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September 30, 2005

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

RE: Docket No's. E-01345A-03-0437 and E-01345A-05-0526
Approval of Power Supply Adjustor

Dear Sir/Madame:

Pursuant to the Procedural Order dated September 14, 2005, Arizona Public Service Company ("APS") hereby files its Direct Testimony for Steven M Wheeler, Peter Ewen and Thomas Carlson in the above referenced Dockets.

If you or your staff should have any questions, please feel free to call me at (602)250-2060.

Sincerely,

Justin Thompson
EG

Justin H. Thompson
Manager
Regulation, Policy & Analysis

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Steven Wheeler

DIRECT TESTIMONY OF STEVEN M. WHEELER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437
&
Docket No. E-01345A-05-0526

September 30, 2005

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DIRECT TESTIMONY OF STEVEN M. WHEELER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-0437 & E-01345A-05-0526)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Steven M. Wheeler. I am Executive Vice President, Customer Service and Regulation for Arizona Public Service Company ("APS" or "Company"). In that role, I am responsible for the planning, construction and operation of the APS transmission and distribution system. I am also responsible for all customer service, rate and related regulatory matters affecting the Company, including those before the Arizona Corporation Commission ("Commission") and the Federal Energy Regulatory Commission ("FERC").

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. In 2001, I joined APS as a Senior Vice President. I assumed my present responsibilities with the Company in 2003.

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

A. My testimony will summarize the Company's request for a Power Supply Adjustment ("PSA") surcharge and discuss the need for prompt action by the Commission to reduce the escalating level of fuel and purchased power cost deferrals. I also describe the PSA rate mechanism as approved by the Commission in Decision No. 67744 and respond to issues raised about its implementation.

Q. DOES THE COMPANY HAVE OTHER WITNESSES PRESENTING DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. Mr. Pete Ewen will describe and explain the build up of the PSA bank balance beginning in April 2005. Mr. Tom Carlson testifies concerning the Company's hedging policies and programs as they impact gas and purchased power procurement.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR DIRECT TESTIMONY?

A. On July 22, 2005, APS requested a PSA surcharge to collect some $100 million in deferred fuel and purchased power costs. As noted in that Application, APS had deferred over $50 million in such costs as of the date of filing and anticipated reaching at least $100 million in deferrals by the end of August 2005. (The actual level of deferrals in the PSA bank balance by the end of August was approximately $115 million.) Decision No. 67744 is clear in its requirement that APS seek a PSA surcharge prior to the PSA bank balance reaching $100 million. The Company specifically requested that a PSA surcharge of $.00177 per kWh be implemented beginning in November 2005.

Subsequent to filing its Application, APS agreed with Staff and the Residential Utility Consumer Office ("RUCO") to defer $20 million from this specific PSA surcharge request. This represented more than the Company's estimate of the costs included in the $100 million resulting from unplanned Palo Verde outages during the period April 1 through July 2005. (Although Palo Verde experienced unplanned outages in August, any additional costs were not part of the $100 million request, which request expected and reflected anticipated Palo Verde operations after July.) The impact of this removal reduces the required surcharge, again beginning in November 2005, to $.001416 per kWh, or approximately a 1.7% increase for the requested two year amortization period.

By agreeing to remove the Palo Verde-related dollars and hence Palo Verde issues from this proceeding, APS is in no way suggesting or implying, let alone conceding that the costs resulting from these Palo Verde outages should not be fully recovered (subject to the 90/10 sharing, which is already reflected in the $20 million) under the PSA. To the contrary, APS intends to pursue full recovery of these outage costs in a subsequent proceeding. Indeed, by the express terms of the Commission's Procedural Order dated September 23, 2005, the Company's withdrawal of the $20 million from present consideration by the Commission in this proceeding was "without prejudice."

Since April 1, 2005, which was the effective date of the PSA per Decision No. 67744, APS has deferred some $115 million in higher fuel and purchased power costs through the end of August 2005. This, of course, represented only 90% of the actual increase in fuel and purchased power costs over the amounts reflected in base rates plus the current PSA adjustor. The remaining amounts of these higher costs, approximately $13 million, were directly expensed against income,

thus reducing the Company's earnings. Mr. Ewen's testimony indicates that even with the $80 million PSA surcharge and an estimated 3 mill per kWh increase in the Annual PSA Factor, effective April 1, 2006, these PSA deferrals will reach some $255 million by the end of 2006 (including some $40 million of the $80 million surcharge amount, which will still be unrecovered as of year end 2006). And since April 1, 2005, APS shareholders will have absorbed some $39 million in unrecoverable costs by the end of 2006 due to the 90/10 sharing under the PSA, which I describe later in my Direct Testimony.

Obviously, without the requested PSA surcharge, the PSA bank balance would be even higher, reaching $274 million by year-end 2006 (even assuming a 4 mill increase in the Annual PSA Factor in April 2006). Financing such a huge balance of unrecovered costs just adds to the cost burden that eventually must be borne by APS customers. Denial of the requested PSA surcharge or even unexpected delay in its approval will also send a clear message to an already concerned financial community that the Commission is not serious about preserving the Company's financial integrity and has instead singled APS out for uniquely unfavorable treatment with regard to higher fuel costs. Customers are similarly adversely affected as the burden on future customers is increased and conservation messages are diluted when customers are not faced with the higher cost of energy.

In Decision No. 67744, the Commission authorized a PSA mechanism for APS. The PSA permitted the Company to defer for later recovery/refund 90% of the fuel and purchased power costs in excess of/below the amount recovered through base rates ("Base Fuel Recovery Amount") plus the annual fuel and purchased power adjustment factor ("Annual PSA Factor") established each

April, beginning with the $.00000 per kWh established as of April 1, 2005. (Any PSA surcharge revenues received would likewise be credited against the deferrals in the PSA bank balance.) Decision No. 67744 further established the Base Fuel Recovery Amount, using 2003 costs, at $.020743 per kWh and, as noted above, the Annual PSA Factor at zero. The other 10% is expensed (and paid for by APS shareholders) or retained as Other Income, depending on whether the costs are above or below the Base Fuel Recovery Amount plus the Annual PSA Factor.

Adjustments to PSA charges are made at least annually. The change to the Annual PSA Factor is on April 1 of each year beginning in 2006, based on a March 1 filing that compares fuel and purchased power costs per kWh for the preceding calendar year (in this first instance, the last nine months of 2005) after application of the 90/10 sharing provision with the Base Fuel Recovery Amount.

APS is also authorized to request a special PSA surcharge/credit when fuel and purchased power cost deferrals hit $50 million, plus or minus. And the Company is required to seek such a surcharge before the "bank balance" of cost deferrals reaches $100 million. This, of necessity, means that APS may request, and indeed may be required to request multiple PSA surcharges. Upon the date APS requests the PSA surcharge, the level of deferrals used to determine any subsequent surcharge application is reduced by the amount requested.

III. DESCRIPTION OF THE PSA SURCHARGE REQUEST

Q. WHAT IS APS SEEKING IN THE WAY OF A PSA SURCHARGE?

A. On July 22, 2005, APS requested a PSA surcharge to collect some $100 million in deferred fuel and purchased power costs. This would represent an

approximate 2.2% increase if recovery is spread over 24 months, as had been proposed by the Company. APS had deferred over $50 million in such costs as of the date of filing and anticipated reaching at least $100 million in deferrals by the end of August 2005. (Deferrals to the PSA bank balance by the end of August 2005 actually reached $115 million.) The Company specifically requested that a PSA surcharge of $.00177 per kWh be implemented beginning in November 2005.

Q. WHY DID APS MAKE ITS FILING WHEN IT DID?

A. Decision No. 67744 required APS to request a surcharge prior to the bank balance reaching $100 million. Although that meant APS could have delayed this filing by three or four weeks and still have been in compliance with Decision No. 67744, the request for a PSA surcharge could not have been avoided.

Aside from the requirements of Decision No. 67744, it was and is appropriate to address the escalating APS bank balance before it gets unnecessarily high, as has happened to other utilities in Arizona. As I discuss later in my Direct Testimony and as is described in Mr. Ewen's Direct Testimony, additional fuel and purchased power cost deferrals over and above the levels requested for recovery in this proceeding will add another $175 million to the PSA bank balance by year-end 2006 even with an estimated three mill per kWh increase to the Annual PSA Adjustment Factor in April 2006.

Q. WHY ASK FOR IMPLEMENTATION IN NOVEMBER 2005 RATHER THAN AN EARLIER DATE?

A. There were two primary reasons. First, APS wanted to give the Commission a reasonable period of time in which to consider the PSA surcharge Application.

Second, APS switches to winter rates in November, which on average are for residential customers some 14% less than the rates in effect for the rest of the year. Thus, the upfront impact on customers would be less.

Q. IS APS STILL SEEKING A $100 MILLION PSA SURCHARGE IN THIS PROCEEDING?

A. No. Subsequent to filing its Application, APS agreed to defer $20 million from this specific PSA surcharge request. This represented a high estimate of the additional costs included in the $100 million from unanticipated Palo Verde outages during the period April 1 through July 2005. Although Palo Verde experienced unplanned outages in August, any additional costs were not part of the $100 million request, which assumed expected Palo Verde operations after July. The impact of this deferral reduces the required surcharge, again beginning in November 2005, to $.001416 per kWh, or approximately a 1.7% increase over the two year amortization period.

Q. IS THE COMMISSION NOW BEING ASKED TO APPROVE RECOVERY OF THE COSTS ASSOCIATED WITH THE PALO VERDE OUTAGES SINCE APRIL 1, 2005?

A. No. That was the purpose behind deferring consideration of the approximately $20 million in outage-related costs that had been included in the original PSA surcharge request. But by agreeing to remove the Palo Verde-related dollars and hence Palo Verde issues from this proceeding, APS is in no way suggesting or implying, let alone conceding that the costs resulting from these Palo Verde outages should not be fully recovered (subject to the 90/10 sharing, which is already reflected in the $20 million) under the PSA. APS intends to pursue full recovery of these and other appropriate Palo Verde costs in a subsequent proceeding. Indeed, by the express terms of the Commission's Procedural Order

dated September 23, 2005, the Company's withdrawal of the $20 million from present consideration by the Commission in this proceeding was "without prejudice." APS agreed to remove the Palo Verde-related costs from this proceeding to allow for a timelier procedural schedule – one that could at least potentially still allow for a PSA surcharge to go into effect in late 2005.

Q. IS APS ALONE IN ITS NEED TO RECOVER HIGHER FUEL COSTS?

A. Far from it. The Commission is aware of the situation with UniSource Energy ("UniSource") and Southwest Gas Corporation ("Southwest Gas"). However, this is a nationwide problem. For example, all major Nevada utilities have sought, and some have received large increases to recover these costs (proceedings for the remaining companies are still pending as of the time of this testimony). In fact, in each of these proceedings, the Nevada commission staff recommended greater increases than those requested by the utilities. The three large Florida electric utilities recently asked for $1.2 billion in additional revenues for the same reason. Like these other utilities, APS makes no profit from the PSA – it is a pass through of a portion of its actual costs with zero markup. Unlike these utilities, including the other Arizona utilities, APS does not even get an opportunity to recover 100% of its costs, but instead has to absorb 10% of such costs off the top, irrespective of their prudence.

IV. NEED FOR PROMPT AND POSITIVE ACTION TO ADDRESS THE ESCALATING DEFERRAL BY APS OF UNRECOVERED FUEL AND PURCHASED POWER COSTS

Q. WHY DOES THE COMPANY URGE THE COMMISSION TO ACT PROMPTLY AND POSITIVELY ON THE COMPANY'S MODIFIED REQUEST FOR A PSA SURCHARGE?

A. There are three very good reasons. First, the level of deferred fuel and purchased power costs is becoming excessive. This has adverse impacts on both the

Company and its customers. To understand this, the Commission need look no farther than the UniSource situation, where we have seen bank balances escalate to unprecedented proportions, or to Southwest Gas, where this Commission acted decisively last fall in an attempt to head off a similar problem. Second, the sooner APS customers receive more appropriate price signals about the higher cost of energy, the sooner they can attempt to adjust their usage to mitigate the overall impact. The third reason is because Wall Street is watching this proceeding very closely. There was and is concern in the financial community over the restrictions placed on the PSA by Decision No. 67744. For the Commission to then fail to implement the very PSA surcharge mechanism they had approved just a handful of months ago would diminish if not eliminate any confidence that the PSA would provide the Company with any meaningful relief from the escalating cost of natural gas and others fuel/purchased power costs.

Q. HOW MUCH HAS AND WILL APS DEFER INTO THE PSA BANK BALANCE ABSENT THE PROPOSED PSA SURCHARGE?

A. Since April 1, 2005, which was the effective date of the PSA per Decision No. 67744, APS has deferred some $115 million in higher fuel and purchased power costs through the end of August 2005. The remaining amounts of these higher costs, approximately $13 million, were directly expensed against income, thus reducing the Company's earnings. Mr. Ewen's testimony indicates that even with the $80 million PSA surcharge and an estimated three mill per kWh increase in the Annual PSA Factor, effective April 1, 2006, these PSA deferrals will again reach some $255 million by the end of 2006. And since April 1, 2005, APS shareholders will have absorbed some $39 million in unrecoverable costs through the end of 2006 due to the 90/10 sharing under the PSA. Without the requested PSA surcharge, the PSA bank balance would be even higher, reaching

$274 million by year-end 2006 (even assuming a maximum four mill increase in the Annual PSA Factor in April 2006).

Q. COULD YOU PLEASE EXPLAIN THE IMPACT OF GROWING FUEL AND PURCHASED POWER COST DEFERRALS?

A. Fuel and purchased power costs are out-of-pocket cash expenditures by APS to provide service to its customers. When revenues from the Base Fuel Cost Recovery Amount and the Annual PSA Adjustment Factor are insufficient to cover these outlays, they have to be financed from other sources. Whether this source is other internally-generated cash or outside borrowings, it is obvious that unrecovered fuel and purchased power costs consume capital that could otherwise be used to build infrastructure or refinance higher cost capital.

Q. WHY ARE CUSTOMERS ADVERSELY IMPACTED BY THE FAILURE TO ADDRESS THE CONSEQUENCES OF LARGE BALANCES OF UNRECOVERED FUEL AND PURCHASED POWER COSTS?

A. First of all, it is not in the interest of customers to have a financially distressed utility that must incur additional financing costs – costs that are invariably borne by consumers. Second, customers need to know the facts about higher energy costs so they can make whatever changes they can in their consumption of energy. APS and its customers are making a large investment in promoting conservation and energy efficiency - $48 million over the next three years. This effort is directly undermined when customers are not faced with the true cost of energy, thus effectively reducing the value of conservation and energy efficiency programs. Third, the higher the bank balances are allowed to grow, the greater the eventual impact on customer bills when these IOUs have to be paid, especially when you consider that customers also pay interest on the PSA bank balance.

Q. HOW DO YOU KNOW THAT THE FINANCIAL COMMUNITY IS CLOSELY WATCHING THIS PROCEEDING AND CONSIDER IT CRITICAL IN ITS EVALUATION OF APS' FINANCIAL CONDITION?

A. They have written it. For example, on July 27, 2005, Merrill Lynch stated: "APS has made its first fuel surcharge filing and this case will be watched closely for any signs of pushback from regulators." On August 31, 2005, JP Morgan wrote: "We continue to be concerned with the company's ability to recover the growing deferred fuel balance in a timely manner." Finally, in a report downgrading Pinnacle West, Morgan Stanley indicated on September 19, 2005: "Since PNW's [APS] fuel clause is brand new, it will likely be subject to continued state regulatory 'interpretations,' and may cut into recovery of other operating expenses, especially as AZ has traditionally been a difficult regulatory regime." And recently, Tucson Electric Power Company and its parent, UniSource, have both been placed on negative credit watch by Standard & Poor's in large part due to uncertainty regarding this Commission's willingness to address the impact of escalating energy costs on utility finances.

It will also not go unnoticed if APS is denied a PSA surcharge when the Commission has regularly approved other surcharges for gas utilities, usually for percentage amounts far in excess of the Company's request. Such unequal treatment would only deepen the financial community's concerns about the degree of regulatory support in Arizona for maintaining the financial integrity of its largest utility serving the second fastest growing service area in the country.

Q. WHY ARE THE CONCERNS OF THE FINANCIAL COMMUNITY IMPORTANT?

A. Like it or not, the financial community, which consists of investors, financial analysts and ratings agencies, determines how much APS must pay for the

capital resources it needs and even whether APS will have ready access to such resources. Capital is the "life's blood" of a utility, and neither APS nor this Commission can ignore those who provide that capital and those who advise them.

V. DESCRIPTION OF PSA RATE MECHANISM

Q. COULD YOU PLEASE DESCRIBE THE PSA?

A. In Decision No. 67744, the Commission authorized a PSA mechanism for APS. In general, it was based on a model adjustment mechanism developed by Commission Staff for gas utilities, but with many more restrictions. The PSA permitted the Company to defer for later recovery/refund 90% of the fuel and purchased power costs in excess of/below the amount recovered through base rates, i.e., the Base Fuel Recovery Amount, plus the annual fuel and purchased power adjustment factor, i.e., the Annual PSA Factor, established each April, beginning with the $.00000 per kWh established as of April 1, 2005 by Decision No. 67744. (Any PSA surcharge revenues received would likewise be credited against the deferrals in the PSA bank balance.) Decision No. 67744 further established that Base Fuel Recovery Amount at $.020743 per kWh. The other 10% is expensed (and essentially paid for by APS shareholders) or retained as Other Income, depending on whether the costs are above or below the Base Fuel Recovery Amount plus the Annual PSA Factor.

Adjustments to PSA charges are made at least annually, up to a cumulative cap of four mills per kWh. The change to the Annual PSA Factor is on April 1 of each year beginning in 2006, based on a March 1 filing that compares fuel and purchased power costs per kWh for the preceding calendar year (in this first

instance, the last nine months of 2005) after application of the 90/10 sharing provision with the Base Fuel Recovery Amount.

APS is also authorized to request a special PSA surcharge/credit when fuel and purchased power cost deferrals hit $50 million. And the Company is required to seek such a surcharge before the "bank balance" of cost deferrals reaches $100 million. *See* Decision No. 67744 at 17, lines 13-14. This, of necessity, means that APS may request, and indeed may be required to request multiple PSA surcharges. Upon the date APS requests the PSA surcharge, the level of deferrals used to determine any subsequent surcharge application is reduced by the amount requested.

It is important to note that the Annual PSA Factor and a PSA surcharge serve two related functions. Thus they are not redundant ("adjustor to an adjustor") but complements to a unitary and integrated PSA mechanism. The Annual PSA Factor is essentially to update the Base Fuel Recovery Amount with more recent data and is intended to, on a prospective basis, reduce or eliminate the need for additional accumulations of deferred costs in the PSA bank balance. It also may or may not result in a prospective reduction of current bank balances. The PSA surcharge, on the other hand, deals explicitly with past deferrals into the bank balance and how they will be recovered or refunded through rates. Each component of the PSA is essential to the Company's ability to recover prudently incurred fuel and purchased power costs above the level represented by the Base Fuel Recovery Amount.

Q. ON WHAT DO YOU BASE YOUR DESCRIPTION OF THE PSA?

A. It is what Decision No. 67744 says as does the rate schedule, PSA-1, filed in compliance with that Decision and effective by its own terms on April 1, 2005.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. APS filed its request for a PSA surcharge both because it was required by Decision No. 67744 and to address the problem of a rapidly increasing PSA bank balance. The Company agreed with Staff and RUCO to remove prudence issues from this proceeding until a later date and reduce its present request for a PSA surcharge by $20 million in order to allow for a more expedited consideration by the Commission of the balance of the surcharge Application.

Failure of the Commission to act promptly and positively in this matter has significant negative consequences. First, we must begin the process of reducing at least the rate of growth of the PSA bank balance. Otherwise we will be building up a huge burden for future customers to pay while denying to present customers the appropriate price signals about the cost of energy consumption. It also places a strain on the Company's ability to raise necessary capital on reasonable terms for other purposes, including construction for new growth and reliability. Second, the financial community is clearly looking at this proceeding as a test case of this Commission's resolve to come to grips with higher energy costs.

The PSA was approved by the Commission in Decision No. 67744, effective April 1, 2005. All components of that rate mechanism, including the Base Fuel Recovery Amount, the Annual PSA Factor, and the potential for a PSA surcharge likewise became effective on April 1, 2005. APS is required to seek a

PSA surcharge prior to the bank balance reaching $100 million, irrespective of when and how many times that occurs. Having made such a request, the Company can continue to defer 90% of fuel and purchased power costs in excess of the sum of the Base Fuel Recovery Amount and the Annual PSA Adjustment Factor pending Commission action on the surcharge request so long as the PSA bank balance, exclusive of the amount sought in the PSA surcharge request, does not again reach $100 million prior to APS making a subsequent (second) PSA surcharge filing.

APS therefore urges the Commission to approve and authorize a PSA surcharge of $.001416 per kWh for 24 months beginning in November 2005, or as soon thereafter as possible. Although such surcharge will not eliminate the unrecovered bank balance or even prevent it from significantly growing during the amortization period, it is an important start and will send a positive signal to the financial community, smooth the impact of recovery for customers while giving more appropriate price signals, and reduce the financial burden on the Company that is inherent in significant balances of unrecovered costs.

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

A. Yes, it does.

Peter Ewen

DIRECT TESTIMONY OF PETER M. EWEN

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0526

&

Docket No. E-01345A-03-0437

September 30, 2005

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DIRECT TESTIMONY OF PETER M. EWEN
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0526 & E-01345A-03-0437)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Peter M. Ewen. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004.

Q. WHAT IS YOUR POSITION WITH ARIZONA PUBLIC SERVICE COMPANY?

A. I am Manager of the Forecasts Department for Arizona Public Service Company ("APS" or "Company"). In that role, I am responsible for preparing the Company's short-range and long-range forecasts of system peak demand and energy sales and for projecting the optimal dispatch of available resources to 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.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am supporting the Company's application for a 0.1416¢/kWh power supply adjustor ("PSA") surcharge, as shown on Schedule PME-1, by describing the extent of the Company's under-collection of its fuel and purchased power expenses as they relate to the fuel costs included in the Company's current base rates approved in Decision No. 67744 (April 7, 2005). (Here and throughout the remainder of my testimony, I will refer to fuel and purchased power expenses collectively as fuel expenses.) I describe what the extent of this under-collection is expected to be through the end of 2006, with and without the requested surcharge. I also explain the various reasons why the Company is experiencing this under-collection.

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. From April 1, 2005 through August 31, 2005, the Company has under-collected $127.7 million in fuel expenses in the provision of electricity to its retail customers, of which $115.2 million has been deferred and $12.5 million has been paid for by the Company's shareholders, reflecting the Company's 10% share of higher fuel costs as mandated by the Commission in Decision No. 67744. The Company, in its July 22 filing, initially requested a surcharge to recover $100 million over 24 months beginning November 1, 2005. As Company witness Mr. Steve Wheeler indicates in his testimony, the Company has subsequently modified its request, and is now seeking to recover $80 million over 24 months with a surcharge of 0.1416¢/kWh. If the Commission were to approve the requested $80 million surcharge, the application of the annual PSA adjustment formula results in an estimated Annual PSA Factor of 0.3¢/kWh in April 2006.

Under such circumstances, the under-collected fuel expense balance is expected to reach $255 million by the end of 2006, including the as of yet unrecovered portion of the $80 million. In the absence of this surcharge, the under-collected balance will approach $274 million by the end of 2006.

The reasons for this are fairly straightforward. First, higher fuel prices account for $45 million, the largest single source of the under-collection. These higher fuel costs are in spite of the significant savings of $31 million the Company was able to achieve through its fuel hedging program. Second, the incremental electricity sales growth since 2003 – the time period which served as the basis for the Company's base fuel rate – has been served predominately by high-cost natural gas and purchased power resources, a cost increase of $13 million. Third, the Company is under-collected by $30 million simply because the monthly pattern of fuel costs is at its highest during the spring and summer periods captured in the filing. This amount assumes no changes in fuel prices, energy sales levels, or plant operations.

II. UNDER-COLLECTED FUEL EXPENSE BANK BALANCE

Q. WHAT WAS THE AMOUNT OF FUEL EXPENSE THAT THE COMPANY DID NOT RECOVER FROM APRIL THROUGH AUGUST 2005?

A. $127,675,173.

Q. WHAT WAS THE UNDER-COLLECTED BANK BALANCE AT THE END OF AUGUST 2005?

A. $115,216,605.

Q. WHAT IS THE DIFFERENCE BETWEEN THESE NUMBERS?

A. The difference of almost $12.5 million is accounted for by the amount of fuel the Company paid for but does not get to collect from customers as a result of the 10% sharing mechanism incorporated in the PSA. The actual expense amounted

to $12.8 million but was slightly offset by the interest of $0.3 million that has accrued on the unrecovered fuel expense balance.

Q. HOW WERE THESE AMOUNTS CALCULATED?

A. Each month, the Company records its fuel and purchased power expenses incurred in serving native load customer energy needs, and the revenues and fuel expenses associated with making off-system sales. The fuel and power purchase and sale transactions associated with both of these activities are managed internally in the Company's "System Book." A net cost of serving native load customers is calculated by crediting the revenues from the Company's off-system sales against the total fuel and purchased power expenses incurred in serving native load customers and off-system sales. The retail component of this net cost is calculated based on each month's proportion of retail electricity sales to that month's total native load sales. This retail customer net fuel cost is compared to the amount of revenue the Company collected from retail customers for fuel expenses, which is the Company's approved base fuel rate of 2.0743¢/kWh multiplied by that month's electricity sales to retail customers, in order to find the dollar amount the Company has under- or over-collected. Finally, any under- or over-collection is split with 90% going into a bank balance for future rate determination and 10% being expensed by the Company during the period.

Schedule PME-2 is the Company's standard monthly PSA filing with the Commission, which shows these monthly calculations for April through August 2005, the time period during which the PSA has been in effect. As can be seen from page 1 of the exhibit, the Company has under-collected its approved fuel costs in every month since the start of the PSA, with the highest cost months of July and August being the largest contributors to the under-collected balance. Of the $127.7 million the Company has spent on fuel but not recovered, $86.6

million, or two-thirds of the total, occurred in the two months of July and August.

Q. PLEASE EXPLAIN WHY THE COMPANY DOES NOT SEPARATELY CALCULATE FUEL AND PURCHASED POWER EXPENSES FOR NON-RETAIL NATIVE LOAD.

A. The Company's non-retail (wholesale) native load customers all are small districts serving rural areas of Arizona and comprise approximately 3% of total native load sales. These non-retail customers are served from the same common set of resources as the Company's retail customers, and their fuel and purchased power costs were allocated on the same basis as in the PSA Plan of Administration in determining the Base Fuel Cost adopted by the settlement and Decision No. 67744. For that matter, it is the same allocation procedure used in prior APS rate proceedings. Thus, the treatment of these loads is both consistent with prior precedent and with how costs are actually incurred to serve them.

Q. DO YOU EXPECT THE BANK BALANCE TO CORRECT ITSELF AND RETURN TO ZERO?

A. No, quite the opposite. By December 2006, the Company's under-collection is expected to be around $255 million. This amount is more than the Company's 2004 earnings. The Company will add some $214 million in under-collected fuel costs to this balance through the course of 2006, but will collect only $40 million in 2006 through the surcharge, if approved, and $67 million from re-setting of the Annual PSA Factor on April 1, 2006. This $107 million in collections will not even recoup the Company's shortfall in 2005. The December 2005 under-collected balance will be $143.1 million, or $36 million more than the Company will collect in 2006.

Q. WHAT WOULD THE UNDER-COLLECTED BALANCE BE WITHOUT THE APPROVAL OF THE SURCHARGE?

A. At the end of 2006, the bank balance would be $274 million, or about $19 million higher than the current projection. Without the 0.1416¢/kWh surcharge, the Annual PSA Factor – under current projections – will be re-set to 0.4¢/kWh on April 1, 2006, which partially offsets the loss of the $40 million in surcharge collections in 2006.

III. SOURCES OF UNDER-COLLECTED FUEL EXPENSES

Q. WHAT ACCOUNTS FOR THESE HIGHER COSTS?

A. Schedule PME-3 provides a list of the major factors that have contributed to the increase in average costs relative to the 2003 base fuel rate and quantifies the impact in dollar terms. On page 1, it shows the bank balance at the end of August 2005 and the amounts which the Company is not seeking to recover at this time. The result is the "Net Balance for Current Request" of $80 million (the $.1 million difference is due to rounding). Page 2 shows a breakdown of the sources of fuel expense increases over the Company's base fuel rate. Note that the principal factors listed on page 2 account for more than the Company is requesting in its current application by $8.2 million. See Schedule PME-3, page 2. This is because the Company is setting aside $20 million of under-collected fuel expenses related to unplanned outage replacement power costs for future rate determination and because $15 million of higher costs were never included in the Company's original request due to the timing of the application (i.e., before July and August final balances were known).

First on the list is higher fuel prices, which account for $45 million of the increase and would be even greater were it not for the Company's hedging program. Prices for natural gas and purchased power are up 23% and 46%, respectively, for the April-August 2005 time period relative to the 2003 prices included in the Company's base fuel rate of 2.0743¢/kWh. Delivered prices for

natural gas averaged $6.96/mmbtu and purchased power prices averaged $57.15/MWh in 2005. The corresponding prices in the base fuel rate reflect 2003 prices of $5.65/mmbtu for natural gas and $39.14/MWh for purchased power. These price increases contribute almost $70 million to the Company's costs in excess of the base rate levels.

These cost increases are offset by savings of $34 million from the Company's hedging program, or almost half of the overall price increase. The Company hedged a substantial portion of its 2005 natural gas and power needs in advance, beginning in the 4th quarter of 2003. As gas and power prices for 2005 increased steadily from the end of 2003 through the 2nd and 3rd quarters of 2005, these financial hedges that the Company had purchased gained significantly in value. When it was time to take physical delivery of natural gas and power, the Company liquidated these financial hedges and is using the proceeds to reduce the net cost to customers of high natural gas and power prices. Mr. Carlson describes the Company's hedging program in more detail in his testimony.

The change in gas and power prices has also contributed to lower off-system sales margins as the Company's gas-fired generating units became less economic relative to the 2003 base fuel rate prices. The reduced margins from these sales increased net costs by $2 million. In combination with the other factors I have just described, the ultimate increase in cost due to higher natural gas and power prices nets to $38 million, or $34 million after accounting for the Company's 10% share of the increase.

Q. HAVE OTHER FUEL PRICES INCREASED?

A. Yes. In particular, prices for coal have experienced fairly substantial increases that have led to an additional $12 million of under-collected costs, net of the

Company's 10% share. Average coal production costs are 15% higher in 2005 than what is included in the 2003 base fuel rate. Rail transportation costs for the coal burned at the Company's Cholla Generating Station also have increased as a result of a Surface Transportation Board ("STB") action in December 2004. In addition, coal prices otherwise have increased at all three of the Company's coal-fired generating plants, due to higher costs at the mines. Coal production costs averaged $15.29/MWh in the 2005 period, but are only $13.27/MWh in the Company's base fuel rate.

In summary, the higher prices for coal, natural gas and power account for $45 million, or 56%, of the $80 million under-collection in 2005.

Q. WHAT OTHER CONDITIONS ARE CONTRIBUTING TO THE FUEL EXPENSE UNDER-COLLECTION?

A. Another significant contributor is the incremental load growth that the Company has experienced since the base fuel rate was set. Retail sales of electricity are approximately 500,000 MWh greater in the April – August 2005 time period than in the corresponding months of 2003 used for the base fuel rate calculation. Holding fuel prices constant at base fuel rate levels, this additional 500,000 MWh has resulted in an under-collection of $13 million (16%) net of the Company's 10% share. The incremental cost to serve these additional sales at base fuel rate prices is approximately $50/MWh, or 5.0¢/kWh. When compared to the 2.0743¢/kWh collected from customers for these additional sales, it becomes apparent that the Company is under-collecting 2.93¢/kWh on each incremental kWh sold. For every 1,000 MWh, the Company ends up short by $29,000. After absorbing 10% of the increase, every 1,000 MWh contributes just over $26,000 to the under-collected balance.

Q. WHAT ELSE HAS LED TO THE UNDER-COLLECTION OF FUEL EXPENSES THROUGH AUGUST?

A. The monthly pattern of fuel expenses is another contributor to the uncollected balance and accounts for $30 million (37% of the $80 million) net of the Company's 10% share. This would be the case even if fuel prices, energy sales, and generator availability all were exactly the same as the values included in the base fuel rate. Schedule PME-4 shows graphically the pattern of 2003 average monthly fuel costs that averaged out to 2.0743¢/kWh over the entire year. The most salient feature in the exhibit is the higher costs in the summer months that are moderated out by lower costs in the spring and fall months. In the absence of higher fuel prices and higher energy sales, these short-term "timing" costs would be the only amounts uncollected through August, and the corresponding "over-collection" would occur in future months to balance out the under-collection. Combined with fuel prices that average out much higher than the 2003 prices included in base rates, though, this pattern, along with growth, helped to push the Company's under-collected balance over the $100 million threshold that required a filing for recovery under Decision No. 67744.

Q. WILL THIS PATTERN ACT AS A SELF-CORRECTION AND REDUCE FUTURE BALANCES TOO FAR THE OTHER WAY?

A. No. Between October 2005 and April 2006, the monthly amount collected from customers is expected to be modestly over or under, depending on the specific month, the Company's actual fuel costs. Because prices are as high as they are, however, future under-collected balances will only accelerate once the summer months of 2006 arrive. As I mentioned earlier, the Company currently projects that base revenues will produce a shortfall of $214 million relative to the anticipated fuel costs in 2006. Because this incorporates the full year, any "timing" issues are not a factor.

IV. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. The Company has spent significantly more on fuel and purchased power between April and August 2005 than it has collected from customers through the established base fuel rate. Under current projections, this trend is only expected to continue and, in the absence of Commission approval of the Company's requested surcharge, will grow to close to $300 million by the end of 2006.

The reasons for these fuel cost increases are straight-forward. Higher natural gas and power prices, higher coal prices and the high cost of incremental sales growth are the primary contributors to the Company's request. These higher costs have been mitigated to a large extent by the Company's forward hedging of its natural gas and purchased power needs. However, the fuel prices allowed in the Company's base fuel rate from 2003 are not likely to return in the foreseeable future, so the Company's requested surcharge is necessary to prevent the under-collected fuel expense bank balance from becoming unmanageablely large.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
Calculation of the Revised November 2005 PSA Surcharge

Line No.	Mth	Projected Retail Calendar MWhs	Less E-3/E-4[1] Projected MWhs	Less E-36[2] Projected MWhs	Total MWhs
1	Nov 05	1,921,888	(17,765)	(5,090)	1,899,033
2	Dec 05	2,062,795	(20,996)	(5,090)	2,036,709
3	Jan 06	2,109,012	(23,186)	(5,090)	2,080,736
4	Feb 06	1,821,752	(19,440)	(5,090)	1,797,222
5	Mar 06	1,929,711	(16,764)	(5,090)	1,907,857
6	Apr 06	2,025,386	(15,933)	(5,090)	2,004,363
7	May 06	2,374,205	(17,161)	(5,090)	2,351,954
8	Jun 06	2,704,478	(23,573)	(5,090)	2,675,815
9	Jul 06	3,041,028	(29,271)	(5,090)	3,006,667
10	Aug 06	3,253,145	(34,101)	(5,090)	3,213,954
11	Sep 06	2,670,087	(32,227)	(5,090)	2,632,770
12	Oct 06	2,096,903	(23,721)	(5,090)	2,068,092
13	Nov 06	1,998,967	(18,476)	(5,090)	1,975,401
14	Dec 06	2,146,316	(21,836)	(5,090)	2,119,390
15	Jan 07	2,192,234	(24,113)	(5,090)	2,163,031
16	Feb 07	1,893,694	(20,218)	(5,090)	1,868,386
17	Mar 07	2,006,883	(17,435)	(5,090)	1,984,358
18	Apr 07	2,105,708	(16,570)	(5,090)	2,084,048
19	May 07	2,469,635	(17,848)	(5,090)	2,446,697
20	Jun 07	2,818,195	(24,516)	(5,090)	2,788,589
21	Jul 07	3,169,580	(30,442)	(5,090)	3,134,048
22	Aug 07	3,390,383	(35,465)	(5,090)	3,349,828
23	Sep 07	2,781,625	(33,516)	(5,090)	2,743,019
24	Oct 07	2,182,782	(24,670)	(5,090)	2,153,022
		57,166,392	(559,241)	(122,160)	56,484,991

Amortized Amount	**$ 80,000,000**
Total kWhs	56,484,991,000
PSA Surcharge per kWh	**$ 0.001416**

[1] E-3 and E-4 customers will not have to pay PSA charges per Decision No. 67744.

[2] E-36 customers are directly assigned incremental fuel and purchased power per the terms of the rate schedule. Therefore, both the incremental cost and the associated MWh usage are excluded from the PSA calculations. The PWEC Units are excluded from the E-36 projections because they are being transferred to APS.

Note: The PSA Surcharge will expire at the end of the 24 month period. Any over/under collection remaining at the end of the period will be credited/debited to the PSA balancing account.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
2005 Monthly Energy Sales and Costs

Line No.	Month	(a) PSA Retail [1] Energy Sales (kWh)	(b) Native Load [2] Wholesale Energy Sales (kWh)	(c) Native Load Energy Sales (kWh)	(d) System [3] Book Fuel and Purchased Power Costs	(e) System Book [4] Off-System Sales Revenue	(f) Net Native Load Power Supply Cost	(g) PSA Retail Power Supply Cost	(h) Base Rate Power Supply Cost	(i) Pre-Sharing (Over)/Under Collection	(j) Post-Sharing (Over)/Under Collection
				(a + b)			(d - e)	(a/c * f)	(a * 0.020743)	(g - h)	(i * 0.9)
1	January	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	February	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	March	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	April	1,740,332,253	66,132,000	1,806,464,253	$ 43,121,614	$ 3,912,992	$ 39,208,622	$ 37,773,252	$ 36,099,712	$ 1,673,540	$ 1,506,186
5	May	2,235,997,989	74,575,395	2,310,573,384	$ 68,036,346	$ 4,071,192	$ 63,965,154	$ 61,900,633	$ 46,381,306	$ 15,519,327	$ 13,967,394
6	June	2,565,383,692	59,137,886	2,624,521,578	$ 82,638,364	$ 3,805,618	$ 78,832,746	$ 77,056,422	$ 53,213,754	$ 23,842,668	$ 21,458,401
7	July	3,075,187,048	98,176,607	3,173,363,655	$ 117,004,560	$ 3,172,422	$ 113,832,138	$ 110,310,432	$ 63,788,605	$ 46,521,827	$ 41,869,644
8	August	2,932,462,804	95,743,670	3,028,206,474	$ 108,099,009	$ 3,857,282	$ 104,241,727	$ 100,945,887	$ 60,828,076	$ 40,117,811	$ 36,106,030
9	September	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	October	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	November	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	December	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Total	12,549,363,786	393,765,558	12,943,129,344	$ 418,899,893	$ 18,819,506	$ 400,080,387	$ 387,986,626	$ 260,311,453	$ 127,675,173	
14											$ 114,907,655

[1] PSA Retail Energy Sales are the calendar month's kWh sales. Cumulative Retail Energy Sales of 2,894 MWhs under rate schedule E-36 were excluded from the PSA Calculations.

[2] Includes traditional sales-for-resale and Pacificorp supplemental sales.

[3] Includes native load and off-system fuel and purchased power costs less those costs associated with E-36 ($2,359,648), the non-fuel Bridge PPA, ISFSI and mark-to-market accounting adjustments. Excludes net savings of $1,159,000 associated with the Sundance units pursuant to Decision No. 67504. The Wheeling costs included this month are $2,087,952. The Broker Fees included this month are $34,515.

[4] Includes off-system revenue less mark-to-market accounting adjustments.

Definitions of commonly used terms for this filing are included in the PSA Plan for Administration. Any new terms will be defined on this page.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
2005 Annual Balancing Account Interest

Line No.	Month		Balancing Account Monthly Interest
			(Schedule 4, Line 15)
1	January	$	-
2	February	$	-
3	March	$	-
4	April [1]	$	-
5	May	$	3,502
6	June	$	35,984
7	July	$	85,959
8	August	$	183,505
9	September	$	-
10	October	$	-
11	November	$	-
12	December	$	-
13	Total	$	308,950

Move Forward to Schedule 3, Line 2 $ 308,950

[1] No interest was accrued in April since it is the first month for the PSA.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3
2005 Year End PSA Adjustor Rate Calculation

Line No.				
	PSA Adjustor Rate Calculation			
1	Post-Sharing (Over)/Under Collection Amount (From Sch. 1)		$ -	
2	Annual Balancing Account Interest (From Sch. 2)		$ -	
3	Less: Approved Amortization Surcharge Balance		$ -	
4	Bandwidth Carry Forward from Prior Period		$ -	
5	Total (Credit)/Charge Amount (Line 1 + Line 2 + Line 3 + Line 4)			$ -
6	Total (Credit)/Charge Amount	$ -		
7	Actual Energy Sales without E-3, E-4 and E-36 (kWh)	-		
8	Computed Adjustor Rate per kWh (Line 6 / Line 7)		0	
	Adjustor Rate Bandwidth			
9	Adjustor Rate Bandwidth Upper Limit		$ 0.004000	
10	Adjustor Rate Bandwidth Lower Limit		$ (0.004000)	
11	Applicable Adjustor Rate per kWh			$ -
12	Total (Credit)/Charge Carried Forward Due to Adjustor Rate Bandwidth			$ -

Note: This calculation is done once a year for the change to the PSA Adjustor Rate in April.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4
2005 Monthly Balancing Account Calculations

Line No.		January	February	March	April	May	June	July	August	September	October	November	December
	BALANCING ACCOUNT LESS APPROVED AMORTIZATION SURCHARGE BALANCE				Begins								
1	Beginning Balance	$ -	$ -	$ -	$ -	$ 1,506,186	$ 15,477,082	$ 36,971,467	$ 78,927,070	$ -	$ -	$ -	$ -
2	Approved Balance for Amortization Surcharge (if any)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Balance Less Amort. Surcharge (Ln. 1 - Ln. 2)	$ -	$ -	$ -	$ -	$ 1,506,186	$ 15,477,082	$ 36,971,467	$ 78,927,070	$ -	$ -	$ -	$ -
4	Monthly Interest ((Ln. 3 * (2.79%/12)) 1yr. Const. Mat. Rate)	$ -	$ -	$ -	$ -	$ 3,502	$ 35,984	$ 85,959	$ 183,505	$ -	$ -	$ -	$ -
5	Post-Sharing (Over)/Under Collection (From Sch. 1)	$ -	$ -	$ -	$ 1,506,186	$ 13,967,394	$ 21,458,401	$ 41,869,644	$ 36,106,030	$ -	$ -	$ -	$ -
6	Less Revenue from Applicable Adjustor Rate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Residual (Over)/Under Collection (Ln. 5 - Ln. 6)	$ -	$ -	$ -	$ 1,506,186	$ 13,967,394	$ 21,458,401	$ 41,869,644	$ 36,106,030	$ -	$ -	$ -	$ -
8	Ending Balance with Interest (Ln. 3 + Ln. 4 + Ln. 7)	$ -	$ -	$ -	$ 1,506,186	$ 15,477,082	$ 36,971,467	$ 78,927,070	$ 115,216,605	$ -	$ -	$ -	$ -
	AMORTIZATION SURCHARGE BALANCE												
9	Balancing Account Amort. Surcharge per kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Beginning Amortiztion Surcharge Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Amort. Monthly Int. ((Ln. 10 * (2.79%/12)) 1yr. Const. Mat. Rate)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Less Revenue from Applicable Amortization Surcharge(s)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Ending Amortization Surchage Balance (Ln. 10 + Ln. 11 - Ln. 12)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	COMBINED BALANCE												
14	Combined Balance (Ln. 8 + Ln. 13)	$ -	$ -	$ -	$ 1,506,186	$ 15,477,082	$ 36,971,467	$ 78,927,070	$ 115,216,605	$ -	$ -	$ -	$ -
15	Combined Interest (Ln. 4 + Ln. 11)	$ -	$ -	$ -	$ -	$ 3,502	$ 35,984	$ 85,959	$ 183,505	$ -	$ -	$ -	$ -

ARIZONA PUBLIC SERVICE COMPANY
August PSA Bank Balance versus Surcharge Request Amount
April - August 2005

	Fuel Expenses Greater Than Base Fuel Revenue ($000,000)	Company Shared Amount ($000,000)	Net Fuel Expense Greater Than Base Fuel Revenue ($000,000)
Balancing Account Balance at 8/31/05	127.7	12.5	115.2
Amounts Not Included in Current Request			
April-July 2005 Net Replacement Power Costs [(a)]	22.2	2.2	20.0
Other [(b)]	16.8	1.6	15.2
Subtotal	39.0	3.8	35.2
Net Balance for Current Request	**88.7**	**8.7**	**80.0**

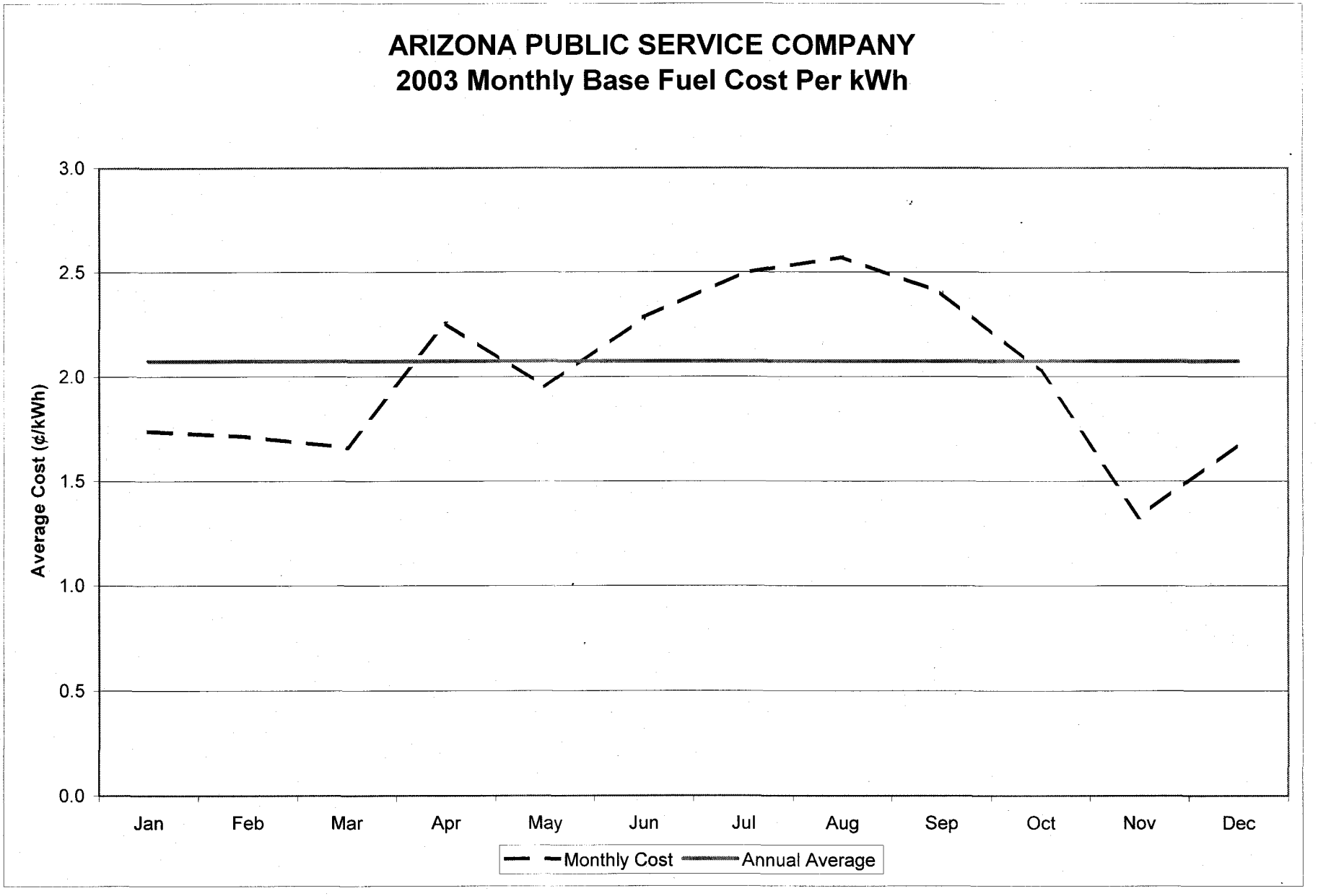
[(a)] These amounts reflect an upper-end estimate of the net replacement power costs related to unplanned outages during the April through July period. Although the Company is not seeking to recover these amounts in the current proceeding, the Company believes these are legitimate and prudently incurred costs and will pursue recovery of them in the future.

[(b)] These amounts were not included in the Company's current request because the initial filing occurred prior to the closing of the Company's books in July and August and, therefore, before the final August month-end balance was known. Amounts reflected here include any additional unplanned outage costs incurred in August as well as a portion of the cost increases explained on PME-3 page 2.

ARIZONA PUBLIC SERVICE COMPANY
Major Factors of Fuel Expense Under-Collection
April - August 2005

	Fuel Expenses Greater Than Base Fuel Revenue [a] ($000,000)	Company Shared Amount ($000,000)	Net Fuel Expense Greater Than Base Fuel Revenue ($000,000)
Factors			
A. Fuel Prices			
1. Gas and Power Prices	69.5	6.9	62.5
2. Gas and Power Hedges	(34.0)	(3.4)	(30.6)
3. Coal Prices	12.8	1.3	11.6
4. Off-System Margin Credit	2.1	0.2	1.9
Subtotal	50.3	5.0	45.3
B. Incremental Load Growth	14.4	1.4	13.0
C. Monthly Cost Pattern	33.2	3.3	29.9
Total	**98.0**	**9.8**	**88.2**

[a] The Fuel Expenses shown are before the 90/10 Sharing in the PSA.


ARIZONA PUBLIC SERVICE COMPANY
2003 Monthly Base Fuel Cost Per kWh
Average Cost (¢/kWh)
3.0
2.5
2.0
1.5
1.0
0.5
0.0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Monthly Cost
Annual Average

Thomas Carlson

TESTIMONY OF THOMAS J. CARLSON

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0526

&

Docket No. E-01345A-03-0437

September 30, 2005

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TESTIMONY OF THOMAS J. CARLSON
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0526
&
Docket No. E-01345A-03-0437)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Thomas J. Carlson. I am the Portfolio Manager for Arizona Public Service Company ("APS" or "Company") Regulated Marketing and Trading Division. In that role, I am responsible for procuring wholesale purchased power and natural gas for APS Native Load needs and also the marketing of surplus APS generation and natural gas.

Q. WHAT IS YOUR EDUCATION 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 in 2001 and to Portfolio Manager in 2004.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony will describe APS' natural gas and purchased power hedging philosophy and policies as such policies and procedures relate to procuring the gas and power needed to serve our native load.

II. SUMMARY OF TESTIMONY

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. Yes. APS incorporates extensive use of financial and physical contracts to minimize commodity price volatility when purchasing natural gas and purchased power to serve retail load. Since price stability is the goal of our system hedge position, financial risks associated with projected requirements of these commodities are systematically hedged at various levels three years prior to delivery with standard energy products.

APS has hedged its financial commodity risk since the late 1990's in response to unprecedented market price fluctuation and has continued with this policy, increasing its hedge percentages in June of 2005 in light of even greater price uncertainty. Because of these hedges, the current hedged price of natural gas and purchased power is significantly below the now prevailing market price through 2008.

The measured approach utilized by the system hedge plan helps APS customers largely avoid much of the turbulence of price volatility that can occur in the short-term commodity markets. Coupled with the practice of optimizing natural gas or purchased power to provide the lowest cost commodity to meet load, the current approach to hedging financial risk can provide APS customers with significant economic savings while, most importantly, attaining future price stability.

III. APS HEDGING PROGRAM AND PHILOSOPHY FOR GAS AND POWER PROCUREMENT

Q. WHAT IS A "HEDGE?"

A. As applied in our industry, a hedge is defined as "any technique designed to reduce or eliminate financial risk." Since commodity prices of natural gas and purchased power are extremely volatile and can change significantly from day to

day, the use of a hedge can eliminate much (but not all) of the financial risk associated with price changes in these markets. From the perspective of APS, we hedge primarily with fixed price contracts, i.e. we fixed the price of the commodity for a specific term, in order to eliminate price risk during that term.

Q. HOW LONG HAS APS BEEN HEDGING ITS NATURAL GAS AND PURCHASED POWER NEEDS?

A. APS has hedged natural gas and purchased power requirements for native load customers in various respects since the late 1990's. The impetus for hedging these commodities originated from the increased exposure arising from APS' retail load growth and a coincident increase in the volatility of prices in the energy market. The continuing development of organized and relatively liquid commodity markets, and subsequently financial equivalent contracts, has since made the implementation of hedging plans far more efficient and manageable.

Q. HOW WOULD YOU DESCRIBE APS' "GOAL" IN HEDGING AND HAS THAT GOAL BEEN ATTAINED THROUGH THE APS HEDGING POLICIES?

A. Price stability is the goal of the system hedge. Price stability is, of course, a relative concept. In a consistently rising market, even hedged prices will also increase, albeit less quickly. The converse is true in a falling market. APS' system hedging philosophy is not one of trying to predict the direction of the market – that's what speculators do, and we do not speculate on behalf of our customers. This goal of price stability is achieved in the current system hedge plan by virtue of definitive target hedge levels, a requirement for strict compliance in meeting those hedge levels, and senior management oversight and direction of the hedging program.

This measured approach helps APS' customers largely avoid the turbulence that can occur in short-term commodity markets. Perhaps the most obvious recent example as to the inherent value of a long-term hedge policy is the California energy crisis of 2001 and 2002. Over-reliance on the spot markets for procurement of electricity and natural gas resulted in extreme price volatility. As a result of the implementation of a deregulation plan, the investor-owned utilities in California were restricted from entering into long-term contracts for energy. As spot energy prices increased due to any number of factors, including rising natural gas prices, transmission constraints and limited hydro production, those utilities were forced to buy power from the near-term market. Coupled with this market turbulence, both PG&E and SCE had no rate mechanism to recover rising costs from their customers. This caused extreme financial distress for the utilities and provided no incentive for their customers to curb their consumption of an increasingly expensive commodity. The result was the very well documented "energy crisis" that dramatically impacted both the utilities and their customers.

By hedging purchased power and natural gas needs over a three-year horizon, APS can mitigate the impact of volatile gas prices and wholesale capacity concerns. Many issues relating to APS' hedging activities were outlined in my presentation to the Commission's Natural Gas Forum on September 8, 2005. For reference, I have attached the slides from that presentation as Schedule TJC - 1.

Q. CAN YOU PLEASE DESCRIBE THE EVOLUTION OF THE APS HEDGE PLAN?

A. In the years prior to 2003, the volumes of natural gas and purchased power exposed to price volatility were considerably less than today's volumes (over

33% less) and, for the most part, the costs of those commodities were also significantly lower (over 66% lower) than today's costs. As APS' exposure to the requisite volumes of natural gas and/or purchased power increased dramatically, the hedges employed by APS in the fall of 2003 were restructured to allow lower levels of variances in required hedge levels.

Specifically, in the fall of 2003, APS initiated a hedge plan for total energy (natural gas and purchased power needs combined) that required near term (or "prompt calendar year") requirements to be 75% hedged prior to January 1st of that particular year. As a result of those requirements, the following hedge levels were obtained or were to be obtained by the following dates:

- Calendar 2004: was 75% hedged as of December 31, 2003.
- Calendar 2005: was 75% hedged as of December 31, 2004.
- Calendar 2006: was to be 75% hedged as of December 31, 2005.

In addition to the 75% year end hedge requirements listed above, interim hedge levels were established for Calendar Years 2005 and 2006 as follows:

- Calendar 2005: hedge levels of 25% by December 31, 2003 and 50% by June 30, 2004.
- Calendar 2006: hedge levels of 15% by December 31, 2003, 25% by December 31, 2004, and 50% by June 30, 2005.

The above requisite hedge levels were attained by APS on or before the deadlines listed above.

Q. DID APS REVISE ITS HEDGE PLAN IN 2005, AND IF SO, WHY?

A. In June of 2005, APS revised its system hedge plan to address growing concerns about still increasing market volatility and the related financial risks to APS customers. The revised hedge plan was prepared in consultation with Risk

Advisors, an industry expert in the design and implementation of hedging policies and practices.

Under the revised APS System Hedge plan for total energy (again, natural gas and purchased power combined), the following hedge levels were established and met by August 1, 2005.

- Remainder of 2005: 85% hedged at the following prices:
  - Natural Gas, with an average delivered hedge price of $6.93/dth.
  - Purchased Power, with an average hedge price of $69/MWh (peak and off peak combined).
- Calendar Year 2006: 85% hedged at the following prices:
  - Natural Gas, with an average delivered hedge price of $7.24/dth.
  - Purchased Power, with an average hedge price of $56/MWh (peak and off peak combined).

(Note: The current cost and value of the 2005 and 2006 hedge prices for natural gas and/or purchased power can change as market price of the underlying commodities changes, and APS continues to manage its hedge positions to achieve physical delivery.)

Our hedge targets for 2007 (50%) and 2008 (35%) have also been met.

Q. HOW DO THESE HEDGED PRICES FOR GAS AND ELECTRICITY COMPARE TO TODAY'S FORWARD MARKET PRICES?

A. The value of the current hedged natural gas and purchased power prices are significantly lower than current forward market prices, as established by various gas and power trading hubs. Since forward market pricing changes from day to day and the price of the hedge will change as a result of any change in hedge percent or makeup, the comparison between the hedged price and forward market will also change from day to day. The following depicts forward natural

gas and purchased power prices as of September 23, 2005, and the variance between those prices and the current hedge prices to date.

Remainder of 2005:

Natural Gas (delivered to APS power plants)

- Current forward market: $11.66/dth
- Hedged prices: $6.93/dth
- Current variance = $4.73/dth

Purchased Power

- Current forward market: $86/MWh
- Hedged prices: $69/MWh
- Current variance = $17/MWh

Calendar 2006:

Natural Gas (delivered to APS power plants)

- Current forward market: $10.82/dth
- Hedged prices: $7.24/dth
- Current variance = $3.58/dth

Purchased Power

- Current forward market: $80.25/MWh
- Hedged prices: $56/MWh
- Current variance = $24.25/MWh

Q. HOW DOES APS ESTIMATE ITS NATIVE LOAD REQUIREMENTS AND THUS ITS REQUIRED HEDGE VOLUMES?

A. APS serves retail load requirements by sourcing power from its nuclear, coal, and natural gas generators, and by purchasing wholesale power in the

marketplace under long term agreements, or when purchasing power in shorter term or real-time markets is more cost effective than self generation.

Fuel used in the nuclear and coal fired generators is purchased through long term contracts at prices that, although escalated over time in accordance with contractual formulae, allow those units to generally run as base load units. Since our retail load demand cannot be readily predicted on an hour by hour or day to day basis, the incremental or "swing" supply of energy needed to serve load is sourced through our natural gas fired generators, through market purchases of electricity, or through a combination of both.

In attempting to assess future native load energy needs, APS utilizes a computerized simulation model called Real Time Simulation ("RTSIM") to project the requisite necessary level of incremental energy (gas fired or purchased power, or both). In the case of the APS System Hedge, we use this model to forecast three years worth of incremental energy needs, summarized monthly, in order to establish our hedge requirements. Key inputs into the model include:

- Forecast of system load requirements.
- Forward price curve of natural gas and purchased power.
- Scheduled outages of APS generators.
- Heat rate efficiencies and capacities of APS generators.
- Operating constraints such as Reliability Must Run ("RMR") requirements, minimum run time, ramp rates, etc.

In assessing estimated needs, we are also aware that generators are going to have non-scheduled outages. Because these outages generally occur randomly, APS

includes a planning reserve in the monthly supply/demand balance prior to calculating the monthly total energy hedge requirement.

Q. WHAT SYSTEMS DOES APS USE TO ATTEMPT TO OPTIMIZE ITS HEDGE POSITIONS?

A. In order to capture the impact of price changes on our required hedge volumes, APS re-runs the RTSIM model every week with updated forward prices for natural gas and purchased power. Under normal situations, the total energy requirements for the three years change only minimally, although the appropriate volumetric mix between natural gas and purchased power can vary significantly. As a result, the traders will attempt to "optimize" the hedge position to capture the least expensive incremental energy to serve load, as depicted by the model, while adhering to the total energy hedge targets. By optimizing, term traders can:

- Adjust hedge levels of each specific commodity (purchased power versus natural gas).
- Modify receipt and/or delivery points by commodity in order to minimize costs and retain reliability.
- Investigate the economic value of financial/physical derivatives as opposed to outright financial/physical contracts in managing risk.

Notwithstanding such optimizations, the total energy hedge at any given time must remain at the target levels in accordance with the existing system hedge plan.

Q. WHAT TYPES OF TOOLS AND/OR CONTRACTS DOES APS USE TO HEDGE ITS NATURAL GAS AND PURCHASED POWER NEEDS?

A. APS transacts in various markets and uses various hedge tools in managing price volatility and financial risk. The most common hedge tools include:

- Physical purchased power contracts delivered at Palo Verde, Four Corners, Mead, and other accessible delivery points.
- Physical purchased power call options to hedge financial capacity risk delivered at Palo Verde, Four Corners, and Mead.
- Financial natural gas futures contracts traded on the New York Mercantile Exchange ("NYMEX"). (The NYMEX financial contracts used to hedge natural gas are very liquid and allow for physical natural gas contracts purchases prior to the delivery month).
- Physical natural gas contracts for gas from the San Juan and Permian Basins.

To give some perspective on the scope of our program, at any one time the Company has more than 10,000 individual financial and physical contracts in place.

Q. HOW DOES APS THEN GO FORWARD AND TRANSITION CONTRACTS BOUGHT FOR HEDGES TO DELIVER POWER TO APS' CUSTOMERS?

A. As stated earlier, APS uses a number of mechanisms to hedge its needs. Some are called "physical" contracts (e.g. deliverable power) and others "financial" contracts (e.g. cash settled). The most common "financial contract" is a futures contract. Futures contracts used to hedge our financial risk must be converted to physical contracts in order to obtain the physical commodity to serve load. The most common example of this is the natural gas NYMEX futures contract, which APS uses extensively in hedging.

NYMEX futures contracts expire three business days prior to the first day of the next month. For example, the September 2005 NYMEX natural gas futures contract expired on August 29, 2005. Since APS typically owns these contracts by virtue of our hedge plan, APS will sell all futures contracts back to the

market on or near August 29th, and simultaneously, purchase a physical supply contract with a natural gas producer or marketer through an electronic trading platform or via 3rd party brokers, that allows APS to deliver that gas to one of our power plants. In other words, if APS had hedged the equivalent of 5 billion cubic feet (Bcf) of NYMEX natural gas futures for a particular month, APS will sell 5 Bcf of futures contracts back to the NYMEX market, and purchase 5 Bcf of physical supply through ICE (Intercontinental Exchange – the most commonly used electronic trading platform in our markets). This activity normally occurs during the last week of the month prior to delivery but must occur prior to the expiration of the NYMEX contract.

Within the delivery month, APS will take appropriate short term positions in natural gas and/or purchased power in response to changes in market price or load requirements. These modifications include both the purchase and sale of natural gas and electricity as our load requires. For example, if APS had expected to burn 100,000 mmbtu of natural gas in our generators on a given day, but because of cooler than normal temperatures, the expected load demand was reduced, APS will sell back to the market any excess natural gas purchased for that day. The same holds true for any excess purchased power. In the event the load is higher than projected, APS will purchase from the market any additional natural gas or electricity needed to serve that load in the most cost effective manner. Natural gas is normally purchased one day prior to delivery while electricity can be purchased either one day prior or hourly (real time) during the day of delivery.

Q. WHAT IS THE ECONOMIC IMPACT OF APS' HEDGING PRACTICES?

A. APS believes that price stability, and not speculative gain, is the goal of hedging. As a result, the "economic impact" of hedging can and will vary with the swings in commodity prices in short term markets. That said, under certain conditions, it is possible to also achieve positive economic value from hedging practices. Specifically, if the hedge is priced at a cost below the current market value, the "market" value of the hedge itself is positive, and can result in lower costs to the customer versus relying on spot market prices for procurement. For example, during the time period from April 2005 to August 2005, the realized value of hedging in advance saved APS over $30,000,000 in fuel and purchased power costs. Put another way, if APS had not hedged commodities in advance, and relied solely on the near term (monthly) markets to purchase its projected gas and purchased power volumes, the eventual costs of those commodities would have been over $30,000,000 more due to higher month to month prices for gas and purchased power.

It is important to note, however, that the economic value of hedging can be reduced or even eliminated if the short term price of gas and purchased power turns lower than the hedge costs. In those instances, even though price stability is realized, the final costs of hedging may be higher than purchasing needs short term (monthly or daily). That does not mean that the hedges were imprudent or even that they had no value to customers. Hedging is essentially price insurance. Insurance does not lose its value nor is its purchase imprudent simply because the risk insured against does not, in any particular instance, materialize.

The volatility of commodity pricing has been well documented over the last several years. Given the size of APS' load, even a minimal movement in pricing can have a dramatic impact to APS' customers. By example, Schedule TJC-2 to

my testimony is a chart that shows the impact of a $1 adverse move in natural gas for the unhedged portion of APS' energy needs. As that chart evidences, a $1 increase in price over the next three years can have an approximately $83 million negative impact to APS' customers.

It is also important to note, that the economic value of hedging can be reduced or even eliminated in the event a contracted counterparty fails to perform. The use of NYMEX futures contracts significantly reduces the counterparty performance risk for the term natural gas markets.

Notwithstanding, and as briefly addressed at the beginning of my testimony, the failure to hedge and instead wait for the spot market can, and has, on any number of occasions in the past, proven catastrophic. In short, we believe hedging is a long-term safety net for APS customers and in many ways should be regarded more like insurance than a speculative profit center.

Q. WHAT ARE SOME OF THE LIMITATIONS ON APS' ABILITY TO HEDGE?

A. Credit restrictions, market liquidity, and load uncertainty are the three primary factors that limit hedging.

- Credit restrictions: Can limit the number of counterparties and hedge tenor (both volume and length of transactions).
- Market liquidity: Reduced liquidity further out in time (2007 and beyond).
- Load uncertainty: Customer demand for electricity changes daily due mostly to weather.
- APS' Credit Score: The strength of APS' credit is critical in allowing APS to transact with favorably-rated counterparties, which in turn limits the amount of credit risk to APS customers.

IV. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. APS incorporates extensive use of financial and physical contracts to minimize commodity price volatility when purchasing natural gas and purchased power to serve retail load. Since price stability is the goal of our system hedge position, financial risks associated with projected requirements of these commodities are systematically hedged at various levels three years prior to delivery with standard energy products.

APS has hedged its financial commodity risk since the late 1990's in response to unprecedented market price fluctuation and has continued with this policy. In June of 2005, APS increased its hedge percentages in light of even greater price uncertainty. Because of these hedges, the current hedged price of natural gas and purchased power is significantly below the now prevailing market price through 2008.

The measured approach utilized by the system hedge plan helps APS customers largely avoid much of the turbulence of price volatility that can occur in the short-term commodity markets. Coupled with the practice of optimizing natural gas or purchased power to provide the lowest cost commodity to meet load, the current approach to hedging financial risk is providing APS customers with significant economic savings while attaining future price stability.

Arizona Public Service Company

ACC Natural Gas Forum

September 8, 2005

Energy Markets and Hedging Practices

Tom Carlson

Portfolio Manager

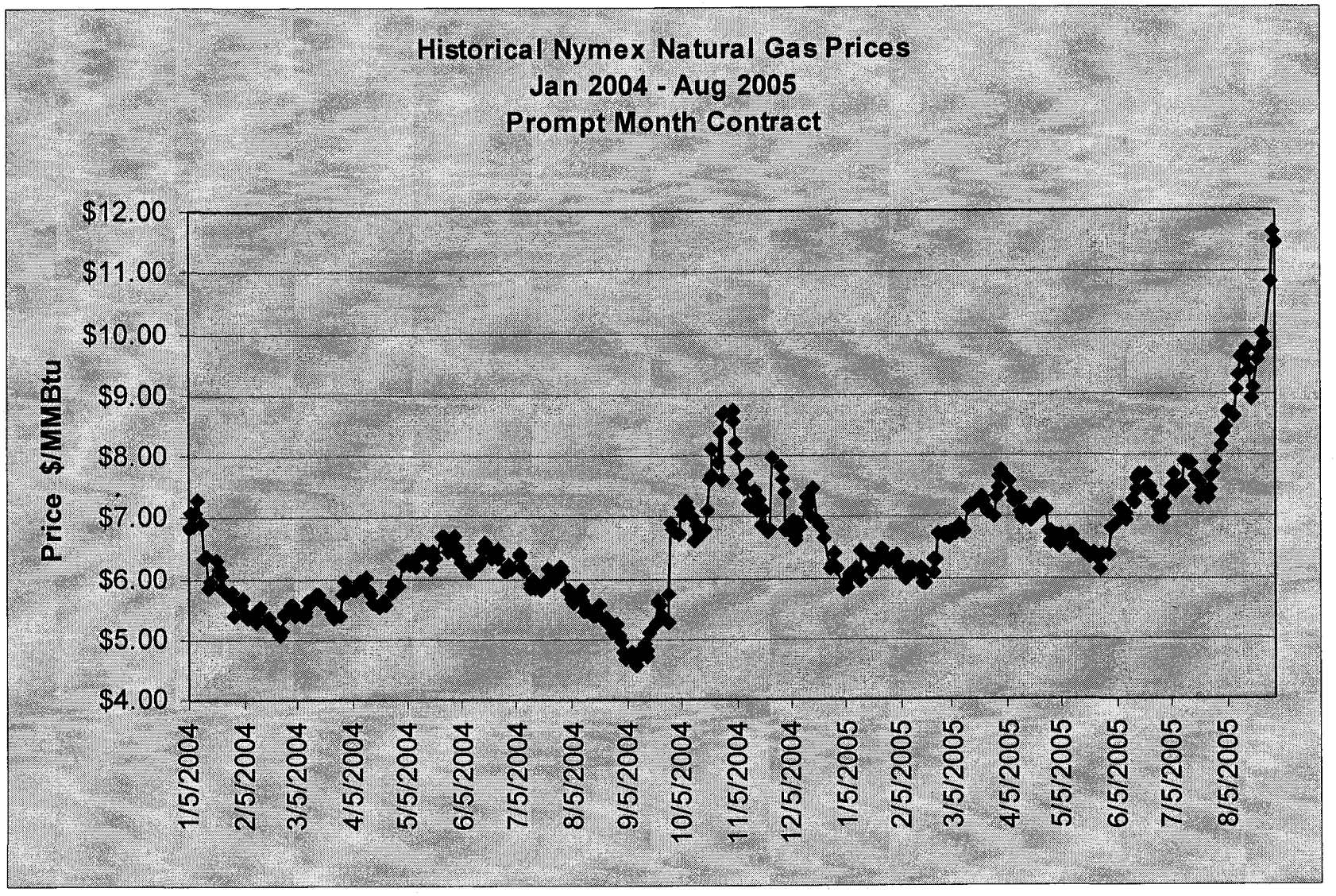
APS Marketing & Trading

Overview of How APS Manages Gas Costs

- General Market Issues
- APS Gas and Infrastructure Requirements
- APS Hedge Policy

Energy Market Overview

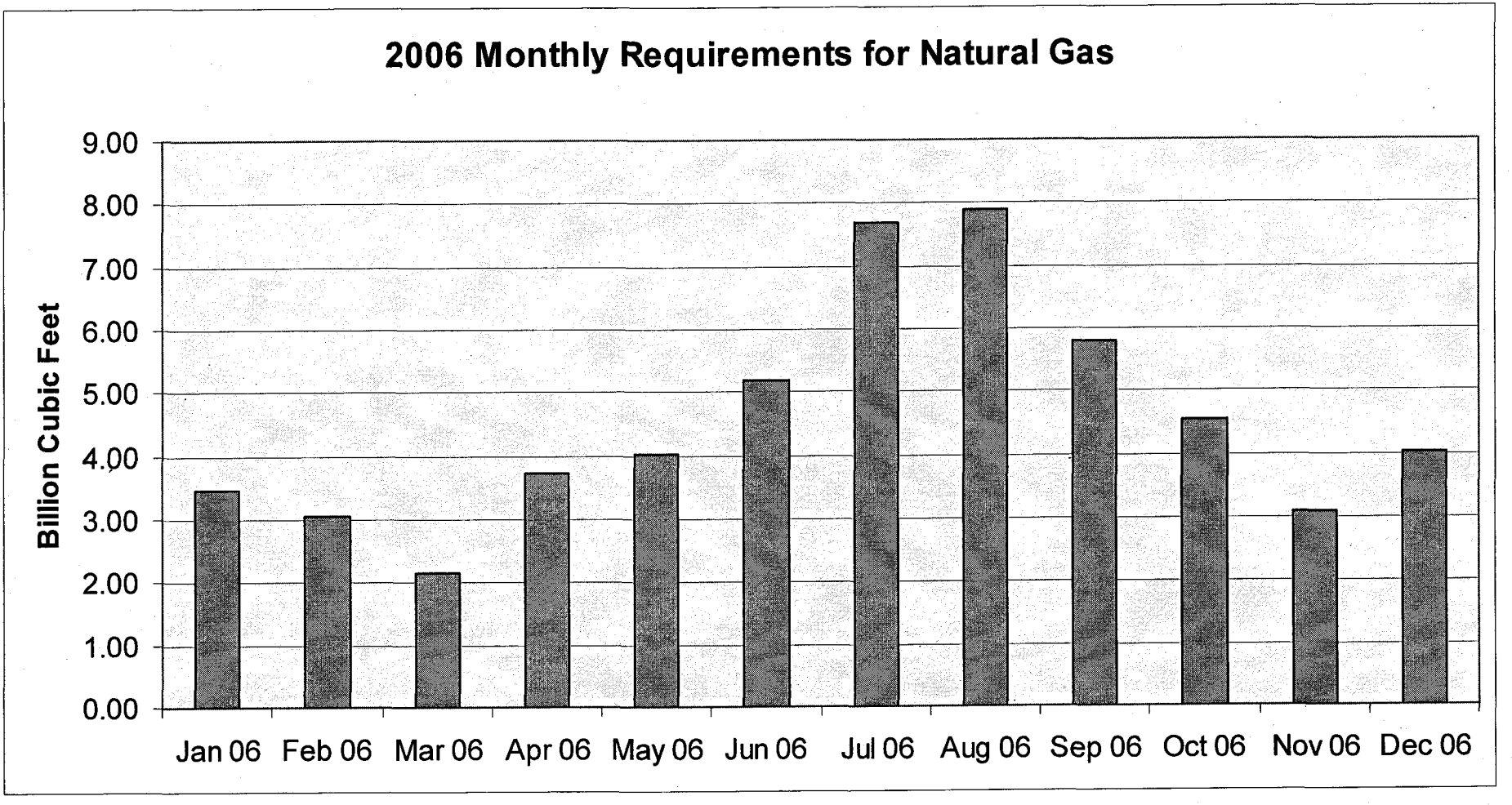
- Natural gas prices at historical highs
- Wholesale power prices follow natural gas
- US economy remains strong
- Increased world demand on crude oil
- Natural gas storage surplus is shrinking
- Impact from Katrina still being assessed
- Deliverability issue on horizon
- LNG not a factor for Arizona until 2008


Historical Nymex Natural Gas Prices
Jan 2004 - Aug 2005
Prompt Month Contract
Price $/MMBtu
$12.00
$11.00
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
1/5/2004
2/5/2004
3/5/2004
4/5/2004
5/5/2004
6/5/2004
7/5/2004
8/5/2004
9/5/2004
10/5/2004
11/5/2004
12/5/2004
1/5/2005
2/5/2005
3/5/2005
4/5/2005
5/5/2005
6/5/2005
7/5/2005
8/5/2005

APS Energy Sources
(Projected)

	Summer 2006	Winter 2005
• Nuclear:	25%	37%
• Coal	40%	43%
• Natural Gas	22%	15%
• Purchased Power	13%	5%

APS Projected Gas Requirements



Gas and Infrastructure Issues

- Hedging
- Gas Transportation
  - El Paso Natural Gas
    - Upcoming FERC rate case = higher costs
  - Transwestern?
  - North Baja – Yuma?
- Gas Storage
  - Copper Eagle?
  - Red Lake?
  - Picacho?

APS Hedge Policy

- Natural Gas and Purchased Power
- Designed to minimize price volatility
- Strict guidelines – little trader discretion
- Significant compliance requirements
- Forward hedge for three years
- Credit limitations
- Liquidity limitations
- Load forecast uncertainty impacts hedge levels

Current Hedge Position

(Total Energy – Gas and Purchased Power)

	% Hedged
• Balance of 2005:	85
• Calendar 2006:	85
• Calendar 2007:	55
• Calendar 2008:	30

- Natural gas hedges at NYMEX (Henry Hub)
- Purchased power hedges at PV, FC, Mead

Impact of Hurricane Katrina on NYMEX Natural Gas Futures

- November 2005 – March 2006 Pricing Impact
  - August 1st: $ 9.28/mmBTU
  - August 31st: $11.93/mmBTU
- Increase of $2.65/mmBTU

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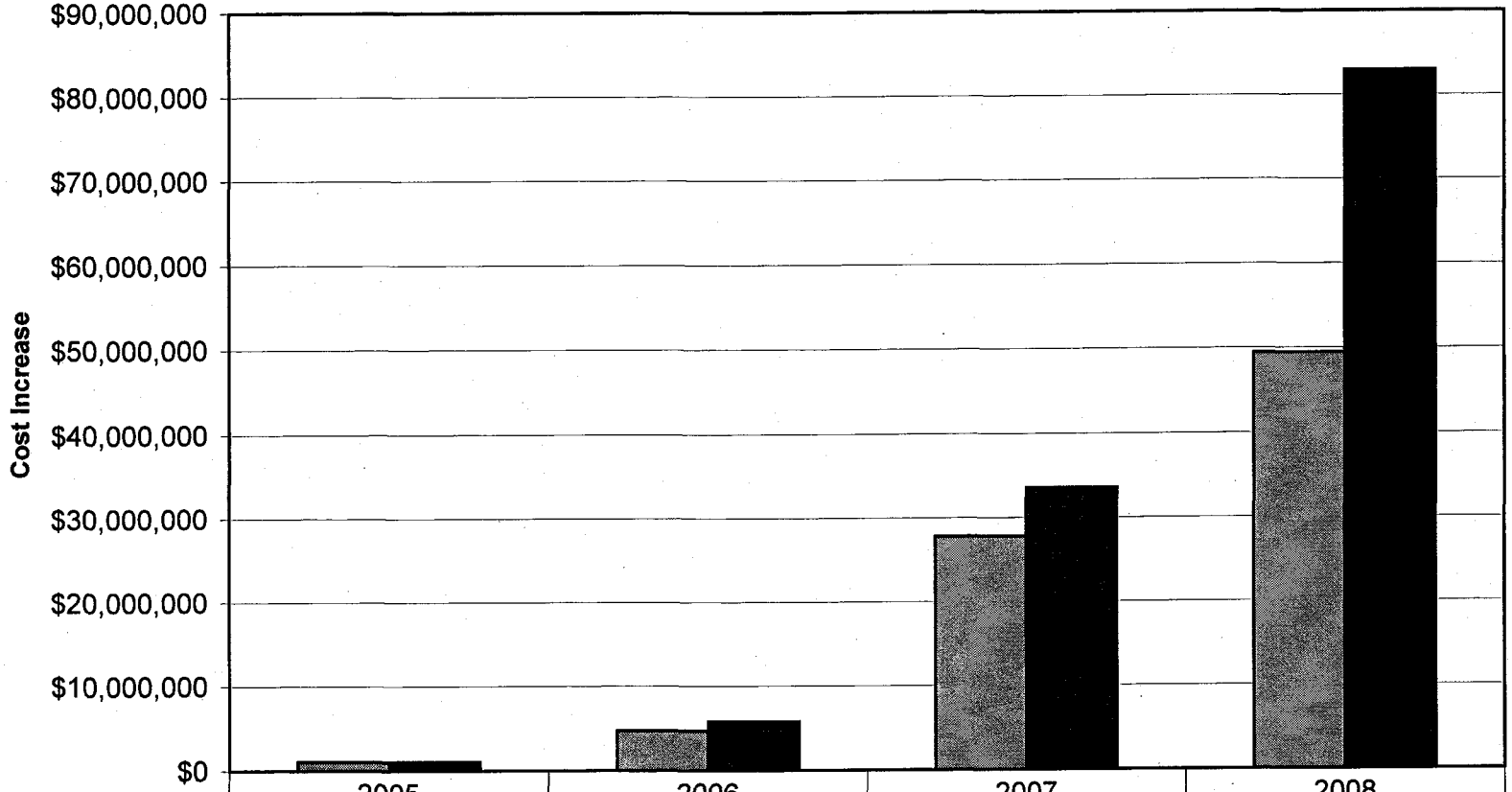
Financial Impact of $1/dth Change in Unhedged Natural Gas

September 28, 2005 Forecast Loads and Market Prices



	2005	2006	2007	2008
Annual	$1,048,900	$4,706,800	$27,766,300	$49,425,500
Cumulative	$1,048,900	$5,755,700	$33,522,000	$82,947,500