair competitive advantage by UDC affiliates, the lack of any TEP affiliate obviates such concerns. The imposition on TEP of requirements focused on eliminating unfair advantages for affiliates simply imposes an unnecessary burden on TEP without any corresponding benefits.

Q: What specific transmission concerns exist for TEP's service area that need to be addressed?

A: All of TEP's retail load is contained within a load pocket as identified by ACC Staff in its Biennial Transmission Assessment. As such, this load can only be served through a combination of (i) remote generation brought in over existing transmission facilities and (ii) local generation resources owned and operated by TEP within the load pocket. Since the late 1970's when TEP began participation in remote generation resources to obtain economies of scale through regional resource development, as well as to reduce its dependence on oil and gas generation, TEP has planned and developed its load serving capabilities through a balanced mix of remote generation, local generation and transmission additions that would be most economical and reliable for serving its customers. That goal of achieving an optimal mix led TEP to install gas combustion

[1] ACC Decision No. 65154, p. 33.

turbines ("CTs") in 2001 to provide the required voltage support capability at peak load conditions. Under current Commission terminology these local units are referred to as Reliability Must-Run ("RMR") units. These units (and other TEP RMR units) have been considerably more cost effective than constructing a major transmission project to provide additional import capability. Moreover, constructing additional transmission facilities would have created excess transmission capacity not needed to serve the peak load. This excess capacity would be idle and provide no benefit to TEP or its customers. Further, TEP presently controls very little available transmission capacity ("ATC") to transmit power from remote interconnection points into TEP's service territory.

Q: Does the location of the new merchant generation plants provide specific challenges?

A: Yes. The majority of the new merchant plants are located where there is no Firm ATC for delivery to TEP's retail service area. Some plants are able to reach TEP's service area but require multiple wheels from transmission providers resulting in uneconomic alternatives when compared to the cost of TEP's own generating resources.

Q: How are these transmission constraints being remedied?

A: TEP is assessing options to improve import capability into TEP's retail service area. TEP is working with merchants and other utilities to define other transmission bottlenecks and using the Central Arizona Transmission Study ("CATS") process to plan additional transmission upgrades accordingly. However, this is a long-term process and the permitting and construction phases for new lines will put any line addition several years out.

COMMENTS ON TEP'S UNRESOLVED ISSUES

Q: What were TEP's unresolved issues listed in its October 1, 2002 filing?

A: TEP listed two primary unresolved issues that it would like to address. The first is the amount of TEP's Contestable load and the second is the involvement of TEP's marketing employees in the solicitation process. As more fully explained in my November 4, 2002 Needs Assessment testimony, TEP was under the impression that these issues were agreed upon by all parties participating in the workshops.

Q: If TEP felt that its contestable load was agreed to in the workshops, why did TEP list it as an unresolved issue?

A: The agreement was basically a settlement of three related issues: (i) the inclusion of TEP's new RMR CTs in its existing assets; (ii) the inclusion of TEP's wholesale load in its contestable load calculation; and (iii) the ability of TEP's Wholesale Marketing department to conduct TEP's solicitation. TEP listed the issue as unresolved in order to be able to address the issue in front of the Commission in the event that resolution of any of the three terms changed. As noted in my November 4, 2002 testimony, Staff's report reversed the resolution of two of the three issues leaving only the inclusion of TEP's wholesale load intact.

Q: Why does TEP request that its Wholesale Marketing department be allowed to conduct the solicitation?

A: As discussed in my November 4, 2002 testimony, in light of the absence of any TEP affiliate that could be involved in the process and the fact that the TEP procurement functions currently fall into this group's purview, the requirement to prohibit this group from participating would disadvantage TEP and impose an uneconomic and unnecessary consequence on TEP.

Q: How would this disadvantage TEP and impose such burdens?

A: TEP's Wholesale Marketing department manages TEP's load and resources. In that capacity, it performs the procurement of electricity and fuel by evaluating the operational and economic terms of such procurement. While at times the economic evaluation can be fairly straightforward, it often involves complex products that require detailed modeling and market analysis. Further, the operational requirements of TEP's load and resources require detailed and specific knowledge. It is TEP's Wholesale Marketing department that has this knowledge and therefore the best ability to evaluate TEP's needs and assess the solicitation options. If TEP must use others for this evaluation, TEP would lose this critical knowledge and would incur increased (and unnecessary) costs by creating a duplicate department that would be conducting the same analyses and tasks. Given the lack of any TEP affiliate, the apparent prohibition on TEP's Wholesale Marketing

department provides no benefit to the process whatsoever and makes no sense. It should be noted that no party to the workshops contested TEP's recommendation that its wholesale group be allowed to conduct the solicitation process. Indeed, it appeared that the recommendation was unanimously agreed upon.

Q: How does this change on the role of TEP's Wholesale Marketing department affect TEP's position on its amount of Contestable Load?

A: If the other two issues are resolved to TEP's satisfaction – specifically that TEP's two newest RMR CTs are included in its existing assets and TEP's Wholesale Marketing department can conduct the solicitation – TEP will continue to include its wholesale load in calculating its contestable load and commit to the capacity and energy quantities provided in the workshops. Absent a favorable resolution of these issues for TEP, TEP will take the position that its unmet needs should not be calculated including FERC jurisdictional Market-Based Tariff Wholesale Agreements.

Q: Does the inclusion of TEP's wholesale load in calculating its unmet needs infer any future rate-making treatment of the energy purchased in the solicitation?

A: No. The inclusion of the wholesale load was discussed in the workshops as a way to address the existence of TEP wholesale contracts and to provide TEP with some amount of load to bid in the solicitation process. Even though the wholesale load is under TEP's market-based tariff – and *not* under a cost of service tariff – it was Staff's position that if TEP did not include its wholesale load, Staff would contend that an equal amount of TEP's existing generation assets should be set aside and not included in calculating unmet needs – even though Decision No. 65154 contemplated that such assets should be included in the contestable load calculation. The resulting unmet need is the same regardless of whether wholesale load is included or an equal amount of existing generation is excluded. In a spirit of compromise and for ease of computation, TEP agreed to the inclusion of wholesale load. The fact that TEP's market-based wholesale contracts were not moved to an affiliate should not unfairly disadvantage TEP.

Q: Does the inclusion of TEP's wholesale load in calculating its unmet needs infer the inclusion of this or new wholesale load in future solicitations?

A: No. Its inclusion would represent a settlement for the 2003 solicitation. TEP has to be able to manage its wholesale business under traditional jurisdictional processes. Specifically, it cannot effectively manage its wholesale business if it is saddled with additional, non-jurisdictional procurement requirements. TEP further understands Staff's position that this process will most likely change and evolve before the next solicitation is undertaken.

COMMENTS ON STAFF REPORT

Q: What are TEP's comments on the October 25, 2002 Staff Report in this docket?

A: TEP generally agrees with the solicitation process set forth in that report. TEP has already expressed its disagreements on the Staff's position concerning TEP's contestable load and the exclusion of TEP's Wholesale Marketing department from the solicitation process, both above and in my November 4, 2002 testimony in this docket. I will not repeat all of TEP's position here. However, there are a few additional portions of the Staff Report that TEP would like to address further.

Q: Should utilities be given the latitude to reject any or all bids in the solicitation process?

A: Yes. The purchasing utilities must be given the flexibility to reject any or all bids that do not meet its economic or reliability criteria. Without such ability, the utility would be put at a grave disadvantage to the bidders. The Staff agrees: "The solicitation materials will contain the terms and conditions proposed by the utility, including the right of the utility to reject all bids and to amend the request for service without notice" [October 25, 2000 Staff Report, p. 16:14], as does APS [Testimony of Thomas Carlson (dated November 4, 2002), pp. 10:13, 15:22].

Q: Does TEP agree with Staff's position on p. 4:16 that the "process itself had to be flexible enough to allow purchasing utilities and selling merchants the latitude to structure the terms and conditions under which service would be provided in a manner that made economic, operational and regulatory sense"?

A: Yes. TEP strongly agrees with this explicit statement made by Staff and Staff's position throughout the workshop process that the solicitation would not impose uneconomic requirements on the utilities.

Q: Does the current structure of the solicitation process in Staff's report provide the flexibility and latitude referenced?

A: For the most part it does. TEP agrees with the general structure and direction of the solicitation process defined in Staff's report but feels that the requirement that all its unmet needs be met through one particular process at one instance in time unnecessarily removes some of that flexibility and management's business discretion.

Q: What is TEP's position on Staff's recommendation [p. 4:25] that "short-term power and daily, weekly or monthly power acquired to meet unplanned needs, would however continue to be purchased in the normal course of business as it is today"?

A: TEP strongly agrees with this position. It is an obvious necessity that the utility be afforded discretion to enter into short-term transactions. As Staff recognizes, this gives the utility the opportunity to economically displace plant or contract energy with cheaper market power or purchase to cover unplanned needs arising from temperature extremes and unplanned generation or transmission outages without jeopardizing system reliability by being unnecessarily burdened with a cumbersome procurement process. It is again important to point out that any such purchase that TEP would make in this timeframe would be from unaffiliated third parties.

Q: Does TEP agree with Staff's "Scope of 2003 Solicitation" on p. 6 of the Staff Report?

A: No. Staff has defined contestable load (*i.e.*, the amount to be bid in the solicitation) as "all load and energy requirements not served by generation owned by the utility and included in the utility's rate base as of September 1, 2002" or by "power supplied pursuant to FERC or Commission approved contracts."[2] In the workshops, Staff and the other parties explicitly agreed to TEP's recommendation to modify this phrase from Staff's draft report to include generation leased by the utility and to strike the reference to

[2] October 25, 2002 Staff Report, p. 6.

rate base. The result was defining the contestable load as "all load and energy requirements not served by generation owned or leased by the utility as of September 1, 2002" or by "power supplied pursuant to FERC or Commission approved contracts." TEP believes that revision meets the letter of Decision No. 65154 and should be adopted by the Commission.

Q: What is TEP's view of Staff's recommended "Price to Beat?

A: TEP recognizes that the desired result is an expedited prudency review given that contracts entered into are priced below this metric. While TEP believes that the recommended structure may deter long-term contracts by requiring an additional discount to the price to beat, this issue has been somewhat mitigated by Staff's recognition that contracts which do not meet the price to beat standards "will not automatically be viewed by Staff as unreasonable or imprudent" but rather require that they "will need to be evaluated by Staff in subsequent proceedings." [October 25, 2002 Staff Report, p. 26:9-12]

Q: What is TEP's position on Qualifying Facility ("QF") contracts not being subject to competitive solicitation?

A: Again, this was discussed, albeit briefly, in one of the workshops. It was mentioned that a very large merchant generation project had filed for QF status and the parties present at the workshop generally agreed that QF contracts started after September 1, 2002 would be subject to the competitive solicitation process. However, TEP understands that Staff may not have wanted this to be such a general and exclusive requirement given that other, legitimate QFs may surface in the future which should be excluded from the competitive bid process. Given that Staff and the Commission have ultimate oversight over both the QF and Solicitation processes, TEP is comfortable with the language in Staff's Report.

Q: What are TEP's views of the process timeline?

A: The timeline is aggressive given the number of responsibilities and obligations placed on the utilities. TEP recognizes this and has already started to collect its data and set up a solicitation website so that it can provide information to bidders – as early as possible and solicit input on contract structure, product definition, etc. It is imperative that all the

parties to the process work together to insure timely collection and dissemination of data to be able to meet the deadlines set in Staff's proposal.

Q: Is an independent monitor needed for TEP's solicitation?

A: While TEP recognizes that Staff and other parties may desire an independent monitor to assist them in evaluating the bids and insure the integrity of the process, this comes at the cost of a bid fee. Given TEP's unique circumstances discussed above regarding the lack of an affiliate – and if Staff and the other parties agree – TEP believes that the bidding fee and monitor requirement could be waived for bids to TEP.

Q: How are the contracts entered into in this solicitation treated in future solicitations?

A: The Staff report is silent on this issue but TEP believes that it must be explicitly stated and understood that any contract entered into in this solicitation process would be considered an existing asset and therefore not be contestable in later solicitations if it has not expired.

COMMENTS ON OTHER PARTIES' UNRESOLVED ISSUES

Q: Does TEP have any comments on unresolved issues raised by other parties?

A: Yes, there are a couple of key issues that TEP would like to address at this point.

Q: Should bids be selected on a least-cost basis and include longer term bids in the process?

A: Yes. However, in order to determine least-cost alternatives in a competitive bid process, it is imperative that *all* "costs" be evaluated including, but not limited to, contractual performance metrics, credit, delivery, risk management and contract remedies. Longer-term agreements should be considered, at the utility's discretion, in the process to enable necessary transmission infrastructure to be built and to insure that the output from power plants located in Arizona stays in Arizona to meet its growing demand.

Q: How should the "Commission Approval" process and cost-recovery mechanism be addressed?

A: TEP believes that the Commission approval process and cost-recovery mechanism for purchases made under the solicitation process be addressed in these hearings. It is critical

that the utility knows what the approval process will be at the beginning of the process because it will affect procurement decisions and other issues in the proceeding. The Commission approval process should provide a specific timeline for contract approval and the ability of the utility to reject accepted bids if the Commission does not find those contracts reasonable and prudent. The shorter the time period for Commission approval, the less risk premium sellers will build into their prices. The cost-recovery mechanism for all contracts entered into in the solicitation process should be clearly in the record of these proceedings and insure that the utility is afforded the opportunity to recover all costs associated with the contracts and the process.

TEP'S RECOMMENDATIONS

Q: Given TEP's position on the unresolved issues, does TEP have a recommendation that addresses its unique circumstances while still maintaining the integrity of the general proceeding in this docket?

A: Although TEP has commented on a variety of issues in this testimony, two minor modifications to the October 25, 2002 Staff Report will address TEP's primary concerns. In fact, these modifications were already agreed to in the workshop process with respect to TEP given its unique circumstances. TEP believes that it has presented compelling evidence of those circumstances and that the requested modifications are justified. Therefore, TEP recommends waivers be granted TEP for the 2003 Solicitation as follows:

1. With respect to the "Scope of 2003 Solicitation" in the Staff Report, with respect to TEP, the Commission should delete p. 6:5-18 and replace it with "For 2003, TEP's solicitation will be for all retail and wholesale load and energy requirements not served by generation owned or leased by the utility as of September 1, 2002 or by power supplied pursuant to FERC or Commission approved contracts with affiliated and non-affiliated suppliers entered into prior to September 1, 2002. To the extent that affiliated suppliers provide service pursuant to contracts dated on or after September 1, 2002, such service will be subject to competitive solicitation.

To the extent that load is served pursuant to capacity or energy contracts with Qualifying Facilities or Environmental Portfolio Standard requirements, that load will also not be contestable. All demand-side management commitments in place as of September 1, 2002, shall be considered in determining contestable load."

2. Waive the applicability of Section IV. C, paragraph 1 [lines 10-19] of the Staff Report with respect to TEP, thus allowing TEP's Wholesale Marketing department to be involved in the solicitation process.

Q: Does this conclude your testimony?

A: Yes.

EXHIBIT
TEP-3
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	Docket No. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. 4-14-2-1606	Docket No. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR	Docket No. E-00000A-01-0630
ISSUES IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES	Docket No. E01933A-02-0069

RESPONSE TESTIMONY OF DAVID HUTCHENS

ON BEHALF OF

TUCSON ELECTRIC POWER COMPANY

RE: TRACK B ISSUES

NOVEMBER 18, 2002

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WITNESS BACKGROUND

Q: Please state your name and employment position.

A: My name is David Hutchens. I am Manager of Wholesale Marketing for Tucson Electric Power Company.

Q: What are your job responsibilities at Tucson Electric?

A: I oversee the Wholesale Marketing department functions, including wholesale gas and electricity procurement, resource management, risk management, marketing, scheduling and trading.

Q: What has been your involvement in the Track B proceedings?

A: I have represented TEP in every workshop and submitted testimony on TEP's Needs Assessment and Procurement Proposal (November 4, 2002) and Track B Issues (November 12, 2002).

Q: What is the purpose of your Response Testimony?

A: The purpose of this testimony is to provide TEP's comments on November 12, 2002 testimony submitted by other parties in the Track B process and provide clarifications on TEP's previously filed Track B testimonies.

SUMMARY

Q: Please summarize your testimony.

A: Several parties have suggested modifications or additions to the initial competitive solicitation process. Some of those suggestions make sense, such as using standard industry contracts, and should be incorporated into the process as appropriate. Other suggestions would unduly complicate and prolong this initial solicitation process, such as including RMR or Environmental Portfolio needs as a part of the energy put out for bid. Further, nothing in the testimony of the other parties changes TEP's recommendations concerning the process, as set forth in my direct testimony. In fact, other parties' testimony supports TEP's two key recommendations that (i) all existing generation assets, including TEP's two newest RMR units, be included in the needs assessment and

(ii) TEP's Wholesale Marketing department be allowed to conduct the solicitation for TEP because TEP does not have an affiliate that will participate in the solicitation.

COMMENTS ON TESTIMONY BY OTHER PARTIES

RUCO (RICHARD A. ROSEN, PH.D)

Q: Do you agree with Dr. Rosen's testimony (at pp. 39-40) that longer-term contracts should be included in the solicitation?

A: Yes. It is TEP's position that longer-term contracts can, at the utility's discretion, be included in the solicitation. The inclusion of RFPs for longer-term contracts should be done only on a purely economic basis to give the utilities and ratepayers the best deal available. However, such RFPs should not be issued (or awarded) to address project financing concerns raised by other parties. [*See* Direct Testimony of Robert W. Kendall (Wellton-Mohawk), p.10] TEP believes that the Arizona utilities are not obligated to structure their RFPs to ensure the viability of existing merchant plants as a going concern – or create a favorable financing environment for proposed plants – to the detriment of the utilities' ratepayers.

Q: What is TEP's position on RUCO's least cost planning recommendations?

A: Least cost planning must play an integral role in any utility procurement process. Such planning is essential to protect both ratepayer and utility from uneconomic outcomes of a solicitation process. All costs, operational constraints and reliability parameters must be considered in that analysis to determine what truly constitutes the "least cost" option. That analysis also provides the Commission information necessary to evaluate the prudency of any procurement. Although TEP intends to evaluate solicitation bids on a least cost basis using its production modeling software systems, it also will consider other factors that can affect the acceptance of bids including counter-party risk, price assumptions and volatility, contract terms, imbedded options, and the desired portfolio structure. Even though other factors should be evaluated in the RFP process, least cost is important and Staff's involvement in the solicitation processes should insure the implementation of the least cost planning principles without the necessity of a formal integrated resource planning ("IRP") process.

Q: According to Dr. Rosen (at p. 39:12), TEP is "limiting the types of generation products that they will solicit." Does TEP intend to limit the products it will solicit?

A: While this may be inferred from TEP's initial procurement proposal, it was not TEP's intent to limit the products. The products listed in TEP's November 4, 2002 Needs Assessment and Procurement testimony were meant to be more indicative than absolute. While the products listed are likely to be included in any TEP solicitation, TEP will not preclude other products in its pre-solicitation analysis. This does not mean, however, that TEP will be soliciting for every possible product type. Rather, TEP will perform preliminary analysis of the products available in the pre-solicitation process and bid those products that meet its operational and economic requirements on a least-cost basis.

Q: What is Dr. Rosen's position regarding TEP's recommendation regarding the inclusion of TEP's two new Combustion Turbines in its existing assets for purposes of calculating unmet needs?

A: Dr. Rosen agrees (at p. 40:13) with TEP's position and "cannot understand why it would not be appropriate to include these two relatively new units in TEP's list of existing generating resources for the purposes of determining TEP's remaining capacity needs to be bid out." Thus, RUCO appears to support one of TEP's key recommendations in the Track B proceeding – that all of TEP's existing RMR generation be included in its existing assets for purposes of needs assessment.

WELLTON-MOHAWK GENERATING FACILITY (ROBERT W. KENDALL)

Q: Mr. Kendall on behalf of Wellton-Mohawk suggests (at p. 4) that "all of the load within these load pockets, including that served by the existing RMR units, should be contestable in the Track B process." Does TEP agree?

A: Absolutely not. This is an extreme suggestion given the parameters of the 2003 solicitation and the very nature of RMR. Further, it is contrary to the Commission's Track A order to "acquire, at a minimum, any required power that cannot be produced

from it own existing assets"[1] and Staff's recommendations in the Track A proceedings that "no reliability must-run ("RMR") should be divested."[2] It has been, and should remain, the utility's responsibility to ensure the reliability of its service. That responsibility includes the determination of such critical components of service as *reliability* must-run generation requirements. The very idea of another private entity controlling a jurisdictional utility's RMR generation raises issues of market power that TEP believes the Arizona energy market is not prepared to address at this time. Mr. Kendall correctly identifies (at p. 23) Staff's recommendation that the Commission should order jurisdictional utilities to resolve RMR generation concerns but Staff's recommendation, and the Commission's resulting Order, simply do not contemplate including utility-supplied RMR in the solicitation process at this time.

Q: Does TEP's position on RMR mean that TEP will not include competitive options in its future RMR needs?

A: No. What it means is that a jurisdictional utility such as TEP, subject to review by Staff and the Commission, should retain control over both the planning and operation of RMR generation. In the evaluation phase of determining future RMR options, TEP would welcome involvement of the market participants in providing options, including building RMR generation, for evaluation by TEP. In fact, when TEP was planning to build its DeMoss CT for RMR needs, TEP initially requested proposals for third party provision of RMR services. Upon review of these proposals, TEP then competitively bid a TEP owned CT project that resulted in a lower cost solution for serving its customers. If Staff and the Commission should decide that current and future RMR requirements should be supplied through a competitive solicitation process, it should be separated from the 2003 solicitation.

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[1] ACC Decision No. 65154, p. 30.

[2] Id., p.11.

Q: Why should any future RMR solicitation be performed separately from the initial 2003 solicitation?

A: At this stage of the game, including RMR obligations would greatly complicate and prolong the solicitation process to the detriment of all parties involved. From TEP's perspective, given the critical nature of RMR obligations, the competitive solicitation of RMR would involve analyzing a completely new and different set of procurement issues and would delay the 2003 process. Moreover, given TEP's unique situation where *all* of its RMR generation is owned by TEP and is located within TEP's constrained load pocket, it is highly unlikely that any third party could compete with these existing units with new generation or transmission given the Staff's apparent focus on short-term procurement for the 2003 solicitation. First, any new RMR generation (that would have to be built in the TEP load pocket absent any immediate transmission upgrades into that load pocket) or any transmission upgrades (that would allow access to RMR generation outside of the load pocket) would require a long-term planning and commitment to ensure the economic benefits. Second, any non-transmission or non-generation alternatives that might be considered as a possible RMR solution would require extensive analysis of their ability (and reliability) to meet TEP's actual RMR needs. Because of this complexity and the importance of RMR, an RFP for RMR should focus only on competing generation and transmission solutions. Any RMR solicitation focusing on third-party generation or transmission solutions would require an extensive evaluation and negotiation period that simply does not fit with the envisioned 2003 solicitation.

Q: Do you agree with Mr. Kendall's testimony (beginning at p. 16) that suggests including Environmental Portfolio (EPS) obligations in the solicitation?

A: No. TEP believes that this solicitation should focus on procuring bulk wholesale power needed to serve its customers. The inclusion of EPS in the procurement process unnecessarily complicates the process. Because a utility can meet its EPS obligations in a number of ways, including through the use of offsets and credits, it is not clear that the Commission intended its inclusion in the solicitation process by using the term "required power". As referenced in the October 25, 2002 Staff Report (at pp.32, 39) – and apparently agreed to in the workshops (although not everyone seems to agree now) – the

solicitation would not preclude bidding for EPS requirements but the initial solicitation was not the right place to decide if EPS *must* be included.

RELIANT RESOURCES, INC.
(CURTIS L. KEBLER)

Q: What is TEP's position regarding Reliant's recommendation (beginning at p. 3) for utilizing an auction process for a portion of the solicitation?

A: There are certain products for which an auction process is well-suited including standard on-peak and super-peak products that TEP is contemplating in its solicitation. TEP did not intend to preclude any specific procurement type by only listing the RFP process in its November 4, 2002 testimony. Rather, TEP believes that the auction process referenced in the Staff proposal was a complicated and limiting "descending clock" auction that would take too much time and resources to implement. For standard products that TEP solicits in the first solicitation, TEP contemplates using an abbreviated RFP process that mimics an auction. This abbreviated process would require bidders to hold their bids for just a few days or less. TEP simply does not believe it should be forced to use a specific auction format.

Q: What is Reliant's position on requiring an Affiliate Code of Conduct?

A: Mr. Kebler states (at p.13): "To the extent an affiliate of any Arizona utility wants to participate in the utility's competitive solicitation, including economy and short-term energy transactions, clearly defined firewalls should be in place to protect the competitive process".

Q: Do you agree with that statement?

A: Absolutely. It is consistent with one of TEP's two recommendations in its November 12, 2002 testimony.

Q: Would this require TEP to submit a code of conduct for the 2003 solicitation?

A: No. Because TEP will have no affiliate participating in the 2003 solicitation, a code of conduct would not, and should not, be required.

SEMPRA ENERGY RESOURCES
(E. DOUGLAS MITCHELL)

Q: Mr. Mitchell, on behalf of Sempra Energy Resources, states (at p. 10:4): "Given the stated intention of the two Arizona utilities to increase their reliance on the receipt of economy energy." Does TEP agree?

A: Absolutely not. Without making any representation for other Arizona utility and assuming he implies TEP is one of the two utilities referenced, TEP has *never* stated in this process that it plans on increasing its reliance on economy purchases. To provide some indication of TEP's forward purchases made to cover its summer peak period, I have provided the table below. It should be noted that the products purchased were standard on peak (6x16) firm (WSPP Schedule C) energy.

Summer Period (June-September)	Forward Purchase Amount (MW)
2000 and prior	0
2001	25
2002	50

Q: Mr. Mitchell suggests (at p. 11) that using certain contract forms in the bid process will help remove a risk premium associated with uncertainty. What contracts does TEP propose using for its solicitation?

A: TEP plans on using two industry-standard contracts; the WSPP contract for short-term (up-to-3-years) standard products and EEI for longer-term or non-standard products.

CONCLUSION

Q: Other than the two recommendations set forth in your Direct Testimony, what is TEP's overriding concern on the competitive solicitation process in light of the direct testimony filed by other parties?

A: TEP is concerned that the polarity of the parties to this proceeding has resulted in extreme positions regarding the economics of the new merchant-owned generators compared to the utility's existing assets. When certain assertions are presented out of context or when narrow and incomplete examples are provided (*e.g.*, neglecting the significant effects of capacity payments and transmission costs that are necessarily a part of a competitive bid), the economic reality of such comparisons is inaccurate and

misleading. TEP is committed to a solicitation process that provides economic results and will enter into purchase agreements accordingly. But TEP believes that the economic realities of non-fuel related costs remain big hurdles to this goal in the near future given TEP's location with respect to the new merchant plants that have actually been built. Moreover, a complete analysis of *all* of the costs of the delivery of energy from a new plant reveals that the "all-in cost" of a new plant delivered to TEP is much more expensive than the incremental cost to run existing TEP units.

Q: Does this conclude your testimony?

A: Yes.

Staff

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STAFF REPORT ON TRACK B:

COMPETITIVE SOLICITATION

DOCKET NOS E-00000A-02-0051 ET AL.

OCTOBER 25, 2002

STAFF REPORT

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STAFF REPORT

1. Introduction

Staff's goal is to have a transparent process that results in cost savings for ratepayers. The major benefit of a utility obtaining power through competitive solicitation is cost savings for ratepayers. Competition can help to obtain the best deal for ratepayers. However, a solicitation process needs to be designed in such a way as to ensure that benefits occur instead of pitfalls. In order to facilitate a manageable transition to a competitive wholesale power market that provides economic benefits to consumers in Arizona, the Staff believes that a transparent process, one that is equitable and auditable, needs to be established. That process must be well developed, flexible, and understood by all participants in the process. Furthermore, the process must result in reliable power being available over the long term at prices that are reasonable. Finally, all bidders prepared to provide power must be afforded the opportunity to compete for sales on equal and unbiased terms. The following pages describe a set of steps and requirements that, if adopted, will establish a process that encourages development of a wholesale market that benefits consumers.

The process described herein is intended to be used by Arizona utilities, as applicable, in the initial solicitation for competitive power to be commenced by March 2003. Subsequent solicitations may be conducted using this process. More likely, changes to the process will be recommended based on lessons learned from the initial solicitation and changes in wholesale market conditions as well as consideration of non-price factors.

2. Overview of Track B Proceeding

A. Background

On October 18, 2001, Arizona Public Service Company ("APS") filed a request for a variance to A.A.C. R-14-2-1606(B) and Approval of a Purchase Power Agreement (Docket No. E-01345A-01-0822). On January 22, 2002, by Procedural Order, a generic docket (Docket No. E-

00000A-02-0051) was opened to examine various electric restructuring issues. The Commissioners, through a series of letters requested that the parties file responses to questions regarding certain aspects of electric competition in the generic electric restructuring docket. On January 28, 2002, Tucson Electric Power Company ("TEP") filed a request for a variance to A.A.C. R-14-2-1606(B). On April 25, 2002, the Arizona Corporation Commission ("Commission") held a Special Open Meeting, at which the Commission stayed APS' Request for a Variance, and directed that certain issues be addressed in the generic electric restructuring docket. The Commission divided the issues to be addressed into two tracks, A and B. The Track A issues identified are the transfer of assets and associated market power issues, code of conduct issues, the Affiliated Interest rules, and jurisdictional issues. The Track B issue identified is the development of a competitive solicitation process.

On September 10, 2002, in Decision No. 65154 the Commission issued its decision in the Track A proceeding. In the Track A decision, the Commission stayed A.A.C. R-14-2-1606(B) which required that 100 percent of power purchased for Standard Offer Service shall be acquired from the competitive market, with at least 50 percent through competitive bid. However, the decision directed APS and TEP to acquire, at a minimum, any required power that cannot be produced from its own existing assets, through the competitive procurement process as developed in the Track B proceeding. The Decision further ordered that the amount of power, timing, and the form of procurement be determined in the Track B proceeding with the target date for a competitive solicitation process taking place by March 1, 2002.

B. Participants

The parties that have participated in one or all of the Track B workshops are: APS, TEP, Pinnacle West Capital Corporation, Panda Gila River, L.P., Reliant Resources, Inc., PG&E National Energy Group, Harquahala Generating Company, Sempra Energy Resources, Wellton Mohawk Generating Facility, Duke Energy North America, LLC, Calpine Corporation, Southwestern Power Group II, PPL Southwest Generation Holdings, LLC, PPL EnergyPlus, LLC, PPL Sundance Energy LLC, El Paso Electric, Desert Energy, Public Service Company of New Mexico, Citizens Utilities Company, Salt River Project, the Grand Canyon State Electric

Cooperative, Association, Inc., the Arizona Independent Scheduling Administrator Association, the Arizona Competitive Power Alliance, the Arizona Utilities Investors Association, Arizonans for Electric Choice in Competition, Arizona Transmission Dependent Utility Group, Arizona Clean Energy Industries Alliance, the Land and Water Fund of the Rockies, the Residential Utilities Consumer Office, NERA Economic Consulting, R.W. Beck, Inc., Industrial Power Technology, the City of Scottsdale, the City of Tucson, and Staff.

C. Collaborative Process

The workshops were conducted on July 24 and 25, 2002, August 13 and 14, 2002, and September 26 and 27, 2002. Prior to each workshop, an agenda was sent electronically to the distribution list and posted to the Utilities Division website. Staff developed a draft working paper regarding the competitive solicitation process and parties were able to provide substantive comment and make suggestions to Staff on the draft-solicitation process. A variety of issues relating to competitive bidding were raised, and through the collaborative process, the parties reached agreements in principal on several areas which are listed on page 34 of this report.

3. The Solicitation Process

A. Specific Process Goals

As more fully detailed in the following sections of this chapter, the Staff's goal in proposing this process is to facilitate a manageable transition to a competitive wholesale power market that provides economic benefits to consumers in Arizona. The proposed process has been designed to be open to all bidders, flexible, understandable by all participants in the process, and to result in reliable power being available over the long term at prices that are reasonable.

The process was developed with the view that prevailing wholesale market conditions are dynamic and that the potentially favorable conditions for buyers today are subject to potentially significant changes over time. Accordingly, the Staff has developed a process that aligns the utilities' responsibilities for providing reliable service at reasonable rates with the authority to

manage their power supply portfolios in a prudent manner. The process also preserves all of the Commission's ability to regulate the actions of its jurisdictional companies in a way that best serves the public interest.

The process described below is intended to be used by Arizona utilities, as applicable, in the initial solicitation for competitive power to be commenced by March 2003. If adopted, the Track A requirement of beginning a competitive solicitation by March 2003 will be met. Subsequent solicitations may be conducted using this process. More likely, changes to the process will be recommended based on lessons learned from the initial solicitation and to reflect changes in wholesale market conditions as well as to take into consideration non-price factors that have not been incorporated into the process at this time.

B. Assumptions Supporting the Proposed Process

Basic assumptions were developed by the Staff in preparing this proposed Solicitation Process, including the assumption that the process itself had to be flexible enough to allow purchasing utilities and selling merchants the latitude to structure the terms and conditions under which service would be provided in a manner that made economic, operational and regulatory sense, and provided benefits to all affected parties. Accordingly, the Staff has assumed that this process, if adopted, will be subject to changes based on the lessons learned during the initial solicitation conducted by the utilities during 2003. To the extent that a utility has load requirements, capacity or energy, not served by generating capacity owned by the utility or through existing contracts for capacity or energy or from sources from which the utility must purchase power as a result of law or regulation, that unmet need will be acquired through a competitive solicitation. Short-term power and daily, weekly or monthly power acquired to meet unplanned needs, would however continue to be purchased in the normal course of business as it is today.

The Staff assumed that all current regulatory standards would be maintained and that post solicitation reviews of the manner in which the solicitations were conducted and the

appropriateness of the power supplies purchased would be reviewed by the Commission at hearings to be scheduled by the Commission at such time as it deems proper.

In conducting the initial solicitation, the Staff assumed that an independent party would monitor the process to provide assurances to all parties that the process was implemented as proposed and that no bidder was afforded an undue advantage or disadvantage.

Finally, the Staff assumed that no RTO or ISO would be operational prior to July 2003 and that each utility would make available to all bidders transmission access on its system in an unbiased fashion and that each utility would cooperate with all bidders in planning and scheduling deliveries of power.

C. Alternative Approaches Considered

In developing the proposed solicitation process detailed in the following section of this report, the Staff examined numerous alternative approaches to structuring the process. Among those were proposals relating to the amount of power to be procured, restrictions on the ability of the utility or any of its affiliated companies to participate in any solicitation, the type of procurement mechanisms (e.g. auctions, RFP's, bilateral contract negotiations) to be employed and the various roles and responsibilities to be assumed by the utility, the bidders, the Staff, the Commission and other persons participating in the solicitation process. Additionally, the Staff reviewed a myriad of potential terms and conditions that could be incorporated in any solicitation.

Many of those alternatives and potential terms and conditions were presented to the participants in the Track B workshops for their comments and input. The testing of the alternative approaches considered by the Staff and the terms and conditions reviewed has resulted in a significant narrowing of the issues that initially existed between the parties to Track B and has in the opinion of the Staff significantly contributed to the quality of the proposed process. In the following section of this Report the Staff presents the detailed proposed Solicitation Process it believes will best serve to meet the goals it set out above.

D. Detailed Staff Proposed Solicitation Process

I. Scope Of 2003 Solicitation

For 2003, the solicitation will be for all load and energy requirements not served by generation owned by the utility and included in the utility's rate base as of September 1, 2002, except to the extent that such generation is providing RMR service during RMR hours or by power supplied pursuant to FERC or Commission approved contracts with affiliated and non-affiliated suppliers entered into prior to September 1, 2002. To the extent that affiliated suppliers provide service pursuant to contracts dated on or after September 1, 2002, such service will be subject to competitive solicitation except to the extent that such contract is to provide RMR service during RMR hours. To the extent that load is served pursuant to capacity or energy contracts with Qualifying Facilities or Environmental Portfolio Standard requirements, that load will also not be contestable. Any generation capacity owned by a utility that has not been included in the utility's rate base may be bid by the utility in the initial solicitation on the same terms and conditions as all other bidders, including affiliated bidders. All demand-side management commitments in place as of September 1, 2002, shall be considered in determining contestable load.

For solicitations during 2003, each utility may contract for energy and capacity deliveries for differing time periods in order to test the efficiency of this process for acquiring short-term, medium-term and long-term contracts. While it is anticipated that during 2003 each utility will primarily require peaking capacity and energy with contract terms of one to three years, if, in the judgment of the utility, market conditions or economic opportunities dictate contract terms longer than three years, it will be the responsibility of the utility to enter into such contracts as are reasonable. For resource planning purposes each utility must demonstrate that its power supply portfolio contract durations are adequately diversified and that its portfolio's structure mitigates both cost and reliability risks appropriately.

Based on information available at this time, contestable loads for each utility for each year through 2006 are estimated to be:

CAPACITY (MW)

	2003	2004	2005	2006
APS[1]	1951	2289	2628	2898
TEP[2]	242	309	441	488

ENERGY (MWH)

	2003	2004	2005	2006
APS[3]	6,566,910	7,704,591	8,845,638	9,754,436
TEP[4]	345,300	345,460	388,460	389,460

The above capacity numbers for APS were provided by APS at the August workshop and were used by Staff to derive the energy numbers. Staff was subsequently informed by APS that the numbers provided at the August workshop required revision. In response to a data request from Staff, APS provided revised capacity and energy numbers on October 23, 2002. Staff has not had time to review and analyze these numbers for inclusion in the Staff report by the October 25, 2002 publication date. APS' response to Staff's data request is included in this report as Appendix Two.

II. Roles & Responsibilities

A. Utility

[1] Source: From data provided by APS at the August Workshop.
[2] Source: From data provided by TEP at the August Workshop, plus 95 MW of combustion turbines that are not presently in rate base.
[3] Assumes 38.6% average annual load factor for all contestable capacity.
[4] From August data provided by TEP plus 95 MW combustion turbines at 40% average annual load factor.

Absent evidence of abuse, the utility will be responsible for preparing the solicitation and conducting the solicitation process. Acquisition of energy and capacity to meet the needs of customers remains the responsibility of the utility, and the utility shall use accepted business standards for acquiring these resources, as it does when it buys all other products used in providing service.

B. Bidders

In order for the Solicitation to attract wide participation, the process must be accepted as fair, open and transparent. To achieve this, prospective bidders, and interested persons who agree to keep certain information confidential, will have the opportunity to review supporting data and draft documents in advance of the solicitation being distributed to bidders. All bidders and other interested persons may provide comments to the utility, the Independent Monitor or the Staff regarding the completeness or quality of the information provided. Bidders and interested parties may also provide comments to the utility, the Independent Monitor or the Staff regarding the process being employed or the decisions made regarding execution of the solicitation process.

All bidders will be required to consent to use appropriate alternative dispute resolution practices, specified by the utility and fully disclosed in the Solicitation materials if a dispute arises.

Each bidder must agree to permit the Commission Staff to inspect any generating facility the bidder owns or controls from which it proposes to provide capacity or energy to any Arizona utility pursuant to any contract awarded as a result of this solicitation.

1. Access to data

Bidders will have the opportunity to review non-restricted information used by the utility in preparation for the solicitation, as well as draft solicitation materials, before the solicitation is released. Bidders may provide comments to the Staff and the Independent Monitor regarding the materials at any time before the bidders' conference.

2. Opportunities to contribute & review

One or more bidders' conferences will be held so that all interested parties will have the opportunity to ask questions directly of the utility as well as to identify any deficiencies in the solicitation documents or supporting data. The bidders' conference will be held at least 10 days before the release of the solicitation.

Each utility shall schedule at least one bidders' conference prior to the distribution of its solicitation materials in final form to answer questions and to receive comments and suggestions regarding the materials to be distributed from interested persons. The first bidders' conference must occur no later than February 15, 2003.

Bidders will be invited to review non-proprietary materials produced by the utility and to address comments or inquiries to the utility, Staff or the Independent Monitor regarding those materials at any time between the release of reports, plans or drafts and the conclusion of the bidders' conference.

C. Independent Monitor

1. Overview

To assist the Staff and to assure all parties to the Solicitation for power supplies that the process employed is conducted in a transparent, effective, efficient and equitable manner, an Independent Monitor will be appointed by the Staff of the Commission to oversee the conduct of the Solicitation. The Independent Monitor will be selected by the Staff and will work at the Staff's direction. Any person expecting to participate in the solicitation process may suggest to the Staff any individual to serve as the Independent Monitor. The utility will retain the Independent Monitor selected by the Staff and will be responsible for all related costs. The Independent Monitor shall submit all invoices to the Staff for review. The Staff shall forward the invoices to the utility with a recommendation as to payment.

The Independent Monitor will be responsible for:

- monitoring all communications regarding the solicitation by and among the utility and any bidders or potential bidders;
- evaluating the adequacy, accuracy and completeness of all solicitation materials, and the quality of the evaluations conducted;
- monitoring any negotiations conducted by the utility and any bidder;
- assisting the Staff in developing the "prices to beat" and such other tasks as required;
- advising the Staff and the utility of any issue affecting the integrity of the solicitation process and providing the utility an opportunity to remedy the defect identified;
- periodically submitting status reports to the Commission and the Staff on the solicitation being conducted, noting any deficiencies identified in the preparation of solicitation materials, maintenance of records, communications with bidders, or in evaluating or selecting bids;
- advising the Commission and the Staff of significant unresolved issues as they arise;
- after bids have been selected, preparing and submitting a report to the Commission detailing the Independent Monitor's observations and findings relating to the conduct of the solicitation and any recommendations for improvements of the solicitation process employed in the initial solicitation; and
- making all written status reports and the final reports to the Commission available to any person having an interest in the solicitation.

The Independent Monitor shall have full access to all materials used in or relating to the Solicitation. The utility shall make its personnel available for consultation with the Independent Monitor as requested. The Independent Monitor shall attend, in person or telephonically, any negotiations conducted with bidders.

Following the bidders conferences and before the distribution of the solicitation materials, the Independent Monitor shall submit a status report to the Commission and the Staff noting any unresolved issues that could impair the equity or appropriateness of the solicitation process.

2. Post Selection Requirements

Subsequent to the final bid selections and prior to announcing the selection of winning bids, the utility shall meet with the Staff and the Independent Monitor to review its bid evaluations and to explain the basis for its selections. Within 3 days of the selection of winning bids, the Independent Monitor will file with the Commission a status report identifying the winning bids and outlining any deficiencies noted in the solicitation process.

The Independent Monitor will also file with the Commission a report on the fairness and effectiveness of the solicitation within 14 days of the selection of winning bids. In that report, the Independent Monitor will describe the process employed and will evaluate the utilities' conformity with the process requirements. If the Independent Monitor finds that the utility unfairly or erroneously conducted the solicitation, the report should so state. If the Independent Monitor believes that the selection process was flawed, the report submitted should detail the Independent Monitor's basis for such belief.

D. Staff

Throughout the solicitation process, the Staff and Independent Monitor will review data, review draft solicitation materials, and monitor the solicitation process. The Staff will observe the solicitation process, but will not approve any action or certify any aspect of the solicitation activities. If any disagreement concerning the solicitation occurs, the Staff or the Independent Monitor will promptly notify the utility of its concern and discuss the matter with the utility.

The Staff, in conjunction with the Independent Monitor, will be responsible for reviewing the resource plans, the price and cost forecasts, and the network transmission assessment to encourage the utility to develop comprehensive supporting data, and advise the Commission should the utility fail to address the information needs of the solicitation process. Also, the Staff

and the Independent Monitor will review forecast data provided by interested parties and compare it to the forecasts provided by the utility when assessing the system needs.

E. Commission

The Commission may upon request of the Independent Monitor or at such time or times as it deems appropriate, suspend or terminate the Solicitation in order to remedy any defect in the solicitation process identified by the Independent Monitor. The Commission may order the utility conducting the Solicitation to make changes to the solicitation process it deems necessary to promote effectiveness, reasonableness, and fairness.

In the event that the Independent Monitor finds that the utility failed to conduct the solicitation in an equitable manner, the Commission, after notice and hearing, may, among other things, disallow the recovery of costs of power incurred pursuant to contracts entered as a result of this Solicitation as well as the costs of conducting the solicitation or bar any bidder inequitably awarded a contract as a result of the solicitation from bidding in any subsequent solicitation. If the Commission finds that the utility failed to conduct an appropriate solicitation, it may order that a new solicitation, conducted by an independent party, be commenced forthwith.

III. Pre-Solicitation

A. Overview of process

In order to be ready to conduct a solicitation by March 1, 2003, as required by the Track A order, the utility must assemble information supporting the determination of products to be solicited and the amount of each product that is needed. The utility must be prepared to evaluate, without delay, all offers presented, including offers to deliver power to points that may differ from the utility's requested points of interconnection. The required data typically collected in the ordinary course of business will serve as the basis for all information to be provided to the Staff, Independent Monitor and bidders, though some will need to be modified to be suitable for the

solicitation. To facilitate a timely solicitation, the utility should begin assembling the necessary information without delay.

B. Data Collection

Prior to preparation of solicitation materials, supporting data shall be assembled by the utility and provided to the Staff and the Independent Monitor for their review at the earliest date practicable. These data shall include resource plans, load, price, and cost forecasts, and a network transmission assessment containing such information and in formats acceptable to the Staff, designed to facilitate the solicitation process. Once the Staff and the Independent Monitor have completed their review, the following data shall be made available to bidders expressing intent to bid and who have signed a confidentiality agreement: load forecasts, resource plans, needs assessments, and transmission assessments, as appropriate. Price and cost forecasts for power supplies and fuel costs prepared by, or available to the utility, will not be made available to bidders. Bidders may provide comments to the Staff or Independent Monitor on the quality or completeness of any information provided at any time.

In preparation for the solicitation, each utility shall prepare a list of potential bidders to whom bid materials will be sent. That list should be as expansive as is reasonable. Once assembled, that list is to be provided to the Staff and the Independent Monitor and posted on the solicitation website. Identified potential bidders are to be contacted and invited to submit a letter of intent to bid. Prospective bidders not identified by the utility will be added to the bidders list by submitting a letter of intent to bid.

C. Resource Plans

Prior to the first solicitation, each utility that will solicit power during 2003 must provide to the Staff and the Independent Monitor its current 10-year load and energy forecast and resource plan. Utility personnel must be made available to discuss the load forecast and resource plans with the Staff and the Independent Monitor.

The Resource Plan must describe all power sources currently employed to meet load including: generation owned by the utility, existing power supply contracts with affiliated and non-affiliated utilities, planned additions and retirements, contract expirations, loads to be met through the use of demand side management and contracts to satisfy the Environmental Portfolio Standard. The Resource Plan should identify RMR plants, the hours during which such plants are RMR, and the criteria employed to determine RMR. Additionally, the Resource Plan should detail the utility's planned outage schedule and any planned unavailability of power from contract suppliers. Planned reserve requirements shall also be specifically identified.

The utility will review with the Staff and the Independent Monitor the adequacy of resources committed to serve expected loads and the reliability of the resources planned to serve that load.

Based on the utility's load and energy forecast and the resource plan, the utility will develop a needs assessment. The needs assessment will be designed to identify specific capacity and energy needs and such other services and/or facilities as may be needed over the term of the load forecast.

The load forecast resource plan and needs assessment will be reviewed with the Staff and the Independent Monitor.

D. Price & Cost Forecasts

Each utility will provide to the Staff and the Independent Monitor its four-year forecast of its power supply costs from its existing power sources.

Each utility shall provide to the Staff and the Independent Monitor the forecast of fuel prices that the utility used in preparation of its power supply costs and all other fuel forecasts relied on, or reviewed by, the utility.

Additionally, each utility shall provide to the Staff and the Independent Monitor a four-year forecast of the prices of wholesale power products, including both capacity and energy products by season and time period, in Western wholesale markets for delivery in Arizona prepared by an independent source that makes such estimates available in the normal course of its

business. Each utility shall also provide to the Staff and the Independent Monitor copies of all other forecasts of the prices of wholesale power supplies in Western wholesale markets for delivery in Arizona in the possession of or reviewed by the utility. The utility shall identify the source of each such forecast, and explain the strengths and weaknesses of each of the forecasts supplied.

Potential bidders may also submit wholesale price forecasts to the Staff. Those forecasts must clearly identify the source of the forecast and all assumptions relied on in preparing the forecast.

All forecasts provided will remain confidential and will serve as the basis for certain evaluative and review purposes as are discussed later in this document. During the reviews described above, the Staff and the Independent Monitor will examine the assumptions relied on in making the forecasts and assessments presented.

E. Deliverability Qualifications

The utility must provide Staff and the Independent Monitor with a listing of each committed use of its transmission capacity for the period over which resources are to be solicited.

The utility will perform and submit for review by the Staff and the Independent Monitor a network transmission assessment of the maximum resource capacity that can be physically and reliably accommodated simultaneously at all technologically feasible interconnection and delivery points. Such transmission limitations are to be used as a guide in the evaluation of deliverability of specific combinations of bid resource capacity and energy.

Upon completion of this review, the utility will be responsible for preparing and conducting a solicitation that encourages multiple bidders to respond to the solicitation. The specifics of products to be solicited, contract terms and conditions, terms of the confidentiality agreement, and the specific solicitation mechanics to be employed will be at the discretion of the utility. In any event, the process must be designed to promote acquisition of reliable power at reasonable costs over the long term.

F. Identification of Products

Each utility shall determine the specific products it will contract for in order to maintain an appropriately structured power supply portfolio. For 2003, utilities may request bids for firm power (e.g. on-peak and off-peak, annual or seasonal, capacity and energy blocks), and unit contingent supplies, as appropriate. Additionally, to the extent required, solicitations for ancillary services including, but not limited to, load following or spinning reserves, may be undertaken. It is, anticipated that bidders will provide all ancillary services required to support their bids. If the utility provides ancillary services to any generating asset not in its rate base, the utility shall make those ancillary services available to all bidders on the same terms and at the same price as available to those assets.

In identifying the products to be contracted for, the utility will specifically define the capacity and energy sought on a time-differentiated basis and the periods for which services will be purchased. The solicitation materials will contain the terms and conditions proposed by the utility, including the right of the utility to reject all bids and to amend the request for service without notice. The solicitation materials shall include a model contract.

IV. Preparation Of Initial Solicitation

A. Overview

The materials to be provided to potential bidders shall be prepared by the utility and shall be developed in a manner that facilitates the preparation of responsive and competitive bids. The materials must be accurate and sufficiently detailed so that no bidder is afforded an undue advantage. The terms and conditions must be reasonable and commercially acceptable and must be reviewed by the Independent Monitor and the Staff.

B. Solicitation Material Content

The utility will have responsibility for preparing all solicitation materials. The materials will be prepared in a timely manner so that the Staff and the Independent Monitor will have time to review the documents and suggest changes, before they are provided to interested parties for comment.

The utility will prepare bid packages that contain a description of the specific products to be acquired, the capacity and energy to be acquired, the bidding method to be employed (e.g. Request for Proposal or Descending Clock Auction), a copy of the contract to be executed, the preferred delivery points, the evaluation criteria to be used, bid fees (if any), credit requirements, due dates and such other information as may be appropriate.

It will be the responsibility of the utility to prepare draft solicitation materials and to discuss these drafts with the Staff and the Independent Monitor prior to distributing them in draft form to potential bidders. These drafts will include but will not be limited to: the specific power supply products sought, points of delivery, a model contract and confidentiality agreement, the bid requirements, pre-qualification requirements, creditworthiness requirements, the solicitation method to be employed, information describing the utility and its forecast load, and the evaluation criteria to be used.

In the Solicitation materials the utility will describe in detail how it will conduct bidding, such as how many rounds of bids will be accepted, Descending Clock Auction procedures, etc. The utility may specify that bids must be firm and for how long bids must be open after the auction is completed. If a Request for Proposal is used, a utility may specify that bids must be valid for up to 30 days.

Price caps or auction reserve prices may be established by the utility. Any caps or auction reserve prices established must be disclosed to and discussed with the Staff and the Independent Monitor before the solicitation occurs. No limitations are to be placed on the maximum or minimum capacity or energy that any bidder may bid for or provide.

The solicitation materials will also describe the criteria to be used to select winning bids and the weighting, if any, to be placed on each criterion.

The following criteria may be used to evaluate bids:

- Delivered price
- Deliverability
- Reliability
- Creditworthiness
- The source(s) of power for unit contingent products
- System benefits
- Exceptions to bid specifications and/or model contract terms and conditions
- Other criteria as appropriate and made publicly available

The bid package prepared by the utility should specify preferred delivery points and, if available, equivalent delivery points and any incremental costs the utility will incur if bidders deliver to those equivalent delivery points. The utility shall disclose to the bidders the existence of the network transmission assessment previously provided to the Staff and the Independent Monitor, and disclose that the assessment will be used in evaluating equivalent delivery points. The solicitation materials will specify the process the utility will use to identify whether any constraints would be created on its system as a result of deliveries to any alternative delivery point, how it will estimate the cost and time required to relieve the constraint, and the costs a bidder will incur to mitigate the constraint.

The bid materials will also describe the Supplier information to be provided and the dates when such information is due. This requirement may include a demonstration of the bidder's experience in providing services and evidence of the bidder's creditworthiness. Utilities shall require bidders to provide a description of the sources of electricity they intend to use to supply service.

The bid materials will specifically describe the credit support acceptable to the utility both as to form and amount. However, bidders may provide alternative credit support arrangements

and, if equivalent to that specified, the utility must evaluate the proposal as it would a conforming bid. Equivalent credit support arrangements may include, but will not be limited to, appropriate parental or affiliate guarantees.

Bid materials will also include:

- A draft Confidentiality Agreement
- Identification of any pre-qualification requirements
- Identification of any bid fees

C. Communications

Only those employees, officers, directors or contractors of the utility or its affiliates specifically assigned by January 1, 2003, to prepare the solicitation materials or to evaluate bids received, may participate in the preparation of solicitation materials or evaluation of bids. All persons assigned to the solicitation by the utility shall be subject to a standard of conduct established for the purpose of maintaining a separation between the utility and any affiliated entity or person. Persons who work for an affiliate, parent, or part of the utility involved in the sale or marketing of resources from generating assets owned by the utility shall not participate in the solicitation preparation or evaluation of bids, or have any contact regarding the solicitation with any personnel assigned to conduct the solicitation, except on the same terms as any other bidder.

A protocol shall be established for all communications between the utility and all prospective bidders, regardless of whether they are affiliates or third party bidders. The protocol must prohibit the dissemination of any data to an affiliated person that are not provided to all other interested persons on equal terms and at the same time. The utility will identify to the Staff and the Independent Monitor, the information it proposes to restrict access to by bidders and other interested persons.

The Staff and the Independent Monitor will review all draft solicitation materials before they are released to the parties for their review.

Concurrently, the utility will establish the procedures it will employ to communicate with all potential bidders. That communications plan must be designed to maintain confidentiality and to provide equal access to information to all. All bidders, including utility affiliates, must be required to communicate with the utility on equal terms. The approach adopted must be shown to provide no undue advantage to any potential bidder.

By January 1, 2003, each utility shall establish and maintain a solicitation website as the medium for communicating with bidders prior to the bid date, except for confidential exchanges regarding pre-qualification and creditworthiness. Bidders will address all inquiries to the utility on the website. Each inquiry and the utility response thereto shall be posted so that all bidders have equal access to information. The website will also be used to provide timely access to data and other information, such as the bidders list and the form letter of intent to bid that bidders may use to be placed on the bidders list.

Pre-solicitation data shall be posted on the website as soon as it has been reviewed by Staff and the Independent Monitor but in no case less than 5 days before the last bidders' conference.

Bidder inquires to the Independent Monitor may also be addressed using the solicitation website. All bidder inquiries to the Independent Monitor and the response provided, regardless of how the inquiry is made, will be posted on the solicitation website for review by all bidders.

As part of the communications protocols established by the utility, each utility shall establish a system for logging all contacts between utility personnel and bidders and potential bidders. That protocol must, at a minimum, require recording the date and time of any conversation, whether telephonic or in person, the substance of that discussion and whether the Independent Monitor participated in the contact. The utility shall maintain copies of all e-mails exchanged between the utility and bidders or potential bidders, copies of all correspondence, and all such other communications as may occur regarding the solicitation, for the terms set forth below.

Each utility shall schedule one or more bidders' conferences to answer questions posed by potential bidders and to take comments regarding the adequacy and quality of the information

provided to bidders. All bidders' conferences must be completed at least 10 days before the release of the final bid package.

Based on the comments received, the utility, after consultation with the Staff and the Independent Monitor, shall make such changes, as it deems necessary and produce in final form its solicitation materials.

D. Pre-qualification

Participation in pre-qualification shall be a prerequisite to having a bid accepted. The utility shall begin pre-qualifying bidders at the same time it assembles the list of prospective bidders. As bidders indicate their intent to submit a bid, the utility shall provide all necessary documents to complete the pre-qualification and undertake the review of completed bidder submissions as they are received.

Bidders shall be pre-qualified for:

- Creditworthiness
- Deliverability
- Reliability
- Business reputation and experience

The utility shall notify bidders of their pre-qualification status no less than 14 days before bids are due. Any bidder that has not successfully pre-qualified by that date shall be afforded the opportunity to submit pre-qualification materials or to cure any failure to pre-qualify before the bid date.

The specific pre-qualification requirements are dependent on the products to be contracted for and will be established by the utility. Standards for pre-qualification, including minimum credit worthiness, shall be included in the solicitation materials. Information provided by bidders as part of the pre-qualification process is to be considered confidential.

E. Solicitation Cost

The cost of conducting each solicitation is a business expense to be borne by all bidders in a fair and equitable manner. To that end, bid fees of up to $10,000 per bidder will be permissible. To the extent that bid fees collected exceed the incremental expenses incurred by the utility to conduct the solicitation, such excess is to be refunded to all non-winning bidders pro rata up to the amount of the bid fee actually paid by the bidder. Any costs incurred by the utility in excess of bid fees collected may be considered in subsequent regulatory proceedings.

Any utility requiring the payment of bid fees will be responsible for their collection and, if required, the refund of any amounts collected in excess of the costs incurred in conducting the solicitation.

Once a solicitation is provided to potential bidders, the utility will employ the steps laid out in the following section (V. Conducting the Solicitation) for each type of solicitation.

V. Conducting The Solicitation

A. Overview

In conducting the solicitation, whether by Request for Proposal or Descending Clock Auction, the utility shall employ standard sets of requirements and evaluative tools, appropriate to the type of solicitation conducted.

Bid evaluation will be conducted by a team of personnel including representatives of the utility and the Independent Monitor. In evaluating bids, the utility shall use a standard set of evaluative criteria, including a single fuel forecast for each type of fuel. The utility will also determine creditworthiness and deliverability using criteria that are unbiased and allow differing means of providing risk mitigation. Final bid selections will be at the sole discretion of the utility.

During the solicitation process, the Independent Monitor will oversee the solicitation process to ensure compliance with process requirements and to assure that evaluations are

conducted in an unbiased fashion. The Staff may be present during bid evaluations and may observe the solicitation process at its discretion.

B. Bid Evaluation

Bid evaluations should be conducted in three phases. The first should be to rank order the bids by price using valuation methods that equalize volumetric and or duration differences on a price basis. In the case of a Descending Clock Auction for firm power at fixed prices, only pre-qualified bids will be rank ordered. In the case of unit contingent Requests for Proposals or for non-conforming offers, approaches to valuing the bids that determine an equivalent per MWh net present value of the cost of the bid to the utility by using approved annuity-based approaches may be employed.

Phase Two should, to the extent not determined during pre-qualification, evaluate deliverability using the network transmission assessment previously provided to the Staff and the Independent Monitor. To the extent practicable, network resource status should be assigned to appropriate bids. Network service is to be provided pursuant to each utility's OATT. Bidders may propose delivery to alternative points (i.e. points other than those specified). In such case, the utility shall determine the deliverability of the capacity and energy bid using its best efforts. If a bid imposes delivery costs on the utility, the bid price as evaluated should be adjusted to reflect those costs and a new rank order established. If the bidder is prepared to mitigate those costs at its expense, no such adjustment need be made. All assessments of alternative delivery points shall be provided to the Staff and the Independent Monitor prior to the selection of winning bids.

During Phase Three all other factors not previously considered are to be evaluated. These include evaluations of creditworthiness, experience and proposed exceptions to model contract terms and/or conditions.

To the extent necessary, the utility may conduct post bid negotiations with selected bidders to clarify bid terms or to resolve issues relating to exceptions noted in submitted bids. Additionally, the utility may conduct final negotiations with selected bidders to resolve any other

issues that may arise. All such meetings are to be attended, in person or telephonically, by the Independent Monitor to assure that no undue advantage is afforded any bidder. Based on the evaluations conducted, the utility will, after consultation with the Independent Monitor, and discussion with Staff, select the winning bids.

C. Request for Proposal Bid Evaluation Procedures

Bids in response to a Request for Proposal are confidential and are to be submitted in sealed envelopes to be opened simultaneously at the Commission in the presence of the utility's bid evaluators, assigned Staff personnel, and the Independent Monitor. RUCO may also attend. Bids submitted may not be withdrawn for up to 30 days or until rejected by the utility.

Bid evaluation will be conducted by a team of personnel including representatives of the utility and the Independent Monitor. During the evaluations, the Staff may be present. Final bid selections will be at the sole discretion of the utility.

If the utility determines that all bids submitted are to be rejected, it will notify all bidders of its decision to reject all bids within 21 days of the day bids were opened.

D. Descending Clock Auctions Bid Evaluation Procedures

All bids are confidential and must be firm until the auction has been completed. Electronically submitted bids must be secured and may not be reviewed except in the presence of the Independent Monitor. If feasible, bids will be reviewed at the offices of the Commission. The Staff and RUCO may also attend. However, no person selling or which may sell energy in competitive markets may review the bids (except of course for utility personnel assigned to the solicitation.)

E. Terms Required for Staff Recommendation

Based on the utility's forecasts of its power supply cost, the submitted forecast of wholesale power supply in Arizona, and such other information as it deems appropriate, the Staff, assisted by the Independent Monitor, shall establish "prices to beat" for each product solicited for

each utility. The "prices to beat" established by the Staff will be used for the purpose of determining whether the Staff will recommend without further analysis a finding that prices contained in any contract meeting the conditions outlined below are reasonable. For contracts not meeting the "prices to beat" conditions outlined below, the Staff will, after further analysis, make findings and recommendations relating to prudence, reasonableness and used and usefulness as appropriate in any subsequent proceedings as scheduled by the Commission.

In any subsequent proceedings to recover the cost of power purchased pursuant to contracts entered as a result of the initial solicitation, the Staff will, without further analysis, recommend the Commission find the prices contained in such contracts are reasonable if the Monitor determines the solicitation was conducted appropriately and the following conditions are met:

- For contracts with durations of three years or less, the Staff will recommend without further analysis approving contract prices when such prices in each year of the contract are less than the "prices to beat" established by the Staff and permit, at the utility's sole discretion, extension of the contract for the same number of years at comparable prices and on the same terms.
- For contracts with durations longer than three years but less than eight years, the Staff will recommend without further analysis that the Commission find the prices contained in any contract reasonable when, in each year of the contract delivery period, prices for power are less than the "prices to beat" established by the Staff pursuant to the following schedule:
    - Contracts of 4 years if contract prices are less than the "prices to beat" by 4% or more during each year
    - Contracts of 5 or 6 years if contract prices are less than the "prices to beat" by 6% or more during each year

- Contracts of 7 years if contract prices are less than the "prices to beat" by 10% or more during each year.

- For contracts not meeting the conditions outlined above, the Staff reserves the right to challenge the prudence, reasonableness or usefulness of the contract entered.

The above-described recommendations by the Staff do not constitute a finding by the Staff that any contract was prudent or that the utility's power supply portfolio was prudently structured. The Staff reserves the right to contest the reasonableness of any recommended contract on its non-price terms or the utility's portfolio in its entirety in any future proceeding. Additionally, contracts not meeting the above stated standards will not automatically be viewed by Staff as unreasonable or imprudent. The reasonableness and prudence of contracts not meeting the above criteria will need to be evaluated by Staff in subsequent proceedings.

The "prices to beat" set by the Staff will not be disclosed. After final bid selections are announced, the Staff will identify those winning bids that have met the conditions set forth above.

VI. Post Selection Requirements

Within 14 days of the selection of winning bids, the utility will submit to the Commission a detailed report on the process employed to conduct the solicitation and an explanation of the basis for selecting the winning bids. To the extent that confidential information is to be provided it should be noted.

Within 3 days of the selection of winning bids the Independent Monitor will submit a status report on the solicitation process employed by the utility to the Commission. Within 14 days of the completion of the solicitation, the Independent Monitor will submit to the Commission the report described in Section II C 2 above.

Each utility shall maintain a complete record of all materials developed for, generated during or used in conducting the solicitation for the life of the longest contract, plus 5 years. The retained records shall include, but not be limited to, reports, internal and external communications, analyses, contracts, forecasts, bids submitted, questions received from bidders

and the answers provided in response, and resource plans. These materials will be available to the Staff. To the extent that the material is not subject to a confidentiality agreement, these materials will be available to the bidders upon reasonable terms and conditions.

Sometime after the completion of each utility's initial solicitation, the Commission Staff will commence a review of the utility's power supply portfolio to examine the prudence of that utility's planning and procurement practices, and to determine the effectiveness and efficiency of the solicitation process employed.

Also, sometime after the completion of the initial solicitation, the Commission Staff will commence a proceeding to review the solicitation process described in this document and will recommend such changes to the process as may be appropriate. Any refinements will be intended to improve the process and to enhance the development of a robust wholesale energy market in Arizona. Additionally, that proceeding will address the planning for future solicitations at such time and for such amounts of capacity and energy as may be needed.

E. Solicitation Timelines

On the following pages we have presented Solicitation Timelines for the two primary solicitation methodologies discussed at the workshops: The Descending Clock Auction (as proposed by APS in its initial comments on Track B Issues) and a more traditional Request for Proposals approach to power supply acquisitions. The timelines illustrate the time periods during which various required tasks are expected to be completed in order to assure that adequate power supplies are available by July 1, 2003.

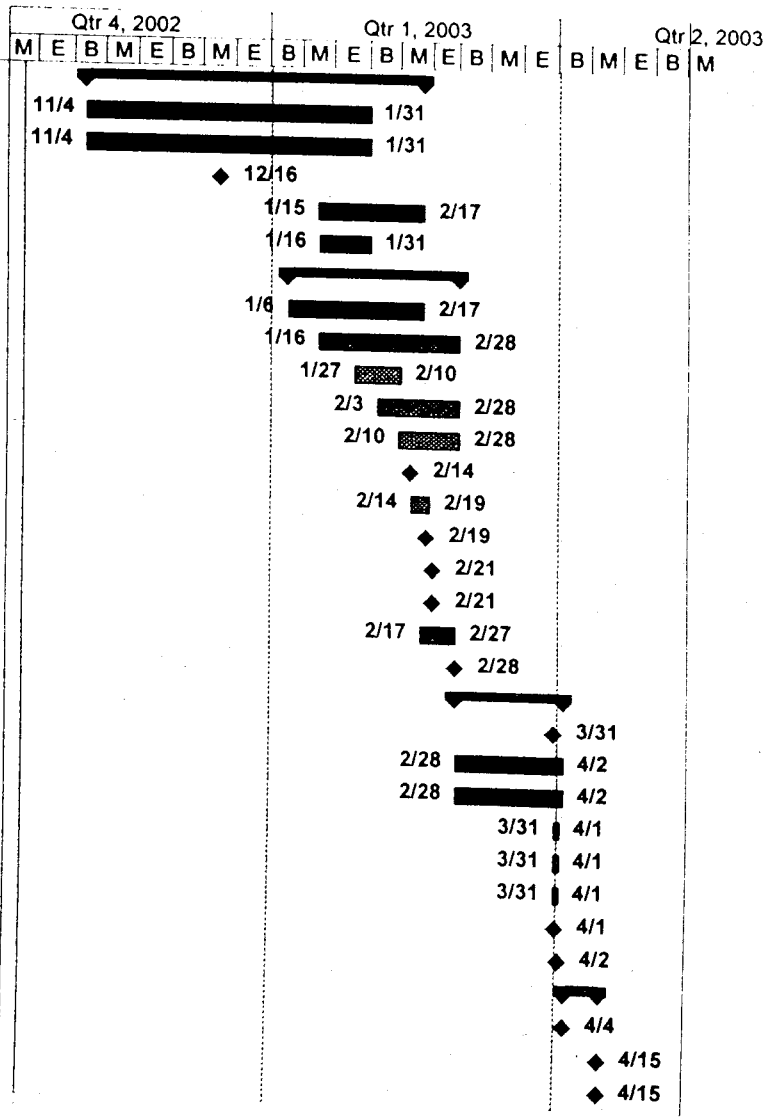
The timelines were reviewed with the workshop participants and there was a general consensus that they captured the major tasks that will need to be undertaken and that in the aggregate the tasks could be completed within the allotted timeframes.

ELAPSED TIME

Preparation – Monitor Recommendation: 67 Days
Solicitation – Selection: 32 Days

Commission STAFF SOLICITATION TIME LINE FOR DESCENDING CLOCK AUCTION

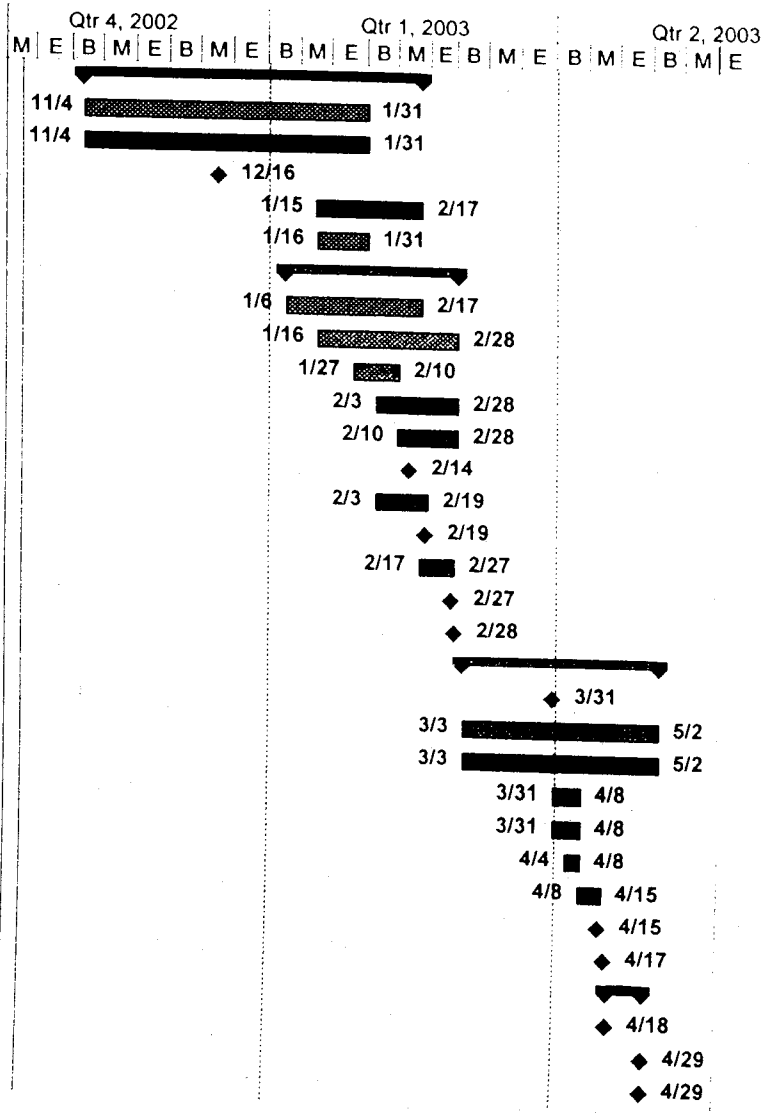
ID	Task Name	Duration	Start	Responsibilty	Finish
1	**Pre-solicitation**	**76 days**	**Mon 11/4/02**		**Mon 2/17/03**
2	Resource & cost data	65 days	Mon 11/4/02	Utility	Fri 1/31/03
3	Deliverability modeling	65 days	Mon 11/4/02	Utility	Fri 1/31/03
4	Monitor appointed	0 days	Mon 12/16/02	Staff	Mon 12/16/02
5	Staff & Monitor review	24 days	Wed 1/15/03	Staff	Mon 2/17/03
6	Identify products & bidders	12 days	Thu 1/16/03	Utility	Fri 1/31/03
7	**Solicitation Preparation**	**40 days**	**Mon 1/6/03**		**Fri 2/28/03**
8	Prepare documents	31 days	Mon 1/6/03	Utility & Monitor	Mon 2/17/03
9	Bidder Pre-qualification	32 days	Thu 1/16/03	Utility & Monitor	Fri 2/28/03
10	Establish communications	11 days	Mon 1/27/03	Utility	Mon 2/10/03
11	Pre-qualification notices	20 days	Mon 2/3/03	Utility	Fri 2/28/03
12	Staff & Monitor review	15 days	Mon 2/10/03	Monitor & Staff	Fri 2/28/03
13	Publish draft	0 days	Fri 2/14/03	Utility	Fri 2/14/03
14	Review by bidders	4 days	Fri 2/14/03	Bidders	Wed 2/19/03
15	Bidder conference	0 days	Wed 2/19/03	Utility & Bidders	Wed 2/19/03
16	Letter of intent	0 days	Fri 2/21/03	Bidders	Fri 2/21/03
17	Monitor status report	0 days	Fri 2/21/03	Monitor	Fri 2/21/03
18	Finalize documentation	9 days	Mon 2/17/03	Utility	Thu 2/27/03
19	Release solicitation	0 days	Fri 2/28/03	Utility	Fri 2/28/03
20	**Bid Evaluation**	**24 days**	**Fri 2/28/03**		**Wed 4/2/03**
21	Bids received	0 days	Mon 3/31/03	Utility & Bidders	Mon 3/31/03
22	Monitor oversight	24 days	Fri 2/28/03	Monitor	Wed 4/2/03
23	Observation by Staff	24 days	Fri 2/28/03	Staff	Wed 4/2/03
24	Evaluate prices	2 days	Mon 3/31/03	Utility & Monitor	Tue 4/1/03
25	Evaluate deliverability	2 days	Mon 3/31/03	Utility & Monitor	Tue 4/1/03
26	Post-bid negotiations	2 days	Mon 3/31/03	Utility & Monitor	Tue 4/1/03
27	Announce winners	0 days	Tue 4/1/03	Utility	Tue 4/1/03
28	Staff support identified	0 days	Wed 4/2/03	Staff	Wed 4/2/03
29	**Post-selection review**	**7 days**	**Fri 4/4/03**		**Tue 4/15/03**
30	Monitor status report	0 days	Fri 4/4/03	Monitor	Fri 4/4/03
31	UDC report	0 days	Tue 4/15/03	Utility	Tue 4/15/03
32	Monitor report	0 days	Tue 4/15/03	Monitor	Tue 4/15/03



ELAPSED TIME
Preparation – Monitor Recommendation: 82 Days
Solicitation – Selection: 45 Days

Commission STAFF SOLICITATION TIME LINE FOR REQUEST FOR PROPOSAL

ID	Task Name	Duration	Start	Responsibilty	Finish
1	**Pre-solicitation**	**76 days**	**Mon 11/4/02**		**Mon 2/17/03**
2	Resource & cost data	65 days	Mon 11/4/02	Utility	Fri 1/31/03
3	Deliverability modeling	65 days	Mon 11/4/02	Utility	Fri 1/31/03
4	Monitor appointed	0 days	Mon 12/16/02	Staff	Mon 12/16/02
5	Staff review	24 days	Wed 1/15/03	Staff	Mon 2/17/03
6	Identify products & bidders	12 days	Thu 1/16/03	Utility	Fri 1/31/03
7	**Solicitation Preparation**	**40 days**	**Mon 1/6/03**		**Fri 2/28/03**
8	Prepare documents	31 days	Mon 1/6/03	Utility & Monitor	Mon 2/17/03
9	Bidder Pre-qualification	32 days	Thu 1/16/03	Utility & Monitor	Fri 2/28/03
10	Establish communications	11 days	Mon 1/27/03	Utility	Mon 2/10/03
11	Pre-qualification notices	20 days	Mon 2/3/03	Utility	Fri 2/28/03
12	Review by Staff & Monitor	15 days	Mon 2/10/03	Monitor & Staff	Fri 2/28/03
13	Publish draft	0 days	Fri 2/14/03	Utility	Fri 2/14/03
14	Review by bidders	13 days	Mon 2/3/03	Bidders	Wed 2/19/03
15	Bidder conference	0 days	Wed 2/19/03	Utility & Bidders	Wed 2/19/03
16	Finalize documentation	9 days	Mon 2/17/03	Utility	Thu 2/27/03
17	Monitor status report	0 days	Thu 2/27/03	Monitor	Thu 2/27/03
18	Release solicitation	0 days	Fri 2/28/03	Utility	Fri 2/28/03
19	**Bid Evaluation**	**45 days**	**Mon 3/3/03**		**Fri 5/2/03**
20	Bids received	0 days	Mon 3/31/03	Utility & Bidders	Mon 3/31/03
21	Monitor oversight	45 days	Mon 3/3/03	Monitor	Fri 5/2/03
22	Observation by Staff	45 days	Mon 3/3/03	Staff	Fri 5/2/03
23	Evaluate prices	7 days	Mon 3/31/03	Utility & Monitor	Tue 4/8/03
24	Evaluate deliverability	7 days	Mon 3/31/03	Utility & Monitor	Tue 4/8/03
25	Evaluate other issues	3 days	Fri 4/4/03	Utility & Monitor	Tue 4/8/03
26	Post-bid negotiations	6 days	Tue 4/8/03	Utility & Monitor	Tue 4/15/03
27	Announce winners	0 days	Tue 4/15/03	Utility	Tue 4/15/03
28	Staff support identified	0 days	Thu 4/17/03	Staff	Thu 4/17/03
29	**Post-selection review**	**7 days**	**Fri 4/18/03**		**Tue 4/29/03**
30	Monitor status report	0 days	Fri 4/18/03	Monitor	Fri 4/18/03
31	UDC report	0 days	Tue 4/29/03	Utility	Tue 4/29/03
32	Monitor report	0 days	Tue 4/29/03	Monitor	Tue 4/29/03



4. Consensus Issues Among Parties

While there appeared to be few agreements among the participants to Track B when the workshops began in July 2002 the vast majority of the issues that separated the parties at that time were identified and discussed at the three workshops facilitated by the Staff. As a result of those discussions, only seven issues remain to be resolved by the Commission. Those issues are discussed in Section 5 of this Report.

During the workshops, the participants considered issues ranging from defining products to be solicited through defining what will indicate that the solicitation failed. In reaching consensus, the participants drew upon the experience of marketers who have participated in competitive solicitations in other states and utility personnel responsible for meeting the needs of consumers in Arizona. The Staff and its advisors directed the discussion through all necessary areas, with special attention being paid to transmission access.

On the following pages we set forth a list of the major issues considered during the workshop sessions and the agreements reached regarding those issues.

ISSUE	AGREEMENT IN PRINCIPLE
1. What is the appropriate way to structure the solicitation process?	1. Structure must be transparent 2. Structured to meet goals of: a. System reliability b. No increase in consumer risk c Reasonable prices to consumers d. Environmental standards met 3. Structure must be flexible a. Tailored to UDC b. Change over time c. Acquisition of multiple products from diverse generating sources should be encouraged. Multiple contracts from diverse suppliers are appropriate.
2. Are there power supplies that should be exempt from, or treated differently in, a competitive solicitation?	1. Exempt from competitive solicitation: a. Existing contracts b. Future QF contracts
3. What role should Least Cost Planning play in competitive markets?	1. UDC will continue to forecast load & develop supply portfolio 2. Least Cost Panning will not require self-build by UDC
4. Who should bear price risks?	1. Assigning risk to UDC increases UDC cost 2. Assigning risk to bidders will increase bid prices 3. Contract fuel adjustment mechanisms are appropriate 4. UDC will be free to seek cost recovery in future proceedings
5. Should there be a standard approach to competitive solicitations?	1. Process should accommodate all possible products 2. Same process should be used for all UDC's. 3. Load growth is contestable 4. Unmet needs are contestable 5. Contestable load will change over time 5. Affiliated suppliers may compete for load

ISSUE	AGREEMENT IN PRINCIPLE
6. How should UDC's meet the Environmental Portfolio Standards?	1. Bidders should not be required to include EPS in each bid. 2. EPS, Renewables and DSM should be permitted to bid in first solicitation, but no mandated "bonus points" awarded in review process. 3. Any EPS not acquired through this solicitation should be acquired in a separate process.
7. How should a competitively procured power supply portfolio be structured?	1. Current transmission allows some level of competitive solicitation 2. Must address load shape 4. Product diversity 5. Term diversity 6. Deliverability must be considered 7. Ancillary services are not to be solicited in the first solicitation as separate products. 8. Ancillary services should be phased in accordance with Standard Market Design 9. Slice of system should not be bid in first solicitation. 10. Slice of system should not be included in the first solicitation. 11. Unit contingent bids may be used in 2003 Solicitation 12. Bids for multiple years should be considered in 2003 Solicitation
8. What are the acceptable pricing regimes?	1. Bidders should have option to bid pricing structure. 2. UDC not required to accept a particular structure. 3. For first solicitation, UDC will use pricing structure and terms approved by Commission.
9. Does a competitive solicitation address market power concerns?	1. Market power is mitigated by permitting bidders to identify equivalent transmission points 2. Deliverability of load must be verifiable 3. No preference to transmission should be given to UDC affiliates 4. Bidders' proposed transmission path cannot displace contract load or native load. 5. Through the use of equivalent delivery points, swaps should be permitted.

ISSUE	AGREEMENT IN PRINCIPLE
10. Who can participate in the solicitation?	1. Solicitation open to all bidders.
11. Are there requirements to qualify to bid?	1. Pre-qualification of bidders should be required 2. All pre-qualification requirements should be disclosed before bidding. 3. Amount of any bid fee imposed on bidders to be disclosed before bidding. 4. Minimum qualification should be demonstration to provide creditworthiness.
12. How should bids be evaluated?	1. Evaluation criteria disclosed with solicitation: a. Draft contract b. Review process c. Specific criteria d. Bidder & product requirements to close. 2. Commission Staff and Monitor should: a. Review solicitation before issuance b. Monitor bid review by UDC c. Monitor selection process d. Review bids and final selection(s) e. Assure fairness & arms-length review
13. Failure of the solicitation	1. Solicitation will be a failure if: a. No consumer benefit b. No power contract is signed d. Commission determines the process, as employed, was flawed e. Market power exacerbated f. Not enough capacity to meet load 2. If solicitation fails, Commission should require immediate new solicitation 3. UDC should retain solicitation records beyond life of contract

5. Unresolved Issues Among Parties

At the conclusion of the sixth day of workshops, the participants agreed on a list of seven unresolved issues to be presented to the Commission. The list was prepared to include all unresolved issues raised by any individual participant who was present at the workshop on September 27, 2002. Accordingly, the issues identified by the Staff and referenced in the Third Procedural Order were all of the issues the workshop participants claimed were unresolved at the end of the workshops. While discussed below, the Staff does not agree that all of these issues should be addressed in this proceeding. The seven issues presented were:

A. What portion of APS' load represents its unmet needs?

B. How the Staff will determine and use the "price to beat".

C. The timing of Commission prudence evaluation of solicited contracts.

D. Should the utility or a third party conduct the solicitation in 2003?

E. The standards of conduct governing utility-affiliate communications.

F. Whether a least-cost planning process should be adopted by the Commission.

G. Whether the Commission should initiate a proceeding to address DSM and Environmental Risk Mitigation.

The Third Procedural Order on Track B issues catalogs all of the issues presented by the individual parties at the procedural conference held on October 2, 2002. Many of the issues are variations of the seven issues listed above.

The procedural order also identifies issues that the Staff addressed in the Solicitation Proposal and discussed with the workshop participants. The Staff position on how those issues should be addressed by the Commission are set forth in the Solicitation Proposal, and a cross reference to that document is provided for ease of reference.

A. What portion of APS' load represents its unmet needs?

This is the penultimate issue to be resolved by the Commission. Clearly, there must be a clear identification of the capacity and energy that will be required in order to serve load before a solicitation can occur. The Staff believes the solicitation in 2003 should be for the energy and capacity the utility cannot supply from generation assets that are included in the utility's rate base, from contracts in effect, as of September 1, 2002, and from generation sources it must take as a result of law or regulation (QF's and Environmental Portfolio sources). This unmet need for each of the next 4 years should be the minimum amount that is included in the solicitations in 2003.

In Section I, B of the Staff proposed solicitation process, charts are provided showing Staff's current estimates of the capacity and energy needs for the next 4 years that should be deemed to be contestable loads in the 2003 solicitations for TEP and APS. These estimates were determined from information provided by the utilities during the workshops. In the case of TEP, the figures were provided by the utility. APS declined to provide energy and capacity estimates requiring the Staff to calculate the figures from information provided by the utility, which the utility now claims, is erroneous. Staff may, upon receipt of revised APS data, schedule an additional workshop to review APS' submitted data with the Track B participants and if appropriate revise the estimates contained in this Report. The Staff further believes that these estimates will need to be adjusted periodically to reflect changes in load, forecasted load, or power supply identified over time.

B. How the Staff will determine and use the "price to beat".

During the workshops, some participants expressed the desire to have prompt Commission review of selected bids, in order to reduce regulatory uncertainty resulting from the possibility of a future disallowance of related costs. Staff did not agree that all contracts awarded under the solicitation should be automatically approved by the Commission. However, Staff developed the price to beat concept to provide certainty of Staff support for cost recovery as an alternative to an expedited Commission review process.

The Staff will calculate the price to beat with the assistance of the independent monitor before the solicitation is released to prospective bidders. Available information on the forecast cost of delivered electricity in the Arizona market will be used to develop the price to beat. The Staff will review multiple sources of data to be provided by the utilities and any participant in the process who chooses to supply such data in establishing its price to beat. The price to beat is discussed in Section V, E (Terms Required for Staff Recommendation) of the proposed Initial Solicitation Process.

The "price to beat" calculated by the Staff will be used by the Staff to determine whether Staff will support the prices contained in any contract, without further investigation, when the utility seeks recovery of related costs from consumers. The price to beat will be used only by the Staff, and will not be disclosed to the utility or to bidders, even after the solicitation is completed. In this way, the chance that the price to beat will influence the evaluation process or the selection decisions made by the utilities will be minimized. After the solicitation is completed and contracts have been executed, the Staff will announce whether any of the winning bids have satisfied the price to beat criteria and, in turn, whether any contracts executed will have the support of the Staff in a future cost recovery proceeding.

C. The timing of Commission prudence evaluation of executed contracts.

In the opinion of the Staff, the Commission should review the contracts entered into as a result of the solicitation at such time as the utility seeks to recover the associated costs from customers.

During the Track B workshops some parties urged Commission review before contracts were executed, arguing that this would remove the risk to both utilities and merchants of regulatory disallowance and, presumably, result in lower cost bids. The Staff is interested in ensuring that consumers receive service at the best price, but believes that factors beyond price alone need to be considered in determining the reasonableness and prudence of decisions made by regulated utilities. At least in the case of this first solicitation the Staff believes that sufficient

time must be allocated to a review of each utility's power supply portfolio resulting from the solicitation to fully evaluate the success of the solicitation process implemented and the reasonableness of the decisions made by the utility in the solicitation.

D. Should the utility or a third party conduct the solicitation in 2003?

The solicitation should be conducted by the utility barring evidence of impropriety by the utility. The procurement of energy and capacity to meet the needs of consumers is the responsibility of the utility. The judgment of a third party should not, in the ordinary situation, be substituted for that of the utility. However, the Commission should, through the Staff and an Independent Monitor, review the actions of the utility and be prepared to appoint a third party to conduct the solicitation should the utility fail to conduct a fair and transparent solicitation. In particular, should there be any evidence of improper contact between the utility and an affiliate, the Commission should have a third party conduct the solicitation if it is determined that the contact was a material violation of the standard of conduct.

E. The standard of conduct governing utility-affiliate communications.

For the solicitation to be successful all bidders must be treated equally, starting with access to personnel assigned to the solicitation and information pertinent to the utilities' power supply requirements and delivery capabilities. To accomplish this, an enforceable standard of conduct controlling contact between any person including affiliated companies, their personnel and contractors, that may bid in the solicitation and the utility must be established. Absent such standards, bidders will lack confidence in the process, which may result in a less robust bidding process.

The standards must require that all contact between the utility and its affiliates be on the same terms and under the same conditions as with all other bidders. That is, there should be no contact between the utility and affiliates that may bid in the solicitation, except through the communications protocol established for bidders. The key elements of the Staff proposed protocol is set forth in Section IV C of the Staff proposal (Section 3D). The protocol would

require the utility to establish a solicitation team by January 1, 2003, and prohibit contact relative to the solicitation with the team by any individuals associated with any affiliate. The Staff anticipates that the team would include personnel from the utility and such other personnel as the utility may require and that those persons would be barred from assisting any affiliate in the evaluation of the solicitation or preparing a bid in response to the solicitation.

The utility should be required to prepare a draft standard of conduct and provide it to the Staff and the Independent Monitor as soon as possible as part of the pre-solicitation information and document preparation process. Once the Staff and the Independent Monitor have completed their review of the draft standard of conduct submitted by the utility and discussed changes with the utility, the draft should be shared with the prospective bidders. Their input on the draft standard of conduct will be reviewed by the Staff, the Independent Monitor and the utility. Upon completion of that review, the utility should make all changes to the draft standard of conduct deemed necessary and publish the final standard of conduct to the solicitation team and to all interested parties as part of its solicitation information. As discussed above, the Staff believes the utilities should begin that process in November 2002 and have all documents, including a draft standard of conduct, completed by the end of January 2003.

An acceptable standard of conduct will, at a minimum, address the following:

- Personnel who may be assigned
- Roles and Responsibilities
- Maintenance of confidential information
- Communications with affiliated entities and persons
- Equal access to information for all persons
- No undue advantage included in solicitation terms and conditions
- Standards for evaluations
- Protocols for logging communications
- Records maintenance, including communications records
- Procedures for monitoring by Staff and independent monitor
- Procedures for verifying compliance, internal and external

F. Whether a least-cost planning proceeding should be adopted by the Commission.

Least-cost planning was an issue raised by RUCO during the workshops. No other workshop participant joined RUCO in making this observation. Staff believes that least cost planning is not an issue to be explored in this initial solicitation proceeding.

G. Whether the Commission should initiate a proceeding to address DSM and Environmental Risk Mitigation.

The Law Fund requested that a proceeding be opened to examine the issue of how and when a solicitation for DSM and Environmental Risk Mitigation should be factored into the solicitation process. Staff believes that DSM and Environmental Risk Mitigation should not be addressed by the Commission in this proceeding. Also, the Commission need not decide at this time whether a separate proceeding is necessary to examine these issues.

Pursuant to the Staff proposed process, bidders would be free to submit bids that include DSM or Environmental Risk Mitigation in response to a product solicitation, and utilities will be required to evaluate those bids on the same basis as they evaluate all other bids. Several participants in the Track B workshops have suggested that bidders should be required to include in their bids an environmental component. Staff believes that bidders should not be required to include DSM or Environmental Risk Mitigation components as a part of their response to a solicitation but may do so if they deem it appropriate.

6. Lessons To Be Learned From The Initial Solicitation

While the proposed process described above is comprehensive and based on successful models from other jurisdictions, the unique circumstances that exist in Arizona will undoubtedly require that modifications to the process be made. The Staff has therefore planned to conduct thorough post solicitation reviews of the process each utility employs to determine what changes, if any, will need to be made to the process adopted by the Commission in this proceeding. While

the initial solicitations will be for all unmet needs presently identified, the Staff intends to review the appropriateness of the process for meeting future needs as they present themselves. The creation of an ISO or RTO or the ramifications of FERC's SMD NOPR will also need to be considered and factored into changes that may be needed to assure that the solicitation process can continue to meet the goals established by the Staff.

The Staff anticipates that codes of conduct and rules concerning affiliated transactions will also be reviewed.

The Staff intends to review and, if necessary, to amend the process to reflect lessons learned regarding the effectiveness of the various methods employed by the utilities to solicit bids. In particular, the communications protocols established to manage relations with affiliated companies, the power supply products solicited, the contract durations and terms and conditions sought and the tools used to solicit and evaluate bids submitted will be reviewed.

Finally, the Staff will evaluate the time allocated to each phase of the process to determine whether adequate time was allocated to allow for preparation of all required data, development of specifications and bids and for comprehensive evaluations of all bids received.

7. Subsequent Solicitations

After completion of the initial solicitations, the Staff will conduct the reviews described above in Chapter 6. To the extent that the Staff determines that changes to the process are required, it will recommend such changes to the Commission.

While presented as the "initial" solicitation process, the Staff believes the process is comprehensive and will be adequate to manage future solicitations to acquire power supplies to meet unmet needs identified in the future or to meet needs of the utility in the event that asset divestiture may be approved by the Commission. However, the creation of an ISO or RTO or the implementation of FERC's SMD proposal may significantly alter the dynamics of competitive wholesale markets and would likely require significant amendments to the process, particularly

with regard to the roles and responsibilities of the process participants and the range of power supply products to be acquired.

8. Appendix One To ACC Staff Report On Track B: An Overview Of Competitive Solicitation In Selected States For Wholesale Supply 2002

INTRODUCTION

As the restructuring of the electric utility industry in the United States has evolved, regulators have examined various models in order to find the model that best provides sustainable benefits to consumers from development of competitive markets. In some states, the focus has been on retail choice accompanied by mandatory divestiture of generating assets. In other jurisdictions, retail choice was encouraged without divestiture. Still other jurisdictions have determined that neither retail choice nor divestiture is appropriate at this time, but that power supply additions should be competitively procured. With each model, the utility retained the responsibility for providing service to those customers who were not served by another supplier.

This review of the regulatory approaches of selected other state commissions concentrated on how those commissions used competitive bidding processes to meet default service obligations. A second part of the review examined what restrictions, if any, were imposed by regulators on wholly-owned affiliates of utilities in competitive solicitations.

In summary, each state that implemented competitive solicitation for wholesale supply of electricity adopted an approach unique to that jurisdiction. For example, states that required divestiture of generation implemented solicitation programs designed to procure full system requirements, typically with slice-of-system all requirement contracts, while utilities with owned-generation used solicitation programs to supplement their installed capabilities. The processes adopted were also significantly dependent on the state of development of the RTO, ISO, or power pool in which the affected utilities operated. There is no "perfect model" that can be adapted from another state for use in Arizona. Rather, the experience from a number of states should be

drawn upon, modified, and applied to the needs of Arizona to fashion a solicitation program that will meet the needs of this state.

Status of State Electric Industry Restructuring Activity
-- as of July 2002 --

As of June 2002, twenty-four states and the District of Columbia have either enacted enabling legislation or issued a regulatory order to implement retail access. Each state's retail access schedule varies according to its unique legislative mandates and regulatory orders. The information in the "Status of State Electric Industry Restructuring Activity Map" was gathered from state public utility commissions, state legislatures, and utility company web pages. The map was prepared by the Energy Information Administration of the U.S. Department of Energy.

DISCUSSION

Arizona has challenges that are different from those other states had to address when implementing a wholesale solicitation process. Most states that have moved forward in this area have had well developed and integrated transmission pools, providing the ability to balance needs and reserves with a high degree of certainty. Typically, those pools have well defined load management processes. In many of those states, the regulators have established rules and regulations to ensure that the wholesale power purchases made by utilities do not impair system reliability and are contracted for in a manner that is fair, equitable and provides tangible benefits for consumers.

Following are brief descriptions of the approaches adopted by several states that have addressed wholesale solicitation requirements as part of restructuring the electric utility industry.

Colorado

Background

Colorado has repeatedly rejected legislation to restructure the electric utility industry. Instead, the PUC, by rule making, requires utilities to use competitive solicitation to meet the Integrated Resource Plan (IRP) standard established by the Commission.

Wholesale solicitation

Utilities retain the obligation to procure capacity and energy to meet the needs of consumers. Each utility must file an IRP with the Commission (Code of Colorado Regulations 723-3, Rules 3600-3615), which includes a forecast and needs assessment every four years. The IRP must also include the draft RFP the utility will use to solicit energy and capacity bids. Under the recently amended rules, the PUC will review the resource plan and approve the plan for the utility before competitive solicitations are conducted, including the plan for competitive solicitation. Approval by the PUC creates the presumption that the utility actions are prudent. However, the rules expressly state

that approval of a plan carries no presumption that the selection of specific resources are prudent. The obligation to conduct a solicitation and to acquire resources and to prove that costs should be recovered *after the fact* remains with the utility. Public comments on the IRP are not required.

Florida

Background

Before an electric utility can build an electrical power plant that generates more than 75 megawatts of steam or solar generation, the electric utility must conduct a solicitation for wholesale power and secure a determination of need from the Florida Public Service Commission.

In making its need determination, the PSC takes into account:

1. the need for electric system reliability and integrity;
2. the need for adequate electricity at a reasonable cost; and
3. whether the proposed plant is the most cost-effective alternative available.

The need determination process enables the PSC to verify that more electricity generation capacity is needed to prevent unnecessarily burdening consumers with the costs associated with constructing new power plants.

The intent behind the bidding rule is to provide consumers with benefit when, through an open and fair process, the supply side of the wholesale energy equation is subject to competitive bidding.

Wholesale solicitation

Prior to filing a need determination petition to build an electrical power plant, an electric utility is required to solicit and evaluate competitive proposals for supply-side alternatives by issuing a Request for Proposals (RFP). The PSC promulgated rules (PSC Rule 25-22-082) regulating the process by which capacity additions are authorized. The rules include evaluation of supply-side alternatives and detailed requirements that the utility must meet as part of a solicitation through a

request for proposal process. The RFP is filed with the PSC, which monitors the solicitation process, while the utility conducts the solicitation. Only parties to the solicitation are permitted to challenge the outcome of the solicitation. Utilities are permitted to bid in a solicitation.

Presently, the PSC is considering reviewing the solicitation process because, since the rules adoption in 1994 no contracts have been awarded to competing proposals, that is, the utility has won all of the contracts itself.

Maine

Background

As part of the 1997 restructuring of the electric utility industry, the legislature directed the Maine Public Utilities Commission (MePUC) to promulgate rules for the provision of standard offer service. In January 2001, the MePUC issued an order adopting detailed rules. Pursuant to those rules, the MePUC has, in the first instance, responsibility for conducting a solicitation to meet standard offer service obligations in the state. Electric companies only have the obligation to procure electricity and capacity in the event the MePUC notifies the company of its failure to procure the standard offer needs. Electric utilities retain the obligation to provide standard offer service to customers who chose not to switch providers.

Wholesale solicitation

Chapter 301 of the MePUC rules provides for the commission to conduct requests for proposal to meet the standard offer requirement. The rules limit sales by affiliates to no more than 20% of the amount of the solicitation, and the initial solicitation was only for contracts of one year. Bidders are permitted to bid for portions of the requirement in multiples of 20% of the total solicitation.

Maryland

Background

Pursuant to settlements reached with each of Maryland's electric utilities, generation was deregulated and retail customer choice was implemented beginning in 2000. Each utility retained the responsibility to provide Standard Offer Service for finite periods at rates that were frozen by the Commission for various classes of customers through as late as 2006. Each utility was given complete discretion to arrange electric supply, but for all SOS service to be rendered from 2004 through 2006 that supply has to be procured through competitive wholesale markets. No power supply contract executed to serve SOS customers could contain prices that exceeded the Price Freeze rates established by the Maryland Commission.

Wholesale solicitation

The Maryland PSC has not established rules or regulations mandating the conduct of power supply solicitations. Rather, through settlements with individual utilities, the Commission defined the responsibilities of each utility to acquire power in competitive solicitations to serve standard offer service customers.

Massachusetts

Background

The Massachusetts Department of Telecommunications and Electricity's (DTE) final decision to officially open the retail electricity market to competition in March 1998 was issued in January 1997. In early 1998 the DTE issued rules establishing licensing and disclosure requirements for retail suppliers and standard offer service and issued rules for distribution, default generation services, standard offer generation, aggregation requirements, and ownership of meters. During 2000 the DTE issued an order that allowed utilities to base their rates for default service on wholesale bid prices, beginning in January 2001. Utilities began issuing competitive bids seeking 6-month to 1-year contracts for the

power needed to serve their default service customers. Default service is defined as those customers who have left their competitive supplier, or are new to the utility's territory.

Wholesale solicitation

Massachusetts' four distribution utilities are each a member of NEPOOL, an integrated transmission pool with sophisticated load management and settlement procedures. Massachusetts required full divestiture of generating assets as part of electric utility restructuring. Each distribution company is responsible for default service. Each distribution company conducts a solicitation every 6-12 months and solicits bids for a subsequent 6-12 month period. Typically, there is a short round and then a final round of bidding. The issue of wholly-owned subsidiaries with load is not an issue in Massachusetts and, accordingly, there are no specific prohibitions on affiliate sales of power. However, regulators do monitor solicitations and if an affiliate were to bid, the solicitation would receive closer review. The regulators do not receive copies of the RFPs issued by the distribution companies.

New Jersey

Background

The Electric Discount and Energy Competition Act of 1999 ("EDECA" or "Act"), N.J.S.A. 48:3-49 et seq., provides that for at least three years from the starting date of electric retail choice and until the New Jersey Board of Public Utilities (the Board) finds it to be no longer necessary and in the public interest, electric public utilities shall provide basic generation service (BGS). N.J.S.A. 48:3-57(a).

By Order dated June 6, 2001, the Board directed the four electric distribution companies ("EDCs") in New Jersey to each file specific proposals to implement an RFP process for BGS for Year 4 of the Transition Period.

Wholesale solicitation

The four New Jersey electric distribution utilities filed a generic proposal for the provision of Basic Generation Service The generic proposal recommended a simultaneous, multi-round, descending clock auction format.

The EDCs jointly proposed a single Auction Process for the procurement of supply to meet the full electricity requirements (i.e., energy, capacity, ancillary services, transmission, etc.) of retail customers that had not chosen a Third Party Supplier. Under the proposal, the BGS Loads of all EDCs would be bid out in the same auction. The annual BGS retail load of each EDC is considered a separate "product."

The EDCs proposed that an Independent 3rd party conduct the Auction.

After hearings, the Board authorized the proposed process with modifications and assigned its consultant to monitor the auction.

Subsequent to the auction the Board commenced a proceeding to review the outcome of the process employed and to consider modifications to the process suggested by the Auction Manager, the Board's consultant and other persons who submitted comments.

Pennsylvania

Background

The Electricity Generation Customer Choice and Competition Act was enacted in 1996. The law allowed consumers to choose among competitive generation suppliers beginning with one third of the State's consumers by January 1999, two thirds by January 2000, and all consumers by January 2001. Utilities were required to submit restructuring plans by September 1997. Utilities are required to be providers of last resort and customers have the right to return to default service at any time through 2010.

Wholesale solicitation

The distribution company is required to meet its obligation as provider of last resort by purchasing required amounts of energy and capacity from wholesale sources. Procurement from affiliated generating companies is permitted. The utility retains discretion to determine the source of wholesale energy and capacity. As of January 1, 2001, the utility's recovery from customers is limited, through the terms of approved settlement agreements, to pre-established rates for each class of ratepayer.

Texas

Background

Restructuring legislation was enacted in 1999 to restructure the Texas electric industry allowing retail competition. The bill required retail competition to begin by January 2002. Rates are frozen for 3 years, and then a 6 percent reduction will be required for residential and small commercial consumers. This will remain the "price to beat" for five years or until utilities lose 40 percent of their consumers to competition. Utilities must unbundle into 3 separate categories, using separate companies or affiliate companies, the generation, the distribution and transmission, and the retail electric provider. Utilities will be limited to owning and controlling not more than 20 percent of installed generation capacity in their region (ERCOT).

The PUC adopted rules for the provider of last resort for when competition began in early 2002. The provider of last resort is required to provide to consumers no longer served by their provider of choice service at a fixed price. A competitive bidding process will designate the last resort providers for each consumer class. Bidding was completed by June 1, 2001.

During 2001, utilities in Texas began the process of auctioning part of their generating capacity. The auction is designed to increase the pool of available power for new retail suppliers entering the market, prevent market power, and promote competition in electricity markets.

Wholesale solicitation

As part of the restructuring of the market, utilities are required to acquire 15% of their capacity requirement through auction. The utility has the responsibility to procure the necessary capacity and energy, adhering to the rules established by ERCOT. Capacity in addition to the mandated capacity auction is procured through solicitation and secured by bilateral contracts.

9. Appendix Two: APS' Response To Staff's October 15, 2002, Data Request

Jana Van Ness
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October 22, 2002

RECEIVED

OCT 23 2002

ARIZ. CORPORATION COMMISSION

VIA FACSIMILE

Janet F. Wagner
Attorney, Legal Division
Arizona Corporation Commission
1200 W. Washington
Phoenix, Arizona 85007

RE: ARIZONA CORPORATION COMMISSION STAFF'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY PURSUANT TO ACC DOCKET NO. E-00000A-02-0051, ET AL.

Dear Ms. Wagner:

Enclosed is a copy of Arizona Public Service Company's ("APS") responses to the Arizona Corporation Commission Staff's (Staff's) First Set of Data Requests dated October 15, 2002.

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

Sincerely,

Jana VanNess
Manager
Regulatory Compliance

Attachment

JVN/vld

Cc: With Attachments
Matt Rowell, ACC
Christopher Kemply, ACC
Thomas Mumaw, Esq. PWCC

STAFF'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE IN DOCKET NO's. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630 AND E-01933A-02-0069 (TRACK B)
October 15, 2002

MR 1.1 Please provide all forecasts of APS' total *retail* load capacity and energy for the following years: 2003, 2004, 2005, 2006, and 2007. For each forecast provided, please describe the purpose for which it was prepared, its strengths and weaknesses, and the degree of reliance that APS has placed upon it.

RESPONSE:

See attached table. [Attachment Staff DR 1, Q. MR1.1]

APS prepares forecasts of retail customer peak demands and energy requirements to support the operational, financial, and system improvement planning needs of the company. Each of the forecasts presented here has influenced the company's view of what actions are required to best meet the anticipated customer demands. APS places heavy reliance on each forecast to develop its plans, but recognizes that each forecast is inherently uncertain and plans accordingly.

Each forecast is typically characterized by the same set of strengths and weaknesses. Strengt include: preparing each forecast with sufficient detail such that actual results can be compared against projections and resulting deviations can be used in the preparation of subsequent forecasts; having a management review of the key assumptions underlying each forecast for consistency and, to the extent practical, accuracy; and the knowledge of how much uncertainty may be reflected in each forecast. Weaknesses are generally to be found in the areas of greatest volatility and uncertainty, such as the difficulty in accurately forecasting net population migration to Arizona, sudden changes to customer behavior, actual weather conditions, and customer coincident peak load factors.

Response to Staff Data Request MR 1.1 Dated October 15, 2002

Description	Date	Retail Energy Load in Gigawatthours					Retail Peak Load in Megawatts				
		2003	2004	2005	2006	2007	2003	2004	2005	2006	2007
1993 Long-Range Forecast	Feb 1993	22,157					4,354				
1994 Long-Range Forecast	Feb 1994	21,100	21,581				4,339	4,419			
1995 Long-Range Forecast	Jun 1995	24,273	24,922	25,561			4,725	4,836	4,945		
1996 Long-Range Forecast	Apr 1996	24,429	25,084	25,746	26,381		4,666	4,776	4,890	4,992	
1997 Long-Range Forecast	Feb 1997	25,064	25,736	26,414	27,080	27,781	4,888	5,005	5,122	5,231	5,347
1998 Long-Range Forecast	Feb 1998	25,590	26,369	27,176	27,964	28,797	5,288	5,445	5,611	5,761	5,918
1999 Long-Range Forecast	Apr 1999	25,689	26,530	27,370	28,195	29,068	5,509	5,700	5,890	6,078	6,276
2000 Budget	Oct 1999	25,233	26,074	26,918	27,757	28,611	5,609	5,786	5,981	6,179	6,378
2000 Long-Range Forecast	Apr 2000	26,339	27,376	28,326	29,187	30,048	5,852	6,073	6,294	6,498	6,698
2001 Budget	Oct 2000	26,845	27,860				5,945	6,164			
2001 Long-Range Forecast	Apr 2001	26,954	27,914	28,813	29,723	30,641	6,077	6,325	6,538	6,755	6,973
2002 Budget	Oct 2001	26,552	27,871	29,271	30,744	32,295	5,946	6,228	6,652	6,994	7,354
2002 Long-Range Forecast	Apr 2002	26,200	27,526	28,770	29,902	31,108	5,928	6,260	6,563	6,804	7,081
2003 Budget	Oct 2002	26,289	27,635	28,790	29,967	31,175	5,717	6,016	6,262	6,515	6,780

STAFF'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE IN DOCKET NO's. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630 AND E-01933A-02-0069 (TRACK B)
October 15, 2002

MR 1.2 Please specify whether there is an "official" forecast(s), i.e., one which APS uses for any formal purpose. If so, please identify it and describe its use. If there are more than one, please identify and describe each.

RESPONSE:

APS typically prepares two "official" forecasts each year: a 10-year forecast in the spring to support long range planning efforts and a forecast in the fall to support near-term budget and operational plan development. Historically, this has been for a 3-year period, although this year's budget forecast covers additional years. Of course, APS also has an on-going planning process that requires these forecasts to be modified and updated on a more periodic basis. These updates are generally adopted and used by the various planning groups within the Company to update their own plans.

STAFF'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE IN DOCKET NO's. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630 AND E-01933A-02-0069 (TRACK B)
October 15, 2002

MR 1.3 Please list each rate-based plant that APS uses to serve its retail load. For each plant listed, please specify the plant's capacity and capacity factor.

RESPONSE:

See attached table. [Attachment Staff DR 1. MR 1.3]

RESPONSE: MR 1.3

APS Generating Unit Historical Capacity Factor

2000 -2002

Unit	2002 SUMMER CAPACITY (MW)	ANNUAL CAPACITY FACTOR (%) 2000	2001	2002
Palo Verde 1	361.7	100.4	87.8	90.0
Palo Verde 2	361.7	87.2	92.6	91.0
Palo Verde 3	362.9	90.3	83.9	100.8
Four Corners 1	170.0	87.7	81.5	77.6
Four Corners 2	170.0	90.6	80.9	90.4
Four Corners 3	220.0	73.3	91.2	86.9
Four Corners 4	111.0	75.9	90.6	90.9
Four Corners 5	111.0	90.6	83.0	62.8
Navajo 1	105.0	86.4	80.2	81.9
Navajo 2	105.0	81.4	91.4	79.1
Navajo 3	105.0	85.3	82.5	83.7
Cholla 1	110.0	82.4	68.7	85.9
Cholla 2	245.0	90.2	81.1	74.4
Cholla 3	260.0	76.0	86.5	81.1
W. Phx. CC 1	80.0	49.0	49.0	32.6
W. Phx. CC 2	80.0	40.0	60.2	33.7
W. Phx. CC 3	80.0	54.0	42.7	42.9
Ocotillo Steam 1	110.0	34.6	39.8	17.4
Ocotillo Steam 2	110.0	31.5	38.5	10.6
Saguaro Steam 1	110.0	27.2	36.7	9.3
Saguaro Steam 2	100.0	30.6	40.9	11.7
W. Phx CT 1	50.0	15.2	18.4	2.6
W. Phx CT 2	50.0	17.0	19.2	3.8
Ocotillo CT 1	50.0	11.2	24.4	3.3
Ocotillo CT 2	50.0	9.6	21.8	3.0
Saguaro CT 1	50.0	13.3	19.7	3.0
Saguaro CT 2	50.0	14.7	16.4	1.9
Yucca 1	18.0	5.0	23.4	3.7
Yucca 2	18.0	6.9	21.8	4.3
Yucca 3	52.0	12.2	22.0	14.1
Yucca 4	51.0	4.8	11.9	0.3
Douglas	15.0	3.2	14.5	0.2
Childs / Irving	4.2	66.8	65.9	59.7
APS TOTAL	**3927**			

NOTE: Capacity factors are affected by planned outages, forced outages, APS fuel and variable O&M costs, market prices of economy energy, operational constraints, and APS load requirements

STAFF'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE IN DOCKET NO's. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630 AND E-01933A-02-0069 (TRACK B)
October 15, 2002

MR 1.4 Please list each contract under which APS obtains capacity and energy to serve its retail load. For each contract listed, please specify the contract's capacity and energy or load factor and the date it was entered into.

RESPONSE:

PacifiCorp Diversity Exchange
480 MW on-peak capacity limited to maximum 40% capacity factor May 15-Sep 15 each year. The contract was entered into September 1990.

Salt River Project Territorial Agreement
350 MW capacity for delivery January-December each year. This amount increases per a formula by 7 or 8 Mw per year. Energy is distpatchable and varies as a function of APS economics and to meet the needs of APS system reliability. The annual capacity factor has ranged from 31% to 59% in the 2000-2002 time frame. The contract was entered into in 1955 and was most recently amended in 1998.

Constellation Power (entered into March 2000)
25 MW on-peak capacity with 100% capacity factor during on-peak period for delivery July 2003 - September 2003

Williams Energy Marketing and Trading (entered into March 2000)
25 MW on-peak capacity with 100% capacity factor during on-peak period for delivery July 2003 - September 2003

Morgan Stanley Capital Group (entered into March 2000)
50 MW on-peak capacity with 100% capacity factor during on-peak period for delivery July 2003 - September 2003

Morgan Stanley Capital Group (entered into November 2001)
25 MW on-peak capacity with 100% capacity factor during on-peak period for delivery July 2003 - September 2003

NOTE: APS also has a QF agreement with Abitibi, but it is not for firm capacity or energy and thus has been excluded from APS resources for Track B purposes.

STAFF'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE IN DOCKET NO's. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630 AND E-01933A-02-0069 (TRACK B)
October 15, 2002

MR 1.5 Please identify APS' forecasted unmet needs, i.e., the difference between forecasted load and capacity and associated unmet energy needs, for the years 2003, 2004, 2005, 2006, and 2007. Please identify the specific forecast used to determine your response, and please explain why that forecast was selected. For the purposes of this question, capacity and energy refers to rate-based generation assets and contracts to purchase power entered into before September 1, 2002.

RESPONSE:

See attached table [Attachment Staff DR 1, Q. MR 1.5] for the amount of energy and capacity APS currently expects to require to meet its reliability needs based on the October 2002 budget forecast. This is the most recent "official" forecast available. This table considers both its current rate-based generation assets referenced in Response MR 1.3 and the contracts referenced in Response MR 1.4. APS has further excluded capacity and energy for RMR above that provided from APS units because of the small number of even potential competitors and also amounts from renewable resources acquired or to be acquired under the EPS (APS believes this was a consensus position during the workshops).

In addition, APS expects to procure a certain amount of economy energy in each of these years depending solely on the actual energy cost of APS resources compared with market prices for power. Based on current expected forward market prices for natural gas and power, APS could potentially purchase up to 3,557 GWH of economy energy in 2003; 4,033 GWH in 2004; 6,695 GWH in 2005; 6,948 GWH in 2006, and 9,278 GWH in 2007. If actual power prices are 10% lower or higher (and all other factors remain as projected), APS would expect to make additional (fewer) economy energy purchases of 800 GWH or (500 GWH), respectively, for 2003 in response to these changing conditions.

This economy energy will be acquired competitively in a process that will permit qualified and interested sellers to participate and which APS will describe in more detail in its November 4, 2002 testimony in Track B.

As can be seen by the Attachment, APS requires approximately 22% of its 2003 retail load (plus reserves) to be competitively acquired in 2003, increasing to more than 25% in 2007. On the other hand, its energy needs are both significantly less initially and are at all times dependent upon the relative costs of gas and purchased power, but given current forecasts would range from some 15% in 2003 to 33% in 2007.

Response to Staff Data Request MR 1.5
APS Projected Unmet Capacity and Energy Needs as of 10/22/02
2003 - 2007

Description	2003		2004		2005		2006		2007	
	Capacity (MW)	Energy (GWH)	Capacity (MW)	Energy (GWH)	Capacity (MW)	Energy (GWH)	Capacity (MW)	Energy (GWH)	Capacity (MW)	Energy (GWH)
Total standard offer load [1]	5,723	26,494	6,023	27,841	6,269	28,999	6,522	30,178	6,787	31,388
+ 15% reserve margin [2]	598	-	602	-	602	-	606	-	606	-
- Physical capability of APS units [3]	(3,927)	(24,132)	(3,953)	(25,313)	(3,949)	(25,733)	(3,975)	(26,563)	(3,975)	(28,047)
- Full capability of purchase contracts [4]	(955)	(1,972)	(837)	(1,678)	(844)	(2,006)	(852)	(2,057)	(860)	(2,108)
- RMR generation from non-APS units [5]	(29)	(0)	(184)	(2)	(338)	(8)	(493)	(27)	(647)	(40)
- Planned renewable energy supply under EPS [6]	(9)	(41)	(17)	(85)	(23)	(114)	(29)	(142)	(35)	(170)
= Net unmet reliability needs [7]	1,401	349	1,634	763	1,717	1,138	1,779	1,389	1,876	1,023

[1] Standard offer load includes all retail customer energy and coincident peak demands plus APS wholesale contracts served by APS resources from Oct 2002 budget projections. Under Staff's proposal, this calculation would be updated prior to any actual procurement.

[2] Reserve margin is calculated on APS generation and known contingent purchases only.

[3] Includes the production from all rate-based APS generation units subject to standard planned and forced outage assumptions.

[4] Includes the contracts referenced in Response to Staff Data Request MR 1.4.

[5] RMR generation assumes a Valley import limit of 3,535 MW, 660 MW of local APS generation, and 110 MW of required reserves. To the extent that bidders can demonstrate higher import capability or import capability is increased, RMR would be reduced, all else remaining the same. The present import limit of 3,535 MW assumes timely completion of the Southwest Valley line and also uses its most recent (and higher) capacity rating.

[6] Includes solar and renewable resource additions planned each year under current funding levels. To the extent the Commission approves higher funding levels, capacity and energy under EPS will increase.

[7] Energy figures do not include economy purchases, which as noted in the text of APS's response would add some 3,500 gwh in 2003 (and more in subsequent years) assuming present forecasts of gas and power costs.

EXHIBIT
S-2
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES	)	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606	)	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING THE INDEPENENT SCHEDULING ADMINISTRATOR	)	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES	)	DOCKET NO. E-01933A-02-0069

TRACK B REBUTTAL TESTIMONY

OF

ERNEST G. JOHNSON

DIRECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 18, 2002

SUMMARY
TRACK B REBUTTAL TESTIMONY
ERNEST G. JOHNSON
GENERIC ELECTRIC RESTRUCTURING DOCKET
DOCKET NO. E-00000A-02-0051, ET. AL.

My rebuttal testimony responds to APS witness Steven M. Wheeler and focuses on two issues: **Expedited Contract Approval** and **Price to Beat.**

I conclude that Expedited Contract Approval is unnecessary, inappropriate and is not in the public interest, and could result in rates that are not just and reasonable. This conclusion is bolstered by the fact that this process is occurring against a backdrop of a wholesale marketplace which is not workably competitive as determined by the Commission in Order #65154. If adopted, an expedited approval process may inadvertently relieve the utility of its responsibility to procure power in a prudent manner resulting in rates that are not just and reasonable. Also, an expedited approval process may short change or limit the Commission's opportunity to thoughtfully and completely examine both the process and the results emanating therefrom. Such a result would clearly not be in the public interest.

Turning to the issue of Price to Beat, Staff proposed the price to beat concept as a compromise position which would provide some cost recovery assurance to the utilities and merchants within certain parameters, while avoiding the pitfalls of pre-approval. From Staff's review of the testimony, it would appear that some parties perceive Staff's proposal as too problematic or undesirable.

Therefore, Staff respectfully withdraws its proposed Price to Beat and urges the Commission not to pre-approve or allow for Expedited Contract Approval.

Rejection of Expedited or Automatic recovery is necessary in order to protect ratepayers against significant unknown economic harm without adequate recourse.

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1 **INTRODUCTION/SUMMARY**

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

3 A. My name is Ernest G. Johnson, 1200 West Washington, Phoenix, AZ 85007.

4 **Q. By whom are you employed and in what capacity?**

5 A. I am employed by the Arizona Corporation Commission ("ACC" or "Commission") as the
6 Director of the Utilities Division.

7

8 **Q. Briefly describe your responsibilities as Utilities Director.**

9 A. I am responsible for the day to day operations of the utilities division, including policy
10 development, case strategy and overall division management.

11

12 **Q. Please summarize your educational background and professional experience.**

13 A. In 1979 and 1982 respectively, I earned Bachelor of Science and Juris Doctorate degrees,
14 both from the University of Oklahoma. I have been involved in the regulation of public
15 utilities since 1986. I was employed by the Oklahoma Corporation Commission in 1986
16 in various legal capacities. In 1993, I was named acting Director and served in that
17 position until mid 1994. I served as permanent Director from mid 1994 until October
18 2001. While serving in these capacities I have participated in numerous regulatory
19 proceedings including providing policy analysis concerning Electric Restructuring before
20 the Oklahoma Corporation Commission and Oklahoma State Legislature.

21

22 **Q. Did you participate in the Track B workshops?**

23 A. Yes, I attended and participated in each of the Track B workshops.

Q. Are you sponsoring the Track B Staff Report, which was filed on October 25, 2002?

A. Yes, I am one of three witnesses sponsoring the Track B Staff Report.

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

A. I respond to comments made by APS witness Steven M. Wheeler. In particular I address the issues of expedited contract approval and the price to beat.

EXPEDITED CONTRACT APPROVAL

Q. Have you reviewed the testimony of APS witness Steve Wheeler?

A. Yes, I have.

Q. Do you have any comments regarding his testimony?

A. Yes, I do.

Q. In his testimony (page 6, line 25 – page 7, line 11) Mr. Wheeler argues that the Commission should approve the contracts resulting from the solicitation on an expedited basis and that such approval should provide for full and timely cost recovery. What is Staff's position on this issue?

A. In Staff's opinion, expedited contract approval would not be in the public interest and is unnecessary and inappropriate for this solicitation.

Q. Why?

A. While Staff is committed to assisting the Commission in its efforts to transition to and facilitate a robustly competitive wholesale electric market in Arizona, this is not the time to adopt an expedited approval process. Staff believes that expedited contract approval is

not a necessary component in facilitating a robustly competitive wholesale electricity market. This is especially true when viewed against two facts:

1. A backdrop of a wholesale market place, which is not workably competitive as determined by this Commission in Order # 65154,
2. And the level of risk that ratepayers would be required to assume under the APS' proposal.

In Staff's opinion, adoption of the APS proposal could result in rates that are not just and reasonable. Staff would not be opposed to reconsidering this issue in subsequent solicitations.

In light of the oversupply of generation that currently exists in Arizona, Staff believes that in-state generators will be compelled to bid for APS' contestable load. Also, out of state suppliers may find the solicitation process amenable and APS' contestable load desirable. Consequently, expedited approval simply is not required to attract bidders at this time. In this case, it would appear that APS is simply seeking to shift the risk of cost recovery away from itself on to consumers.

Q. Could adoption of the APS proposal result in adverse consequences to consumers?

A. Yes, if adopted an expedited approval process may, inadvertently relieve the utility of its responsibility to procure power in a prudent manner resulting in rates that are not just and reasonable. Such a result would clearly not be in the public interest.

It is my understanding that currently APS procures its required resources without ACC expedited approval. It would appear that APS is able to meet its service obligation and

remain financially viable. In Staff's opinion, APS has not made a compelling showing to support expedited approval.

Staff's proposal in Track B leaves the utility with the ultimate decision-making authority regarding its needs and the ultimate responsibility to act prudently.

Q. Are there other concerns with Expedited or Pre-Approval Processes?

Yes, in Staff's opinion, utilities must have sufficient incentive to procure power in a prudent manner on behalf of its customers. An expedited or pre-approval process may eliminate prudency reviews, a very necessary incentive.

Q. Do you have any further thoughts on this matter?

A. Yes, in Staff's opinion an expedited approval process may short change or limit the Commission's opportunity to thoughtfully and completely examine both the process and the results emanating therefrom. I would think that in the initial solicitation the Commission would decide to retain utmost flexibility such that it is not limited in its abilities to effectuate remedies or make course adjustments as may be necessary. This would seem most appropriate based upon the fact that this will be the first time that the Commission has ventured down this path. Retaining flexibility would seem to be critical at this juncture.

Q. Do you think expedited approval is necessary for competition to develop and succeed?

A. Not in my opinion. It has been my observation that industries that are competitive operate effectively without guarantees of cost recovery. For example, when an automobile manufacturer enters into a contract to buy parts from a supplier neither the manufacturer nor the supplier has any guarantee that the cost of the contract will be recovered. In spite of this uncertainty, competition is quite vibrant within the highly capital intensive automobile industry.

PRICE TO BEAT

Q. Can you explain the genesis of the Staff's "Price to Beat" concept?

A. As more fully discussed in the testimony of Staff witness Alan Kessler, the price to beat was a compromise proposed by Staff. During the workshops, it was apparent that the utilities and merchants favored expedited review or pre-approval of their power agreements. Staff proposed the price to beat concept as a compromise position: that would provide some assurance to the utilities and merchants within certain parameters while avoiding the pitfalls of pre-approval.

Q. At page 8, lines 13-24 of his testimony, Mr. Wheeler criticizes Staff's intent not to disclose the price to beat. Can you comment on this?

A. First, I would like to point out that Mr. Wheeler's assertion that the price to beat could be revealed at some "...future moment to support disallowance of power costs for which the utility was already contractually committed..." is not consistent with Staff's position. Staff believes that revealing the price to beat before contracts are executed could adversely influence bids and that disclosure subsequent to bidding but before contracting could

possibly skew the selection process. Staff did not view either possible outcome as desirable or consistent with the public interest.

Q. Are there any changes to the price to beat concept that you would like to propose?

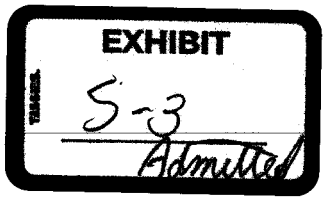
A. Yes, as indicated in Staff testimony, the price to beat was put forward as an accommodation or compromise to address the concerns expressed by the utilities and merchants. It was the Staff equivalent of an 'olive branch.' It would appear that to some parties Staff's proposal is too problematic or undesirable.

Therefore, at this time the Staff respectfully withdraws its proposed price to beat and would urge the Commission not to pre-approve or provide for expedited contract approval because such a course of action could subject ratepayers to significant unknown economic harm without adequate recourse.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION



WILLIAM A. MUNDELL

Chairman

JIM IRVIN

Commissioner

MARC SPITZER

Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUE.	DOCKET NO. E-00000A-02-0051
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IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069

TRACK B REBUTTAL TESTIMONY

OF

ALAN KESSLER

ON BEHALF OF

UTILITIES DIVSION

ARIZONA CORPORATION COMMISSION

November 18, 2002

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Q. Please state your name and business address.

A. Alan Kessler, 244 N. Main Street, Concord, NH 03301

Q. By whom are you employed and in what capacity?

A. I am a Managing Director of Accion Group, Inc., a consultancy providing regulatory, strategic, operational and financial advisory services to a broad range of clients, including electric, gas, and water utilities, regulatory agencies, and other organizations involved in utility-related matters. My responsibilities include coordinating our practice activities relating to services we provide in planning and regulatory matters, as well as in business organizational issues.

Q. Please discuss your educational background.

A. I graduated from the City College of New York in 1969 with a B.S. degree in Economics. In 1975, I was awarded a J.D. degree by Capital University. I have also done graduate studies in Economics at the Massachusetts Institute of Technology. Since graduation, I have continued my education by taking professional education courses in finance, law, and economics.

Q. Please discuss your professional experience.

A. After graduation from the City College of New York, I was employed by the Columbia Gas System as an economic analyst assigned to financial and asset acquisition issues. Subsequent to law school, I was employed by the Public Utilities Commission of Ohio as a hearing officer where I presided over rate, fuel clause, and quality of services cases for electric, gas and telephone companies. In 1978, I joined the law department of Ohio Power Company where I was responsible for all of the company's regulatory litigation. I was promoted to

General Counsel in 1984. In 1987, I joined the Utilities Consulting practice of Ernst & Young, where I focused on advising clients on issues related to financially distressed utilities. In 1998, I joined Deloitte Consulting, specializing in mergers and acquisitions and regulatory matters. In 2002, I co-founded Accion Group, Inc., my current employer.

Q. Have you ever testified before any regulatory agencies prior to this testimony?

A. Yes. I have previously testified before the Vermont Public Service Board, the New Hampshire Public Utilities Commission, the Public Utilities Commission of Ohio, and the Federal Energy Regulatory Commission (FERC). Additionally, I have testified on utility-related matters in bankruptcy court and before the New Hampshire and Ohio legislatures. I have also advised clients on regulatory matters before the utility regulatory authorities of New York, Michigan, Missouri, Kansas, Virginia, Pennsylvania and California.

Q. Would you please describe your role in the Track B proceedings?

A. Accion Group, Inc. was retained by the Staff to assist in planning and facilitating the four Track B workshops and to advise the Staff on matters relating to the operations of competitive wholesale markets. Our assistance included advising the Staff on the different approaches to conducting solicitations for wholesale power employed in various markets, and how other regulatory bodies monitor competitive solicitation processes. We assisted the Staff in preparing the Staff Report that was issued on October 25, 2002. I participated in each phase of our engagement and attended each workshop held.

Q. Are you sponsoring the Staff Track B Staff Report?

A. Yes, I am one of three witnesses sponsoring the Track B Staff Report.

Q. What is the purpose of your Rebuttal Testimony?

A. Several witnesses have expressed concerns relating to the Staff's proposed use of a "price to beat." I will explain why the Staff proposed the approach and the purpose to which the Staff intended to use the "price to beat" concept. I will discuss APS' and TEP's approach to quantifying their unmet capacity and energy needs, as presented in the Needs Assessments they filed on November 4, 2002. Also, my testimony presents an amendment to the Staff Report that should be considered by the Commission. This change results from discussions held at the Workshop conducted on November 6, 2002, after the issuance of the Staff Report. The amendment will clarify the Staff's position on the issue of how to define "unmet needs." Finally, I discuss the Staff's position regarding communications among the utilities, the Staff, the Independent Monitor, potential bidders, and other persons having an interest in the solicitation process. Finally, I address the Staff's position on issues raised regarding how renewable energy resources should be treated in the initial solicitation.

Q. Please summarize the workshop process and its impact on the Staff's proposed solicitation process.

A. Through the workshop process, the Staff successfully forged agreement among the parties on nearly all of the issues surrounding a competitive solicitation. It is a credit to all those involved that they came together to provide a consensus on what would produce the best solicitation approach.

As the testimony of the parties shows, disagreement remains on a few important points, such as how the amount of the solicitation will be determined and whether pre-approval will be granted by the Commission.

Q. How was the Staff solicitation proposal developed?

A. The Staff used the workshops to first identify and then narrow the issues that needed to be addressed in creating a competitive solicitation process. Next the Staff circulated a draft proposal for comments from the workshop participants, and conducted an additional one-day workshop to refine concerns of the parties and provide an opportunity for the parties to reach agreement. Finally, the Staff revised its solicitation proposal to incorporate workshop comments, and released it to the parties.

Q. Please discuss why the Staff proposed the use of a "price to beat."

A. Several workshop participants, including the utilities, sought an assurance that the power contracts resulting from a solicitation would receive pre-approval by the Commission through the use of an expedited prudence review. The utilities wanted to mitigate the risk of a future disallowance of some or all of the cost of purchase power. The merchants sought regulatory approval in order to make it easier for them to assign the power contract proceeds as a financing tool.

The Staff believed that such a process was, and still is, unworkable because this Commission is unfamiliar with the operation of competitive wholesale power markets, and time is required for careful review of the reasonableness of the Utilities' decisions before full approval can be granted. In particular, the Staff believes that both the bids selected and the reasonableness of each utility's power supply portfolio resulting from the addition to its existing power supplies of the supplies selected will need thorough review. It is the Staff's opinion that the expedited approvals sought could not be issued in the time frame proposed

without unduly compromising its ability to conduct a meaningful analysis of the complex issues that arise from redesigning a power supply portfolio.

At the same time, the Staff understands the parties' desire to have some indication of the likelihood that specific contracts will not be challenged by the Staff when the utility seeks to recover its costs from consumers. To address that need, the Staff proposed to accept as reasonable, without further analysis, the prices contained in specific contracts if they met certain conditions and were at prices below the Staff's "price to beat." As proposed, the Staff would determine the "price to beat" before bids were selected, based on the Staff's review of historic and forecast market prices for delivery of capacity and energy in Arizona.

While the Staff Intention was to support contracts meeting the "price to beat", the Staff did not propose finding all other contracts unreasonable or imprudent. Rather, the Staff reserved judgment so it could, in a thoughtful manner, consider whether the utility exercised reasonable business judgment and whether, when taken as a whole, the utility's power supply portfolio was appropriate.

Q. Why did the Staff decide not to disclose the "prices to beat" it established?

A. The Staff chose not to disclose its "prices to beat" because such a disclosure could bias the decision making process. If the "price to beat" is disclosed prior to bidding, bidders are likely to use it as a target price. If it is disclosed subsequent to bids being submitted but prior to contracts being entered, the utilities may skew their selection to gain the Staff's support. Either result would diminish the effectiveness of the solicitation process. Therefore, the Staff decided not to disclose its "prices to beat", but rather proposed to simply announce which selected bids met the "prices to beat" criteria.

Q. Do the parties to Track B agree with the Staff's proposal?

A. Based on the testimony of several parties, apparently not. Several would require the Staff to disclose the "prices to beat," others believe it will be extremely difficult to establish "prices to beat" while others apparently believe the Staff proposal is inadequate to provide the assurances they seek.

Q. Do utilities presently have their power supply purchases pre-approved by this Commission?

A. To the best of my knowledge, Arizona utilities presently do not have their power supply contracts, or other contracts for goods or services, pre-approved by this Commission. Rather, they exercise their business judgment and enter such contracts in the normal course of business. Those contracts are generally only reviewed at such time as their reasonableness is contested.

Q. Which Staff witness will testify on the Staff's current proposal regarding regulatory approvals?

A. Mr. Johnson of the Staff addresses this issue in his filed testimony.

Q. How does the Staff define the unmet needs for utilities?

A. It is the Staff's belief that unmet needs should be defined as the difference between a utility's capacity and energy requirements, and the amount of capacity and energy that it has available to it at reasonable and competitive cost.

Q. Please explain how the Staff determined the unmet needs of APS and TEP.

A. As explained in the Staff Report at Page 7, the estimates contained in the Staff Report were based on information provided to the Staff by the utilities during the August workshops. The Staff used the capacity requirement and an average system capacity factor provided by the utilities to develop the estimate of unmet needs as presented in the Staff report. The Staff did not attempt to establish precise estimates of the contestable capacity or energy requirements for either utility because unmet needs are fluid. Under the Staff's approach, contestable load and energy would be adjusted during the Pre-Solicitation phase of the process to accommodate changes in projected load and system economics. Final unmet needs are expected to be quantified prior to the issuance of the initial solicitation.

Q. Did the utilities adopt that definition in preparing their needs assessments filed November 4, 2002?

A. No. In particular APS defined unmet needs as the difference between its forecast load and all capacity and energy it was physically capable of producing, irrespective of the cost of that generation.

Q. Did this create a significant difference between what the Staff proposed as unmet needs and what APS proposed?

A. Yes. The current APS approach significantly reduced the amount of energy APS proposed to solicit from what the company identified during the workshop.

Q. Would the APS approach mean that APS would not competitively acquire any significant amount of energy in the 2003 solicitation ?

A. No. According to Mr. Carlson, APS would probably acquire a significant amount of its energy requirement through competitive solicitations for both short-term and economy energy. Mr. Carlson claims APS' approach would meet all of APS' unplanned needs and that the as yet undefined subsequent competitive solicitation for economy energy would displace higher cost APS generation when opportunities to do so occurred.

Q. How did APS propose to acquire that energy?

A. APS proposed to acquire capacity and energy to cover what they call unplanned needs and to purchase economy power, as it has in the past, by relying on the spot market.

Q. Does the Staff disagree with this approach?

A. Not if the utilities make every effort to first solicit for all their unmet needs, including an amount equal to or greater than their anticipated economy energy requirements, in a fair and transparent solicitation.

Q. Then why is there a dispute between the utilities and the Staff regarding the level of unmet needs to be solicited in this initial solicitation?

A. The Staff believes that for the initial solicitation each utility should seek bids for all of the capacity it reasonably expects it will need for the periods it believes are reasonable and for all of the energy it expects to purchase from third parties, in

order to determine market prices for both capacity and energy and to then assess the risks of alternative supply scenarios.

The Staff believes the first solicitation should include (1) all of the additional capacity, including reserves, the utility expects it will need for the periods covered by the solicitation, and (2) all of the energy the utility expects to purchase from third parties for specified time periods. Once bids are received, the utility will be responsible for assessing the risks of accepting each alternative supply scenario. In contrast, APS wants to solicit the capacity it will need, and then procure short term and anticipated economy energy purchases from the spot market, without evaluating the potential benefit of contracting for all unmet energy needs.

Q. Is there a fundamental difference between the Staff's proposal and the utilities' approaches?

A. Interestingly, there is not a fundamental difference. As APS witness, Mr. Carlson stated, APS plans to solicit for three products: capacity only, capacity with minimal energy, and physical "call" options. He also noted that subsequently and as circumstances dictated APS would purchase economy energy.

The Staff believes that, in addition to the products APS proposes to solicit bids for, it should also solicit bids for firm energy and dispatchable energy (whether coupled with bids for capacity or not) in an amount equal to its total unmet needs as defined by the Staff and as finally determined during the pre-solicitation phase of the process proposed by the Staff.

Q. What is the benefit of the approach supported by the Staff?

A. First, it is important to remember that the Staff has taken the position that this process is intended to enable each utility to manage its power supply portfolio in a reasonable manner. The process is not intended to relieve the utilities of their obligation to manage their businesses in a prudent manner, nor is it intended to deprive the utilities of the means and flexibility they need to do so. Soliciting for all of the energy reasonably expected to be purchased from third parties, that is to say unmet needs as defined by the Staff, during the initial solicitation does not obligate the utilities to purchase all of the power sought during the solicitation. As the Staff clearly stated in its Staff Report at Page 16, the utilities have the right to reject all bids if, based on a reasonable rationale, their opinion is that the bids do not meet the needs of the utility and are not in the best interests of consumers. For instance, a utility soliciting firm or dispatchable energy may find that firm energy is available at prices that make the potential benefits of the spot market, with its price volatility, unattractive. The utility may also find that dispatchable energy is available at prices below the utility's marginal costs of generation. Locking in that dispatchable energy during the initial solicitation will assure some consumer benefits and still maintain the flexibility to go to the economy market when circumstances dictate.

Q. That sounds like a very different approach than the one presented by APS. Is it?

A. Not really. Mr. Carlson proposed a solicitation for call options on energy. Call options as Mr. Carlson explains, give the Utility the right to take capacity and energy at predetermined prices when it chooses consistent with the terms of the option. In other words, the utility can in effect dispatch the capacity and energy. Options are in fact a financial proxy for a contract for dispatchable energy.

Q. Has the Staff recalculated its estimate of APS' and TEP's unmet energy needs?

A. We are still in the process of completing that analysis and will provide that information as soon as it is available.

Q. Does the Staff dispute APS' or TEP's quantification of their unmet capacity needs?

A. Yes. APS has quantified its needs based on a reserve level reflecting reserves associated only with APS generation. They argue that firm capacity acquired from third parties will provide reserves and therefore APS will not need to solicit for those reserves. In effect, that approach limits APS' ability to decide when it is most cost efficient to take and pay for reserves offered by bidders, and what cost savings would be realized by APS providing its own reserves.

As Dr. Roach observed, reserves provided by bidders could easily be counted against unmet needs. Recognizing bidders' reserves will also make it easier for the Staff and the Independent Monitor to compare the merits of alternative bids as the evaluation of bids is conducted.

The Staff also has concerns relating to the RMR capacity and energy needs quantified by both APS and TEP. These concerns are addressed by Mr. Smith in his testimony.

Q. You mentioned earlier that you would present a change to the Staff Report. Could you please identify that change and explain why it is being proposed?

A. Yes, at Page 4 of the Staff Report, the Staff would insert the word "economically" on line 20 before the word "served." The Staff proposes this change to make it clear that during the development of the solicitation process, the Staff's intention was to have the vast majority of reasonably expected purchases of capacity and energy acquired through the process proposed by the Staff. The Staff was clear that only power, capacity and/or energy to meet "unplanned needs" would be acquired outside the process. Obviously, the utilities plan to make economy purchases. After they conduct the initial solicitation and acquire all the capacity and energy they deem to be appropriate as a result of that solicitation, they should still take advantage of economy purchases if, and as, they are available. The Staff believes the amount of anticipated economy energy should be solicited on a firm or dispatchable basis, and then evaluated by the utility based on the information it will acquire as a result of the solicitation, to determine whether contracts for power are better alternatives than reliance on spot markets. As stated before, the utility remains responsible for making, and justifying, Its decisions when evaluating bids.

Q. Several parties expressed concerns over how open the Staff's process was and how parties would communicate with the Staff, the Independent Monitor, and the utilities. Would you care to comment on those concerns?

A. Yes. The Staff made every effort to ensure that the process would be as transparent as possible and as accessible to all parties as they could make it. The Staff proposal was developed with the assistance of the workshop parties. Particular interest was paid to transparency and preventing any potential bidder from gaining an unfair advantage, especially utility affiliates.

The Staff's process is designed to encourage open and frank discussion of issues as they arise. It is not the Staff's intention to hinder, in any way, the free flow of conversation between bidders and the utilities, the access to data made available as a result of the solicitation, or the ability of non-bidding parties to attend or participate in meetings held by the utility to discuss their proposed bid packages, or to keep from the utilities concerns developed by the Staff or the Independent Monitor during the solicitation process. On the contrary, as indicated in the Staff Report, there are mandated information requirements for the solicitation and informational meetings to discuss that data, and there are defined obligations of the Independent Monitor to communicate with all parties, including the utilities. There are also requirements that communications by and between utilities and their merchant affiliates with regard to the solicitation be monitored and restricted. Also, all bidders should have access to the same data, so all communications between utilities and bidders will be made available to all bidders on a web site. The Staff believes that the standards set out in its proposed process will allow the process to progress in an orderly and appropriate fashion.

Q. Mr. Kendall, representing Wellton-Mohawk Generating Facility, recommended in his Direct Testimony (pages 4 and 5) that in the competitive procurement process, utilities give additional credit to renewable resources for their public benefits. What is the Staff's position on this issue?

A. The Staff believes that bidders of renewable resources should be allowed to bid in this initial solicitation and that utilities should not be required to give credit for the value of the renewable resource to the utility in meeting the Environmental Portfolio Standard. However, whether such credits should be

required in subsequent solicitations should be considered in any future review of the process adopted.

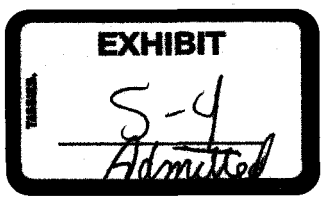
Q. On page 17 of his Direct Testimony, Mr. Kendall recommends that renewable resources be specifically solicited in Track B and that separate renewables-only solicitations may be held as needed. What is the Staff's position on this issue?

A. The Staff believes that the utilities may solicit renewable resource products through the competitive procurement process. In addition, renewables-only solicitations may be held. However, utilities should be allowed to solicit renewable resource products in the initial solicitation.

Q. Does that conclude your testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION



WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	)	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	)	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	)	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	)	DOCKET NO. E-01933A-02-0069

TRACK B REBUTTAL TESTIMONY

OF

JERRY D. SMITH

ELECTRIC UTILITIES ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

November 18, 2002

SUMMARY
TRACK B REBUTTAL TESTIMONY
JERRY D. SMITH
GENERIC ELECTRIC RESTRUCTURING DOCKET
DOCKET NO. E-00000A-02-0051, ET. AL.

Mr. Smith's Track B rebuttal testimony identifies discrepancies and omission of RMR capacity and energy figures in the APS and TEP Track B needs assessment filings. In addition, he restates Staff's position regarding when RMR capacity and energy are legitimately contestable. Mr. Smith's testimony concludes with a Staff recommendation of including APS and TEP RMR capacity and energy in the contestable load tables of Staff's Track B report. He also recommends that the RMR Study results filed by APS and TEP with the Commission by January 31, 2003, should be used to adjust Staff's recommended contestable load offered in Track B.

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INTRODUCTION

Q. Please state your name and business address.

A. Jerry D. Smith, 1200 West Washington, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("Commission") as an Electric Utilities Engineer for the Utilities Division.

Q. Please summarize your educational background.

A. I graduated from the University of New Mexico with a Bachelor of Science degree in Electrical Engineering. I received a Masters of Science degree in Electrical Engineering from New Mexico State University majoring in power systems and electric utility management.

Q. Do you hold any special licenses or certificates?

A. I am licensed with the State of Arizona as a Professional Engineer - Electrical.

Q. Have you previously submitted testimony on behalf of Arizona Corporation Commission Staff in Track A and Track B proceedings?

A. Yes, I have. I submitted direct and rebuttal testimony in Track A proceedings and contributed to the Staff Report filed in both the Track A and Track B proceedings.

Q. Did you participate in the Track B workshops?

A. Yes, I attended and participated in each of the Track B workshops.

Q. Are you sponsoring the Track B Staff Report, which was filed on October 25, 2002?

A. Yes, I am one of the three witnesses sponsoring the Track B Staff Report.

PURPOSE OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony in these proceedings?

A. My rebuttal testimony will respond to specific segments of Track B direct testimony provided by Peter M. Ewen, David Hutchens, Dr. Craig Roach, Curtis L. Kebler, and Robert W. Kendall. My rebuttal testimony focuses on the following topics:

1. Local service area transmission import constraints for the Arizona Public Service Company ("APS") and Tucson Electric Power ("TEP");
2. Reliability Must-Run ("RMR") generation requirements associated with the above transmission import constrained areas; and
3. Staff recommended treatment of RMR capacity and energy requirements in the competitive solicitation process.

Q. Please summarize the contents of your rebuttal testimony.

A. My testimony identifies discrepancies and omission of RMR capacity and energy figures in the APS and TEP Track B needs assessment filings. In addition, I restate Staff's position regarding when RMR capacity and energy are legitimately contestable. My testimony concludes with a Staff recommendation of including APS and TEP RMR capacity and energy in the contestable load tables of Staff's Track B report. I suggest the RMR Study results filed with the Commission by January 31, 2003, should be used to adjust the recommendation about contestable load offered by Staff in Track B.

LOCAL TRANSMISSION IMPORT CONSTAINTS

Q. Please describe how transmission constraints impact the "contestable capacity and energy" levels procurable from the competitive wholesale market.

A. Transmission constraints limit what capacity and energy can be delivered from particular generators over particular lines to the intended load. Furthermore, a Reliability Must-Run (RMR) condition exists, for a geographic area, during any period of time that local load exceeds the transmission import capability for that local area. When that occurs, the load

serving utility must rely upon local generating units to serve the amount of load that exceeds the local transmission import limit. When determining how much energy and capacity should be procured by competitive solicitation, it is necessary to (i) accurately define the extent of transmission constraints, (ii) determine what hours of the which days the constraints occur, and (iii) what generating units can meet RMR requirements.

Q. How is this relevant to this proceeding?

A. In the case of APS, the utility has suggested that only units it owns can meet RMR needs, though the company has agreed to entertain bids for RMR service. The result is the utility claiming that RMR capacity and energy should not be considered contestable when procuring capacity and energy from the competitive wholesale market. This approach has the potential to diminish the benefits to be derived from competitive bidding, and serve to encourage the utility to continue using generating plants within a constrained area, and not looking to meet system needs from cheaper and cleaner sources.

Q. APS and TEP filed needs assessments in accordance with the third procedural order on Track B issues dated October 9, 2002. Have APS and TEP accurately defined their transmission import constraints for their respective local service areas in their needs assessments?

A. There are inaccuracies in the transmission import limits reported by APS. Mr. Peter Ewen identifies the APS transmission import limit for metro Phoenix as being 3535 MW from 2003 through 2012.[1] This import capacity assumes 600 MW of additional APS transmission import capacity resulting from construction of the Palo Verde to Rudd 500 kV line by the summer of 2003. However, Staff confirmed with APS and SRP during the October 18th 2002 Biennial Transmission Assessment workshop that only half of that import capacity addition would actually be realized. Similarly, it was confirmed that APS would share in each 600 MW transmission import capacity increase assumed to result

[1] Work Papers, APS Metro Phoenix Reliability Must Run Estimates, Peter M. Ewen, November 4, 2002, page 76.

from the addition of the Palo Verde to Southeast Valley 500 kV line in 2006, and the Palo Verde to Table Mesa 500 kV line in 2008. Neither of these two transmission import improvements was acknowledged by Mr. Ewen in his Reliability Must Run Estimates. In addition, Mr. Ewen ignored the transmission import constraints known to exist for APS' Yuma service area.

Neither transmission import capacity nor RMR capacity and energy calculations were included in TEP's needs assessment filed by David Hutchins on November 4.[2] Therefore, Staff will use information about transmission import constraints for the Tucson area presented by TEP throughout the electric restructuring proceedings and the Biennial Transmission Assessment workshops. Its transmission import capability is dependent upon the combination and output of local generating units in service.

Q. What are the consequences of the local transmission import capacity inaccuracies and omissions from the APS and TEP filed needs assessments?

A. In the case of APS, it means the RMR capacity and energy is understated in 2003 through 2006 and overstated in later years. In other words, the unmet RMR capacity and energy needs are similarly understated from 2003 to 2006 and overstated in later years. In the case of TEP, it means we have no record of RMR capacity and energy components in their needs assessment.

RELIABILITY MUST-RUN GENERATION REQUIREMENTS

Q. Did Staff include RMR capacity and energy in the contestable capacity and energy tables[3] of its Track B Staff Report?

A. No, we did not. Staff did not have adequately defined RMR capacity and energy numbers available at the time of the report. Such information still is not available to Staff as stated

[2] Track B Needs Assessment and Procurement Proposal, David Hutchins, November 4, 2002.
[3] Staff Report on Track B: Competitive Solicitation, October 25, 2002, page 7.

earlier in this rebuttal testimony. In fact, that is why Staff took particular steps to include the deliverability qualifications section of our recommended solicitation process.[4]

Q. Does Staff support the supposition that RMR capacity and energy should be considered contestable for the 2003 competitive solicitation?

A. Staff believes RMR capacity and energy should be considered contestable. Throughout the Track B workshops, Staff has stated conditions under which RMR capacity and energy could be contestable. Dr. Craig Roach has eloquently captured those conditions in his testimony.[5] RMR capacity and energy could be contestable if: 1) non-utility owned or non-rate based generation units exist locally, 2) remote generation has access to non-APS or non-TEP firm transmission capacity to delivery to the respective local area, or 3) remote generation offers to finance transmission improvements to mitigate the transmission import constraint. While the third condition may not be achievable within the early years of the 2003 solicitation, it may be feasible for the later years.

Q. Mr. Curtis L. Kebler expressed concerns about the RMR hours, capacity and energy not being known until a decision in the Track B process is rendered.[6] Does Staff share this concern?

A. Yes, we do. However, transmission providers have committed to an RMR Study Plan that will be documented in the 2002 Biennial Transmission Assessment. That commitment includes an agreement to perform RMR Studies for years 2003-2007 to be filed with the Commission in January 2003. The identification of RMR hours, capacity and energy is one of the study requirements. Refinement of the transmission import limitation is also a requirement of that study. The resulting study information will then be available to incorporate in the pre-solicitation activities of the 2003 competitive solicitation process.

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[4] Ibid, pages 15 and 18.
[5] Testimony of Dr. Craig R. Roach, TECO/Panda Gila River, November 12, 2002, page 27.
[6] Direct Testimony, Reliant Resources, Curtis L. Kebler, November 12, 2002, page 16.

Q. Mr. Robert Kendall suggests that the competitive solicitation process is an ideal mechanism to use to identify any generation solutions that could help resolve local transmission import constraints and associated RMR conditions.[7] Does Staff agree?

A. Yes, Staff agrees with Mr. Kendall on this point. In fact, his reference to Track A Decision No. 65154 ordering that APS and TEP work with Staff to develop a study plan to resolve RMR generation concerns and include the resulting plans in the 2004 Biennial Transmission Assessment is on point. Including RMR capacity and energy as contestable load in the 2003 competitive solicitation will offer a market response reference for Staff regarding the relative economic and environmental merits of generation solutions to the transmission import constraint. Such a comparison is most important before finalizing the ten-year RMR study plan results to be incorporated into the 2004 Biennial Transmission Assessment.

TREATMENT OF RMR IN CONTESTIBLE LOAD DETERMINATION

Q. How does Staff propose RMR capacity and energy be handled in the contestable load determination?

A. Staff recommends that APS and TEP RMR capacity and energy be added to the contestable load tables provided at page 7 of the Track B Staff Report.

Q. How does Staff propose to determine what quantity of APS and TEP RMR capacity and energy should be included in Staff's definition of contestable load for the 2003 competitive solicitation?

A. Staff agrees with Mr. Ewen that his metro Phoenix RMR figures should serve as a place holder until completion of the RMR study to be filed with the Commission by January 31, 2003.[8] The capacity need identified as "RMR Need" and the energy identified as "Total Energy" in Mr. Ewen's Metro Phoenix Reliability Must Run Estimates should be used for this purpose.[9] Staff's

[7] Direct Testimony, Welton-Mohawk Generation Facility, Robert W. Kendall, November 12, 2002, page 24.
[8] Track B Testimony, APS, Peter M. Ewen, November 4, 2002, page 21.
[9] Work Papers, APS Metro Phoenix Reliability Must Run Estimates, Peter M. Ewen, November 4, 2002, page 76

Track B contestable recommendation should include these RMR figures. As the RMR Study for the Phoenix area progresses, the APS transmission import capacity and contestable RMR figures should be adjusted accordingly.

In addition, APS should develop similar RMR figures for the Yuma area. Similarly, TEP should develop RMR figures for the Tucson area. The basic foundation of this information, at least the RMR capacity number is available from the Biennial Transmission Assessment. It is Staff's opinion that such numbers should be developed early in the required RMR study effort and should be added to the contestable load quantities approved by the Commission in Track B.

Q. How does Staff recommend RMR conditions should be administered?

A. Staff recommends that APS and TEP should administer RMR conditions in accordance with applicable Arizona Independent Scheduling Administrator (AzISA) or WestConnect protocol approved by FERC.

Q. Does that conclude your testimony?

A. Yes.

EXHIBIT
1 S-5
Admitted

STAFF REVISED CONTESTABLE LOADS ESTIMATE
GENERIC ELECTRIC RESTRUCTURING - TRACK B
DOCKET NO. E-00000A-02-0051, ET AL

CAPACITY (MW)

YEAR	2003	2004	2005	2006
Net Unmet Reliability Needs[1]	1661	1935	2055	2151
APS Phoenix Resources[2]	660	660	660	660
APS Yuma Resources[3]	139	139	139	139
APS	**2460**	**2734**	**2854**	**2950**
TEP Retail Load[4]	1890	1956	1993	2030
-Transmission Import Limit[5]	-1132	-1132	-1132	-1132
TEP	**758**	**824**	**861**	**898**

ENERGY (GWH)

YEAR	2003	2004	2005	2006
Net Unmet Reliability Needs[1]	639	840	1228	1469
APS Phoenix Supplied[2]	37	90	165	263
APS Yuma Supplied	0	0	0	0
Economy Purchase[6]	3705	4033	6695	6948
APS Short Term Hedge[7]	215	0	0	0
APS	**4381**	**4963**	**8088**	**8680**
Unmet Needs[8]	50	46	120	104
Local Generation Supplied[9]	0	0	0	0
TEP	**50**	**46**	**120**	**104**

[1] Schedule PME-1, Peter M. Ewen, November 4, 2002 adjusted to include 15% reserves for all load.
[2] Work Papers, APS Metro Phoenix Reliability Must Run Estimates, Peter M. Ewen, November 4, 2002, page 76.
[3] Schedule PME-9, Peter M. Ewen, November 4, 2002.
[4] Exhibit 5, Track B Needs Assessment and Procurement Proposal, David Hutchins, November 4, 2002.
[5] Ibid, existing capability with no local generation plus 182 MW for Saguaro to Tortolita 500 kV line #2 in 2003.
[6] Schedule PME-, Peter M. Ewen, November 4, 2002.
[7] Work Papers, APS Monthly Generation By Resource Type, Peter M. Ewen, November 4, 2002, page 99.
[8] Exhibit 1, Track B Needs Assessment and Procurement Proposal, David Hutchins, November 4, 2002.
[9] To be determined, excludes energy for 95 MW of combustion turbines (at least 1,000 GWH annually).

Wellton-Mohawk

1 - 4

EXHIBIT
W-1
admitted

WELLTON-MOHAWK GENERATING FACILITY'S FIRST SET OF
DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630, E-01933A-02-0069
TRACK B
November, 6, 2002

RK 1.7 Please provide a year-by-year listing of APS's unmet EPS renewable resource requirement under the EPS.

RESPONSE:

See Attachment [ATTACHMENT WM DR 1 Q. RK 1.7]

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Solar electric (or equivalent EPS credits) required (MWh)	75,194	124,982	161,573	174,789	188,440	193,803	199,130	204,697	210,288	215,909
Solar electric (or equivalent EPS credits) planned (MWH) *	15,745	23,428	32,535	38,466	48,698	55,479	62,261	76,050	82,832	83,832
Shortfall (MWh)	59,449	101,554	129,038	136,323	139,742	138,324	136,869	128,647	127,456	132,077
" Other" (or equivalent EPS credits) required (MWh)	75,194	83,322	107,715	116,526	125,627	129,202	132,753	136,465	140,192	143,940
"Other" (or equivalent EPS credits) planned (MWh) *	35,301	75,419	100,385	125,351	133,235	172,874	193,898	233,537	254,561	254,561
Shortfall (MWh)	39,893	7,903	7,330	(8,825)	(7,608)	(43,672)	(61,145)	(97,072)	(114,369)	(110,621)

* Includes off-grid applications and multipliers not appropriate for determining APS unmet needs.
* Please note this assumes current funding levels. To the extent the funding levels are increased, APS' shortfall would be reduced accordingly.

EXHIBIT W-1
WITHDRAWN

NEWS RELEASES

TO: EDITORS, NEWS DIRECTORS **DATE:** February 1, 2001
FOR: IMMEDIATE RELEASE

Commission Issues Mandate Requiring Renewable Energy Technologies

PHOENIX - Arizona is one of the leading states in the nation to support the use of renewable energy sources for electric power generation. In May 2000, the Arizona Corporation Commission adopted a renewable portfolio standard requiring that utilities derive a portion of their electricity through renewable sources. The May decision ordered Commission staff to begin the rulemaking process. The Commission on Tuesday voted to codify the Environmental Portfolio Standard, as it's now known, as a formal rule.

The Environmental Portfolio Standard requires regulated utilities to generate a minimum of 0.2 percent of their total retail energy sales from renewable sources in 2001. The percentage will increase each year to 1 percent in 2005 and top out at 1.1 percent in 2007. The decision applies to all load-serving entities - companies that sell retail electricity in Arizona.

The Renewable Portfolio Standard covers solar technologies such as solar generation, solar water heating and solar air conditioning. Non-solar technologies such as landfill gas generators, wind generators and biomass generators are also qualifying technologies.

Key provisions of the Environmental Portfolio Standard are:

- Solar must make up at least 50 percent of the Environmental Portfolio resources in 2001. The remaining 50 percent can be other environmentally friendly technologies, solar hot water or research and development on solar electric resources. Research and development must be limited to 10 percent or less.

- All load-serving entities must meet the following portfolio requirements. The percentages are based on total retail energy sold.

- 0.2% in 2001
- 0.4% in 2002
- 0.6% in 2003
- 0.8% in 2004 - The Commission will review the costs and benefits of the portfolio requirement at this point to determine if the percentage should be frozen at 0.8% for a period of time or if it should continue to increase as currently anticipated.
- 1.0% in 2005
- 1.05% in 2006
- 1.1% from 2007 to 2012

- From 2004 through 2012 the portfolio must be 60 percent solar electric with no more than 40 percent solar hot water or other environmentally friendly renewable electricity technologies.

- The Commission's Utilities Division will establish an Environmental Portfolio Cost Evaluation Working Group in 2003. The group will assess the costs and benefits of the Portfolio and make recommendations as to whether the portfolio percentages should be increased.

- The Environmental Portfolio Standard also includes extra credit multipliers to encourage the early installation of these environmentally friendly technologies.

Are rates affected?

Beginning this spring, Arizona ratepayers will pay a portion of the costs associated with the increased investment in environmentally friendly technologies. The Environmental Portfolio Surcharge will be $0.000875 per kilowatt-hour when it takes effect. The Commission has set a rate cap for three different categories of ratepayers. There is a monthly cap of 35 cents for all residential customers. A typical residential customer who uses 400 kilowatt-hours or more will be assessed 35 cents per month. According to APS, approximately twenty-five percent of their residential customers use less than 400 kilowatt-hours per month and are therefore expected to be assessed less than 35 cents.

Business accounts will be assessed the same monthly surcharge rate of $0.000875 per kilowatt-hours. Over 99 percent of non-residential accounts will be subject to a maximum cap of $13.00 per month. Hotels, schools, office buildings and most medium to large retail stores are likely to reach the $13.00 cap. Smaller businesses such as beauty salons, barbershops, strip mall stores and others will probably fall below the $13.00 monthly assessment.

A $39.00 cap will apply to the state's largest non-residential users - those using more than 3 megawatts of power such as mining facilities and large manufacturing plants. There are fewer than 100 accounts statewide that will be affected by the larger monthly cap.

The Commission is committed to encouraging investment in renewable technology in Arizona without adversely impacting ratepayers. The Commissioners believe that this decision balances the need for sound environmental policy with sensitivity to ratepayers' concerns.

Voting in favor of the rules, Commissioner Marc Spitzer said: "Billions of dollars are being spent on clean air and clean water. It only follows that the utilities should be encouraged to invest in clean energy technologies. This, I believe, is a good example of government balancing the sometimes competing interests of cost with the very real issue of preserving our environment."

"The Environmental Portfolio Standard breaks new ground for Arizona," Commissioner Jim Irvin said. "If we are ever going to see a broader mix of fuels, we have to take the first step. My vote in favor of the rules sends a message that the time is now."

Chairman Bill Mundell cast the final vote in favor of the Environmental Portfolio Standard saying: "It is critical to encourage electricity providers to reduce their reliance on fossil fuels. Government has a responsibility to encourage change where public health and safety can be enhanced. These measures are intended to bring down the cost of solar and other renewable energy technologies so they become more cost competitive with other energy sources."

A copy of the Commission's final order will be posted on the Arizona Corporation Commission website, www.cc.state.az.us. It will be under Hot Topics, Electric Competition in the section labeled "Renewable Portfolio Standard Developments."

EXHIBIT W-2

WELLTON-MOHAWK GENERATING FACILITY'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630, E-01933A-02-0069
TRACK B
November, 6, 2002

RK 1.8 Please provide a year-by-year estimate of funds to be collected from ratepayers pursuant to the EPS surcharge and the reallocation of APS's Public Benefits Charge to renewable resources.

RESPONSE:

The following are the estimates of SBC and EPS funds collected by year for the forecast period.

Year	System Benefit Charge	Environmental Portfolio Standard	TOTAL
2003	$ 6,000,000	$ 7,068,787	$ 13,068,787
2004	$ 6,000,000	$ 7,430,676	$ 13,430,676
2005	$ 6,000,000	$ 7,741,307	$ 13,741,307
2006	$ 6,000,000	$ 8,057,741	$ 14,057,741
2007	$ 6,000,000	$ 8,382,691	$ 14,382,691
2008	$ 6,000,000	$ 8,726,767	$ 14,726,767
2009	$ 6,000,000	$ 9,079,191	$ 15,079,191
2010	$ 6,000,000	$ 9,434,034	$ 15,434,034
2011	$ 6,000,000	$ 9,734,709	$ 15,734,709
2012	$ 6,000,000	$ 10,031,597	$ 16,031,597

EXHIBIT W-3

Arizona Corporation Commission
NEWS RELEASES

TO: Editors, News Directors **DATE: February 27, 2002**
FOR: Immediate Release

COMMISSION APPROVES BOWIE POWER PROJECT
Requires Use of Solor Technology & Groundwater Monitoring Program

PHOENIX - In a decision yesterday, the Arizona Corporation Commission approved the Bowie Power Station proposed for eastern Cochise County in southeastern Arizona. The project, to be constructed in two 500-megawatt phases, is a water-cooled power plant using a maximum of 6,000 acre-feet of groundwater per year when both units are operating continuously at full output. SouthWestern Power Group II is the project developer.

The approval requires SouthWestern to install solar technology when they begin building the second power block. This is the first merchant power plant that is required to incorporate solar technology as a core part of the total project. Merchant power plants supply power to the wholesale market as opposed to power plants built by a utility with the primary objective of serving its own customers.

During Tuesday's meeting, the Commission accepted the 22 restrictions placed on the project by the Arizona Power Plant and Transmission Line Siting Committee. After hearing from several representatives of the Bowie and Willcox communities, the Commissioners approved an amendment offered by Commissioner Spitzer. The Spitzer amendment specifically addresses concerns by nearby pistachio farmers that groundwater pumping could affect the surrounding water table.

Summary of the Spitzer Amendment: The amendment requires SouthWestern Power Group II to establish and pay for a groundwater monitoring program that meets Arizona Department of Water Resources criteria. Once the project is operating, the SouthWestern will have to establish and make annual contributions of $100,000 to a

of $500,000. Any business or individual who can prove, through successful arbitration, that groundwater pumping has caused property or economic damage will be able to submit a claim for reimbursement. SouthWestern will be required to maintain a total balance of $500,000 in the fund.

Status reports on the program are to be filed with the Town of Bowie, the Pistachio Pass Irrigation District and the Cochise County Board of Supervisors. The Groundwater Impact Mitigation Fund must be maintained for three years after the plant ceases operation and is decommissioned.

Commissioner Marc Spitzer said the amendment was prudent considering that the lasting impact of the power project. "I proposed this amendment to answer the concerns of the pistachio farmers and the irrigation district," Commissioner Marc Spitzer said. "Although we heard testimony that the power plant's groundwater needs would be less than if the land were farmed, I don't think you can be too careful. We're making decisions that could affect an economically depressed area for generations to come."

Other Environmental Conditions: Twenty-two conditions were imposed by the Arizona Power Plant and Transmission Line Siting Committee. They include:

· Establishment of a monitoring project and mitigation fund for ground subsidence and earth fissure monitoring. Subsidence is a potential side effect of groundwater pumping. Cracks, fissures or dips can form in the surface of the earth because the water deep underground that provided physical support is no longer there.

· Contributions to the Bowie Fire District to enable it to acquire an additional emergency services vehicle as well as funding of emergency response and hazardous materials training for firefighters.

· Making arrangements with local law enforcement and the Cochise County Sheriff because the project will involve an increase in traffic and may result in the need for emergency responses by local law enforcement. This was an amendment sponsored by Commissioner Jim Irvin.

· Prior to construction of the facility, SouthWestern must provide the Commission with a technical study showing that sufficient transmission capacity exists to accommodate the output of the plant and the effect of its output on reliable operation of the electric grid.

· Conditions requiring compliance with air and water quality standards imposed by the Arizona Department of Environmental Quality and the Arizona Department of Water Resources. Additionally, the applicant

will have to participate in and comply with all standards for safe, reliable power delivery.

"I was pleased to support this project, in part because it includes solar technology as a key component of the whole project. The level of support from the local community was also impressive. Les Thompson, Chairman of the Cochise County Board of Supervisors indicated that Bowie has one of the highest tax rates of any Arizona community," Chairman Bill Mundell explained. "The residents and business people were very excited about the tax and economic development benefits of having the power plant in their community. Additionally, the project will bring several hundred construction jobs to Bowie and Willcox and, ultimately, the 30 or 40 people needed to run the plant."

Commissioner Irvin voted in favor of the project, saying: "I do believe the need for this project was established in the record. Further, I believe the project is in the public interest and meets the balancing test." He was referring to the siting statute that requires the Commission "to balance, in the broad public interest, the need for an adequate, economical and reliable supply of electric power with the desire to minimize the effect thereof on the environment and ecology of this state." (Arizona Revised Statutes § 40-360.07, subsection B.)

For more information about recent power plant sitings, visit the Arizona Corporation Commission's website at http://www.cc.state.az.us/news/index.htm.

EXHIBIT W-4

NEWS RELEASES

TO: Editors, News Directors **DATE: April 10, 2002**
FOR: Immediate Release

Commission Approves La Paz Generating Facility

41 Conditions Address Environmental & Operational Compliance

PHOENIX - In a 2-1 vote Monday, the Arizona Corporation Commission approved La Paz Generating Facility proposed for La Paz County in southwestern Arizona. When completed in 2005, the power plant will be capable of delivering 1,080 megawatts to the power grid. Allegheny Energy Supply, the project developer, expects to begin construction on the $540-million natural gas fired plant later this year.

The plant will include a 100-kilowatt solar array that will augment the project's own electricity use. This is the second merchant power plant that is required to incorporate solar technology as a core part of the total project. Merchant power plants supply power to the wholesale market as opposed to power plants built by a utility with the primary objective of serving its own customers.

The developers had strong support from the communities surrounding the project site, which is in a sparsely populated part of Arizona.

During Monday's meeting, the Commission accepted the 40 restrictions placed on the project by the Arizona Power Plant and Transmission Line Siting Committee.

An amendment from Commission Chairman Bill Mundell changed one of the Siting Committee's conditions dealing with the amount of water the company must purchase and recharge into nearby aquifers. Over the next 30 years, the La Paz Generating Facility will have to recharge 100,000 acre-feet of water through nearby recharge projects or purchase and permanently retire the irrigation rights of existing agricultural lands. At least 50,000 acre-feet of the recharge or irrigation retirement obligation must be made in the first 10 years.

Commissioner Jim Irvin sponsored an amendment that requires the project developer to establish a program with a local community college, labor union or contractor to fill skilled positions for the construction, operation and management of the power plant. All three Commissioners supported the amendment to facilitate safe operations and add job opportunities to a region of Arizona that has seen many businesses, primarily agricultural, leave.

Other Environmental Conditions: Forty conditions were imposed by the Arizona Power Plant and Transmission Line Siting Committee. They include:

- Prior to construction of the facility, Allegheny must provide the Commission with a technical study showing that operation of the plant will not compromise the reliable operation of the interconnected transmission system.

- If upgrades to the transmission system are necessary, the study will have to identify the upgrades to be completed before the project commences commercial operations.

- Groundwater withdrawal is anticipated to be under 6,500 acre-feet per year operating at full capacity but the total annual pumping cannot exceed the amount of water spelled out in Arizona Revised Statute §45-440(A).

- Establishment of a monitoring project for ground subsidence and earth fissures. Subsidence is a potential side effect of groundwater pumping. Cracks, fissures or dips can form in the surface of the earth because the water deep underground that provided physical support is no longer there.

- Before selling power elsewhere, La Paz Generating Station must first offer wholesale power to companies serving power to Arizona users.

- The plant operators must try to use qualified Arizona contractors and encourage the hiring of qualified local employees.

- Allegheny will have to coordinate activities to minimize construction and operational impacts on local wildlife and native vegetation. A biologist and archeologist will monitor all ground clearing and construction activities.

- Other conditions require compliance with air and water quality standards imposed by the Arizona Department of Environmental Quality and the Arizona Department of Water Resources.

Commissioners Jim Irvin and Commissioner Marc Spitzer voted in favor of the project. Chairman Bill Mundell had proposed three amendments seeking to require dry cooling, a technology that would cut the amount of groundwater used at the plant. After all three amendments failed, Chairman Mundell voted against the plant.

For more information about recent power plant sitings, visit the Arizona Corporation Commission's website at http://www.cc.state.az.us/news/index.htm.

Back

EXHIBIT W-5

WELLTON-MOHAWK GENERATING FACILITY'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630, E-01933A-02-0069
TRACK B
November, 6, 2002

RK 1.7 Please provide a year-by-year listing of APS's unmet EPS renewable resource requirement under the EPS.

RESPONSE:

See Attachment [ATTACHMENT WM DR 1 Q. RK 1.7]

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Solar electric (or equivalent EPS credits) required (MWh)	75,194	124,982	161,573	174,789	188,440	193,803	199,130	204,697	210,288	215,909
Solar electric (or equivalent EPS credits) planned (MWH) *	15,745	23,428	32,535	38,466	48,698	55,479	62,261	76,050	82,832	83,832
Shortfall (MWh)	59,449	101,554	129,038	136,323	139,742	138,324	136,869	128,647	127,456	132,077
" Other" (or equivalent EPS credits) required (MWh)	75,194	83,322	107,715	116,526	125,627	129,202	132,753	136,465	140,192	143,940
"Other" (or equivalent EPS credits) planned (MWh) *	35,301	75,419	100,385	125,351	133,235	172,874	193,898	233,537	254,561	254,561
Shortfall (MWh)	39,893	7,903	7,330	(8,825)	(7,608)	(43,672)	(61,145)	(97,072)	(114,369)	(110,621)

* Includes off-grid applications and multipliers not appropriate for determining APS unmet needs.
* Please note this assumes current funding levels. To the extent the funding levels are increased, APS' shortfall would be reduced accordingly.

Arizona Public Service
Renewable Energy RFP

EXHIBIT
W-2
Admitted

Request for Proposals

Energy Requirements:

The following is an estimate of the renewable energy required each year by APS over the years 2001 to 2010.

Year	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
GWh*	45	94	145	200	258	281	304	314	325	336

The EPS allows this energy to be composed of both solar electric energy and "other" renewable energy generated from resources such as wind, landfill gas, biomass etc.

Estimates of the minimum amount of solar electric energy and the maximum amount of "other" renewable energy that APS is allowed to derive each year over the years 2001 to 2010 are shown below.

Year	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Minimum Solar (GWh)	23	47	73	120	155	168	182	189	195	202
Maximum "other" (GWh)	23	47	73	80	103	112	122	126	130	134

* 1GWh = 1,000,000 kWh

R14-2-1618. Environmental Portfolio Standard:

A copy of "Attachment B" to the ACC decision, as it is currently written, is enclosed and contains relevant information regarding the sources of energy that can be considered and also information on certain multiplier credits that can be used to, in effect, reduce the actual energy that needs to be generated to be in compliance with the mandate.

Required Information:

Respondents to this invitation are requested to address the following parameters in their proposals to the extent possible to allow APS to evaluate the response and determine a value of the energy package being proposed.

All information submitted will be considered confidential and will be used solely for internal evaluation purposes.

Arizona Public Service
Renewable Energy RFP

1. CHARACTERISTICS OF THE POWER SUPPLY

- A general description of the resource, fuel source, etc.
- Firm/Non-Firm - is the generation unit contingent or backed by multiple units or by an electric utility system?
- Does delivery carry with it a provision for liquidated damages for non-performance?
- What is the availability factor and is this guaranteed daily, monthly, annually, etc.?
- What is the expected production pattern (seasonally, hour of day, etc.)?
- What is the potential in variability of production? (any information which might help APS further define the resource value)

2. DELIVERY LOCATION

- Where will the energy be delivered to the APS system?
- At what voltage will the energy be delivered?
- Is new transmission required to be built?

3. PRODUCT SHAPE

- Describe the specific hours of delivery
- Is there any option for APS to shape the product the way it wants? (i.e. could APS refuse to take at some hours or back down quantities at certain hours?)

4. TERM OF AGREEMENT

- What is the term of the purchased power agreement
- Is there any option to extend the agreement? If so, for which party?
- What is the minimum term acceptable for the project?
- What is the maximum term acceptable for the project?

5. PRICING

- What pricing structure is required by the contracting party - fixed or floating?
- If a floating indexed structure is chosen, what index is proposed?
- Would a gas index applied against a heat rate be potentially acceptable?

6. CREDIT REQUIREMENTS

- The specific contracting party legal name is required
- Provide financial data on the contracting party for review
- How is the project being financed?

7. EMISSION / GREENHOUSE ISSUES

- What are they?
- Are allowances provided to APS along with the purchased power?

8. GENERAL INFORMATION

- What experience does the contracting party have with similar power purchase projects?
- Provide the name, address and telephone number of the contact person for the contracting party.

9.RESPONSES

- Four (4) copies of the response should be sent to the following address

Peter Johnston
Manager, Technology Development
M/S 8931
Pinnacle West Capital Corporation
400 N 5th Street
Phoenix, AZ 85004

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
W-3
Admitted

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING ELECTRIC RESTRUCTURING ISSUES.	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069

DIRECT TESTIMONY OF

ROBERT W. KENDALL

ON BEHALF OF

WELLTON-MOHAWK GENERATING FACILITY

NOVEMBER 12, 2002

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RESUME OF ROBERT W. KENDALL .....ATTACHED

SCHEDULE RWK-1: ENVIRONMENTAL PORTFOLIO STANDARDS IN STATES .....ATTACHED

INTRODUCTION

Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A. My name is Robert W. Kendall. My business address is 225 West Broadway, Suite 400, Glendale, California 91204-1331.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND EXPERIENCE.

A. Appendix 1, which is attached to this Direct Testimony, describes my professional qualification and experience.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am providing expert testimony on behalf of the Wellton-Mohawk Generating Facility ("WMGF").

Q. CAN YOU DESCRIBE THE WELLTON-MOHAWK GENERATING FACILITY?

A. WMGF is a generation project being developed in southwestern Arizona. WMGF will be a natural gas fired 620 MW (peak) combined cycle generating facility constructed on land to be owned by the Wellton-Mohawk Irrigation and Drainage District ("WMIDD") and leased to the project, located about 25 miles east of Yuma, Arizona and 9 miles west of Wellton, Arizona. The project will be constructed in two phases with the first phase of 310 MW (peak) projected to be

in commercial operation by spring 2005. The project participants in WMGF are Dome Valley Energy Partners LLC ("Dome Valley"), WMIDD, and the Yuma County Water Users Association ("YCWUA"). It is expected that the members of Dome Valley will be Jasper Energy Development LLC ("Jasper") and Primesouth, Inc., a wholly owned subsidiary of the SCANA Corporation.

WMGF is unique in that it intends to utilize the patented SEECOT™ Solar Thermal Technology to increase efficiency by converting solar energy into thermal energy for inlet air-cooling of the Combustion Turbine Generator ("CTG"). This would result in an approximate 12 percent increase in CTG electric output during times of peak solar radiation, as well as improved efficiency and/or a lower heat rate. Using this system, WMGF will generate kilowatt-hours that qualify as renewable energy credits under Arizona's Environmental Portfolio Standard ("EPS") and that qualify as renewable energy purchases under similar programs in both Nevada and California.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide recommendations for consideration by the Arizona Corporations Commission ("ACC" or "Commission") on several key issues relevant to the Track B Competitive Solicitation Process ("Track B" or "Competitive Solicitation Process") to be conducted in March 2003, as formulated by Staff in the Staff Report submitted in this proceeding. I also intend to respond

to testimony submitted in this proceeding by Arizona Public Service ("APS"). WMGF fully agrees with the goals for the solicitation articulated by the Staff—that the process facilitates a manageable transition to a competitive wholesale power market that provides reliable power and economic benefits to Arizona's consumers over the long term and that the process is open, transparent, understandable, and flexible. WMGF also believes that the process can and should be designed in a manner to encourage the achievement of two additional public policy goals; namely, (1) the elimination or mitigation of the reliability must run ("RMR") issues in Arizona's Phoenix, Tucson, and Yuma Transmission Import Constraint Areas and (2) the meeting of the utilities' obligations under Arizona's Environmental Portfolio Standard ("EPS"). The recommendations contained in this testimony have been developed to help achieve all of these goals summarized as follows:

1. In order to result in the best prices for Arizona's electric consumers, the solicitation process should be designed to allow for the Independent Power Producers ("IPPs) to propose, and the utilities to choose, power contracts of varying durations including long-term contracts of 15 to 20 years in length. This should be done without biasing the process to favor or disfavor contracts of any particular length. Such a mixture of contract terms will encourage the development of a competitive market by allowing both existing and new generation projects to submit proposals that will provide Arizona's electric

consumers with a natural hedge against a wide range of future risks, and should allow the utilities to obtain the most favorable prices on behalf of ratepayers.

2. RMR has been identified by the Commission as an impediment to obtaining a competitive wholesale market in Arizona. In addition, there are growing loads within the Commission's identified load pockets, namely the Phoenix, Tucson, and Yuma Transmission Import Constraint Areas, which must be served. Thus, all of the load within these load pockets, including that served by the existing RMR units, should be contestable in the Track B process. This will allow the utilities and the Commission to assess what competitive alternatives besides new transmission might be available to mitigate or eliminate the RMR problem and will provide alternatives to the existing RMR generation.

3. Track B presents a golden opportunity for the utilities to access the market for competitive proposals to fill their EPS obligations and, if properly structured, can encourage bidders to propose innovative technologies to provide cost-effective renewable resources. The bid evaluation process should provide appropriate recognition for the additional value provided by renewable resources. The Commission has recognized that renewable resources are currently more costly than other resources, yet has decided to mandate the EPS mandate due to the many other public benefits provided by such resources. Thus, it is only

reasonable and in the best interests of the utilities' ratepayers for any competitive procurement process to give appropriate credit for these other benefits.

GOALS OF COMPETITIVE SOLICITATION PROCESS

Q. WHAT SHOULD BE THE GOALS OF TRACK B?

A. Staff in its Staff Report articulates that the goal of Track B should be as follows:

> In order to facilitate a manageable transition to a competitive wholesale power market that provides economic benefits to consumers in Arizona, the Staff believes that a transparent process, one that is equitable and auditable, needs to be established. That process must be well developed, flexible, and understood by all participants in the process. **Furthermore, the process must result in reliable power being available over the long term at prices that are reasonable.** [Emphasis Added] (Staff Report, Page 1, Lines 7 – 12)

WMGF believes the above statement encouraging the procurement of reliable power at reasonable prices over the long term is entirely consistent with Commission public policy, is consistent with economic principles of competitive markets, is reasonable and prudent, and is in the best interests of Arizona's ratepayers. In addition to long term reliable power at reasonable prices, WMGF believes that the Competitive Solicitation Process should be designed in a manner to achieve two additional public policy goals articulated by Staff or the Commission in other proceedings including the Second Biennial Transmission Assessment proceeding and the recent Commission promulgation of the EPS Rule A.A.C. R14-2-1618. The Second Biennial Transmission Assessment proceeding attempts to find solutions to Arizona's Phoenix, Tucson, and Yuma load

pocket problems and the EPS mandates all of Arizona's regulated utilities to derive a portion of their total retail load from renewable energy resources as part of the utilities' total generation portfolio. Unfortunately, although Staff emphasizes reliability and low prices over the long term as a stated goal in the Staff Report, Staff strongly encourages short-term contracts over long-term contracts by providing incentives for short-term contracts while creating regulatory uncertainty for long-term contracts. (Staff Report, Section E, Terms Required for Staff Recommendation, Pages 24 – 26). APS allows for contracts of no longer than four years under its proposed competitive solicitation proposal. (Direct Testimony, Thomas J. Carlson, Page 3, Line 10). Moreover, Staff in its Staff Report apparently contradicts the EPS Rule by recommending exclusion of generation sources that the utilities' must take in compliance with the Arizona's EPS from the utilities' unmet needs calculation. (Staff Report, Page 35, Lines 1 through 8). APS followed Staff's recommendation and excluded renewable resources as well as RMR generation from APS' unmet needs calculations. (Direct Testimony, Peter M. Ewen, Schedule PME-1). Accordingly, my arguments: (1) for the inclusion of long-term contracts in the Competitive Solicitation Process; (2) the inclusion of renewable energy generation as unmet needs in the Competitive Solicitation Process; and (3) the inclusion of RMR generation as unmet needs in the Competitive Solicitation Process, are discussed in my testimony below.

LONG-TERM CONTRACTS

Q. WHAT LENGTH OF CONTRACT TERM DOES APS PROVIDE FOR IN

ITS TRACK B TESTIMONY?

A. As I indicated above, APS provides for contract terms ranging from one quarter to up to four years. (Direct Testimony, Thomas J. Carlson, Page 3, Line 10).

Q. WHAT IS YOUR UNDERSTANDING OF APS' REASONS FOR LIMITING THE MAXIMUM LENGTH OF THE CONTRACT TERM TO FOUR YEARS?

A. APS witness Mr. Carlson on page 9 of his testimony gives three reasons for limiting the maximum length of the contract term to four years. First, he indicates that the future establishment of an RTO may expand the number of potential bidders in the Arizona market. Second, he believes that FERC's proposed Standard Market Design ("SMD") is a "wild card" that may affect both the price and availability of transmission for one set of potential bidders *vis a vis* others. Third, he states that counterparty credit issues make it more risky for APS to enter into long-term transactions. At the November 6, 2002 workshop, Mr. Carlson appeared to add a fourth reason for his recommendation; namely, that there is the risk APS could buy power under a long term contract only to find out later that it could have procured that same amount of power in the market at a lower price.

Q. WHAT IS YOUR UNDERSTANDING OF STAFF'S POSITION ON CONTRACT TERM LENGTH?

A. As I indicated above, Staff encourages short-term contracts only. I understand

that Staff anticipates that during 2003 each utility will primarily require contract terms of one to three years; however, it also believes that if in the judgment of the utility market conditions or economic opportunities dictate longer contract terms, each utility is responsible for entering into such contracts that are reasonable (Staff Report, Page 6). Staff, however, provides some level of regulatory certainty for rate recovery only for short-term contracts, which creates a strong disincentive for the utilities to enter into long-term contracts. (Staff Report, Pages 25 - 26)

Q. DO YOU AGREE WITH EITHER STAFF'S OR APS' POSITION ON CONTRACT TERM LENGTH?

A. In my opinion the Commission should allow for contracts of varying terms, including long-term contracts with terms of 15 to 20 years. The evaluation process should also neither encourage nor discourage the utilities from selecting bids of varying contract terms of 15 to 20 years, but should consider the merits of the bids, including price, against reasonable forecasts of the future market. Such a portfolio approach will result in the lowest generation prices for Arizona's ratepayers and will provide some natural hedges against an uncertain future.

Q. WHY SHOULD CONTRACT TERMS OF LONGER THAN FOUR YEARS BE ENCOURAGED?

A. The Commission's stated purpose of the Track B solicitation is "to encourage a phase-in to competition, encourage the development of a robust wholesale market

for generation, and obtain some of the benefits of the new Arizona generation resources, while at the same time protecting ratepayers." (Decision No. 65154, Pages 23-24) This argues for a highly inclusive process, which encourages both large and small entities to bid both new and existing generation with the generation offering fuel, location, equipment, and contract term diversity. In addition, in order to protect ratepayers, there is a need to avoid two of the problems that have plagued the California market; namely, placing too much reliance on the short-term market and having too much generation being supplied by too few entities.

The best way to achieve these purposes is to design the Track B solicitation so that new generation projects have an equal opportunity to compete with existing generation. For it is with new generation projects that you typically bring new developers into the market. In addition, new generation adds incremental power to the grid thereby increasing supply margins and improving reliability. New generation facilities also are generally more efficient and more environmentally friendly than existing generation due to their ability to more easily employ the newest technologies. For example, the WMGF project is being designed to employ the patented SEECOT™ Solar Thermal Technology to increase efficiency by converting solar energy into thermal energy for inlet air-cooling of the CTG. Furthermore, new generation projects can be located in areas that provide greater overall system and customer benefits.

Q. ARE YOU SUGGESTING THAT NEW GENERATION PROJECTS CAN ONLY COMPETE IN THE COMPETITIVE SOLICITATION PROCESS IF THE PROCESS ALLOWS LONG-TERM CONTRACTS?

A. Yes. Today's business environment for development and construction of new power plants throughout the United States has changed dramatically from the business environment prior to mid-2001, making it highly unlikely that an IPP can obtain non-recourse financing for a new power plant over roughly 50 MW in size without having a significant amount of the project's output contracted to a credit worthy entity. Prior to mid-2001, IPPs found it relatively easy to obtain non-recourse financing for new generation projects in a market that was (1) opening up to new entrants with deregulation, (2) experiencing rapidly increasing market prices, and (3) experiencing shortages of generation. In this market, Enron, other large generation developers, and energy traders were reporting large profits and the financial community was generally very willing to finance new projects even if they were purely for merchant purpose.

However, the market has now changed considerably. Today we have a financial community that is hesitant to loan any funds for new generating facilities due in large part to the financial meltdown of Enron, several other large generation developers, and energy traders. We are also seeing throughout the West spot market prices at far lower levels than before mid-2001. Thus, today new

generation facilities cannot generally be financed without having a significant portion of their output sold through contracts such as long term power purchase agreements ("PPAs") to a credit worthy entity. Since project financings are generally tied to such PPAs, longer contract terms translate into lower annual debt service requirements, which in turn can translate into lower offered prices. In my opinion, for these reasons contract terms need to be in the 15 to 20 year range for new generation projects.

Q: WHAT KIND OF TERMS ARE LENDERS REQUIRING IN PPAs BEFORE AGREEING TO FINANCE A NEW GENERATING FACILITY ON A NON-RECOURCE BASIS?

A: The answer to this question depends on the financial strength of the entity seeking the non-recourse financing; however, as a general proposition lenders are willing to lend to creditable IPPs 60% to 75% of the total capital cost of the project for a term of 10 to 20 years so long as a PPA with a credit worthy counterparty provides 80% to 100% of the debt service. The key here is that the minimum needed PPA contract term must tie to the length of the financing. Today, in Arizona a minimum 15-year contract term and preferably a 20-year term is probably needed in order for a developer to offer what would be viewed as a competitive price.

Q. DO YOU BELIEVE IT IS IN THE BEST INTERSTS OF ARIZONA'S RATEPAYERS TO LIMIT CONTRACT TERMS TO A MAXIMUM OF FOUR YEARS?

A. No. Neither the possible establishment of an RTO in Arizona nor the implementation of FERC's SMD, which may not even be adopted due to opposition in many states throughout the United States, are likely to dramatically change the competitive market in Arizona for several years. Also, if this were a serious concern to Arizona, contract terms should probably be no longer than one year. Second, just because some counterparties may not be able to meet a utility's credit criteria for a long-term contract should not be cause to eliminate long-term contracts all together. This would be a classic case of throwing the baby out with the bath water. The obvious way to address this issue is to establish appropriate and reasonable credit criteria to protect both parties to the contract, which WMGF supports and is being done in the Track B process.

Third, the argument that a long-term contract could increase the utility's costs by locking in prices that later prove to be higher than market prices ignores two key items. First, this is not an "all or nothing" proposition. In other words, I agree that a utility should not lock in all of its needs with long-term contracts. Instead, it should strive to have a well-balanced portfolio of contract purchases consisting of contracts with varying terms, expiring in varying years, and with varying

physical attributes of size, fuel type, location, and so forth. In this way, the utility would have natural hedges to protect its customers in an uncertain world

The second key item that is important to keep in mind is the fact that this is a very good time to go to the market seeking long-term contracts. It is axiomatic that today's market prices are at very low levels compared to prices in recent years. While no one knows for certain what future prices will be, recent forecasts clearly predict rising electricity prices with an improving economy and the reduction of the temporary power surpluses in the West resulting from the recent completion of a number of new, large generating facilities. Perhaps even more importantly, the Arizona load serving utilities are in the enviable position of being two of only a handful of credit worthy entities in the region who are planning to enter into power purchase contracts in the near future. In short, this is a classic "buyers market" that experience teaches us will not last forever. What better time can there be for the Arizona load serving entities to enter into a long-term contract?

Q. AS A RESULT OF WORKSHOP DISCUSSIONS, HAS APS CHANGED ITS POSITION ON LONG-TERM CONTRACTS IN ANY WAY?

A. APS may have softened its position on this issue. During the workshop held on November 6, 2002, Mr. Carlson, as head of energy trading for APS and after indicating he would be APS' lead person overseeing the Track B solicitation process, stated that APS will entertain bids for terms longer than four years as

long as these bids meet APS' credit requirements and offer attractive prices. Mr. Steven Wheeler, a Vice President for APS, also stated at this same workshop that APS would consider comments and concerns expressed during the workshop and would determine whether it would revise its testimony in any way. Accordingly, it is hoped that APS will restate its position on the record in its responsive testimony due on November 18, 2002 to reflect its new desire to entertain long-term contracts in its competitive solicitation request for proposals.

Q. DOES THIS STATED POSITION SATISFY YOU THAT THIS ISSUE HAS BEEN PROPERLY ADDRESSED?

A. No. For all of the reasons stated in my testimony and so that potential bidders have some certainty, I recommend the Commission in its Track B order specifically allow bids of varying contract terms of 15 to 20 years, that APS be required to evaluate all bids on an equal basis, and that APS be assured of full rate recovery for its prudent decisions.

RENEWABLE ENERGY

Q. YOU MENTION EARLIER IN YOUR TESTIMONY THAT YOU BELIEVE TRACK B SHOULD BE USED AS A MECHANISM FOR THE UTILITIES TO PROCURE A PORTION OF THEIR RENEWABLE RESOURCE PURCHASE OBLIGATIONS UNDER ARIZONA'S EPS. DOES APS HOLD THIS SAME VIEW?

A. APS, through its witness Mr. Ewen, has excluded any planned "grid connected" EPS requirement from the utility's Schedule PME-1, which summarizes APS' unmet capacity and energy reliability needs. Thus, it is our reading of APS' testimony that procuring renewable resources is not an APS objective under Track B. It is worth noting, however, that during the November 6 workshop, APS stated it would consider bids or proposals from IPPs containing renewable resources in the Competitive Solicitation Process, but without providing specifics on how and in what manner APS would consider these proposals. In my opinion, APS seemed to imply it would evaluate such bids or proposals on the same basis as all other bids, thus giving no recognition to the fact that the bid contained renewable energy in furtherance of the Commission's EPS public policy goal.

Q. WHAT REASONS HAS APS GIVEN FOR NOT MAKING SUCH PROCUREMENT AN OBJECTIVE IN THE COMPETITIVE SOLICITATION PROCESS?

A. To my knowledge, APS has not clearly articulated its reasons for its position; however, based on comments made during the November 6, 2002 workshop, APS seems to have two reasons. First, APS has emphasized that its decision to exclude renewable energy from the Track B solicitation process is consistent with Staff, which also has excluded APS' EPS requirements from the calculation of unmet capacity and energy reliability needs. Second, APS says that it has initiated a separate "renewables only" solicitation.

Q. ARE YOU SATISFIED WITH THIS POSITION?

A. No. I believe the Commission in its Track B order should specifically set the procurement of a portion of each utility's EPS requirement as a goal of the Competitive Solicitation Process.

Q. WHY DO YOU BELIEVE THAT PROCURING RENEWABLE RESOURCES SHOULD BE AN OBJECTIVE OF THE COMPETITIVE SOLICITATION PROCESS?

A. As indicated early in my testimony, the Commission promulgated the EPS mandate and codified it in A.A.C. R14-2-1618. Under Rule R14-2-1618, all Arizona regulated utilities must have a certain percentage of their total energy portfolios be derived from renewable energy resources. For example, in 2003 .6% of APS' total energy portfolio must be derived from renewable energy resources. Thus, logic has it that if the purpose of the Track B is for the utilities, such as APS, to acquire their wholesale power to meet their portfolio requirements through a competitive process, it only makes sense that the acquisition of the renewable energy portion of their total power portfolio also be acquired through the competitive solicitation process. It is worth noting that the Commission has required two of Arizona's newest power plant projects (Bowie Power Station Case No. 118 and La Paz Generating Facility Case No. 116) to include a renewable energy generation resource as part of the project as a condition of

receiving the Certificate Environmental Compatibility ("CEC"). In my opinion, this demonstrates the Commission's desire that renewable energy be an important component of all future energy generation portfolios held by the utilities in serving Arizona's energy needs.

From a practical standpoint, without renewable resources being included in the Competitive Solicitation Process, it is unclear how some innovative projects combining renewable and fossil fuel technologies ("Hybrid Renewable Generation"), such as WMGF and other projects would be appropriately considered and evaluated. We don't believe it is the Commission's intent nor in the public's interest to disadvantage Hybrid Renewables. Inclusion of renewable resources in Track B is also consistent with the Commission's goal of balancing competing interests of preserving the environment and maintaining or lowering retail rates (Decision 62506, Pages 16-17). In other words, the utilities may very well determine that the most cost effective way to achieve their EPS requirements is to procure at least a portion of their renewable energy requirements through a large-scale process such as Track B. For these reasons, WMGF would recommend that renewable resources be specifically solicited in Track B and that separate renewables only solicitations also be held as needed.

Q. WOULDN'T ADDING THE PROCUREMENT OF RENEWABLE RESOURCES TO TRACK B UNNECESSARILY COMPLICATE THE PROCESS?

A. No, not if the process were properly structured. Each utility could simply include, as one of its unmet needs, its EPS requirement for each year. Each bidder would then clearly specify in its bid the amount of qualifying renewable resources, if any, it was offering by year and under what price, terms and conditions. The utilities would consider this information in their bid evaluations and apply an appropriate credit in recognition of the additional value of renewable resources.

Q. WHAT DO YOU MEAN BY APPLYING AN APPROPRIATE CREDIT FOR THE ADDITIONAL VALUE OF RENEWABLE RESOURCES?

A. The Commission has recognized that most renewable resources at present are more expensive than fossil fuel resources. The Commission, however, also recognizes the public benefits of clean renewable energy resources over fossil fuel resources. The Commission further recognizes the need to diversify Arizona's fuel resource mix so that the State does not over rely on volatile natural gas supplies and prices. Accordingly, the Commission made the EPS a mandate and provided a funding mechanism through a special EPS surcharge on customer bills and the reallocation of all existing System Benefits Charge funding including DSM Program funding to EPS uses (jointly the EPS surcharge and System Benefits Charge referred to as "EPS Funds"). Although we are in the process of

verifying this amount with APS, I understand that APS is currently collecting about $12 million a year from its ratepayers through the EPS Surcharge and the reallocation of the Public Benefits Charge for the procurement of renewable energy under the EPS. Thus, the Commission has already in effect determined that the reasonable additional value of renewable energy is the amounts of funds generated from these two charges. The goal then should be to procure as much renewable resource energy as possible to achieve EPS at the lowest reasonable prices. The maximum amount to be paid under this approach would be the market price for conventional power (as determined in the Track B process) plus an additional value component representing the EPS Funds. Or, in other words, the additional value on a dollars per megawatt hour basis would equal the amounts collected through EPS Funds divided by the total megawatt hours to be purchased from renewables in the EPS.

Q. HOW WOULD THIS BE HANDLED IN THE BID EVALUATION?

A. WMGF would recommend that the Commission establish a higher benchmark "price to beat" for renewables that recognizes this additional value. This additional value would also be reflected in the bid scoring. Use of this approach would be simple, straightforward, and provide a reasonable way to quantify the value of renewables using a method already adopted by the Commission.

Q. WHAT ARE OTHER JURISDICTIONS DOING TO PROCURE RENEWABLE RESOURCES?

A. A total of twelve states (including Arizona) currently have an EPS or are in the final process of codifying an EPS. Schedule RWK-1 attached to this testimony compares some of the key attributes of these programs. These states have generally recognized that renewable resources are more expensive than conventional resources and have allocated additional resources for their procurement. At least one state--California--has very recently implemented a major procurement program for renewables.

California has just within the last few months adopted by state law a 20% EPS to be attained by 2017. In order to implement this requirement and to obtain additional resources to meet the needs of the state's three investor owned utilities ("IOUs"), the California Public Utilities Commission ("CPUC") has recently issued a decision (Decision 02-08-071, August 22, 2002) requiring the IOUs to each implement a competitive procurement process similar to Track B. In its decision, the CPUC struggled with this issue of ascribing an appropriate value to renewable energy and decided to adopt $53.70/MWH for the first 5 years of the contract as an interim benchmark for renewable resources. The decision provides that any proposal at this price or lower is *per se* reasonable. The IOUs are also required to fairly consider proposals from renewable resources offering prices higher than the benchmark as well as longer contract terms and to justify why

each such proposal is or is not acceptable. The $53.70 value was derived from a forecast of expected market prices in the state and prices in contracts recently entered into by entities within the state. The CPUC plans to more fully address this benchmark issue, including the setting of benchmarks beyond five years, during proceedings to be held in 2003.

Q. ARE YOU SUGGESTING THAT THE COMMISSION SHOULD ADOPT THE CALIFORNIA MODEL?

A. No. I provide the summary of the California experience simply for the Commission's information. I recommend that the Commission adopt the model that I stated earlier in my testimony. However, if the Commission decides for any reason not to include the procurement of renewable resources as an objective of the Track B proceedings, the California model could serve as an example of an alternative way to procure EPS required renewable resources. In other words, Arizona could initiate a separate renewable resource solicitation process that specifically provides appropriate means for considering Hybrid Renewables as well as pure renewable resources.

<u>RELIABILITY MUST RUN AND TRANSMISSION IMPORT CONSTRAINTS</u>

Q. YOU INDICATED ABOVE THAT ONE OF THE OBJECTIVES OF TRACK B SHOULD BE TO ACQUIRE RESOURCES THAT WOULD MITIGATE OR ELIMINATE THE RMR ISSUE. DOES APS HOLD THIS

SAME VIEW?

A. APS witness Mr. Ewen does not include in his calculation of unmet capacity and energy reliability needs in Schedule PME-1 any component for either APS owned or non-APS owned RMR generation. Thus, APS provides no specific provision for acquisition of resources to mitigate or eliminate the RMR issue. However, during the November 6 workshop, APS stated it would consider such bids in a Competitive Solicitation Process without specifying how and in what manner they would be considered. In my opinion, APS seemed to imply it would evaluate such bids on the same basis as all other bids giving no recognition to the fact that the bid mitigated or eliminated RMR.

Q. DOES APS STATE ANY REASONS FOR ITS POSITION?

A. I am not aware of APS stating any reasons for its position.

Q. ARE YOU SATISFIED WITH THIS POSITION?

A. No. I believe the Commission in its Track B order should specifically set the elimination or mitigation of the RMR issue as an objective of the Competitive Solicitation Process.

Q. WHY DO YOU BELIEVE THIS SHOULD BE AN OBJECTIVE OF THE TRACK B SOLICITATION?

A. In my opinion, all loads in RMR areas should be contestable in the Track B

process. In the generic proceeding concerning electric restructuring issues, the ACC Staff recommended that the Commission should order jurisdictional utilities to resolve RMR generation concerns (Decision 65154, Page 18). Specifically, Staff argued the utilities should:

1. Perform a study to analyze the merits of existing dependence on RMR instead of building new transmission;
2. Perform a study analyzing merits of any future contemplated utilization of RMR to defer transmission projects; and
3. File such study reports prior to implementing any new RMR generation strategies.

The Commissioners largely agreed with Staff and ordered the utilities to work with Staff to develop a plan to resolve RMR generation concerns and include results in the 2004 Biennial Transmission Assessment (Decision No. 65154, Page 33). The Commission further ordered the utilities to file annual RMR generation study reports with the Commission in concert with their January 31 ten-year plans for review prior to implanting any new RMR generation strategies until the 2004 Biennial Transmission Assessment is issued.

Since RMR generation concerns can be resolved by either new transmission and/or new generation and further since new generation options can come from either the utilities themselves or from IPPs, it is important for any IPP generation

options to be identified as part of the issue resolution process. The Competitive Solicitation Process is an ideal mechanism to use to identify any such generation option.

Additionally, as a matter of public policy older, less efficient, less environmentally friendly power plants should be considered for replacement by newer, more efficient, more environmentally friendly power plants. This is especially true when there are other public policy reasons (i.e., RMR) for replacing the plants.

Q. DOES THIS SITUATION APPLY IN THE YUMA AREA?

A. Yes. The situation in the Yuma area is as follows:

1. There are four early 1970's vintage RMR plants totaling 139 MW owned by APS (Yucca GT 1-4) serving the area.
2. The efficiency of these plants is around 13,000-14,0000 BTU/kWh heat rate versus 6000-7000 BTU/kwh heat rate for new combined cycle plants.
3. New plants would use state-of-the-art pollution control technologies to meet or exceed all state and federal standards compared to the existing plants which have no pollution control equipment installed.
4. New plants, such as WMGF, could add solar features, which provides for the production of renewable energy.

Q. DOES THE RECOMMENDED APS COMPETITIVE SOLICITATION PROCESS ADDRESS PROCURING NEW RESOURCES TO SERVE LOAD GROWTH IN ITS TWO LOAD POCKETS?

A. APS has provided some discussion about serving loads in the Phoenix load pocket, but has provided no discussion on serving loads in the Yuma load pocket. Obtaining resources to serve load growth needs in both the Phoenix and Yuma load pockets should in my opinion be an objective of the Track B process. I will limit my discussion herein to a discussion of the Yuma load pocket.

By 2005 with projected load growth and existing generation and transmission into the Yuma area, installed reserve margins are projected to be only 9%. Low reserves necessitate that some action be taken to increase the reserve margin by 2005. Temporary "fixes" could be employed to forestall a permanent solution for a short period of time; however, a more permanent solution is needed. Permanent options are:

1. Construct new transmission line into area,
2. Increase capacity of existing lines into area, and/or
3. Procure/install new generation in the area.

Since the implementation of either of these two options will take several years, decision makers should obtain the information now on the options so that a timely decision can be made. In my opinion the Competitive Solicitation Process is the

ideal place to obtain the relevant information on possible generation alternatives to meet this need. Relevant information on transmission options to meet this need could also be studied as part of the Competitive Solicitation Process evaluation so that a decision on the relative benefits of the two options could be analyzed.

Q. WHAT THEN IS YOUR SPECIFIC RECOMMENDATION TO THE COMMISSION ON RMR?

A. I recommend that the Commission include the following in its order on the Track B process:

1. State specifically that one of the public policy objectives of the Competitive Solicitation Process is to solicit bids and proposals from generation resources that will help mitigate or eliminate Arizona's RMR issue in the Phoenix, Tucson, and Yuma Transmission Import Constraint Areas.
2. Provide that, as a matter of public policy all load in RMR areas is contestable and order APS to amend its Schedule PME-1 accordingly.
3. Order each utility to include in its report to the Commission on the results of the Competitive Solicitation Process progress it has made to mitigate or eliminate the RMR issue.

Q. DOES THIS CONCLUDE YOUR DIRECT PREFILED TESTIMONY?

A. Yes

APPENDIX 1

RESUME OF ROBERT W. KENDALL

Managing Director
Navigant Consulting, Inc.
225 W. Broadway, Suite400
Glendale, California 91204
818-244-0117

Robert W. Kendall, Managing Director in Navigant Consulting, Inc.'s Energy & Water Practice, has over 34 years experience in the electric power industry. Representing investor-owned utilities, municipal entities, and independent developers, he has played key roles in the development (including financing) of new electric generation and transmission projects; served as an expert or policy witness in regulatory and court proceeding; negotiated new contracts for the purchase and sale of electric power and transmission services; managed the operations of electric generation facilities; and managed the administration of contracts having payments of over $3 billion per year. Included in the contracts Mr. Kendall has negotiated are a settlement of litigation having a financial exposure of over $4 billion, a long-term power purchase agreement having life-time payments exceeding $1 billion, and a long-term power purchase agreement with the developer of the nation's first merchant transmission line. He has also managed and implemented complex asset development strategies and has led statewide teams to develop new institutions to implement electric deregulation. Mr. Kendall is a qualified and recognized expert on electric system planning, project management, utility and independent power plant development and operations, power marketing, utility regulation, complex contract negotiations, electric deregulation, transmission policy, and power contract economics and accounting.

PROFESSIONAL HISTORY

Navigant Consulting, Inc. (NCI) (7/2002 – Present)
Managing Director

Sunlaw Energy Corporation (Sunlaw) (2001- 4/2002)
President

NCI (1998-2001)
Director

Southern California Edison (SCE) (1968-1998)
Director, Municipal Business Alliances
Manager of Planning
Manager of Industry Policy Coordination
Manager of Power Contracts
Manager of Regulatory Coordination
Assistant Counsel
Various Supervisor/Engineer positions

RELEVANT PROJECT EXPERIENCE

Generation Development/Project Management

While serving as president of Sunlaw, a small independent power producer achieved record sales and earnings while simultaneously leading the development and financing of new generation projects.

While serving at NCI, managed contract teams with responsibility for negotiating power sales and other agreements with 3rd parties. Participated in the financing of several projects.

While at SCE, managed an organization of over 100 people with responsibility for negotiating and administering over 1000 contracts with over 500 entities involving expenditures of over $3 billion per year.

Also while at SCE, led statewide teams comprised of electric utility lawyers and engineers, environmentalists, consumer advocates, large electric consumers, and regulators to develop institutions and governing rules for electric deregulation. Developed the financing plan for the over $300 million of costs required to implement the new system.

Transmission

While at NCI, served as principal author of a statewide report titled "1998 Transmission Reliability Report" to the California legislature. Contributions were obtained from the California ISO, California Energy Commission, California Public Utilities Commission, the Western Electricity Coordinating Council, and others.

While at SCE and functioning as head of SCE's Power Contracts organization:

- Managed negotiations and administration of SCE's transmission service agreements.
- Served as a policy witness on SCE's transmission policies before FERC and the CPUC in merger and other proceedings.
- Developed contracts for and testified in certification proceedings in support of several new high voltage transmission lines, including the California-Oregon Transmission project and HVDC Expansion projects.
- Managed SCE's activities associated with the development of the Western Transmission Association (WRTA).

While at SCE and functioning on its electricity deregulation team:

- Led negotiations for the investor owned utilities with the California ISO to create the contract for turning over control of much of California's transmission resources to the ISO.
- Managed SCE's participation in the development of the California ISO's transmission tariff filing to FERC.

Contracts

For two and a half years, with NCI negotiated contracts for the purchase and sale of power, transmission services, generation land leases, transmission/distribution operations and maintenance services, and back office services.

For ten years, functioned as head of SCE's Power Contracts organization having responsibility for:

- Negotiating new contracts that add value to SCE.
- Managing the development and administration of all of SCE's 1000 utility power purchase, transmission, joint participation and independent power purchase contracts (jointly referred to as "Power Contracts").
- Managed negotiation of two sale/leaseback arrangements—one involving SCE's share of the Palo Verde Nuclear Generating Facility and one involving a wind project developed by SeaWest
- Maximizing the value of Power Contracts to SCE's shareholders and ratepayers.
- Negotiating amendments to and protecting SCE's rights under the Power Contracts.
- Defending reasonableness of contracts and amendments before the CPUC.
- Managing SCE's relationship with its QF suppliers and wholesale municipal customers.

Expert Witness

Served as an expert witness on contractual provisions in a contract between an electric utility and independent power producer in litigation before a state superior court.

Testified as an expert witness on electric utility contracting, generation project development, proper contract administrative practices, contract economics, and appropriate accounting treatment for contract benefits and obligations in state superior court in case involving a dispute having a financial exposure of over $100 million.

Throughout SCE career had responsibility on numerous occasions for:

- Testifying as a policy witness or as an expert witness on transmission, contracts, rates and other matters before the CPUC and FERC in merger and other proceedings.
- Providing depositions in litigation filed in federal and state courts.

Regulatory Interface

For three years, managed SCE's regulatory proceedings before the CPUC and FERC and served as SCE's principal lobbyist with these regulatory bodies.

Electric Restructuring

For three years, functioned on SCE's electric restructuring team with responsibility for:

- Designing governance structure of California's Independent System Operator (ISO) and Power Exchange
- Developing transmission access charge pricing methodology and the terms and conditions for turning transmission control over to the ISO
- Serving as SCE's project manager for obtaining FERC approval of the ISO
- Serving as SCE's principal spokesperson on restructuring before high-profile customer and government groups.

Marketing Sales

For eight months, acted as head of SCE's Municipal Business Alliance Organization with responsibility for:

- Marketing and selling Edison International's mass market, energy management, and utility-related services to municipal utilities and government entities across the U.S. and Canada.

International Matters

For four years, served as manager of SCE's team involved in E7, a group of the world's largest electric utilities from the G7 countries with responsibilities for:

- Developing and implementing policies and projects to improve the global environment
- Chairing group's Steering Committee responsible for helping developing countries formulate strategic plans and building environmentally responsible projects
- Working in partnership/cooperation with international utilities' senior management, national governments and entities such as the World Bank, Asian Development Bank and various UN organizations to accomplish objectives.

EDUCATION

J.D., Corporate and Contract Law, Southwestern University
M. B. A., Financial Management, University of Southern California
B.S., Electrical Engineering, University of Illinois

PROFESSIONAL ASSOCIATIONS

Member, Los Angeles County and California Bar Associations

HONORS AND FELLOWSHIPS

Eta Kappa Nu & Sigma Tau Engineering Honor Societies

Selected by the Board of Governors of the California Bar Association to serve as a consultant on the state's bar examination.

PUBLICATIONS/PRESENTATIONS

Have given numerous presentations before electric industry and other groups on topics such as:

- Electric deregulation
- Transmission policy
- Generation project development
- Power marketing & contracting

Table RWK-1 (page 1)
Environmental Portfolio Standards in States
As of November 2002

State	Effective Date	Applicable Time Period	Standard on Capacity or Energy	Standard by Year	Funding Source	Estimated Amounts of Funding	Comments
Arizona	May 2001	2001-2012	Energy	2001 — .2% 2002 — .4% 2003 — .6% 2004 — .8% 2005 — 1.0% 2006 — 1.05% 2007-12— 1.1%	Existing Systems Benefit Charge & New EPS Surcharge	$15 million to $20 million statewide	Solar a min 50% of EPS in 2001 & 60% 2002-2012. Trading of requirements is allowed.
California	January 2003	2003-2017	Energy	2003—1% above baseline renewable 2004-2016—1% above previous yr 2017—20%	--Up to market prices in gen retail rates --Above market prices paid directly to developer through Public Benefits Charge	Trust Fund starts at $135million + $1.35 billion 2002-12 with min 51.5% of these funds for above market EPS compliance.	Above market prices paid o developers must be just & reasonable
Connecticut	January 2000	2000-2009	Energy	.75% in 2000 inc to 6% by 2009 + 7% from "other renewables" (e.g., hydro)	No specific funding program	N/A	Market price renewable credit trading system in place.
Iowa	February 1997	Indefinite	Capacity	Flat 105 MW total each year	No specific funding program	N/A	Long term contracts at fair rates to stimulate renewables development
Maine	November 1999	Review every 5 yrs	Energy	30% of state's energy to be generated by renewable resources	No specified funding program	N/A	Standard is estimated to increase electricity costs by 1% to 10%
Massachusetts	April 2002	2003-2009	Energy	2003—1% 2004-09—Increase by .5%/yr >2010—Increase by 1%/yr until suspended	Suppliers purchase renewable energy certificates in open market trading	$50/MWH payment by suppliers who do not meet standard—funds used for renewables in state	Market price renewable credit trading system in place.

Table RWK-1 (page 2)
Environmental Portfolio Standards in States
As of November 2002

State	Effective Date	Applicable Time Period	Standard on Capacity or Energy	Standard by Year	Funding Source	Estimated Amounts of Funding	Comments
Nevada	May 2002	2003-no end date specified	Energy	2003—5% 2005-13—Increase by 2% biannually to 13% >2015—15%	Rate base funding for all just & reasonable costs for compliance	None specified	≥5% renewables to be solar. Credit trading system being developed.
New Jersey	September 2001	2001-no end date specified	Energy	2001-02—3% 2003-05—3.25% 2006-12—increase by .25%/yr >2007—6.5%	Rate base funding for all reasonable & prudent costs for compliance	None specified	Credit trading system being developed.
New Mexico	Not yet effective (program proposed)	2003-no end date specified	Energy	2003—2% 2005—5% >2007—10%	Rate base funding for all reasonable costs	None specified	Utility's purchase of renewable energy approved if it does not raise total cost of energy more than .08 ¢/kwh
Pennsylvania	January 1999	Varies by each utility	N/A	Each state utility is required to promote new renewable energy using Sustainable Energy Funds	Sustainable Energy Fund (SEF) developed for each utility by settlement with State	As of Aug 2002 $83.5 million in SEF with more $ added annually through rates	Each utility's trust fund has a board, which oversees expenditures.
Texas	January 2002	2002-2019	Capacity	2002-03—400 MW 2004-05—850 MW 2006-07—1400 MW >2008—2000 MW	Rate base funding	None specified	Open market credit trading system is being used.
Wisconsin	October 1999	2002-2011	Capacity & Energy	Capacity: 2000—50 MW Energy: 2001—.2% 2003-09—adds .35% every 2 yrs 2011—2.2%	Rate base funding for all prudently incurred costs	None specified	Credit trading system allowed and in place.

EXHIBIT
W-4
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING ELECTRIC RESTRUCTURING ISSUES.	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069

REBUTTAL TESTIMONY OF

ROBERT W. KENDALL

ON BEHALF OF

WELLTON-MOHAWK GENERATING FACILITY

NOVEMBER 18, 2002

LAW OFFICES
MARTINEZ & CURTIS, P.C.
2712 NORTH 7TH STREET
PHOENIX, AZ 85006-1090
(602) 248-0372

Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A. My name is Robert W. Kendall. My business address is 225 West Broadway, Suite 400, Glendale, California 91204-1331.

Q. ARE YOU THE SAME ROBERT W. KENDALL WHO SUBMITTED PREFILED DIRECT TESTIMONY IN THIS PROCEEDING ON BEHALF OF THE WELLTON-MOHAWK GENERATING FACILITY ("WMGF")?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. The purpose of this testimony is to rebut and respond to (1) testimony filed by intervenors and Arizona Public Service Company ("APS") on November 12, 2002 and (2) information contained in APS' response to WMGF's First Set of Data Requests to APS propounded on November 8, 2002. Since APS' response to these data requests was not received until November 14, 2002, I did not have the opportunity to include this information in my Prefiled Direct Testimony submitted to the Arizona Corporations Commission ("Commission") on November 12, 2002.

Q. COULD YOU BRIEFLY SUMMARIZE THE RECOMMENDATIONS YOU MADE TO THE COMMISSION IN YOUR PREFILED DIRECT TESTIMONY?

A. Yes. Fundamentally, I recommended that the Commission include the following three items in its order on the Track B Competitive Solicitation process:

1. Bids proposing long-term contracts with terms of up to 15 to 20 years should be specifically allowed in the Track B Competitive Solicitation Process ("Track B"), that APS be required to evaluate all bids on an equal basis, and that APS be assured of full rate recovery for its prudent actions.
2. The procurement of at least a portion of each utility's renewable resource requirement under Arizona's Environmental Portfolio Standard ("EPS") should be a specific objective of Track B and be included in each utility's unmet needs calculation, and that the bid evaluation method used by each utility should give appropriate credit to bids containing such resources in recognition of the additional value they provide to the utility. I also recommended a specific method to use for calculating this additional value.
3. The procurement of generation resources to help mitigate or resolve the Reliability Must Run ("RMR") issue should be an objective of the Track B and be included in each utility's unmet needs calculation, and that as a matter of public policy all loads in RMR areas should be contestable.

Q. HAVE YOU REVIEWED THE TESTIMONY FILED BY INTERVENORS AND THE UTILITIES INCLUDING APS ON NOVEMBER 12, 2002 IN THIS PROCEEDING?

A. Yes.

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Q. DO YOU WISH TO MAKE ANY COMMENTS ON ANYTHING YOU READ IN THIS TESTIMONY?

A. Yes. In their Prefiled Direct Testimony filed on November 12, 2002, several intervenors, including the Residential Utility Consumer Office ("RUCO") and Sempra Energy Resources, discuss the benefits of Least Cost Planning and recommend that it be used as the central method of evaluating bids in the Track B process. I wish to comment on the Least Cost Planning proposal since its adoption by the Commission, which I support, is consistent with my recommendations.

Q. ARE YOU FAMILIAR WITH LEAST COST PLANNING?

A. Yes, I am very familiar with Least Cost Planning having used this tool for several years with my former employer, Southern California Edison Company, and in several consulting engagements with my current employer, Navigant Consulting, Inc. For example, while at Southern California Edison Company, I led a major resource procurement activity and used Least Cost Planning as the centerpiece of the utility's bid evaluation process under California's wholesale power competition.

Q. DO YOU AGREE WITH THE RECOMMENDATION THAT LEAST COST PLANNING SHOULD BE EMPLOYED IN THE TRACK B BID EVALUATION PROCESS?

A. Yes. All the parties agree that the overarching objective of Track B is to facilitate the establishment of a competitive wholesale market and to procure from this

market resources that provide the lowest overall costs to the consumer. As I discussed in my Prefiled Direct Testimony, this argues for allowing bidders to have a great deal of flexibility in their bids so they can be shaped to be the most attractive to the utility. Unfortunately, using three standardized products and rank ordering bids by each product as proposed by APS in its Prefiled Direct Testimony is not likely to achieve the above objective. For this and other reasons, I agree with Dr. Rosen's Direct Testimony on behalf of RUCO where at page 10 he states that the proper use of Least Cost Planning will provide a coherent and workable framework for evaluating bids so that the utility's revenue requirement will be minimized providing the lowest rates to consumers. I also agree with Dr. Rosen when he states on page 26 of his Prefiled Direct Testimony that a minimum 20-year planning horizon is needed for the evaluation process.

Q. IS YOUR RECOMMENDATION THAT LONG-TERM CONTRACTS OF UP TO 15 TO 20 YEARS BE ALLOWED IN TRACK B CONSISTENT WITH THE USE OF LEAST COST PLANNING?

A. Yes, it is consistent. The real advantage of Least Cost Planning is that it allows for the price features of each bid to be evaluated on its merits compared with other bids and alternatives the utility has available to it. With respect to a long-term bid of 20 years for example, this bid would be placed in the production simulation model being used and would be dispatched each year in the most efficient manner based on the pricing and flexibility afforded by the bid. The results of this scenario could then be compared against other scenarios containing, for example, several

shorter-term purchases evaluated over the same 20-year time frame. In this manner, the utilities would be able to select the scenario providing the consumer the lowest overall cost.

Q. IS YOUR RECOMMENDATION THAT TRACK B SHOULD BE USED AS A MECHANISM FOR THE PROCUREMENT OF RENEWABLE RESOURCE PUCHASES UNDER ARIZONA'S EPS CONSISTENT WITH USING LEAST COST PLANNING?

A. Yes, it is consistent. As an example, let's assume a bid is received from a hybrid project that produces a quantity of energy that qualifies as solar produced renewable energy and a quantity of energy that is generated by gas. The bid would be modeled in the same production simulation program discussed above and would be dispatched by the model over the minimum 20 year evaluation time period in the most efficient manner as allowed by the bid's parameters. The results of this scenario could then be compared against another scenario containing a bid from other gas-fired generation that would produce an equivalent amount of non-renewable energy as in the above scenario and other alternative solar produced renewable energy from bids that again produce an equivalent amount of renewable energy as in the above scenario. Again, the least cost planning method allows for the attributes of each bid to be fairly compared against the attributes of other bids.

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Q. IS YOUR RECOMMENDATION THAT ONE OF THE OBJECTIVES OF TRACK B SHOULD BE TO MITIGATE OR ELIMINATE RMR CONSISTENT WITH THE USE OF LEAST COST PLANNING?

A. Yes, again it is consistent. The key here would be for the evaluation process to specifically look at each of the state's RMR areas on an individual basis. For each area, a series of scenarios would be developed from bids addressing that RMR area and, as discussed above, the results of each scenario would be compared against the results from the others to arrive at the least cost solution. As Dr. Rosen of RUCO explains in his Prefiled Direct Testimony at page 22, this would allow new transmission investment options, generation options, and DSM to be evaluated to determine the most cost effective way to address the RMR issue. This analysis could also be set up to clearly show if it were in the best interest of the utility ratepayers to replace some of the existing RMR generation with generation options received in the bids.

Q. DO YOU HAVE OTHER COMMENTS TO MAKE ON ANY OF THE OTHER INTERVENORS TESTIMONY?

A. No. I have no further comments on intervenor testimony at this time. My testimony will now focus on the Prefiled Direct Testimony submitted by APS and APS' recent response to WMGF's First Set of Data Requests.

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Q. DID YOU REVIEW APS' RESPONSE TO QUESTION RK 1.1 IN WMGF'S FIRST SET OF DATA REQUESTS?

A. Yes. This question and response, which I have attached as Attachment RK-1, provides information on the Yuma load pocket. I also included in this attachment a table prepared by APS and handed out at the November 6, 2002 workshop, which addresses the Phoenix load pocket and a copy of information submitted by APS relative to the Yuma load pocket at the Commission's July 30-31, 2002 workshop on its Second Biennial Transmission Assessment ("SBTA").

Q. COULD YOU PLEASE EXPLAIN WHY YOU ASKED THE QUESTION IN ATTACHMENT RK-1?

Yes. The treatment of RMR generation has been an issue in these Track B proceedings since it impacts the amount of capacity and energy that constitutes each utility's unmet needs. APS has taken the position that non-APS owned RMR generation should be deducted from its unmet capacity and energy needs (Peter Ewen, Direct Testimony, Schedule PME-1). WMGF asked the question in Attachment RK-1 because the previous discussion on the RMR issue has been limited to the Phoenix Transmission Import Constraint Area only and because this position appears to be inconsistent with the calculation of existing load carrying capability for the Yuma load pocket contained on page 4 of the information presented by APS at the SBTA workshop. In fact, as determined in the Commission's Second Biennial Transmission Assessment Proceeding headed-up by Utilities Division, Staff Engineer Jerry Smith, APS' service area subject to the

Track B Competitive Solicitation Process consists of at least two major Transmission Import Constraint Areas; namely, the Phoenix load pocket and the Yuma load pocket. A third Transmission Import Constraint Area has also been identified in Tucson Electric Power Company's ("TEP") service are; namely the Tucson Load Pocket.

Q. COULD YOU PLEASE EXPLAN WHAT IS SHOWN IN APS' RESPONSE TO WMGF DATA REQUEST RK-1?

A. Yes. The table titled "APS Yuma Area Reliability Must Run Estimates 2003-2012" first shows the loads and transmission import limit for each of the years 2003 through 2012. By subtracting the transmission import limit from the load, one determines the RMR generation needed in the area to keep the lights on. This is identified in the table as "RMR Need." It should be noted that the loads shown in the response to Data Request RK-1 are approximately 20 MW lower than those presented on page 6 of the information presented by APS at the SBTA workshop. Next, the table provides separate lines for the APS resources in the Yuma load area, existing non-APS resources in the area, and APS reserves. To arrive at the line titled "Unmet Need," the "APS Resources" are added to the "Non-APS Resources", the "APS Reserves" are subtracted from this amount, and the total is subtracted from the "RMR Need."

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Q. DO YOU AGREE WITH THE UNMET NEED SHOWN IN APS' RESPONSE?

A. No. As discussed above, the unmet needs calculation shown in APS' response includes a deduction for the existing non-APS resources in the Yuma area. By including this deduction, APS is implicitly stating that these non-APS resources are available to serve local Yuma loads. However, this deduction should not be in the calculation of **APS' unmet needs** unless such resources are being provided under a firm contract entered into prior to September 1, 2002. We have seen no listing of any such contracts by APS either in its Prefiled Direct Testimony, its accompanying work papers, or in its responses to specific data requests presented by Staff and possibly other parties in this proceeding. In fact, the two resources comprising the largest portion of the non-APS resources in the Yuma area (i.e., Yucca Steam 75 MW and Yuma Cogeneration Project 51 MW) are listed by the Western Electricity Coordinating Council ("WECC") as firm resources of San Diego Gas & Electric and the Imperial Irrigation District respectively. Thus, they clearly are not contractually available to serve APS' customer loads.

Q. HAVE YOU PREPARED A CALCULATION OF APS' UNMET NEEDS IN THE YUMA POCKET, WHICH EXCLUDES THE LINE FOR EXISTING NON-APS RESOURCES?

A. Yes.

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Q. PLEASE DESCRIBE THE RESULTS OF THIS CALCULATION.

A. I have prepared a table using APS's numbers contained in its response to Question RK-1 corrected to eliminate the deduction for existing non-APS resources and have included it as Appendix RK-2. This table shows that APS' unmet needs in the Yuma area start out at 68 MW in 2003 and rise to be 157 MW in 2012. These unmet needs would be even larger if the loads presented on page 6 of the information presented by APS at the SBTA workshop were used in the calculations.

Q. HOW LARGE ARE THESE DIFFERENCES?

A. The differences in loads for the Yuma area shown by APS vary by year, but range from a low of 13 MW to a high of 21 MW. These are significant differences since they are on a base of about 300 MW.

Q. DO YOU KNOW WHY THE LOADS IN THE YUMA AREA PRESENTED BY APS AT THE SBTA WORKSHOP ARE DIFFERENT THAN THOSE SHOWN IN THE RESPONSE TO QUESTION RK-1?

A. No, I don't why there are differences.

Q. WHAT IS THE SIGNIFICANCE OF APS HAVING AN UNMET NEED IN THE YUMA AREA FOR THIS TRACK B PROCEEDING?

A. APS' testimony states that it plans on conducting a separate, simultaneous RFP to solicit bids for the non-APS RMR amounts in the Phoenix load pocket (Thomas Carlson, Direct Testimony, Page 10). Assuming that APS treats non-APS RMR

amounts in the Yuma load pocket the same as those in the Phoenix area, I would expect APS to conduct separate, simultaneous RMR solicitations for both the Yuma and Phoenix load pockets.

Q. IS THERE LIKELY TO BE SUFFICIENT COMPETITION TO MAKE A SEPARATE SOLICITATION FOR THE YUMA AREA WORTHWHILE?

A. Of course, no one ever knows the answer to this question until the solicitation actually occurs. However, I believe there are likely to be several competitive options set forth in such a solicitation. APS has set forth several transmission options in its response to RK-1.3, which I have included in Appendix RK-3 attached hereto. There are also likely to be several generation options proposed including perhaps some of the generation listed by APS as non-APS owned resources, the WMGF, and generation by other developers. It should be noted here that there have been other generation projects proposed in the area besides WMGF, which could provide service into the load pocket. Finally, there are DSM options that could be proposed.

Q. YOU MENTION THAT APS HAS TREATED THE PHOENIX LOAD POCKET DIFFERENTLY THAN THE YUMA LOAD POCKET. COULD YOU SUMMARIZE THE DIFFERENT TREATMENT?

A. Yes. There are three key differences in APS treatment of its two load pockets:

1. In its prefiled direct testimony, APS provided no discussion of the Yuma load pocket whereas it did discuss the Phoenix load pocket.

2. APS deducted non-APS resources from its unmet needs for the Yuma load pocket in its response to Question RK 1.1 whereas no deduction for non-APS resources was made in a similar unmet needs calculation for the Phoenix load pocket.
3. APS has proposed conducting a separate RFP solicitation to procure the unmet needs for the Phoenix load pocket but has made no recommendation for procuring the unmet needs in the Yuma load pocket.

Q. DO YOU KNOW OF ANY REASON WHY THE YUMA AND PHOENIX LOAD POCKET ISSUES SHOULD BE AFFORDED ANY DIFFERENT TREATMENT?

A. No. There has been no justification presented in APS' Prefiled Direct Testimony or its response to WMGF's data requests as to why the two load pockets should be afforded different treatment.

Q. DOES YOUR RECOMMENDATION HERE IN ANY WAY CHANGE YOUR RECOMMENDATION STATED IN YOUR TESTIMONY ABOVE ABOUT USING LEAST COST PLANNING IN THE BID EVALUATION PROCESS?

A. No, in fact the two recommendations are quite consistent. As I stated in my testimony above on Least Cost Planning, this analysis for RMR areas needs to be done separately for each RMR area. Having a separate RFP process to solicit bids

on each RMR area makes this process easier to handle since all of the information (bids) for each area are readily identifiable. In addition, as I stated in detail in my prefiled direct testimony, all RMR load should be contestable in the solicitation so that APS and the Commission can determine whether it is in the ratepayers' interest to replace existing RMR resources with alternatives proposed by the market.

Q. DID YOU REVIEW AND HAVE ANY COMMENTS ON APS' RESPONSE TO WMGF'S DATA REQUEST RK 1.3?

A. Yes. I have included both the question and response in Appendix RK-3. The basic comment I have to APS' response is that it leaves the reader with what I believe is a false impression that all is well in the Yuma load pocket and there are plenty of options to provide adequate and reliable service to customers through the next 8 to 10 years. Further, it seems to imply that there is little advantage to adding new local generation in Yuma because "it would just increase the local generation pool from which to purchase the power needs above what the EHV system could deliver." (APS Response to WMGF Data Request RK 1.3). I have a couple of comments on these statements.

First, as I discuss earlier in this testimony, there are three ways of addressing RMR issues: (1) increasing transmission import capability; (2) adding additional local generation; and (3) implementing DSM programs. These three methods are not mutually exclusive. Each method has its advantages and disadvantages and each method has its limitations. In fact, in order to minimize

ratepayer costs and provide a sufficient level of local reliability there may very well be an element of all three methods that should be employed in Arizona's RMR areas including Yuma. Use of Least Cost Planning is designed to identify the proper mix of transmission, generation, and DSM that will achieve this result. In addition, Least Cost Planning will help decision makers to determine whether some of the temporary fixes identified in APS' response are cost effective compared with other and longer-term available options.

Second, I believe it is important for APS and the Commission to fairly and thoroughly consider options from APS, as well as the market, before making capital resource commitments. This is why WMGF recommended that mitigation or elimination of RMR should be one of the objectives of the Track B process.

Q. DID YOU REVIEW AND HAVE ANY COMMENTS ON APS' RESPONSE TO WMGF DATA REQUEST RK 1.7?

A. Yes. APS' response to Data Request RK 1.7 provides a year-by-year breakdown of APS' unmet EPS renewable resource requirement for the period 2003 though 2012. I have attached the question and response in Appendix RK-4 of this testimony for the Commission's convenience. As the table clearly shows, whereas APS does not have an unmet need (shortfall) for "other" (non-solar) renewable energy and resources, it has a considerable unmet need for solar electric renewable energy. It is worth noting that the A.A.C. R14-2-1618 ("EPS Rule") sets minimum solar-only energy requirements of from 50 to 60 percent of the utilities' total EPS requirement. This is a considerable amount of solar energy for APS. I

understand that at least one of the key reasons for APS' expected solar energy shortfall is that photovoltaic technologies ("PVs") were expected to provide a significant portion of this unmet need; however, since the costs of this technology have not been decreasing as rapidly as had been anticipated (actually increasing due to higher demands verses supplies), APS, as well as TEP, may simply not be able to meet the solar requirements under the EPS Rule based on the amount of EPS they are authorized to collect through the EPS surcharge and the reallocation of the Public Benefits Charge. Fortunately, however, there are other solar technologies, such as solar troughs, which are less expensive than PVs and that can be employed in innovative ways to provide solar renewable energy to help utilities, such as APS, meet their EPS solar energy requirements. The best manner to determine the range of market solutions that might be available to fulfill this requirement would be to adopt WMGF's recommendation and specifically include in the Track B process a mechanism to solicit and fairly evaluate bids containing renewable resources to meet the EPS requirement.

Q. DOES THIS CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY?

A. Yes.

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APPENDIX RK-1

WELLTON-MOHAWK GENERATING FACILITY'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630, E-01933A-02-0069
TRACK B
November, 6, 2002

RK 1.1 Please provide a table in the same format as page 18 in the package titled "Projected Unmet Capacity and Energy Needs" presented by APS's Pete Ewen to the ACC workshop on Track B Issues on November 6, 2002 for Reliability Must Run Estimates for the Yuma load pocket.

RESPONSE:

See Attachment. [ATTACHMENT WM DR 1 Q. RK 1.1]

APS Yuma Area Reliability Must Run Estimates
2003 - 2012

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Capacity Need (MW)										
Yuma Area Peak Demand	303	322	330	339	344	355	363	372	382	392
Transmission Import Limit	148	148	148	148	148	148	148	148	148	148
RMR Need	155	174	182	191	196	207	215	224	234	244
APS Resources	139	139	139	139	139	139	139	139	139	139
Existing Non-APS Resources	132	132	132	132	132	132	132	132	132	132
APS Reserves	52	52	52	52	52	52	52	52	52	52
Unmet Need	(64)	(45)	(37)	(28)	(23)	(12)	(4)	5	15	25

APS Metro Phoenix Reliability Must Run Estimates
2003 - 2012

Capacity Need (MW)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Metro Phoenix Peak Demand	4,114	4,269	4,423	4,578	4,732	4,887	5,041	5,196	5,350	5,511
Transmission Import Limit	3,535	3,535	3,535	3,535	3,535	3,535	3,535	3,535	3,535	3,535
RMR Need	579	734	888	1,043	1,197	1,352	1,506	1,661	1,815	1,976
APS Resources - Inside Phoenix	660	660	660	660	660	660	660	660	660	660
APS Reserves	110	110	110	110	110	110	110	110	110	110
Unmet Need	29	184	338	493	647	802	956	1,111	1,265	1,426
Energy Need (GWH)										
Total Energy	37	92	172	291	445	633	862	1,124	1,366	1,628
APS Supplied	37	90	165	263	373	492	614	727	826	923
Unmet Need	0	2	8	27	72	141	248	398	540	705
RMR Hours										
Total	210	455	640	862	1,099	1,293	1,511	1,723	1,909	2,103
APS Supplied	210	455	640	862	1,099	1,293	1,511	1,723	1,909	2,103
Unmet Need	6	19	57	159	313	510	737	944	1,114	1,282
RMR Capacity Factor										
APS Supplied	0.8%	1.9%	3.4%	5.5%	7.7%	10.2%	12.7%	15.1%	17.1%	19.2%
Unmet Need	0.1%	0.1%	0.3%	0.6%	1.3%	2.0%	3.0%	4.1%	4.9%	5.6%
Total	0.7%	1.4%	2.2%	3.2%	4.2%	5.3%	6.5%	7.7%	8.6%	9.4%

Arizona Corporation Commission
Second Biennial Transmission Assessment

Workshop
July 30-31, 2002

Presentation of
Arizona Public Service Company

Cary Deise

APS Overview

- APS Transmission Planning Policy
- Assessment of APS' Transmission System
- Comparison of Biennial Transmission Assessment 1 and 2 for APS
- Transmission Planning Challenges
- Palo Verde Hub Risk Assessment
- Northern Arizona Transmission Update
- Yuma Import Analysis

ACC Second Biennial Transmission Assessment Workshop

Yuma Transmission Import Analysis

I. General Overview of Transmission Constraint Analysis:

- Transmission constraints are part of virtually all transmission systems
  - Generally uneconomic to attempt to relieve all transmission constraints
  - Goal of effective transmission planning is to develop a robust system
- Must balance local generation with transmission import capability and, if appropriate, demand response alternatives
- Cost-benefit analysis should consider non-economic costs
- Need to ensure cost-recovery for transmission projects

Yuma Transmission Import Analysis

Existing Load Serving Capability:

Transmission

• Palo Verde-North Gila 500 kV continuous rating results an allocation for APS		140 MW
• WAPA contractual limit		38

Generation

• Yucca CT	1	19 MW	
	2	19 MW	
	3	55 MW	
	4	54 MW	
Total			147

Delivery Flexibility

• Purchases from West to North Gila	50
Total	375

ACC Second Biennial Transmission Assessment Workshop

Yuma Transmission Import Analysis

Future Alternatives:

• Gila Bend-Yuma 230 kV (APS Planned Additions)	150MW
• Palo Verde-North Gila 500 kV upgrades	40MW
• Joint development Palo Verde-North Gila 500 kV #2 or equivalent	150MW
• Merchant Power Plants interconnected at North Gila	150MW
• Potential alternatives with WAPA	150MW

APPENDIX RK-2

APS Yuma Area Reliability Must Run Estimates
2003-2012
Revisions Made by Robert Kendall
November 18, 2002

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Capacity Need (MW)										
Yuma Area Peak Demand	303	322	330	339	344	355	363	372	382	392
Transmission Import Limit	148	148	148	148	148	148	148	148	148	148
RMR Need	155	174	182	191	196	207	215	224	234	244
APS Resources	139	139	139	139	139	139	139	139	139	139
APS Reserves	52	52	52	52	52	52	52	52	52	52
Unmet Need	**68**	**87**	**95**	**104**	**109**	**120**	**128**	**137**	**147**	**157**

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APPENDIX RK-3

WELLTON-MOHAWK GENERATING FACILITY'S FIRST SET OF
DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630, E-01933A-02-0069
TRACK B
November, 6, 2002

RK 1.3 Please provide a list of all transmission and generation options including proposed operating dates for each option that is available to APS to mitigate or eliminate the RMR situation in the Yuma load pocket.

RESPONSE:

See attachment from APS' presentation at second BTA workshop on various options to be considered. [ATTACHMENT WM DR 1 Q. RK 1.3] However, new generation won't get rid of RMR. It would just increase the local generation pool from which to purchase the power needs above what the EHV system could deliver. The load serving capability has always been a combination of transmission & local generation. Reconductoring of the local 69kv lines is in progress to eliminate local line loading problems. In addition, options of importing power from the West of N. Gila are being evaluated and pursued to increase the import capability to Yuma from the EHV system. This could be accomplished before next summer. We can only increase that value by a maximum of 100 MW which will load the N. Gila transformer to it nameplate rating. This 100 MW of increased capacity could probably meet the local needs for 8-10 years. The current plans of APS call for a new 230kv line into the Yuma area around 2008. The specific amount of import capability this would bring is unknown, but 100 MW is a reasonable assumption. If we were successful in procuring a West of N. Gila resource, the 230kv line project would be delayed.

ATTACHMENT WM DR 1 Q RK 1.3

Yuma Transmission Import Analysis

Future Alternatives:

• **Gila Bend-Yuma 230 kV** (APS Planned Additions)	**150MW**
• Palo Verde-North Gila 500 kV upgrades	40MW
• Joint development Palo Verde-North Gila 500 kV #2 or equivalent	150MW
• Merchant Power Plants interconnected at North Gila	150MW
• Potential alternatives with WAPA	150MW

APPENDIX RK-4

WELLTON-MOHAWK GENERATING FACILITY'S FIRST SET OF
DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630, E-01933A-02-0069
TRACK B
November, 6, 2002

RK 1.7 Please provide a year-by-year listing of APS's unmet EPS renewable resource requirement under the EPS.

RESPONSE:

See Attachment [ATTACHMENT WM DR 1 Q. RK 1.7]

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Solar electric (or equivalent EPS credits) required (MWh)	75,194	124,982	161,573	174,789	188,440	193,803	199,130	204,697	210,288	215,909
Solar electric (or equivalent EPS credits) planned (MWH) *	15,745	23,428	32,535	38,466	48,698	55,479	62,261	76,050	82,832	83,832
Shortfall (MWh)	59,449	101,554	129,038	136,323	139,742	138,324	136,869	128,647	127,456	132,077
" Other" (or equivalent EPS credits) required (MWh)	75,194	83,322	107,715	116,526	125,627	129,202	132,753	136,465	140,192	143,940
"Other" (or equivalent EPS credits) planned (MWh) *	35,301	75,419	100,385	125,351	133,235	172,874	193,898	233,537	254,561	254,561
Shortfall (MWh)	39,893	7,903	7,330	(8,825)	(7,608)	(43,672)	(61,145)	(97,072)	(114,369)	(110,621)

* Includes off-grid applications and multipliers not appropriate for determining APS unmet needs.

* Please note this assumes current funding levels. To the extent the funding levels are increased, APS' shortfall would be reduced accordingly.