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Arizona Corporation Commission
DOCKETED

JUN 22 2011

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June 22, 2011

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

RE: Arizona Public Service Company's ("APS") Rebuttal Testimony in the Matter Requesting Authorization for the Purchase of Generating Assets from Southern California Edison; Docket No E-01345A-10-0474

Attached is APS's Rebuttal Testimony of Mark A. Schiavoni, Patrick Dinkel, Jeffrey B. Guldner and Judah L. Rose in support of the above referenced matter. Please note that portions of Judah Rose's Rebuttal Testimony are confidential and is being provided pursuant to an executed protective agreement.

If you have any questions regarding this information, please contact Zachary Fryer at (602)250-4167.

Sincerely,

Leland R Snook for

Susan Casady

SC/sl
Attachment

cc: Parties of Record

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Mark A. Schiavoni

REBUTTAL TESTIMONY OF MARK A. SCHIAVONI

On Behalf of Arizona Public Service Company

Docket No. E-01345A-10-0474

June 22, 2011

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REBUTTAL TESTIMONY OF MARK A. SCHIAVONI ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (Docket No. E-01345A-10-0474)

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Mark Schiavoni. I am the Senior Vice President of Fossil Generation at Arizona Public Service Company ("APS").

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING THAT DESCRIBES YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. Yes. I have submitted Direct Testimony in this matter, which describes my educational and professional background.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to the Direct Testimony submitted by other parties in this proceeding. I will address four general areas: (1) why it is not "risky" for APS to increase its investment in Four Corners Units 4 and 5 because of their age; (2) why Units 4 and 5 face a significant risk of retiring in 2016 if APS does not acquire Southern California Edison's ("SCE") interest in those units; (3) why certain alternatives proposed by the parties do not favorably compare to the Company's proposal to acquire the SCE interest and retire Units 1-3; and (4) why materially delaying the transaction beyond the anticipated October 2012 closing date ("Closing Date") established in the Asset Purchase Agreement ("APA") negotiated with SCE is neither feasible nor advisable.

II. <u>SUMMARY</u>

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Before I do so, let me comment for a moment on the various pieces of testimony submitted by the other parties to this proceeding. Although certain areas of disagreement between the parties exist, there is no dispute that the transaction proposed in the Company's Application (to acquire SCE's 48% interest in Units 4 and 5 and retire Units 1-3) brings a host of benefits that are unmatched by any conceived alternative. The Application presents an approach that balances what is good for the environment, what is good for the Navajo Nation, and what is good for APS customers. That type of equilibrium is not found in any alternative considered by APS or proposed by any other party. Nor should those benefits be risked by adding new processes or conditions that would only increase the complexity of an already highly complicated situation.

Although the Sierra Club questioned APS's cost-analysis, it offered neither any counter-analysis nor any evidence that the assumptions underlying APS's economic analysis are unsound. Without any supporting authority or even real argument, it raised the specter that Units 4 and 5 will physically deteriorate such that they will no longer generate energy at current levels in the decades to come. But the historical performance of the plant undermines that suggestion, and there is no reason to believe that, with proper maintenance, Units 4 and 5 will perform any worse on average in the future than they do today because of their physical condition.

Neither did the Sierra Club offer any proof for its suggestion that APS is wrong to believe that Units 4 and 5 face a strong risk of closure in 2016 if the proposed transaction is not timely consummated. SCE will exit the plant by 2016, either in 2012 by virtue of this transaction or in 2016 when its current ownership obligations terminate. That is a hard deadline that will not change. No one but APS has stepped up to purchase SCE's 48% share of the plant, nor is it likely that anyone else will. APS is uniquely positioned to benefit from the purchase, which allows the Company's customers to maximize the value of APS's current interest in Units 4 and 5 and receive additional, highly cost-effective generation to replace less cost-effective coal generation from Units 1-3, thus maintaining the current balance of the Company's resource portfolio. No other would-be buyer is similarly situated.

Without a known buyer for SCE's interest, the other co-owners of Units 4-5 are left in the dark about how almost *half* of the hundreds of millions of dollars worth of capital expenditures required for Units 4 and 5 in next few years will be funded. This uncertainty makes it almost impossible for APS and the other co-owners to reach a consensus about how to proceed if this transaction is not approved. Whether and when the required environmental controls should be installed are not decisions that APS can unilaterally make; by contract, all co-owners must approve such investments. The result of continued uncertainty about whether anyone will take SCE's share if this transaction is not timely approved is a strong risk that Units 4 and 5 will retire and the benefits described in the Application will be lost.

III. FOUR CORNERS UNITS 4 AND 5 CAN CONTINUE TO OPERATE AT CURRENT CAPACITY FACTORS FOR THE ASSUMED LIFE OF THE UNITS NOTWITHSTANDING THEIR AGE

Q. IN THE TESTIMONY OF SIERRA CLUB WITNESS DAVID SCHLISSEL, HE STATES THAT APS'S ECONOMIC MODELING ANALYSIS IS BIASED IN FAVOR OF COAL BECAUSE, IN PART, IT "IGNORES THE RISKS ASSOCIATED WITH THE CONTINUED OPERATION OF FOUR CORNERS UNITS 4-5 THAT ARE CURRENTLY OVER 40 YEARS OLD" AND "VERY OPTIMISTICALLY ASSUMES THAT UNITS 4-5 WILL CONTINUE TO OPERATE AT VERY HIGH LEVELS OF PERFORMANCE AS THEY AGE UP TO AND BEYOND THE AGE OF 60."[1] DO YOU BELIEVE THAT SUCH AN ASSUMPTION IS OVERLY OPTIMISTIC?

A. No, I do not. Importantly, the Sierra Club offers absolutely no evidence that, properly maintained, Units 4 and 5 could *not* continue to operate at current levels for the assumed life of the plants because of their physical condition. Indeed, a historical look at the capacity factors of these Units shows exactly the opposite:

[1] Schlissel Testimony at 3, 6.

that, despite some swings (both up and down) year over year, the capacity factors for Units 4 and 5 have remained roughly the same over the past two decades, notwithstanding the increasing age of the facilities. Units 4 and 5 have consistently averaged net capacity factors of roughly 85% and 82% respectively over the 1990 to 1999 timeframe, the 2000 to 2009 period, and over that full 20 year period combined. There is no reason to believe that, if the Units are properly maintained, this trend will discontinue in the decades to come. In fact, the current end of life assumption associated with those Units – 2038 – is tied to the expiration of the lease agreement with the Navajo Nation, not with the physical condition of the plants. The projected costs of operating and maintaining Units 4 and 5 through 2038 have been included in the Company's analysis.

Moreover, Four Corners Units 4 and 5 have several features that distinguish them from other coal facilities throughout the country that face a much higher risk of early retirement. Units 4 and 5 are among the largest in the nation, each providing 770 MW of available capacity, for a combined total of 1,540 MW. The large size of the Units allows them to benefit from economies of scale that makes the investment associated with operating, maintaining, and upgrading them cost-effective relative to making similar investments in smaller units. In addition, significant environmental upgrades have already been installed at Units 4 and 5 (scrubbers and baghouses, for instance). Coal facilities now being retired are typically much smaller and lack such equipment, making their continued operation relatively less cost-effective. APS expert witness Judah Rose explains this point further in his testimony.

IV. UNITS 4 AND 5 FACE A SIGNIFICANT RISK OF RETIREMENT IN 2016 IF APS DOES NOT ACQUIRE SCE'S OWNERSHIP INTEREST

Q. PLEASE EXPLAIN WHY APS BELIEVES THAT UNITS 4 AND 5 RISK CLOSURE IN 2016 IF APS DOES NOT ACQUIRE SCE'S SHARE OF FOUR CORNERS.

A. Despite the Sierra Club's suggestion, it is far from mere "speculation" that Four Corners Units 4 and 5 face a serious risk of retirement in 2016 if APS does not acquire SCE's interest in the plant.[2] SCE has, by far, the largest ownership share of Units 4 and 5 – 48%. That entity has informed its co-owners that, because of regulatory restrictions unique to California entities, it will not fully pay its 48% share of the almost $500 million dollars worth of environmental controls needed on those units by 2016 and will withdraw from the plant entirely in 2016. No one but APS has yet stepped forward to purchase SCE's interest, and it is highly unlikely that anyone else will do so on the timeline required.

Each of the other co-owners of Units 4 and 5 had a right of first refusal to purchase a portion of SCE's share, which none of them exercised. This is relatively unsurprising, given the fact that many of those entities (such as Salt River Project and Tucson Electric Power Company) have a heavier amount of coal in their resource portfolios than does APS. For such utilities, adding new coal would tend to decrease the diversity of their resource mix and increase the risk of reliance on a single resource (in that case, coal). APS is in a different position: our proposed transaction generally maintains an already diverse portfolio and prevents the risk of over-reliance on natural gas (a point that Mr. Dinkel addresses in his Rebuttal Testimony). In addition, several of the co-owners of Units 4 and 5 are also joint participants in multiple coal facilities that face similar environmental issues as those now facing Four Corners. As I see it,

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[2] Testimony of David Schlissel at 3,6.

uncertainty about the future of those other resources makes even more dubious the co-owners' interest in investing further in Four Corners.

Neither is it likely that SCE could find an outside buyer for its majority interest in Units 4 and 5 on the timeframe needed to sustain the Units' operations beyond July 2016 – a hard date by which SCE will withdraw from the plant, irrespective of whether the Units retire or continue to operate in its absence. There simply is a limited market for coal at present given the environmental uncertainties and related costs. Indeed, as I understand it, the Los Angeles Department of Water and Power – which is subject to California laws similar to those that apply to SCE – has been marketing its 21% interest in Navajo Power Plant for approximately two years, off and on.

The opportunity to purchase SCE's ownership interest is attractive to APS for reasons that simply do not apply to other would-be buyers. APS already has a significant investment in Units 4 and 5, which have been reliably serving our customers for decades. We operate the plant and thus are intimately familiar with both what it takes to run the Units and the prospects for their future operations – a perspective that others lack. Most significantly, this transaction provides APS with a unique opportunity to maintain the careful balance of its resource portfolio while it retires three smaller coal units better suited for retirement than Units 4 and 5. I can think of no other potential buyer for whom the acquisition would be similarly beneficial (nor has the Sierra Club identified any).

The existing uncertainty about how almost *half* of the hundreds of millions of dollars worth of capital expenditures required for Units 4 and 5 in next few years will be funded makes it almost impossible for APS and the other co-owners to reach a consensus about how to proceed if this transaction is not approved.

Whether and when the required environmental controls should be installed are not decisions that APS can unilaterally make; by contract, all co-owners must approve such investments. The 2016 deadline is a firm one. The likely result of continued uncertainty about whether anyone will take SCE's share if this transaction is not approved is that Units 4 and 5 could retire.

V. THE SIERRA CLUB'S AND WESTERN RESOURCE ADVOCATES' ALTERNATIVES TO THE PROPOSED TRANSACTION DO NOT FAVORABLY COMPARE TO THE COMPANY'S PROPOSAL

Q. DO YOU HAVE ANY REACTION TO THE SUGGESTION THAT APS SHOULD CONVERT ONE OR MORE OF ITS EXISTING SIMPLE CYCLE COMBUSTION TURBINES ("CT") INTO COMBINED CYCLE ("CC") FACILITIES INSTEAD OF ACQUIRING SCE'S SHARE OF UNITS 4 AND 5?

A. Yes. First – and most importantly – this alternative assumes the shutdown of Four Corners in its entirety. As I described in my Direct Testimony, that result deals a devastating blow to the Navajo Nation's economic well being, as well as that of the small communities surrounding the plant. Moreover, as Pat Dinkel explains in his Direct and Rebuttal Testimonies, a forced closure of Four Corners inadvisably disrupts the existing balance of APS's resource portfolio. Neither is it a cost-effective option. As discussed by Mr. Rose, such an alternative would be far less of a value for our customers compared to the proposed transaction.

In addition, a CT to CC conversion project makes no practical sense for APS. As Mr. Rose notes, our quick start CT facilities can be brought online almost instantly and thus serve several important roles, such as meeting the needs of our customers in the peak hours and providing voltage support, regulation, and back up for the intermittent renewable generation in our resource portfolio. Operated as the Sierra Club intends, CC facilities – which take much longer to come online – would use natural gas in place of coal to meet our baseload resource needs. Were our CT facilities converted to CC facilities to take the place of our existing coal generation, we would have to build new quick start facilities to address the roles these units serve – increasing both the cost of such an alternative and our reliance on natural gas.

In addition, most of our CT fleet consists of lower efficiency 1970-era technology. While it is technically possible to retrofit an industrial-scale heat recovery steam generator ("HRSG") to these older units, it is more cost-effective to build entirely new CC systems with CT and HRSG components that are designed and selected to work together efficiently. Moreover, the typical electric capacity added by a CC steam turbine-generator is approximately half of what is produced by a CT, which means that converting our entire industrial CT fleet (16 units) to CC would only increase the maximum capacity by approximately 390MW – an insufficient replacement for the 560MW produced by Four Corners Units 1-3. Even that 390MW number, however, is too high, when the footprint associated with most of our CTs is considered. For example, the 10 aeroderivative CTs at our Sundance plant are congested and could not accommodate the addition of 10 HRSGs, 5 steam turbines, and 5 cooling towers. Therefore, the maximum additional capacity of conversion is much less than 390MW.

Moreover, it could be difficult for such a conversion to occur in time for the resulting generation to be available to meet our need in 2016. The process underlying such a project is significant. Indeed, before any actual construction work could begin, APS would, among other things, need to identify the infrastructure requirements and water source, design the project, apply for and receive the appropriate permits, and potentially undergo the extraordinarily long and complex process established by the National Environmental Protection Act ("NEPA") to evaluate the project's environmental effects. Depending on the result of the analysis, the NEPA process alone could take anywhere from 3 to 5 years. For these and other reasons, it is much more practical and cost-effective to build a new CC plant than to rebuild one from a prior CT design (though neither alternative is as universally beneficial as the proposed transaction).

Q. IS REPOWERING FOUR CORNERS WITH COMBINED CYCLE TECHNOLOGY A VIABLE ALTERNATIVE TO THE PROPOSED TRANSACTION?

A. No, it is not. First, there is the timing issue that I discussed in response to the previous question, caused by the same design, permitting and regulatory requirements that exist with a CT to CC conversion. Undergoing a conversion project at Four Corners would be even more complex and time-consuming, given the facts that (1) APS is not the sole owner of the plant and cannot make a unilateral decision to materially change the nature of the existing facilities without the consent of the multiple owners (who, in turn, may be required to seek the consent of their multiple respective regulators) and (2) the Navajo Nation would also need to consent to such a project, which the current lease does not contemplate (to the contrary, the land lease with the Nation requires that coal be the plant's primary fuel source). The process required to achieve the Nation's consent and amend the lease would likely take anywhere from 1-3 years, the time it takes to negotiate fuel royalties and water rights, among other things. This process is lengthy and highly political, and the fact that such a project brings far less value to the Navajo Nation compared to the current transaction would make it that much more difficult to secure the Nation's approval of the change. In short, I see no possibility that such a project could be completed in time to meet our need in 2016.

In addition, from an operational perspective, a coal plant and a CC plant are two very different creatures. Little of the existing coal plant infrastructure would be useful in the construction of a new CC plant. Most of the plant infrastructure would be decommissioned and demolished. Even if APS could secure the needed gas from a nearby pipeline, it would need to extend that pipeline to the existing site and procure and then build additional equipment to complete the conversion. And, unlike coal, natural gas plants generate energy less efficiently at the Four Corners site's high altitude. Any CT used to repower the units would thus be derated 10-12%, making any such project even less efficient and less cost-effective.

Even absent all of these hurdles, were APS to seek to build a new gas resource, it would not be located on tribal land in New Mexico. Better places for such development exist in Arizona.

Q. DO YOU HAVE ANY REACTION TO WRA'S SUGGESTION THAT APS SHOULD CONSIDER A SOLAR-COAL HYBRID AT FOUR CORNERS OR ANOTHER COAL PLANT?

A. Yes. Mr. Dinkel describes why WRA's solar-coal hybrid proposal does not make sense from an economic perspective. From an operational perspective, this type of technology is in the very early stages of development. Although parabolic trough concentrated solar power ("CSP") technology is considered a mature technology, there are only eight solar hybrid projects on-line worldwide. All but three of these are solar-CC hybrids. The single solar-coal application in the United States is planned for Cameo 2 in Colorado, which is not yet in service. The average hybrid size is only 25MW and all but two are less than 50MW – a small contribution to the total output at Four Corners. Furthermore, a 50MW CSP solar generation retrofit would require up to 525-acres of additional land adjacent to the plant site for the mirror arrays, up to 9-hrs of thermal storage, and other CSP infrastructure. The Four Corners participants would need to revisit the land lease with the Navajo Nation to include that vast acreage, which again significantly delays the process. Moreover, the annual average solar intensity at Four Corners is far less than what it is in the Phoenix area – there are simply many better areas to install a solar facility. Finally, APS cannot on its own decide to incur the costs and retrofit the plant as WRA recommends. Rather, the co-owners of Units 4 & 5 would all have to approve such a project.

VI. <u>DELAYING THE CLOSING DATE FOR THE TRANSACTION MATERIALLY INCREASES THE RISK THAT IT WILL NOT BE CONSUMMATED</u>

Q. DO YOU HAVE ANY REACTION TO RUCO'S RECOMMENDATION THAT THE COMMISSION APPROVE THE TRANSACTION ON CONDITION THAT THE ACQUISITION WOULD NOT OCCUR UNTIL "THE EARLIER OF JULY 1, 2016 OR WHEN EPA MANDATED CAPITAL INVESTMENTS TO ADDRESS NITROGEN OXIDE EMISSION FOR EACH OF THE PLANT'S FIVE UNITS AND/OR ADDITIONAL PARTICULATE EMISSION CONTROLS ON UNITS 1-3 . . . IS REQUIRED?"

A. Yes. Such a recommendation is misguided, for several reasons. Most strikingly, RUCO's recommendation ignores the commercial realities related to bringing Units 4 and 5 into environmental compliance. Although SCR equipment does not need to be *in service* until 2016 under the EPA's proposed rule (four years after the EPA's regional haze rules will likely become final), the required spend starts almost immediately. As the following depicts, SCRs are massive pieces of equipment that take several years to construct.

As this photograph of an SCR installation shows, the equipment is large and complicated to engineer and build. Indeed, the engineering, procurement, and construction work underlying the SCR installation takes slightly more than three years to complete. For that reason, the co-owners have agreed that – if the transaction moves forward and Units 4 and 5 are to remain online – the EPA-mandated environmental compliance capital requirements begin in 2012 (a date tied to the assumed closing of the transaction). Indeed, through the co-owners' contractually-required capital review process, the owners have agreed that more than $2 million will be spent in 2012 towards SCR installations, a number that rises to $57 million in 2013 and escalates rapidly each year thereafter until the construction is complete and the environmental equipment is brought online.

The contract's Closing Date of 10/12 was designed so that the co-owners (and APS) could proceed with the EPA-mandated investment in 2012 with the knowledge that APS had been authorized to assume SCE's share of the environmental compliance costs on those units and that they will remain in service post-2016. The terms of the contract require APS and SCE each to promptly seek the multiple regulatory approvals required for the transaction, and then consummate the deal shortly after those approvals are received. Although RUCO correctly notes that, under the terms of the contract, the purchase price decreases by $7.5 million per month for each month that the Closing Date is delayed, that provision was intended to allow for some slight delay in each party's ability to receive the multiple regulatory approvals required by the agreement (the term is thus measured in *months*, rather than *years*). Indeed, under Section 10.1(g) of the APA, SCE (and APS) may terminate the contract on December 31, 2012 if the required regulatory approvals of the sale are not satisfactorily obtained.

Nor is there any reason to believe that SCE would *not* terminate the agreement in December of 2012, were the Commission to adopt RUCO's recommendation that the Closing Date be intentionally delayed so that APS could pay a lower contract price. This Commission is not the only regulatory body whose approval is required for the transaction to go forward. The transaction must also be approved by the California Public Utilities Commission ("CPUC"), the Federal Energy Regulatory Commission, and the California Independent System Operator, among others. Indeed, SCE is currently seeking the CPUC's approval of the sale, and the California residential utility consumer advocate is an active participant in that proceeding. Much like RUCO does for Arizona residents, the California residential consumer advocate takes an avid interest in whether SCE's sale to

APS is beneficial to California ratepayers. It is doubtful at best that a condition intended to benefit APS customers even more than the transaction already does at the expense of SCE's ratepayers will engender a sentiment that would cause the CPUC to approve the deal. The CPUC may just as well decide that the Units should retire, as it did in the past with respect to the Mohave coal plant – a point that Mr. Rose explains in detail in his Rebuttal Testimony. If that happens, this transaction will fail and APS customers would lose what RUCO admits is the best of all resource alternatives available to APS under the circumstance. As RUCO's witness succinctly states, "no one could reasonably envision situations where the Company's requested alternative is not best."[3]

Several other factors require the deal to close in 2012, if it is to close at all. For example, the CPUC has ordered SCE to refrain from making any "life extending" investments in Four Corners, not just EPA-mandated investments. As other capital projects are brought for the plant participants' approval, SCE may posit that it cannot approve the expenditure based on this California law, which would place the plant and other owners in a precarious situation. As a practical matter, plant operations benefit greatly from SCE's early withdrawal. Moreover, to meet the requirements of the EPA's proposed mercury rule, environmental compliance costs to install baghouses on Units 1-3 begin in 2012. APS will need certainty by then whether it has a resource available to fill the 560 MW lost by the closure of those Units, if that is the route we take. In addition, in our role as plant operator, APS is currently negotiating a new fuel supply agreement with BHP, which will be contingent upon the consummation of this transaction. The earlier we know that the transaction will be completed, the better for those fuel negotiations. Finally, certainty about this transaction (specifically, the proposed closure of

[3] Testimony of Thomas Fish at 14.

Units 1-3) will better guide the parties during its active negotiations with the EPA over the outcome of its proposed rulemaking for Four Corners.

Any delay in the assumed close of the transaction would significantly increase the risk that the transaction will not move forward on the timeline required. Importantly, APS cannot unilaterally make any timing or investment decisions about Units 4 and 5, EPA settlements, or fuel contract terms. The multiple ownership arrangement of those Units adds a significant complexity – and with each passing day of uncertainty as to whether someone will assume SCE's share of Units 4 and 5 comes an increased risk that a consensus about each complicated piece of the puzzle will not be reached and that the Units will close.

And that would be unfortunate. The proposed transaction is not just about cost (although most parties, including RUCO, Commission Staff, and WRA agree that the deal as proposed is a value for Arizona customers). It is not just about the environment (although even EDF and WRA agree that it brings important environmental benefits). It is also about resource balance and preserving the economic viability of the Navajo Nation – benefits that no one disputes. Introducing a delay that would add increased complexity to an already mind-numbing array of uncertainties simply multiples the risk that the transaction will fail and the entirety of these benefits will be lost. In my opinion, that risk is not worth taking.

Q. DO YOU HAVE ANY REACTION TO THE ARIZONA COMPETITIVE POWER ALLIANCE'S RECOMMENDATION THAT THE COMMISSION REQUIRE APS TO CONDUCT AN RFP FOR REPLACEMENT GENERATION?

A. That recommendation is addressed for the most part by Mr. Dinkel in his Rebuttal Testimony. Nevertheless, I strongly echo his sentiment that it makes little sense to add increased complexity to an already highly complicated environment unless the Commission specifically intends to deny this Application if the results of the RFP favor a merchant generation alternative, notwithstanding the resulting impact to the Navajo Nation that would result from the closure of Four Corners. Adding any new uncertainty to the continued viability of Four Corners simply increases the risk that the plant will close. Unless the Commission is willing to accept that risk, it should reject the ACPA's recommendation.

VII. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Despite the diversions offered by the Sierra Club and the ACPA, we cannot lose sight of the complete package of benefits that the proposal outlined in our Application provides. The Application presents an approach that is good for the environment, good for the Navajo Nation, and good for APS customers. That balance is not found in any other alternative. Nor should those benefits be risked by adding new processes or conditions that would only increase the complexity of an already highly complex situation. We respectfully ask that the Commission approve the requests we need to make these benefits happen.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Patrick Dinkel

REBUTTAL TESTIMONY OF PATRICK DINKEL

On Behalf of Arizona Public Service Company

Docket No. E-01345A-10-0474

June 22, 2011

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REBUTTAL TESTIMONY OF PATRICK DINKEL
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-10-0474)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION WITH APS.

A. My name is Patrick Dinkel. I am the Vice President of Power Marketing, Resource Planning and Acquisition at Arizona Public Service Company ("APS" or "Company").

Q. ARE YOU THE SAME PATRICK DINKEL WHO FILED DIRECT TESTIMONY IN THIS CASE ON BEHALF OF APS?

A. Yes.

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

A. My testimony addresses certain contentions made by David Schlissel on behalf of the Sierra Club, Greg Patterson for the Arizona Competitive Power Alliance ("ACPA"), and Dr. David Berry of Western Resource Advocates ("WRA"). Specifically, I will respond to Sierra Club's criticisms of the economic analyses I presented in my Direct Testimony that demonstrated the great economic benefit the transaction with Southern California Edison ("SCE") would convey to APS customers. I also discuss the practical consequences of ACPA's suggestion that we attempt to place this critical but complicated transaction in limbo until the Company initiates and completes a whole new resource procurement process. Finally, I will address WRA's suggestion that APS be required to consider further retirements of its older coal units at Cholla or a solar/coal hybrid project at Four Corners.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. APS's original economic analyses of the transaction with SCE were thorough, robust and based on direct market intelligence. The Company fully considered the risks of both fuel volatility and future environmental regulation as well as the means of mitigating the former through procurement strategies such as hedging and the latter by the expanded use of energy efficiency and renewable resources, which will provide more than 80% of the growth in APS energy needs. As part of its rebuttal case, the Company asked a nationally-known expert on commercial transactions of this sort, Judah Rose, to review and provide his critique of the APS economic analyses. His independent analysis supported the Company's conclusions, characterizing them as conservative. Finally, these analyses also have been confirmed by Commission Staff experts, the independent consultant for the Residential Utility Consumer Office ("RUCO"), and Dr. David Berry of WRA.

The advantages of APS acquiring SCE's interest go beyond a direct comparison of present value revenue requirements and levelized life cycle cost per MWH. Even if the costs of gas generation were hypothetically comparable to the proposed value of the Four Corners transaction, there are resource diversity and local economic benefits that no party has disputed (although some have selectively ignored them). Increasing APS customers' already substantial bet on the future of natural gas prices, as suggested by ACPA and the Sierra Club, is simply too risky and would effectively devastate what is already one of the most economically challenged portions of this region – the Navajo Nation.

Requiring APS to issue a formal RFP, as ACPA recommends, before proceeding with a Commission review of the proposed transaction with SCE is unnecessary and could easily result in the Four Corners deal being lost irrespective of its benefits for APS customers and the Navajo economy. The generation procurement provisions of the Commission's Resource Planning rules clearly envisioned precisely the circumstance in which we find ourselves – the fortuitous one-time opportunity to acquire a needed resource (and one needed in several ways) at a substantial discount.

Additionally, it is unnecessary and inappropriate in this proceeding to consider additional retirements of APS coal units or a coal/solar hybrid project at Four Corners. The Company already intends to conduct the sort of analysis of coal reduction options suggested by Dr. Berry in the context of its resource planning filings. In the resource planning process, the issue can be examined holistically as part of a broader examination of future APS resource options, with all interested parties having the opportunity to participate. Solar hybrid systems have not proven economic even when the fuel being displaced is natural gas. It is extremely unlikely that displacing an even lower cost fuel such as coal would change that conclusion.

III. <u>THE SIERRA CLUB AND ACPA CRITICISMS OF THE COMPANY'S ECONOMIC ANALYSES ARE UNFOUNDED AND UNSUPPORTED</u>

Q. WHAT CRITICISMS HAVE ACPA AND THE SIERRA CLUB LEVELED AGAINST THE APS ECONOMIC ANALYSES THAT SHOWED VERY SIGNIFCANT ECONOMIC BENEFITS FOR APS CUSTOMERS RESULTING FROM THE PROPOSED ACQUISITION OF SCE'S INTEREST IN FOUR CORNERS?

A. Before getting into that, let me first discuss what they have not contested. No one has argued that supply diversity is undesirable. No one has contended that the Navajo Nation will not suffer irreparable harm if Four Corners is required to close. Yet both these points seem to have been ignored as the Sierra Club debates the nuances of natural gas generation versus coal, future capacity factors, the likelihood of transmission additions, the relative volatility of gas prices, and gas unit acquisition costs, while the ACPA appears far more concerned with the process of APS resource acquisition than with its substance.

APS witnesses Mark Schiavoni and Judah Rose will address Four Corners capacity factors and the practicality (or lack thereof) of converting existing APS combustion turbines into combined-cycle units, so I will first turn to transmission. The issue of whether or not there is sufficient existing transmission to import gas generation to replace Four Corners is a relative minor economic factor. If APS had assumed that existing and available transmission capacity could be used to bring that much new gas generation into our system (which it cannot), it would only have reduced Four Corners' nearly half as billion dollar advantage over new gas by approximately $88 million. It's true that there is some transmission available on the APS system to deliver to the APS load for existing or new gas generation but only in very limited locations and amounts. Some of these locations for building gas generation are not particularly attractive because of being at a higher altitude (which affects unit output and efficiency), having limited gas supplies, or land use restrictions. APS evaluated the economics of the gas alternative using both the cost of a new combined cycle unit ($1,253 per kW) and for already constructed gas units ($750 per kW). The former is based both on APS's experience with such construction (Red Hawk and West Phoenix) and current pricing from manufacturers and vendors of combined cycle units. The $750/kW figure is a reference price meant to communicate the relative impact of a discounted purchase of an existing asset. The price is informed by the multiple, recent sales of existing combined cycle units in Arizona, and the Company's failed efforts to acquire such gas capacity in two recent (early 2010) solicitations. The contention that APS's economic analyses are not based on market information is simply inaccurate. That being said, one should not lose sight of the relative economics as illustrated in my Direct Testimony. Even when it was assumed that we could acquire gas generation at a 40% discount compared to new gas units ($750/kW versus $1253/kW), the Four Corners acquisition still retained half of its enormously positive economic value.

The Sierra Club contends that APS is overstating the volatility of natural gas prices. Anybody that has lived through the California energy crisis, the post-Katrina rise in gas prices or any other number of events in the gas market knows that such statements are unfounded. Just since APS completed the economic analyses presented in my Direct Testimony, long-term gas price forecasts have increased roughly 20%. An improving economy, concerns about hydraulic fracturing of shale gas (concerns fostered, ironically, by the Sierra Club and other environmental groups), the closure or conversion to gas of some coal plants, as noted by the Sierra Club, all will put further upward pressure on gas prices. In fact, as discussed later in my Rebuttal Testimony, the Company's independent expert, Mr. Rose, believes that APS's gas price forecast used in the analysis of the SCE transaction is on the low side and its estimate of CO2 costs (whether a carbon tax or cap and trade) is on the high side which would only widen the gap between this transaction and the natural gas alternative providing even more benefit to our customers. Because of these factors, combined with the application of equal present value discount rates to both the coal and gas scenarios, Mr. Rose concluded that the Company's methodology, far from being biased in favor of coal, was actually biased against coal and in favor of gas. Rose Rebuttal Testimony at 10-15.

Q. HAVE YOU REVIEWED THE SIERRA CLUB'S LEVELIZED COST CALCULATION?

A. Yes. The analysis conducted by the Sierra Club is seriously flawed for at least two reasons. The first overstated the cost of Four Corners, and the second understated the cost of the gas alternative. Correcting for these two errors results in levelized cost numbers as shown on Graph 2 at page 13 of the Company's Application.

The assumed capacity factor for Four Corners was lowered from 85% to 73%, thus increasing the cost per MWH. However, even though reducing the generation output from Four Corners, Sierra Club did not reduce the total fuel cost or the total cost of CO_2 emissions – a mathematical impossibility. With the appropriate and consistent reduction in these two costs to match the Sierra Club's reduced level of output, the Four Corners levelized cost drops from $99/MWH to $90/MWH. This is now comparable to the APS calculation of $85/MWH for Four Corners Units 4 and 5.

With the gas scenario, Sierra Club assumed generation from the Company's existing gas units could replace approximately 400 MW of lost energy and capacity from Four Corners. However, the capacity from these existing units is already fully committed to serving APS customers during system peak conditions and cannot offset the lost Four Corners capacity. When you add the cost of nearly 400 MW of needed new capacity to that calculated by the Sierra Club, you are pretty much back to the $100/MWH originally calculated by APS.

Q. IS THE LEVELIZED LIFE CYCLE COST PER MWH OF FOUR CORNERS VERSUS THAT OF A GAS ALTERNATIVE EVEN THE MOST APPROPRIATE MEASURE OF RELATIVE IMPACT OF EACH ALTERNATIVE ON APS CUSTOMERS?

A. No. Although capital cost per kW and levelized life cycle cost per MWH provide useful snapshots of information, the real test of economic value to customers is present value revenue requirements ("PVRR"). PVRR is the most accurate way to evaluate the merits of the proposed transaction because it is a comprehensive analysis that accounts for all known factors and their complex interrelationships. It simultaneously addresses capacity and energy needs of APS customers through economic dispatch of the system, taking into account things such as relative cost of fuel, generating unit availability and production efficiency. Yet neither the Sierra Club nor the ACPA present any analysis of actual revenue requirement impacts on APS customers.

Q. DID OTHER EXPERTS AGREE WITH APS'S ECONOMIC ANALYSES OF THE FOUR CORNERS ACQUISITION?

A. Yes, there were several. Staff witness Laura A. Furrey concurred with the PVRR savings calculated by APS of $488 million and concluded that this constituted a "unique value to APS customers." Furrey Testimony at 20. Ms. Furrey went on to add:

> **Q. Is there a benefit associated with continued [APS] investment in Four Corners rather than in purchasing new or existing natural gas facilities?**
>
> A. Yes. The alternative of replacing lost capacity from Four Corners (791 MW) with natural gas would involve less certain fuel costs than under the proposed transaction. . . . The proposed alternative [buying Four Corners] also preserves a well-balanced resource mix, reducing the risk to APS customers that comes with dependency on a volatile fuel source."

Furrey Testimony at 21. Dr. Thomas Fish, RUCO's independent expert states: "[I]n my opinion, no one could reasonably envision situations where the Company's requested alternative is not best." Fish Testimony at 14. Dr. David Berry from WRA, although clearly not a supporter of coal-fired generation, likewise concluded that "APS' plan is the least costly option under a range of reasonable assumptions." Berry Testimony at 8. Finally, Mr. Rose from ICF International, using assumptions of his own concluded that the proposed acquisition of SCE's interest in Four Corners produced savings of $712 million on present value basis over the life of Four Corners. The differences between Mr. Rose's analysis and those of the Company are primarily caused by higher gas prices in the ICF forecast and lower CO2 costs, which factors were only partially offset by using a regional annual load growth assumption of 2% compared to APS's slightly higher and service area-specific forecast of 2-3%.

Q. ASIDE FROM CUSTOMER ECONOMICS, FUEL DIVERSITY CONCERNS, AND LOCAL ECONOMIC IMPACT ON THE NAVAJO NATION, ARE THERE OTHER RISKS ASSOCIATED WITH NEW GAS GENERATION?

A. Yes. The Four Corners transaction can be executed with no impact on reliability, but the gas alternative may require new permits, government approvals, and finally construction – all of which take time and could adversely impact system reliability. As I discuss at page 11 of my Direct Testimony, APS simply must have replacement generation for Four Corners in place by the summer of 2016 if Four Corners is not available. Replacing Four Corners power will require additional transmission, generation, or both. Any new transmission or generation will require a pretty tight permitting, transmission right-of-way acquisition and construction schedule with little leeway for even small but unanticipated problems.

Q. WHAT ABOUT ACQUIRING EXISTING UNITS OR A LONG-TERM PPA?

A. APS has already been unsuccessful in acquiring interests in existing combined cycle generation at a reasonable cost. Soliciting a PPA now for delivery in 2016 would likely prove futile, require a very significant risk premium on the part of the seller, and would still require additional transmission to be constructed. Also, a PPA would do nothing to mitigate the increased natural gas price risk to APS customers. Moreover, adding to the Company's already substantial imputed debt burden would weaken APS's financial profile and runs counter to the established goal from the 2009 Settlement of decreasing APS's debt ratio in the eyes of the bond rating agencies.

IV. THERE IS NO NEED FOR AND CONSIDERABLE RISK ATTENDANT TO ISSUING A RFP AS SUGGESTED BY ACPA

Q. DOES ANY COMMISSION ORDER OR REGULATION REQUIRE AN RFP IN CONJUNCTION WITH EVERY ACQUISITION OF NEW SUPPLY RESOURCES?

A. No. Decision No. 67744 (April 7, 2005), the source of the self-build moratorium for APS imposed no such requirement. Indeed, the preceding 2004 Settlement Agreement negotiated between APS and ACPA did not even require Commission approval of the purchase of existing generation. That extension of the scope of the moratorium was added at Open Meeting by means of a Commissioner amendment to the 2004 Settlement.

As Staff, RUCO and WRA all acknowledge, both the Commission Resource Planning Rules and their predecessor, the so called "Best Practices," allow bilateral negotiated transactions under the sort of factual scenario we find here – that is "a genuine, unanticipated opportunity to acquire a power supply resource at a clear and significant discount, compared to the cost of acquiring new generating facilities and will provide unique value to the load serving entity's customers." A.A.C. R14-2-705(B) (5). I was an active participant in these proceedings at the Commission, and the final language used by the Commission was intended for precisely the circumstances of the proposed Four Corners transaction.

Q. WHAT WOULD ACPA'S SUGGESTED RFP LOOK LIKE?

A. I don't really know, there being nothing really comparable to Four Corners that could possibly be available by the summer of 2016. As discussed previously, it is unlikely that an existing gas generator, even if contractually free to do so, would bid on a deal where the closing is four years or more away. Newly constructed gas generation projects would be unlikely to bid if the Four Corners transaction is still in the running, as is apparently contemplated by the ACPA, because they can pencil out the comparative economics as well as APS. Conducting and participating in a large RFP is an expensive and time-consuming activity, and potential sellers have to be convinced that there is a reasonable chance of getting some business in order to participate.

Q. WHAT ARE THE RISKS ASSOCIATED WITH ACPA'S PROPOSAL?

A. Let me first say that I don't believe an RFP should be conducted unless the ACC is willing to approve APS's acquisition of a gas generator as a replacement for APS interest in Four Corners. At a minimum, requiring a RFP would indicate that the Commission places less value on fuel diversity than does the Company. From a timing perspective, I have serious concerns about being able to conduct a RFP solicitation in the time between a Commission decision in this matter requiring such a RFP and the end of 2012, when the Agreement can be terminated. Keep in mind APS would have to negotiate important details of any qualified proposals so that it can bring back valid opportunities for its customers.

Even if the timing of the RFP was such that the Commission could still authorize the 11th hour purchase of SCE's share of Four Corners for all the reasons set forth in the Company's testimony (as well as that of Staff, RUCO, WRA, etc.), what would be the impact of requiring that RFP process on other proceedings and other negotiations? Would this convince SCE and its California regulators that APS is not a serious buyer, thus making approval in that jurisdiction less likely? Would APS's negotiations with BHP Billiton for a new coal contract likewise be put on hold? We don't know the answers to these questions and are unlikely to find out until it is arguably too late. To me, that's just too much risk for what I believe will be the window dressing of a RFP prior to continuing on with a full consideration of the Company's Application.

V. IT IS UNNECESSARY AND INAPPROPRIATE TO ORDER APS IN THIS PROCEEDING TO STUDY THE IMPACT OF CLOSING ADDITIONAL COAL PLANTS OR A SOLAR/COAL HYBRID PROJECT AT FOUR CORNERS

Q. WRA HAS SUGGESTED THAT APS BE REQUIRED TO "[U]NDERTAKE A COMPREHENSIVE PLANNING PROCESS TO RETIRE ADDITIONAL COAL-FIRED POWER PLANTS WITHIN THE NEXT 10 YEARS OR SO AND INCLUDE COAL PLANT RETIREMENT OPTIONS IN ITS RESOURCE PLANS TO BE FILED AFTER A DECISION IN THIS DOCKET." (BERRY TESTIMONY AT 13.) IS SUCH A REQUIREMENT NECESSARY OR APPROPRIATE IN THIS DOCKET?

A. No. A resource planning docket is the appropriate forum for this sort of discussion. And in that context, APS has already determined that an ongoing evaluation of coal in the Company's resource portfolio is appropriate and will include the sort of reduced coal options discussed in Dr. Berry's testimony in its resource portfolio analysis.

Q. WHAT ABOUT WRA'S SECOND RECOMMENDATION CONCERNING THE EVALUATION OF A SOLAR/COAL HYBRID SYSTEM AT FOUR CORNERS?

A. In a sense, APS has already done an evaluation of a solar hybrid system. In a solar hybrid project, solar energy is used to supplement a fossil fuel in producing electricity. Through previous RFPs, the Company has received proposals for gas/solar hybrid projects. Those bids were dramatically more expensive than the renewable projects actually acquired by APS. Gas is a relatively expensive fuel, and thus displacing gas consumption in favor of solar is the most economic opportunity. Yet the gas/solar projects bid to APS were consistently more costly than other alternatives. Since the cost of coal is considerably lower than the cost of natural gas, replacing coal with solar energy would be even less attractive. I'm not even addressing any operational issues associated with such a project, which I leave to Mr. Schiavoni to address.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS TO YOUR REBUTTAL TESTIMONY?

A. The proposal outlined in the Company's Application and in my Direct Testimony makes the most sense for APS and our customers. It has the support of Staff, RUCO, WRA and the EDF. The criticisms of the Company's economic analyses by the Sierra Club are unfounded and unsupported by the facts. ACPA's answer – a new RFP – is unnecessary, elevates that organizations preferred procurement process over the substance of a transaction that greatly benefits APS customers, and carries with it substantial risks. APS urges the Commission to grant its Application as filed.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

Jeffrey B. Guldner

REBUTTAL TESTIMONY OF JEFFREY B. GULDNER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-10-0474

June 22, 2011

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REBUTTAL TESTIMONY OF JEFFREY B. GULDNER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-10-0474)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION WITH ARIZONA PUBLIC SERVICE COMPANY ("APS" OR "COMPANY")?

A. My name is Jeffrey B. Guldner. I am Vice President of Rates and Regulation for APS. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING THAT DESCRIBES YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. Yes. I have submitted Direct Testimony in this matter, which describes my educational and professional background.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The primary purpose of my Rebuttal Testimony is to respond to the Direct Testimony submitted by other parties in this proceeding as related to the Company's request for an accounting order. Specifically, I will respond to the positions of the Arizona Corporation Commission ("Commission") Staff and the Residential Utility Consumer Office ("RUCO") with respect to our request for an accounting order, and address (1) why this ratemaking treatment is a critical component of our request that is appropriate given the unique circumstances presented here, and (2) why including the carrying cost associated with the acquisition (including the cost of equity and debt) is appropriate.

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS ABOUT THE TESTIMONY SUBMITTED BY OTHER PARTIES IN THIS MATTER?

A. I do. With the exception of Commission Staff, each of the six parties in this matter is viewing APS's request through their own particular lens. I urge the Commission to look at this proceeding broadly, and consider the complexity and many competing interests that APS's proposal addresses. Specifically, the Sierra Club, though exclaiming its primary focus is economics, is really an advocate for closing coal-fired generation. The Environmental Defense Fund ("EDF") and Western Resource Advocates ("WRA") are also advocates for environmental reforms that take a constructive view in that regard in this proceeding. RUCO is focused on the short term rate impacts to APS's residential customers. And the Arizona Competitive Power Alliance ("ACPA") represents the interests of merchant generation, who profit by selling wholesale power generation (primarily natural gas) to APS and others. Each of the recommendations these various parties make, unsurprisingly, is based on their assessments of how the transaction will affect their interests. For example, how should the proposal be structured to have the lowest short term rate impact for residential customers? Should APS buy natural gas generation from independent power producers rather than try to keep Four Corners 4 and 5 operating? Does the closure of Units 1-3 provide sufficient environmental benefits to support the transaction?

APS has wrestled with competing interests like these since Southern California Edison ("SCE") first told the Company and its Four Corners co-owners that it would not make "life extending" investments in the plant after 2011 and would withdraw from the plant entirely in 2016, whether there was a buyer for its share or not. Faced with competing demands, looming environmental compliance expenditures, contractual uncertainty with the Navajo Nation and the plant's fuel supplier, the Company landed on a solution that balanced all of the competing interests involved. APS's proposal to acquire SCE's interest in Units 4 and 5 and retire its wholly-owned Units 1-3 was not based on cost alone (though it is a clear value for APS customers); it is not just about the environment (though the environmental benefits of closing three of five coal units and installing environmental compliance upgrades on the remaining two are undisputed); it is not just about communities (though the benefits to the Navajo Nation of continuing the viability of the community's primary economic driver are beyond a doubt). It is about balancing all of these interests to progress to a common goal.

No party has disputed the benefits that the proposed transaction will bring to the Navajo Nation, which are significant (as Mark Schiavoni described in detail in his Direct Testimony). No party has disputed the benefits that the proposed transaction will bring to the environment. Indeed, WRA and EDF – two of the environmentally-focused groups – expressly support it. Neither is there any real dispute about the importance to APS and its customers of maintaining a balanced resource portfolio, which APS, Commission Staff, and RUCO agree that this transaction does.

Only three real disagreements exist among the parties: (1) whether APS's cost analysis was reasonable; (2) whether APS should have conducted a Request for Proposals before executing the purchase contract with SCE, and (3) whether the circumstances of this unique opportunity merit the accounting treatment that the Company has requested. APS Witnesses Pat Dinkel and Judah Rose (from ICF International) will address the first and second issues. As to the third, the only parties to address the Company's request for an accounting order are Commission Staff and RUCO. Each of those parties also appears to support the transaction. RUCO's witness, Dr. Thomas Fish, even comments that "In my opinion, no one could reasonably envision situations where the Company's requested alternative is not best."[1]

But while RUCO agrees with APS about the clear benefits of the transaction, it would deprive APS of the critical regulatory accounting treatment needed to achieve them. Customer growth – once strong in Arizona –is no longer at a level

[1] Direct Testimony of Thomas Fish ("Fish Testimony") at 14.

that it is able to even partially offset the effects of regulatory lag that would arise without a deferral order, and the PSA prevents APS from using the approximately $40 million of annual fuel savings or any incremental off-system sales that result from the proposed transaction to offset the $71 million per year increase in non-fuel costs associated with owning, operating and maintaining the plant. Neither can this mismatch be addressed by filing a rate case sooner– the Rate Case Filing Plan in the Company's 2009 Settlement agreement would prevent it. Granting a deferral will not bias the ultimate ratemaking treatment of the asset, but denying it does.

Although Commission Staff recognizes that the present circumstances warrant the Company's requested accounting treatment, it would dramatically limit the allowed deferral such that the accounting order would no longer adequately serve its intended purpose. As a practical matter, if the Commission adopts either of these recommendations, it simply increases the risk that the proposed transaction will not be consummated and its benefits lost.

II. <u>THE COMPANY'S REQUESTED ACCOUNTING TREATMENT IS APPROPRIATE UNDER THE CIRCUMSTANCES.</u>

Q. PLEASE ADDRESS RUCO'S RECOMMENDATION THAT THE REQUESTED ACCOUNTING ORDER SHOULD BE REJECTED.

A. RUCO's recommendation is based on a mistaken view of the impact that regulatory lag would have on the Company with this acquisition. There are three unique factors at play with this purchase that make a compelling case for a deferral authorization, each of which Commission Staff acknowledges and RUCO witness Dr. Fish ignores. The first is the magnitude of the required investment. The second is APS's inability to control the timing of either the purchase or its next rate case under existing regulatory constraints. The third is APS's inability, because of the Power Supply Adjustor ("PSA"), to offset cost increases associated with the transaction with the fuel savings and any incremental off-system sales margins that will also immediately and directly result. In total, these unique circumstances produce a striking mismatch between APS's costs and its revenues and a considerable inequity for APS – the exact type of circumstances that make a regulatory deferral highly appropriate. I will address each of these factors in turn.

First, this transaction is not a routine capital expense, but the purchase of a significant generation asset that requires an immediate upfront capital cost of $294 million. The revenue requirement associated with the purchase is more than $71 million *per year*, "a significant amount" to use Commission Staff's words.[2] If APS is required to wait to begin collecting that revenue requirement until the end of its *next* rate case, as Dr. Fish suggests, it would forfeit a minimum of $115 million – a highly material amount that the Company would never be able to recover. The financial impact of such a loss, as Commission Staff correctly notes, is "of sufficient magnitude to affect decision-makers such as management or investors."[3]

Neither could APS have chosen to close the transaction any earlier so that the costs may have been included in APS's rate case filed on June 1 of this year (nor, from Dr. Fish's testimony, does it appear that he would want the deal to have closed any earlier). Since learning of the constraints placed on SCE by recent California law, the Company has moved expeditiously to attempt to find a solution to the complex challenge that resulted. After SCE proposed to sell its share to APS, APS spent months in arms-length negotiations with its counterparty and executed the purchase agreement late last year. The contract requires

[2] *See* Direct Testimony of Commission Staff Witness Jeffrey M. Michlik ("Michlik Testimony") at 6.
[3] *Id.*

numerous approvals, not just from this Commission but also from the California Public Utilities Commission, the Federal Energy Regulatory Commission, and others. Under these circumstances, the October 2012 anticipated Closing Date associated with the contract is a reasonable one. The deal cannot close much later than October 2012 either. Among other reasons described in detail in APS witness Mark Schiavoni's Rebuttal Testimony, the purchase contract expressly permits either party to terminate the agreement if the required regulatory approvals are not received by December 31, 2012, and the required capital expenditures on Units 4 and 5 must begin in late 2012 if the EPA-required environmental upgrades are to be in-service in time to meet the EPA's 2016 deadline.

Moreover, contrary to RUCO's suggestion, APS does not have "a great deal of control over their ability to recover costs because [we] decide when to file a general rate case."[4] As part of APS's 2009 rate case settlement (approved in Decision No. 71448), APS agreed not to file its next general rate case any earlier than June 1, 2013 (which date could, theoretically, be pushed further out if the rate application that APS recently filed is not approved on the anticipated timeline). Even then, new rates from any June 2013 filing would be unlikely to take effect before July of 2014 (assuming a 12 month post-sufficiency finding resolution of that case). Were the Company to forego a deferral and wait until the end of such a rate filing to recover its investment, it would forever lose at least $115 million in actual costs incurred for cost-effective energy that will benefit our customers the moment the transaction closes.

[4] *See* Fish Testimony at 26.

Q. WOULD ANY OTHER INEQUITIES RESULT IF THE COMMISSION WERE TO DENY THE DEFERRAL REQUEST?

A. Yes. In the conceptual regulatory framework that Dr. Fish paints, the increased operating costs associated with the transaction would be offset by other cost savings, such as the fuel savings that result from the transaction or any off-system sales that could be made as a result of the additional 179MW in the Company's generation fleet. But in this case, the PSA prevents APS from recognizing all but a small amount (the 10% sharing) of such savings to offset the significant cost of the transaction.[5] Stated differently, not only would customers benefit from the additional energy produced by the asset for upwards of two years without having to pay the $71 million annual cost that comes with it, they would also benefit from approximately $40 million each year in fuel savings that could otherwise be used by APS to offset that $71 million, absent the PSA. Commission Staff agrees with APS that the mismatch between costs and rates exacerbated by the PSA "provides additional impetus for granting regulatory relief." RUCO witness Dr. Fish, on the other hand, alludes to the PSA in passing but otherwise ignores the inequities that would result.[6]

Q. HOW DO YOU RESPOND TO RUCO'S ARGUMENT THAT A DEFERRAL IS UNWARRANTED BECAUSE OF THE "TRADE-OFF IN THE REGULATORY ARENA: RATE PAYERS BENEFIT AT THE BEGINNING OF THE LIFE CYCLE OF THE ASSET AND THE UTILITY BENEFITS AT THE END?"

A. First, the statement ignores several of the inequitable realities of the current asset purchase, which I have just described. Second, the single asset example that Dr. Fish poses is fallacious, at best. There can be no denying that the net present value of an asset is greater at the beginning of its life than it is at the end. As RUCO's witness would have it, APS should absorb the much higher costs

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[5] In APS's recently filed rate case, APS has proposed to eliminate the 90/10 sharing provision. If approved by the Commission, APS would see no benefit from fuel savings or off-system sales revenue resulting from this proposed transaction.

[6] *See* Fish Testimony at 28.

associated with an asset at the beginning of its life (a capital cost on a $294 million asset), even though they will never be fully offset by the much lower earnings associated with it at its life's end (a return on a $20 million asset).

Moreover, the single-asset example that Dr. Fish describes ignores the practical reality of a Company, like APS, that continually adds assets to its rate base. We regularly invest in our system. As a result, the balance of assets on which we under-recover because of regulatory lag continues to grow and the hypothetical balance of under-recovery to over-recovery Fish assumes is never achieved.

Q. DOES THE REQUESTED RATEMAKING TREATMENT HAVE ANY IMMEDIATE BILL IMPACT ON CUSTOMERS?

A. No. If the Commission grants the deferral, customers will see no bill impact until the asset is reflected in rates. Even then, as Commission Staff notes, the customer impact is "certainly within the range of a typical rate adjustment, and it can be modified as deemed appropriate by the recovery method authorized."[7]

Q. DO YOU HAVE ANY REACTION TO RUCO'S RECOMMENDATION THAT, BEFORE IT IS ALLOWED TO DEFER O&M EXPENSES, IT MUST "DEMONSTRATE THAT ANY DEFERRED O&M EXPENSES BE GREATER THAN WHAT OTHERWISE WOULD HAVE OCCURRED AND THAT COMPARISON BE MADE TO UNITS 1-3?

A. I do. The Company's request already addresses RUCO's apparent concern. APS expects that the change in O&M expense on Four Corners from acquiring SCE's share of Units 4 and 5, when offset by the savings associated with retiring Units 1-3, is still an increase of more than $5 million in 2013 (not the decrease in O&M costs that RUCO believes is likely). Even so, in the Company's Application, we requested to defer and capitalize O&M costs only to the extent that APS's share of overall Four Corners O&M increases as a result of the acquisition of SCE's

[7] *See* Michlik Testimony at 6.

interest – any O&M savings to APS at Four Corners related to the shutdown of Units 1-3 will be credited against the deferral balance.[8]

Q. DO YOU HAVE ANY REACTION TO RUCO'S AND STAFF'S RECOMMENDATION THAT APS SHOULD NOT BE AUTHORIZED TO EARN A RETURN ON ANY DEFERRED ACCOUNTS.

A. Yes. APS requests that it be permitted to include carrying costs associated with the ownership of SCE's share of Units 4 and 5 as part of the deferred balance, including a debt and equity return on the $294 million purchase price. The debt and equity return component of those costs is a very material portion of the Company's deferral request, totaling more than $37 million per year – more than 50% of the revenue requirement associated with the transaction. Requiring APS to forfeit such a significant amount would be inequitable, particularly considering the remarkable value of the transaction for customers, the limitations on APS's ability to file a rate case, APS's offer to net the O&M savings related to the shutdown of Units 1-3 against the deferral balance, and the fact that, because of the PSA, APS will not be able to offset the transaction costs with the more than $40 million per year of fuel savings that will immediately flow through to customers through the PSA.

Neither would allowing APS to defer a return result in any inequity for customers. The cost of capital on the $294 million acquisition is a legitimate and significant portion of the overall transaction costs– as real as depreciation, amortization, property taxes, and the other expenses that Staff would allow APS to defer. Staff agrees that the unique circumstances of this transaction merit a cost deferral generally, and there is no reason to distinguish the cost of capital from others in that regard. Allowing a deferral of the cost of capital is not a "guaranteed return," as Staff and RUCO suggest.[9] Precisely the opposite: the

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[8] *See* Application at 30.
[9] Michlik Testimony at 10; Fish Testimony at 31.

requested accounting order would only give APS the *opportunity* to recover the deferred cost of capital; without a deferral, APS is 100% "guaranteed" to forfeit all of those amounts. Absent some other mechanism to allow timely recovery of these costs or otherwise addressing the inequities, the mismatch between costs and rates resulting from the transaction would in large part remain, and APS would have to re-evaluate whether to consummate the deal in light of the resulting adverse financial impact.

APS has also requested that it be allowed to defer a return on all of the deferred costs, including those discussed above, computed using the embedded cost of debt as of December 31, 2010 and the 11% cost of equity used in APS's last general rate case, at the 46%/54% debt to equity ratio also set in that rate case. Deferred costs such as O&M, taxes, interest and equity returns themselves represent investments that APS needs to be able to earn a return on every bit as much as the cash outlay of $294 million. This is how the Allowance for Funds Used During Construction ("AFUDC") is calculated per both Federal Energy Regulatory Commission and this Commission's guidelines.[10]

Q. DO YOU HAVE ANY EXAMPLES WHERE EITHER THIS COMMISSION OR ANOTHER JURISDICTION PERMITTED THE DEFERRAL OF THE COST OF CAPITAL ASSOCIATED WITH AN ASSET?

A. Yes. Each of the accounting orders granted by this Commission that were discussed in the Application and my Direct Testimony permitted APS to defer a cost of capital (either the cost of debt or the cost of debt and equity). And in the Western United States generally, including the cost of capital in a deferral authorization is certainly far more typical for transactions of this sort than the approach that Commission Staff recommends here. For example, in the State of Washington, a statute and implementing regulation specifically allow deferral of

[10] *See* A.A.C. R14-2-212(G) and Decision No. 53761 at 27-28 (September 30, 1983).

"operating and maintenance costs, depreciation, taxes, and cost of invested capital" for the acquisition of baseload generation.[11] Several deferral orders have been issued to Puget Sound Energy ("PSE") under this statute and regulation. For example, PSE was allowed to include "the monthly cost of capital" in its authorized deferral for costs associated with the acquisition of Goldendale Generating Station.[12] PSE was similarly permitted to include "a return of and on the plant investment plus the accrual of interest on the deferred balance" related to its purchase of a combined cycle plant at Mint Farm.[13] In a 2004 deferral order, the Nevada Commission allowed Nevada Power Company to include capital carrying costs in the deferral authorized for Nevada Power's acquisition of the Moapa Generating Station.[14] Just last year, the Colorado Commission granted the Public Service of Colorado ("PSCo") cost recovery equivilant to a deferral order for PSCo's acquisition of two Calpine generation plants.[15] The revenue requirements deferred in that case included all jurisdictional costs, including return on the capital invested by PSCo. And in 2008, the Oklahoma Commission granted OG&E a deferral order that included a tax-adjusted return based on the company's last authorized return for OG&E's acquisition of the Redbud Generating Facility.[16]

Q. DO YOU HAVE ANY REACTION TO STAFF'S RECOMMENDATION THAT, IF THE COMMISSION DECIDES TO GRANT APS A CARRYING FACTOR TO THE DEFERRED BALANCE, IT USE A "RATE NOT TO EXCEED THE COMPANY'S MOST RECENTLY AUTHORIZED RATE OF RETURN IN A RATE CASE?"

A. APS is agreeable to this recommendation.

[11] Wash. Rev. Code 480-100-435 (2007).
[12] *See* PSE Rate Case No. UE-070533 Order No. 01 (April 11, 2007).
[13] *See* PSE Rate Case No. UE-082128 Order No. 03 (April 17, 2009).
[14] *See* Nevada Public Utilities Commission Docket Nos., 04-6029/04-6030 (September 21, 2004).
[15] *See* Public Utilties Commission of Colorado Docket No. 10A-327E (October 10, 2010).
[16] *See* Oklahoma Corporation Commission Decision No. 559892, Cause No. PUD 200800086 (September 23, 2008)

Q. DO YOU HAVE ANY CONCERNS ABOUT RUCO'S SUGGESTION THAT THE CONDITIONS ATTACHED TO THE SUNDANCE ACCOUNTING ORDER (AUTHORIZED IN DECISION NO. 67405) ALSO BE ATTACHED TO ANY ACCOUNTING ORDER GRANTED IN THIS DECISION.

A. Yes. The characteristics of the two transactions are distinctly different, and conditions that may have been reasonable in Sundance are not needed in this case. The economic climate in place during the Sundance acquisition was such that APS was experiencing a high level of customer growth and increasing sales volumes. The conditions in the Sundance Order recognized that this growth in revenue may partially offset the additional (but much smaller than Four Corners) costs of owning, operating and maintaining the Sundance Units. The opposite is true today: because of today's economic climate and the continued pursuit of Energy Efficiency targets, the Company's forecast of future sales per customer is not materially increasing. There will thus be no growth in revenue margins to offset the costs that the Company proposes to defer related to this acquisition. Put another way, the inability to defer costs in the Four Corners acquisition puts a much more significant financial strain on the Company because per customer sales levels will not be increasing, as they were at the time of the Sundance acquisition.

Moreover, the magnitude of the Four Corners transaction is over $100M larger than the acquisition of Sundance. The acquisition thus has a greater negative financial impact on APS compared to the Sundance purchase. The striking differences between the two transactions require an independent evaluation of the need for and nature of a deferral order. The conditions present in the Sundance deferral order were appropriate for that transaction. For the reasons I have discussed, the deferral order requested by the Company is most appropriate here.

Q. DO YOU HAVE ANY REACTION TO STAFF'S RECOMMENDATIONS RELATING TO THE COMPANY'S ACCOUNTING ORDER REQUEST FOR ASSURANCE IN AN ACCOUNTING ORDER THAT THE COMPANY MAY CONTINUE TO RECOVER OUTSTANDING COSTS ASSOCIATED WITH FOUR CORNERS UNITS 1-3?

A. As Staff has phrased its recommendation, the Company can accept it.

Q. DO YOU HAVE ANY REACTION TO STAFF'S RECOMMENDATIONS RELATING TO THE COMPANY'S ACCOUNTING ORDER REQUEST FOR ASSURANCE THAT ANY ADDITIONAL COSTS INCURRED IN CONNECTION WITH THE CLOSURE OF UNITS 1-3 WILL BE RECOVERED?

A. As Staff has phrased its recommendation, the Company can accept it.

Q. DO YOU HAVE ANY OTHER REACTION TO STAFF'S ACCOUNTING ORDER RECOMMENDATIONS?

A. Yes. I am concerned that the language used with respect to Recommendation No. 1 permitting APS to defer "for future consideration of recovery through rates"[17] may not make such costs sufficiently "probable of recovery" such that APS would be permitted to actually defer the amounts under applicable accounting principles. We would suggest that the quoted language be replaced with language that allows APS "to defer for later recovery the prudent and reasonable non-fuel costs of owning, operating, and maintaining the acquired SCE interest . . . ." That language is identical to the language contained in the Commission Order that authorized APS to defer the costs associated with bark beetle remediation.[18]

III. <u>CONCLUSION</u>

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. The proposed acquisition of SCE's interest in Four Corners Units 4 and 5 is a good deal for APS customers, the Navajo Nation, and the environment. Each of the requests contained in the Company's Application – including the requested

[17] Michlik Testimony at 12.

[18] *See* Decision No. 67744 (April 7, 2005).

accounting order – is critical for the transaction to move forward, and APS respectfully requests that they be granted.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Judah L. Rose

BEFORE

THE ARIZONA CORPORATION COMMISSION

IN THE MATIER OF THE APPLICATION	)	
OF ARIZONA PUBLIC SERVICE	)	
COMPANY FOR AUTHORIZATION FOR	)	
THE PURCHASE OF GENERATING	)	DOCKET NO. E-01345A-10-0474
ASSETS FROM SOUTHERN CALIFORNIA	)	
EDISON AND FOR AN ACCOUNTING	)	
ORDER	)	

PUBLIC VERSION

REBUTTAL TESTIMONY OF

JUDAH L. ROSE

ON BEHALF OF

ARIZONA PUBLIC SERVICE COMPANY

June 22, 2011

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I. INTRODUCTION

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

A. My name is Judah L. Rose. I am a Managing Director of ICF International (ICF). My business address is 9300 Lee Highway, Fairfax, Virginia 22031.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. After receiving a degree in economics from the Massachusetts Institute of Technology and a Masters Degree in Public Policy from the John F. Kennedy School of Government at Harvard University, I joined ICF in 1982. I have worked at ICF for over 29 years and am Managing Director of ICF's wholesale power practice. I also have been a member of the Board of Directors of ICF International and am one of three people (in a consulting firm of more than 3,500 people) to have been given ICF's honorary title of Distinguished Consultant.

Q. DOES ICF HAVE PUBLIC SECTOR CLIENTS?

A. Yes. In the United States, ICF has been the principal power consultant to the U.S. Environmental Protection Agency (EPA) continuously for over 35 years, specializing in the analysis of the impact of air emission programs, especially cap and trade programs. We also have worked with the Federal Energy Regulatory Commission (FERC) on transmission issues and the U.S. Department of Energy (DOE). In addition, we have worked with state regulators and state energy agencies, including those in California, Connecticut, Kentucky, New Jersey, New York, Ohio, Texas, and Michigan, as well as with numerous foreign governments.

Q. DOES ICF HAVE UTILITY CLIENTS?

A. Yes. For over 35 years, ICF has provided forecasts and other consulting services to major United States and Canadian electric utilities. In the U.S., ICF has worked with utilities such as American Electric Power, Allegheny, Arizona Public Service, Dominion Power, Delmarva Power & Light, Duke Energy, FirstEnergy, Entergy, Exelon, Florida Power & Light, Southern California Edison, Sempra, PacifiCorp, PEPCO, Public Service Electric and Gas, Public Service of New Mexico, Nevada Power, Southern Company, Tucson Electric, and Xcel Energy. ICF also works with Regional Transmission Organizations and similar organizations including the Western Electric Coordinating Council, Midwest Independent Transmission System Operator, the Electric Reliability Council of Texas, and the Florida Regional Coordinating Council.

Q. WHAT TYPE OF WORK DO YOU TYPICALLY PERFORM?

A. I have extensive experience in assessing wholesale electric power issues, including regulatory analysis, investment analysis, forecasting wholesale electricity prices and valuing power plants. I also have extensive experience assessing environmental regulations and their impacts on supply and demand conditions in wholesale power markets.

Q. WHAT EXPERT TESTIMONY EXPERIENCE DO YOU HAVE RELATED TO ELECTRIC POWER?

A. I have testified before, filed with or made presentations to the FERC, an international arbitration tribunal, federal courts, domestic arbitration panels, and before state regulators and legislators in 21 U.S. states and Canadian provinces: Arizona, Arkansas, California, Florida, Indiana, Kentucky, Louisiana, Manitoba, Massachusetts, Minnesota, Missouri, New Jersey, Nevada, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Quebec, South Carolina, and Texas. I have testified extensively on the topics of electric power prices and markets, utility planning and the development of new generation resources and transmission. In addition, I have authored numerous articles in industry journals and spoken at scores of industry conferences. For specific details, please see my resume, attached hereto as Attachment JLR-1.

Q. HAVE YOU TESTIFIED PREVIOUSLY IN THE STATE OF ARIZONA?

A. Yes, as noted above. Specifically, I have filed the following testimony: (1) Rebuttal Testimony in the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona, Estimation of Market Value of Fleet of Utility Coal Plants, April 1, 2008, and (2) Direct Testimony on behalf of Tucson Electric Power

Company, In the matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona, Estimation of Market Value of Fleet of Utility Coal Plants, July 2, 2007.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Arizona Public Service Company ("APS").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony rebuts the May 31, 2011 testimony of David Schlissel on behalf of the Sierra Club, and supports the Application of Arizona Public Service Company for authorization for the purchase a portion of Four Corners Units #4 and #5 from Southern California Edison (SCE). My testimony also rebuts the May 31, 2011 testimony of Greg Patterson on behalf of the Arizona Competitive Power Alliance (ACPA).

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into ten sections. The first section (*i.e.,* this section) introduces my testimony. The second section (*i.e.,* the next section) summarizes my testimony. My testimony addresses the testimony of the Sierra Club, except for one section responding to the testimony of the ACPA. The third section responds to the Sierra Club regarding the economic risk facing Units #4 and #5 with emphasis on potential national CO_2 regulation and natural gas prices. The fourth section presents ICF's valuation of Units #4 and #5 which equals an estimate of the cost savings available to APS customers from the acquisition of SCE's share of the units. The fifth section discusses the existential risks to Units #4 and #5 in the absence of APS's purchase of SCE's capacity. The sixth section discusses the alternatives to the purchase identified by Sierra Club. The seventh section discusses coal power plant lifetimes and performance. The eighth section discusses natural gas price volatility. The ninth section responds to ACPA's testimony. The tenth section discusses my conclusions.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. APS proposes to buy SCE's interest in the 1,540 MW Four Corners coal power plant Units #4 and #5. This purchase is assumed to occur for analysis purposes as of October 2012. If consummated, APS's interest in these two units increases from 231 MW and 15 percent ownership to 970 MW and 63 percent ownership. APS also proposes to retire Units #1 - #3 which are wholly owned by APS and have 560 MW of capacity. These units are assumed to be retired for analysis purposes as of October 2012. EPA proposes that APS retrofit to a Selective Catalytic Reduction (SCR) NO_x control system in 2016, *i.e.,* in four and one-half years from now. Sierra Club accepts APS's analysis regarding Units #1-#3, but not Units #4 and #5.[1] Sierra Club recommends that APS plan the retirement of Four Corners Units #1 - #3, and that the Arizona Corporation Commission (Commission) reject APS's proposal to purchase SCE's share of Units #4 and #5 with leave to re-file with analysis of the technical and economic viability of alternatives. Sierra Club considers the APS analysis to be biased in favor of the purchase of SCE's share of Units #4 and #5.

I. I disagree with Sierra Club's assertion that APS does not properly address the economic risks of operating Four Corners Units #4 and #5. In addition to responding to each of Sierra Club's points, I conducted my own analysis of the proposed transaction using my own data in part and my own methodology. My analysis concludes that the potential to purchase SCE's share creates a unique opportunity to decrease APS customer costs relative to what they would otherwise be. I estimate the net present value of the transaction in terms of cost savings to APS customers to be very high $712 million[2] in 2012 dollars. This assumes that in the absence of the transaction, Units #4 and #5 will be retired.

[1] Sierra Club testimony dated May 31, 2011, page 3.
[2] This value is net of the cost of the SCR and the $294 million payment to SCE. This value is also a present value as of October 2012.

II. My estimate of the value for APS's ownership of Four Corners Units #4 and #5 is moderately higher than that of APS (+22 percent). ICF believes that APS uses conservatively high CO_2 and conservatively low natural gas prices. However, this is partly offset by lower market prices for "pure" capacity in my analysis. This, in turn is associated with my assumption, based on the projections of the North American Electric Reliability Corporation (NERC),[3] that electricity demand growth in the Desert Southwest will be a fraction of pre-recession historical levels. This NERC forecast is similar to APS's forecast. If electricity demand growth turns out to be higher than forecast by NERC or APS, ICF's value would be significantly higher than estimated.

III. Contrary to Sierra Club's assertion that there is no evidence that Units #4 and #5 will be shut down if APS does not purchase SCE's share of the units, I believe that failure to expeditiously implement the proposed APS purchase of the SCE share creates risks that Units #4 and #5 would retire and that a rare opportunity to lower APS customer costs would be lost. Thus, the benefits of the additional capacity (*i.e.,* SCE's share) would be lost, and to make a bad situation worse, the value of APS's current 231 MW interest in Units #4 and #5 would also be lost.

IV. Evidence supporting this risk includes the experience with the only other major coal power plant owned by SCE, the Mohave power station, which retired December 31, 2005. There are important differences between Mohave and Four Corners. The key differences are Four Corners Units #4 and #5 are already highly controlled for air emissions as the plants have SO_2 scrubbers and fabric filters. On the other hand, Mohave was not scrubbed, lacked adequate particulate controls, and used the nation's only coal water slurry pipeline, a source of particular contention. These differences notwithstanding, the Mohave case has relevance because of the combination of SCE's key position in the plant, a deadline to retrofit a significant amount of pollution control

[3] NERC is the Electricity Reliability Organization of the U.S.

equipment, California's opposition to coal generation, and the multiplicity of parties and regulators. These risks should be well known to the Sierra Club in light of its special role in the Mohave coal plant retirement. The Sierra Club was one of three environmental groups that signed the consent decree that created the deadline for Mohave of December 31, 2005. Sierra Club should also be aware of these risks in light of its extensive efforts against existing coal power plants elsewhere in the region and throughout the U.S.

V. The deal is sufficiently attractive to APS customers, that California regulators may be pressured by intervenors in California's regulatory proceeding (*e.g.*, Sierra Club, The Utility Ratepayer Network) to prevent the sale. This risk is significant in light of the history of Mohave and the fact that the proposed Four Corners' SCR retrofit deadline is even shorter than was Mohave's – four and one-half years versus Mohave's six plus years. Thus, I do not recommend any delays in the process that might jeopardize uniquely large cost savings to Arizona.

VI. Arguendo, even if there is an absolute certainty that an alternative to the transaction exists that prevents the retirement of Units #4 and #5, and the loss of APS's current ownership of 231 MW, the transaction still has a value of $472 million (2010$).[4] I believe this value to be unrealistically low because any alternative is hypothetical and reliance on it ignores the risks that the alternative might fail. However, $472 million is still a large value, and hence, the transaction provides large cost savings for APS customers even under unrealistically adverse assumptions.

VII. Sierra Club's proposed consideration of alternatives is not worth the risks of delay to this unique opportunity. There is very little chance that any alternative would approach the cost savings potential of the proposed transaction. This includes a RFP directed at the competitive market. Unless owners of merchant combined cycles were willing to sell

[4] This value is net of the cost of the SCR and the $294 million payment to SCE and is present value as of October 2012. This is the value of SCE's 739 MW only.

their plants at a price close to zero, there is no prospect that the RFP would result in options that save APS customers more.

VIII. I estimate the value of existing combined cycles with similar capacity to APS's ownership of Four Corners Units #4 and #5 to be approximately [redacted][5] before paying the purchase price (see Exhibit 1). I also expect the price of these plants resulting from a RFP to be similar to the [redacted] value, and therefore, the cost savings will be close to zero (see right-most column in Exhibit 1). In contrast, the value of Four Corners is $712 million even after paying the $294 million purchase price. Even if I am too high in my estimate of the price of combined cycles in a RFP, the breakeven price that makes APS indifferent between combined cycle and Four Corners supply is extremely low as I noted. The combined cycle price must be below [redacted] (approximately [redacted]). No prices have ever been recorded at anywhere near this low level. In fact, prices have been roughly [redacted] times this level and higher.

IX. Even under the unrealistically low value of $472 million, *i.e.*, under a case in which there is an absolutely certain alternative to preventing the loss of Units #4 and #5, the breakeven price is still extremely low at [redacted]. No such price has ever been recorded, and no price has ever been even close to this level.

X. For similar reasons, I reject ACPA's proposal for a RFP process. This special situation should be embraced with special attention and treatment to avoid cancellation.

[5] Based on 970 MW.

Exhibit 1
Comparison of Proposed APS Purchase Expected Results of RFP and Breakeven Analysis
($ Million of October 2012)

Parameter	Four Corners Units #4 and #5[1]	Possible Purchase of Existing Combined Cycle[2]
Present Value of Savings	1,006	[redacted]
Purchase Price	294	[redacted]
Net	712	0

[1] 970 MW. APS interest in Four Corners Units #4 and #5 after transaction.
[2] [redacted]
[3] Price equals [redacted]. This is an illustration of a possible outcome of a RFP. Purchase price could be different. The breakeven price is [redacted]/kW. Even under the unrealistically low estimate of $472 million of value for 739 MW the breakeven price is still extremely low at [redacted]/kW.

XI. Sierra Club's assertions about the risks to APS and its customers due to the aging of Four Corners Units #4 and #5 are not supported by evidence and are wrong. The U.S. EPA uses an 80-year[6] lifetime while APS uses a 70 year lifetime. Other analysts such as the U.S. Department of Energy also assume similarly long potential lifetimes. Indeed, were this not the case, there would be less effort devoted by Sierra Club and regulators to existing coal units because such efforts would be superfluous if Sierra Club's claims about aging coal plants were true – *i.e.,* they would age and retire without all this attention and effort. In fact, the opposite appears to be happening. As large coal plants age, their availability, a critical measure of their performance, has in fact actually been increasing. Sierra Club also ignores the attractive economies of scale at the Units #4 and #5 which are large compared to the average U.S. coal units. They also ignore: (1) the widespread investments in coal power plants of similar age, (2) the ages of Units #4 and #5 are almost precisely equal to the average age of U.S. coal-fired power plants, (3) the tens of thousands of MW of existing coal power plants older than Units #4 and #5, (4) the absence of historical evidence which is relevant to whether modern controlled U.S. coal plants cannot last 70 or 80 years, which places greater emphasis on the technical studies of EPA, DOE and others and (5) that Four Corners Units #4 and #5 are highly

[6] http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#documentation. Table 4-10 Life Extension Cost Assumptions Used in EPA Base Case v.4.10. There are estimated costs for what EPA defines as life extension, but there may be mitigating factors to these costs as discussed in the body of my testimony.

distinguished from and advantaged relative to typical coal-fired units which have been retired or have announced their retirements by virtue of Units #4 and #5 having already existing SO_2 control equipment (*i.e.,* scrubbers), already existing fabric filter particulate control devices, and a nearby low sulfur fuel source.

XII. Sierra Club's claim that the APS economic analysis is biased in favor of Units #4 and #5 and against natural gas is not correct. With respect to two key parameters, *i.e.,* national CO_2 and natural gas prices, APS makes conservative assumptions that bias the results in the opposite direction – *i.e.,* against coal options. Moreover, the risks of natural gas and coal options are treated similarly by virtue of APS using the same discount rate for both natural gas and coal options.

In conclusion, the APS proposal has several elements that the Commission might find attractive, but which my analysis did not address. The retirement of Units #1 - #3 lowers CO_2 emissions, lowers existing power plant supply, and increases demand for the region's merchant IPP natural gas power plants. My analysis addresses cost savings from the proposed transaction. I conclude that this is a unique cost savings opportunity for APS and its customers that deserves special attention and treatment. From the standpoint of minimizing customer costs, the recommendations of Sierra Club and ACPA regarding purchasing SCE's share of Units #4 and #5 should be rejected and the APS proposal expeditiously approved.

III. ECONOMIC RISKS OF FOUR CORNERS UNITS #4 AND #5 – CO_2 AND NATURAL GAS PRICES

Q. WHAT IS YOUR REACTION TO SIERRA CLUB'S ASSERTION THAT APS FAILS TO ANALYZE THE ECONOMIC RISKS OF CONTINUED OPERATION OF UNITS #4 AND #5?

A. I believe the exact opposite is true. The economic analysis of APS is very conservative in several key respects and, as a result, moderately understates the value of Four Corners Units #4 and #5. Indeed, the analysis may understate the extent to which this is a rare opportunity for APS and its customers to decrease costs of service that warrants special attention and treatment. I base this conclusion in large part on APS's conservative treatment of two important economic parameters affecting the analysis of Four Corners Units #4 and #5. Namely, APS uses conservatively high prices for potential CO_2 emission regulations, and in spite of this, uses low natural gas prices. I also believe that the conservative treatment is in part related to the timing of the analysis and November 22, 2010 application of APS. Namely, the analysis and filing did not have the full benefit of information that very recently has become available about the much poorer political prospects for potential national \$/ton CO_2 controls.

Q. WHAT DOES APS ASSUME IN ITS BASE CASE ABOUT POTENTIAL CO_2 REGULATIONS?

A. The APS analysis assumes that potential CO_2 emission regulations will cost \$20/ton (nominal), starting January 1, 2013, and escalate at 2.5[7] percent per year from this level.

Q. WHAT IS YOUR VIEW OF THE APS ASSUMPTIONS ABOUT POTENTIAL CO_2 PRICES?

A. APS's assumptions about potential CO_2 regulations are conservative overall, and its near-term assumptions about potential CO_2 emission regulations are especially conservative. The prospects for a national CO_2 cap and trade program, or \$/ton charge for the emission of CO_2 in 2013 should

[7] Direct testimony of Patrick Dinkel on behalf of Arizona Public Service Company, November 22, 2010, page 10, lines 11-12.

be considered as non-existent based on what we know today. This is because the lead time for major new regulations is approximately five years, and prospects for the near-term initiation of a major national CO_2 control program leading to a $/ton charge have become highly remote in recent months. APS is reasonable to assume there could eventually be national $/ton CO_2 emission regulations. Nonetheless, APS's estimates are conservatively high in ICF's view. ICF expects that potential $/ton CO_2 controls will not start until 2020. Over the next 27 years (*i.e.,* 2013 to 2039), ICF forecasts that the levelized average of potential CO_2 emissions costs will be $13.7/ton versus $18.6/ton for APS.[8] Hence, APS's CO_2 forecasts are approximately 36 percent higher.

Q. WHY ARE POTENTIAL CO_2 EMISSION COSTS SO IMPORTANT IN ASSESSING THE PURCHASE OF SCE'S SHARE OF FOUR CORNERS?

A. A $20/ton CO_2 price adds $20/MWh to the cost of operating a coal-fired power plant compared to the current regulatory situation in which there is no national $/ton CO_2 cost. Also, a $20/ton CO_2 price adds $8/MWh to the cost of a new natural gas-fired combined cycle, or $12/MWh less than the cost add-on for a coal plant. Because APS's forecast of potential CO_2 prices are, in ICF's view, conservatively high, APS's CO_2 assumptions actually bias the results in favor of natural gas which is the exact opposite from what the Sierra Club suggests. The bias of APS's assumption for potential CO_2 regulations over the period of APS's analysis relative to ICF's is $2.94/MWh on a levelized real basis, or approximately $33 million per year in 2010$.[9]

Q. WHAT DOES SIERRA CLUB SAY ABOUT APS'S PRICE ASSUMPTIONS FOR POTENTIAL CO_2 REGULATIONS?

[8] 2010 $, levelized at a 5.4 percent real discount rate. Levelized means converted to an annuity price with the same present value as the individual yearly prices. This effectively weights near-term prices for the greater risk adjusted time value of money in the near-term.

[9] 0.6 tons/MWh x ($18.6 - $13.7)/ton CO_2 levelized premium in APS versus ICF's analysis. In 2010 dollars. $2.94/MWh x 770 MW x 2 x 8,760 hrs/year x 0.83 average capacity factor = $33 million.

A. Sierra Club warns that the future costs of potential CO_2 regulations could be higher than the estimates assumed by APS.[10] This is in addition to Sierra Club's view that APS does not address the overall economic risks of operating Units #4 and #5.

Q. HAS MR. SCHLISSEL TESTIFIED IN THE PAST ON POTENTIAL $/TON CO_2 EMISSION COSTS?

A. Yes,[11] and Mr. Schlissel has been wrong in each instance. More significantly, he repeatedly and consistently presented estimates of potential CO_2 prices that were higher than utility estimates of potential national CO_2 prices. He should not be ignoring the recent significant deterioration in the prospects for near-term national CO_2 $/ton controls. Moreover, he should not characterize the company's analysis as biased and understating the economic risks to Units #4 and #5 when in fact the opposite is happening due to APS's conservatively high projections of potential CO_2 prices.

Q. DOES SIERRA CLUB PRESENT ANY ANALYSIS OF ITS OWN?

A. No. In light of its past testimony on the potential for CO_2 regulations, this is particularly problematic.

Q. WHY ELSE DO YOU DISAGREE WITH SIERRA CLUB'S CHARACTERIZATION OF APS'S ECONOMIC ANALYSIS?

A. I believe APS's natural gas price forecast is conservatively low, especially given its forecast for potential CO_2 emission prices. Sierra Club should not characterize a forecast that has high potential CO_2 prices and low natural gas prices as biased for APS's proposed purchase of SCE's share of Four Corners when the opposite is true. The APS forecast of natural gas prices reflects the NYMEX futures prices for natural gas as of September 30, 2010 and treatment of the local natural gas price relative to the NYMEX market. The NYMEX futures price is for delivery to

[10] Sierra Club testimony dated May 31, 2011, page 14.
[11] For example, 2007 testimony before the Florida Public Service Commission, Docket No. 070098-EI, Florida Power & Light Company; 2008 testimony before the Louisiana Public Service Commission, Docket No. U-30192, Application of Entergy Louisiana, LLC for Approval to Repower the Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery; 2008 testimony before the Arkansas Public Service Commission, Docket No. 06-154-U, In the matter of the Application of Southwestern Electric Power Company for a Certificate of Environmental Compatibility and Public Need for the Construction, Ownership, Operation and Maintenance of a Coal-Fired Generating Facility in Hempstead County, Arkansas; and 2008 testimony before Indiana Utility Regulatory Commission, Cause No. 43114.

Henry Hub, Louisiana, which is the national marker price location. APS Henry Hub forecast is \$4.85/MMBtu on a levelized real average[12] for 2013 to 2039. In contrast, ICF's forecast is \$5.87/MMBtu, or \$1.01/MMBtu higher (21% higher) on a comparable basis.

Q. HOW IS ICF'S FORECAST DEVELOPED?

A. ICF's natural gas forecast is based on highly detailed integrated modeling of the North American natural gas sector. The model is ICF's proprietary Gas Market Model (GMM). GMM accounts for increased demand for natural gas due to CO_2 and other environmental regulations, and the impact of shale gas technology on the industry.

Q. WHY ARE NATURAL GAS PRICES SO IMPORTANT?

A. Our analysis indicates that the principal competition for incremental supply from Units #4 and #5 is natural gas power plants. The natural gas price directly affects the costs and competitiveness of natural gas power plants. Every \$1/MMBtu increase in the natural gas price forecast gives an approximately \$7/MWh – \$8/MWh (in real dollars) advantage to Four Corners coal generation over natural gas generation, all else equal. This \$7/MWh to \$8/MWh advantage is significant because in comparison, delivered coal costs expressed on a \$/MWh basis at Four Corners equals \$18.3/MWh over the 2013 to 2039 period in real 2010 dollars.

Q. ARE THERE OTHER NATURAL GAS PRICE FORECASTS THAT ARE HIGHER THAN APS?

A. Yes. The U.S. DOE's Energy Information Administration (EIA)[13] forecast for Henry Hub natural gas prices for the period of 2015 to 2035[14] averages \$1.1/MMBtu[15] higher than APS's (in 2010 dollars).

Q. HOW DOES YOUR FORECAST COMPARE TO THE HISTORICAL HENRY HUB PRICES OF 2000 TO 2010?

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[12] Used 5.4% discount rate. In 2010 dollars.
[13] Annual Energy Outlook 2011
[14] Forecast years that are available for comparison.
[15] Simple average

A. In real 2010 dollars, the levelized average ICF Henry Hub natural gas price forecast for 2013 to 2039 is \$5.87/MMBtu (real 2010 dollars) versus the 2000-2010 historical average price of \$6.27/MMBtu (real 2010 dollars). Thus, the ICF forecast is 6 percent below the historical price, while being 21 percent above APS's price.

Q. WHY DO YOU CONSIDER THE COMBINATION OF HIGH CO_2 PRICES FOR POTENTIAL CO_2 CONTROLS AND LOW NATURAL GAS PRICES ESPECIALLY CONSERVATIVE?

A. Demand for natural gas will increase in the event that CO_2 regulations are expected and higher natural gas demand contributes to higher natural gas prices. This is in part because potential CO_2 regulation decreases the likelihood of new coal plant construction. Potential CO_2 regulations can also contribute to coal plant retirements. However, as discussed later, these retirements are concentrated at coal plants that are smaller, older, and lacking SO_2 scrubbers. Thus, while Four Corners Units #4 and #5 do not fit this profile, other coal-fired power plant units in the U.S. are potential candidates for economic retirement.

IV. ICF VALUATION

Q. IN LIGHT OF ICF'S FORECASTS FOR NATURAL GAS AND CO_2 PRICES, WHAT IS YOUR ESTIMATE OF THE VALUE OF APS'S PURCHASE OF FOUR CORNERS UNITS #4 AND #5?

A. I estimate the net value of the purchase to be $712 million, or $734/kW (see Exhibit 2). This value represents the discounted difference between the plant's revenues and costs after paying the purchase price of $294 million. The costs include APS's share of the total SCR investment cost of $315 million[16] (nominal dollars), or approximately $325/kW, and other environmental compliance costs such as modifications to ash disposal. The SCR is assumed to come on-line in 2016.

Exhibit 2
Value of Four Corner's Purchase[1]

Parameter	Value
Value of Cost Savings (Millions $)	1,006
Capacity (MW)	970
Purchase Price	294
Net Value (Millions $)	712
Net Value ($/kW)	734

[1] Present value as of October 2012 – 5.4 percent real discount rate, 8.0 percent nominal discount rate.

Q. WHY IS THIS VALUATION IMPORTANT?

A. This value is important because it represents cost savings to APS and its customers obtainable either through reduced purchase of power or greater sales of power.

Q. HOW WOULD YOU CHARACTERIZE THIS VALUATION?

A. This valuation shows the purchase is highly advantageous and indicates that APS faces a special situation. Four perspectives on this result are revealing in this regard.

- First, a more typical result is that the valuation *after* deducting the purchase price is closer to zero as competitive forces push the sales price closer to the next best alternative.

[16] APS response to data request SC 1.8.

In this case, the next best alternative of sellers is to rely on the wholesale market price for power supply.

- Second, I expect the price of existing combined cycle capacity to be close to the estimated value of cost savings to APS from combined cycle plants. Thus, the *net* value after deducting the purchase price will be small and close to zero. There is no chance that the net value will be $712 million for the same amount of MW. In order to achieve this, the owners would have to sell at prices well below any seen to date in the market.
- Third, the deal was negotiated and APS's analysis was conducted before many of the recent developments adversely affecting prospects for national CO_2 $/ton controls. This helps create a rare opportunity to lower customer costs.
- Fourth, ICF estimates the cost of a new large coal power plant to be approximately $3,077/kW (2013 dollars). Thus, the gross value of Four Corners Units #4 and #5 before deducting the payment to SCE is 34 percent[17] of the cost of a new unit. Thus, while we estimate a significant value for Four Corners Units #4 and #5, it is not nearly as much as the cost for a new unit.

Q. HOW IS THIS VALUE CALCULATED?

A. I projected the revenues available to Four Corners Units #4 and #5 using a computer model to project the wholesale power market prices in the western U.S. The revenues reflect prices for delivery at Four Corners and are available both for hourly electrical energy and annual "pure" capacity sales.[18] The model I used is ICF's IPM® model, a widely used and accepted model in both the public and private sectors.[19] The model assumes efficient markets. The costs for operating Four Corners were provided to me by APS, except for CO_2 prices. I used a nominal

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[17] $1,037/kW/$3,077/kW = 34%

[18] Pure capacity refers to a kW suitable for meeting reserve margin requirements. This is also the residual value that is required by marginal capacity not available in the electrical energy market.

[19] Assumptions as of June 2011.

discount rate of 8 percent (5.4 percent real) and calculated the present value as of October 1, 2012 through 2039.[20]

Q. WHAT ARE THE OTHER KEY ASSUMPTIONS IN YOUR ANALYSIS?

A. In addition to natural gas prices, CO_2 prices, discount rates, the sales price, the cost and timing of the SCR installation, and the other costs of operating Four Corners, other key assumptions include:

- **Peak Electricity Demand Growth** – I used the NERC forecast of electricity demand growth for the entire Desert Southwest.[21] This forecast was released in October 2010 and is approximately 2.0 percent per year for projected peak demand growth over the 2013 to 2039 period. The NERC forecast is similar to the APS forecast. I note that NERC forecast of peak demand growth is approximately 63 percent below the historical growth rate prior to the recent recession – *i.e.*, peak electricity demand growth between 1998 and 2007 was 5.3 percent per year or 58 percent cumulatively over this ten year period. After CO_2 and natural gas prices, I consider this the most significant assumption in my analysis.
- **California CO_2 Regulations** – ICF assumed that CO_2 price trajectory under California's CO_2 emission regulations is consistent with the California Air Resources Board's internal analysis of compliance costs under the assumption that complimentary policies under AB32 work as planned. The CO_2 allowance price is modeled for California generation. There is also a transmission charge that is imposed at ten transmission interfaces into California on power imports. The level of transmission charges is a function of the assumed average WECC system emissions rate of approximately 950 lbs/MWh and the assumed California CO_2 price level in that year. From 2020 onwards, when we assume that plants outside California also face a potential national CO_2 emission allowance cost, the CO_2 "tax" on imports takes into account the difference between the California CO_2

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[20] 2.5 percent general economy-wide inflation is assumed.

[21] NERC, Energy Supply and Demand. The forecast was extended beyond the NERC forecast horizon

price and the potential national CO_2 price. This, in turn, assumes that some system will be put in place or market dynamic will occur to prevent emitters from paying twice on the same ton of CO_2 emissions.

- **Renewable Portfolio Standards (RPS)** – I assumed the current Arizona RPS[22] and all state RPSs will be met including the very ambitious RPS program of California. Thus, the price of power in my analysis reflects the impacts of all the state RPSs such as increased power supply.

Q. HOW DOES YOUR VALUATION COMPARE TO THE APS PROMOD RESULTS?

A. APS calculated a CPW (Cumulative Present Worth) cost savings for October 2012 to 2039 for acquiring SCE's share of $582 million as of October 2012.[23] This saving was in comparison to the retirement of all five Four Corners' units, and hence, assumes that failure of APS to purchase SCE's share results in the plant's shutdown. Thus, the ICF estimate is approximately $130 million or 22 percent higher than APS's estimate for the same case. Thus, in spite of different approaches and data, the results are similar, though my estimate is moderately higher.

Q. WHY IS YOUR ESTIMATE OF VALUE SIMILAR TO APS'S IN SPITE OF ICF'S HIGHER NATURAL GAS AND LOWER POTENTIAL CO_2 PRICES?

A. The value is similar in large part because my forecast has a lower "pure" capacity price in the near-term than implied by the APS analysis. This in turn reflects my adoption of the electricity peak demand forecast in the NERC ES&D of 2 percent per year. As noted, this forecast growth rate is approximately 63 percent lower than the 1998 to 2007 pre-recession growth rate. If peak electricity demand growth were higher than the 2.0 percent per year used in my forecast in the near-term (*i.e.,* over the next five to ten years), my forecast would show even greater net value to APS and its customers.

[22] Arizona RPS target is 15% by 2025.

[23] APS response to data request Staff 1.10. I adjusted the APS estimate to be a present value as of October 2012 instead of January 2010.

V. RISKS TO FOUR CORNERS' UNITS #4 AND #5 IN THE ABSENCE OF THE APS PURCHASE OF SCE CAPACITY

Q. DO YOU BELIEVE APS'S PURCHASE OF SCE'S SHARE HELPS AVERT A SHUTDOWN OF UNITS #4 AND #5?

A. Yes. I hold this view for the following reasons:

- SCE was lead owner of the Mohave 1 and 2 coal-fired power plants (1,560 MW, located in Southern Nevada using Arizona coal) where it owned 56 percent of the plant. Mohave 1 and 2 shut down on December 31, 2005 when the plant faced environmental upgrade requirements, primarily the need to install SO_2 scrubbers. Thus, SCE's ownership has already been associated with the shutdown of a major coal plant in the area. This history has some relevance in spite of important differences between Mohave and Four Corners. This is because of: (1) SCE's key position in the plant, (2) the prospects for an even tighter deadline to install a SCR at Units #4 and #5 than Mohave faced vis-à-vis a SO_2 scrubber, (3) risks that the sale could be canceled by unforeseen events just as happened with Mohave, and (4) the multiplicity of parties and regulators.
- The Sierra Club was very involved in the retirement of Mohave 1 and 2. In 1999, the Sierra Club was one of three environmental groups that signed a consent decree with owners of Mohave including SCE that required the installation of SO_2 scrubbers at Mohave or shutdown of the plant by December 31, 2005, *i.e.,* more than six years of lead time.[24] When the consent decree was signed, the more than six year lead time seemed achievable. However, it was not achieved. The California power crisis led to the cancellation by California regulators of the sale of the plant to AES. There also was a multiplicity of parties and regulators, the reluctance of California regulators to approve investments in coal plants, the strong opposition of Sierra Club and other environmental

[24] The other two groups were the Grand Canyon Trust and the National Parks and Conservation Association. The consent decree also required opacity decreases which would have had offsetting benefits of greater plant output and low cost NO_x emission control requirements.

groups, and other unexpected developments that delayed the installation of controls. In spite of efforts to extend the deadline in the consent decree in order to obtain more time to make the needed modifications, and to cushion the economic hardship on the Tribal owners of the coal used at Mohave, the Sierra Club and the two other environmental parties "forced the plant to cease operations."[25] In light of Sierra Club's long history of opposition to Mohave, to other coal plants in the region[26] and nationwide,[27] it makes the Sierra Club's statement that APS presents only speculation in regard to the prospects for a Four Corners shutdown surprising.

- It is my understanding that California law prevents new "life extending" investment in coal-fired generation by SCE. It is also my understanding that co-owners have the right of first refusal to any sale of SCE's interest and any decisions are also subject to regulatory review in multiple jurisdictions. Thus, the implementation of changes at Four Corners is more difficult than in a typical power plant transaction.
- EPA proposes to require that Four Corners install SCR NO_x control equipment by 2016. Thus, there is a large chance that Four Corners will face in four and a half years an inflexible deadline for installation of SCR. In other words, there would be even less of a lead time than the 6 year plus lead time in the Mohave case, and hence, the Four Corners situation is from the perspective of lead time even more precarious. Since SCE owns 48 percent of Units #4 and #5, challenges related to the largest owner making certain investments threatens the ability of the others to make their investments.

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[25] On the Sierra Club website, under "Archived Actions, Case Updates, Out West, a Major Pollution Source Bites the Dust" the retirement of Mohave is described, "A 1998 Clean Air Act Lawsuit brought by the Sierra Club, Grand Canyon Trust, and the NPCA forced the plant to cease operations in December 2005, however, since this date, the plant has remained in limbo while the owners, led by SCE, tried to sell it and negotiate a restart of its operations. Now, nearly 17 months later, owners of the plant have finally admitted that it is officially no more." The coal was owned by the Hopi Tribe and the Navajo Nation. The coal was mined in Arizona at the only mining complex in the state. Nearly half the members of the Hopi Tribe have been unemployed, underlining the economic hardship.

[26] The Sierra Club, the Grand Canyon Trust, and the National Parks Conservation Association, the same parties that signed the 1999 Mohave consent decree, have also filed comments in proceedings related to the last remaining user of Arizona coal, the Navajo Generating Station. These parties seek protection from these plants. See letter to U.S. EPA, Region IX, October 28, 2009.

[27] On the Sierra Club website under goals, in describing its Environmental Law Program, the Sierra Club states the program "has begun targeting the 500 Plus existing coal-fired power plants in the U.S. for retirement."

- In general, the situation in which the largest owner faces regulators potentially preventing it from pursuing economic operations is a threat to the existence of the plant. In Mohave's case, the California PUC and others may face pressure from intervenors to approve retirement rather than a sale, and give SCE the ability to collect outstanding net book value from customers.
- It is logical that APS and its Commission take the leadership role addressing the future of the plant. APS is the largest owner of power plant capacity at the Four Corners power plant.[28] APS is the second largest owner of Units #4 and #5. Failure of APS and the Commission to pursue this special situation creates the risk that the cost savings to APS customers will be lost.
- It is my experience that the future of coal power plants can be heavily affected by complex political and legal considerations that are separate from economic considerations. Also, securing arrangements for continued operation when many parties are involved is challenging. This supports the view that the inaction by APS could result in the shutdown of Units #4 and #5. It also creates the concern that unless this situation is treated as a special situation, the benefits will be lost.

Q. WHAT WEIGHT SHOULD THE COMMISSION GIVE TO THE RISKS THAT FAILURE OF APS TO EXPEDITIOUSLY PURCHASE SCE'S SHARE JEOPARDIZES APS'S CURRENT INTEREST IN FOUR CORNERS?

A. The Commission should give it significant weight.

[28] APS's current ownership of Units #1-#5 is 792 MW. SCE's ownership of Units #4 and #5 is 739 MW. SCE is the largest owner of Units #4 and #5, but second largest owner at the station.

VI. CONSIDERATION OF ALTERNATIVES

Q. WHAT IS YOUR REACTION TO SIERRA CLUB'S PROPOSAL THAT APS CONSIDER CONVERTING ONE OR MORE OF ITS EXISTING TURBINES TO A COMBINED CYCLE UNIT?

A. This is not an economic option for APS, and no further analysis is warranted. APS's only new simple cycle combustion turbines are LM 6000 units installed within the last decade. Were they to be used in a combined cycle, the capital costs would be much higher than for a new combined cycle because the units are small; they are 75 to 85 percent smaller than new combustion turbines typically being installed as part of combined cycle power plants. The steam turbine, Heat Recovery Steam Generator (HRSG), and other combined cycle equipment would have to be downsized, customized in the field, and key economies of scale lost. The retrofit would also likely eliminate the key advantage of LM 6000s, which is quick start. Typical combined cycles require two hours to start up, whereas LM 6000 turbines only require 10 minutes. This quick start can be important for accommodating fluctuating output of variable renewable resources like solar and wind. The company's other turbines are 1970s vintage, and therefore, are quite thermally inefficient compared to new turbines. Use of these units will cause fuel costs to rise because combined cycles should use thermally efficient turbines, and less thermally efficient turbines should be reserved for simple cycle peaking operations. Furthermore, APS faces growing electricity peak demand. APS will eventually need both additional combined cycles and combustion turbines in the future as demand grows. Taking an existing turbine means that it will have to be replaced by a new one, and hence, there will be more costs to APS customers.

Q. WHAT ABOUT USING THE FOUR CORNERS SITE AND EQUIPMENT FOR A COMBINED CYCLE?

A. The site is ill suited to the operation of a combined cycle or simple cycle plant due to its high altitude. Furthermore, the cost of a new combined cycle plant is higher than the likely cost of an existing plant and will not have more cost savings than the proposed purchase.

Q. WHAT IS YOUR REACTION TO SIERRA CLUB'S PROPOSAL THAT APS EXTEND OR ENTER INTO A NEW PPA WITH AN EXISTING MERCHANT POWER PLANT?

A. I have several reactions:

- First, in my valuation analysis, I estimate the value of a merchant combined cycle available October 1, 2012 to be approximately [redacted]. Whether power supply from a merchant combined cycle is structured as a purchase by APS or a PPA, I expect the purchase price would closely approximate the market value, and hence, there would be no net advantage to such a proposal compared to purchasing SCE's share of Four Corners Units #4 and #5, and saving $712 million net of the purchase price.
- Second, in light of the high value of the purchase of SCE's share of Units #4 and #5, supply from existing combined cycles could only have a higher value if owners of existing combined cycles would sell their plant for less than [redacted]/kW. Even under the unrealistic assumption that it was absolutely certain that Four Corners Units #4 and #5 would stay on-line regardless of whether this transaction occurs, the breakeven price is still an extremely low [redacted]/kW. Actual prices paid for combined cycles have been well above this level. The purchase price of Big Horn by Nevada Power at end of 2008 for about $907/kW[29] is [redacted] times higher than my estimate of the breakeven price of [redacted]/kW. Other more recent transactions in the Desert Southwest have been reported to be $553/kW to $600/kW.[30] These are the Spring 2011 sales of combined cycle capacity at Arlington Valley, Griffith and Gila River. These prices are [redacted] times higher than the breakeven price of [redacted]/kW. There is no evidence of combined cycle sales prices ever being close to [redacted]/kW.
- Third, if APS were to present to this Commission a natural gas-fired option, APS and the Commission would still have to compare the advantages and disadvantages of coal versus

[29] http://www.snl.com/interactivex/article.aspx?id=8479021&KPLT=2&Printable=1

[30] ICF has not had access to confidential information related to the transactions, and hence, there is some uncertainty about terms and conditions. However, this uncertainty notwithstanding, the value is not even close to the breakeven price.

natural gas. This, in turn, depends on complex issues related to the risks of natural gas price volatility and coal generation. The need to conduct the solicitation and consider natural gas versus coal issues could result in significant delay. The delay could undermine the proposal without real prospects for benefit given the special situation facing APS, its customers, and the Commission.

- Fourth, APS will have numerous future opportunities to purchase incremental merchant natural gas-fired combined cycle capacity, and/or enter into PPAs for supply from these plants. This is due to future growth in peak electricity demand and the retirement of Four Corners Units #1 - #3. It will not likely have the opportunity to purchase additional coal-fired generation capacity. New coal plants are not likely to be economic even if existing units under special circumstances can be. This unique opportunity is a special situation arising from the legacy position that APS and its customers have created and paid for over many decades.
- Fifth, it is inconsistent for Sierra Club to argue that APS analysis is adequate to make decisions on Units #1 to #3, wholly owned by APS, but not to rely on it *vis-à-vis* alternative supply from natural gas units.

Q. WHAT IS YOUR REACTION TO INCLUDING RENEWABLES AS PART OF A PORTFOLIO OF ALTERNATIVES?

A. Renewables are not competitive with conventional sources of power. In addition, variable energy renewables require natural gas-fired back-up to firm up their supply which contributes to making them less competitive than conventional power sources.

VII. COAL POWER PLANT LIFETIMES AND THE OPERATIONAL PROSPECTS OF FOUR CORNERS' UNITS #4 AND #5

Q. PLEASE BRIEFLY DESCRIBE FOUR CORNERS UNITS #4 AND #5.

A. Both Four Corners Units #4 and #5 have 770 MW of electrical capacity for a total of 1,540 MW (see Exhibit 3). As noted, APS's current share is 15 percent, and would be 63 percent after the purchase. Both units use Flue Gas Desulfurization (FGD or SO_2 scrubbers) combined with low sulfur coal to control SO_2 emissions. The units also use a fabric filter for particulate control, which facilitates compliance with Hazardous Air Pollutants (HAPs) regulations. Unit #4 came on line in 1969 and is 42 years old. Unit #5 is similar to Unit #4, and is 41 years old as it came on-line one year later.

EXHIBIT 3
Four Corners Units #4 and #5

Parameter	Unit #4	Unit #5
Age (Year)	42	41
Capacity (MW)	770	770
SO_2 Scrubbers	Yes	Yes
Particulate Control	Fabric Filter	Fabric Filter

Q. HOW DO THESE UNITS COMPARE TO OTHER COAL POWER PLANTS?

A. These units are advantaged relative to other coal units by virtue of their large size, and hence, large economies of scale, and the existence of pollution control equipment including SO_2 scrubbers and fabric filters. Only 59 percent of U.S. coal power plant capacity is currently scrubbed for SO_2, and only 22 percent has fabric filters.[31] Units without fabric filters have Electrostatic Precipitators (ESPs) which are not preferred given HAPs regulations.

Q. WHAT DID SIERRA CLUB SAY ABOUT THE AGE OF FOUR CORNERS UNITS #4 AND #5?

A. In Sierra Club's testimony, it states:

[31] EPA NEEDS database.

"... it ignores the risks associated with the continued operation of the Four Corners Units 4-5 that are currently over 40 years old, having entered commercial service in 1969-1970. ... APS fails to address the significant economic risks associated with the continued operation of Four Corners Units 4-5".[32]

"... it ignores the risks associated with the continued operation of the Four Corners Units 4-5, which entered commercial service in 1969-1970 and are currently over 40 years old.[33]

"APS currently assumes that Four Corners Units 4-5 will continue to operate as efficient base load units through 2038 at which time each unit will be 68 years old. .....; it is possible that Four Corners Units 4-5 might be retired before 2038."[34]

Q. DO YOU AGREE WITH SIERRA CLUB'S STATEMENT CONCERNING THE AGE OF FOUR CORNERS UNITS #4 AND #5?

A. No. Sierra Club does not provide any supporting evidence about the risks associated with 40 year old coal plants.

Q. WHAT IS THE AVERAGE AGE OF THE U.S. COAL-FIRED POWER PLANTS?

A. The average age of the U.S. coal fleet is 42 years.[35] Four Corners Units #4 and #5 are extremely close to the U.S. average age at 41 and 42 years of age for Units #4 and #5, respectively.

Q. IS IT UNUSUAL FOR 40 YEAR OLD COAL PLANTS TO BE OPERATING?

A. No. This is evident from the average age of the Four Corners Units #4 and #5 being approximately equal to the U.S. average. It is also evident from Exhibit 4 which shows that coal power plants 41 years old or older constitute 38 percent of U.S. coal capacity.

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[32] Page 3, lines 17-19 and 23-24
[33] Page 6, lines 13-15
[34] Page 14, lines 13-20
[35] Source: EPA NEEDS database

EXHIBIT 4
U.S. Coal-Fired Power Plants and Capacity by On-line Dates

On-Line Year	Number of Units	Summer Capacity (MW)	% of Total Capacity
1941-1950	106	3,3938	1
1951-1960	425	46,532	15
1961-1970	336	69,296	22
1971-1980	382	117,170	37
1981-1990	319	60,115	19
1991-2000	71	7,249	2
2001-2010	86	15,243	5
Total	1,725	319,543	100

Source: Ventyx database

Q. WHY DO YOU INDICATE THAT FOUR CORNERS UNITS #4 AND #5 ARE ADVANTAGED BY VIRTUE OF THEIR SIZE?

A. Only 3.6 percent of the coal power plant units in the U.S. are 700 MW or greater (see Exhibit 5). Only 10 percent of U.S. coal power plants are at stations with greater than 1,500 MW of coal capacity. The larger the size of the coal plant, the greater the potential for economies of scale in operations, maintenance, retrofit installation costs, and upgrades.

EXHIBIT 5
U.S. Coal Power Plant Size Distribution

Age Group by On-Line Date	Number of Units					Total
	<100	100 – 200	200 – 500	500 – 700	>700	
1941-1950	95	11	0	0	0	106
1951-1960	184	160	78	3	0	425
1961-1970	117	82	86	42	9	336
1971-1980	97	66	118	65	36	382
1981-1990	170	40	60	38	11	319
1991-2000	47	8	14	2	0	71
2001-2010	50	10	10	10	6	86
Total	760	377	366	160	62	1,725
% of Total	**44.1**	**21.9**	**21.2**	**9.3**	**3.6**	**100.0**

Source: Ventyx database

Q. WHAT IS THE AVERAGE CAPACITY FACTOR OF U.S. COAL PLANTS?

A. U.S. coal plants are operating at an average of 69 percent capacity factor (See Exhibit 6).

EXHIBIT 6
U.S. Coal Plants Utilization by Plant Size

Plant Size (MW)	2010 Summer Capacity (MW)	% Utilization				
		2006	2007	2008	2009	Average
>500	274,554	73	73	72	65	71
200 - 500	37,437	65	66	63	51	61
<200	10,547	60	62	59	49	57
Total	322,538	71	72	71	63	69

Source: Ventyx database

Q. IS THE UTILIZATION OF WESTERN COAL PLANTS HIGHER THAN THE U.S. AVERAGE COAL PLANT?

A. Yes. In WECC, average coal plants and plant's utilization for the same 2006 to 2009 period was 77 percent capacity factor, 8 percent higher than the U.S. average.[36]

Q. WHAT IS THE HISTORICAL CAPACITY FACTOR OF FOUR CORNERS UNITS #4 AND #5?

A. Four Corners Units #4 and #5 have been operating at capacity factors[37] between 86 percent and 80 percent, respectively. This is an average of 14 percent and 6 percent higher than U.S. and WECC averages, respectively.

Q. DO UTILITIES CONTINUE TO MAKE SIGNIFICANT INVESTMENTS AT COAL POWER PLANTS WITH SIMILAR AGES TO FOUR CORNERS UNITS #4 AND #5 INCLUDING RETROFIT INSTALLATION OF FGD AND SCR SYSTEMS?

A. Yes and these investments support the view there is significant remaining useful life for Four Corners #4 and #5. FGD costs are generally higher per kW than SCR costs, but utilities have also been installing FGD and SCR systems at power plants with similar ages to Four Corners Units #4 and #5.

Q. WHAT IS THE AGE DISTRIBUTION OF RETROFIT SCR INSTALLATIONS?

A. Approximately 38 percent of the coal plants that retrofitted SCR were 30 years or older when the SCR was installed.[38]

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[36] Source: U.S. Energy Information Administration's Form EIA-860 and EIA-923 (2008).
[37] For the period of 2006 through 2009.

Q. WHAT IS THE AGE DISTRIBUTION FOR RETROFIT FGD INSTALLATION?

A. Approximately 57 percent of these coal plants were 30 years or older when FGD was retrofitted at the plant. This is significant in part because, as noted, FGD capital costs are higher than SCR capital costs. Note, one of the advantages of the Four Corners plant is it already is fully scrubbed.

Q. WHEN WILL LARGE CONTROLLED MODERN COAL POWER PLANTS RETIRE?

A. APS assumes a 70 year lifetime and terminates its analysis in 2039. The following comments support the potential for very long remaining coal power plant lifetimes and strong performance for controlled units:

- The EPA assumes that U.S. coal power plants can last 80 years with $204/kW (in 2007$/kW) of what EPA defines as life extension costs.[39]
- Most coal units are operated where equipment is periodically repaired or replaced, and costs are treated as ongoing expenses, or capital expenditures. Thus, plants may be incurring as a matter of course what the EPA defines as life extension costs.
- There is no historical record relevant to addressing the issue of how long existing controlled coal power plants will continue to operate and how well they will perform. In the absence of relevant historical data, other considerations such as the studies of EPA and DOE pointing to 80 year lifetimes are particularly important. There are no modern large coal units greater than 61 years old. This is because 61 years ago, the technology used in coal plants was different, *i.e.,* not modern. No U.S. coal generating unit greater than 100 MW was added prior to 1950 (*i.e.,* 61 years ago), and none were added greater than 200 MW until 1960 (51 years ago).
- There have not been any major operational changes over time at large U.S. coal-fired units in terms of availability or heat rates (See Exhibits 7 and 8). There is evidence that the availabilities of large coal units have actually been increasing (see Exhibit 7).

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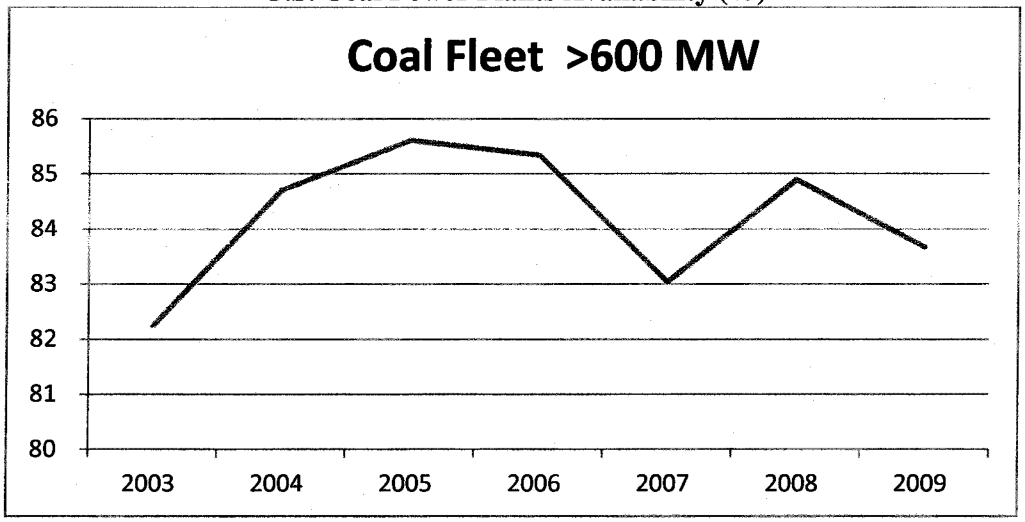
[38] EPA NEEDS database.

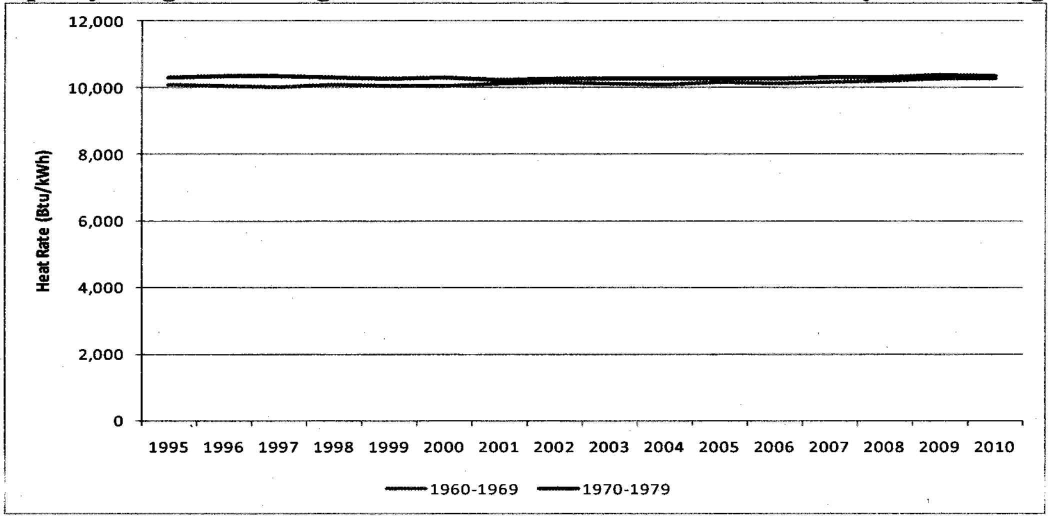
[39] Page 4-13, Table 4-10, U.S. EPA Base Case, v. 4.10.

EXHIBIT 7
U.S. Coal Power Plants Availability (%)



Source: NERC GADS

EXHIBIT 8
Capacity Weighted Average Heat Rate of Coal Units Over 500 MW by Plant Vintage



- The major cause of retirements is impending environmental upgrade requirements at small uncontrolled units, *i.e.*, small old units without SO_2 scrubbers, with site configurations that make retrofit installation of SO_2 scrubbers very difficult.
- The efforts of environmental groups, like Sierra Club, and the need for environmental regulations on the existing coal fleet are motivated, in large part, by the potential that in the absence of incremental environmental controls, existing legacy coal plants will not

retire. Were the opposite true, retirement would occur naturally and the issues would disappear.

- The U.S. DOE's EIA also assumes very long lifetime potential for existing coal plants.
- ICF assumes very long coal plant lifetimes in the absence of new environmental control requirements very similar to EPA assumptions. This assumption is widely used by the industry.
- The effect of discounting mitigates the impact of alternative end of life assumptions. For example, a dollar saved in 2039 affects the estimation of present value of cost savings by only approximately 25 cents.

Q. ARE THERE ANY ANNOUNCED COAL PLANT RETIREMENTS?

A. Yes. Announced coal plant retirements between 2011 and 2025 totaled 22.1 GW. This is approximately 6.9 percent of U.S. coal capacity.

Q. WHAT TYPE OF PLANTS ARE MOST AT RISK FOR NEAR-TERM RETIREMENT?

A. Most of the announced retirements are smaller and older units without FGD environmental controls. In general, smaller unscrubbed coal units are considered the most at risk for economic retirement. Hence, Four Corners Units #4 and #5 do not fit this profile. Only 3.3 GW or 15 percent of the 22.1 GW of announced coal plant retirements between 2011 and 2025 have a FGD. Exhibit 9 shows the announced retirements by control technologies. While I expect there to be more coal retirements, they will be concentrated at units that are very different types of plants than Units #4 and #5 unless state PUCs, legislators or others have decided to eschew potential customer savings in exchange for other considerations.

EXHIBIT 9
Announced Coal Retirements by Control Technologies

Control Type[1]	Capacity (MW)	% of Total
SCR	1,622	7%
SNCR	4,194	19%
FGD	3,308	15%
Baghouse	1,654	7%
ACI	856.3	4%
None of the Above[2]	11,764	53%
Total	**22,172**	**100%**

Source: Ventyx; As of June 16, 2011. Note, some units have already been retired in the first half of 2011.
[1] Capacity values under each control type category are not mutually exclusive. For example, Eddystone and AES Greenidge units are equipped with both an SNCR and FGD; thus, they would fall under both categories. AES Westover has both an SCR and FGD. Note, table does not include Four Corners Units 1-3. Cherokee Unit 4 is planned to be converted to a gas unit and is included in this list.
[2] Includes Low NO_x Burners, ESP, and others.

Q. WHO ARE THE PLANTS RETROFITTED WITH FGD THAT ARE PLANNING TO RETIRE?

A. Only 12 coal units retrofitted with FGD have announced retirement plans between 2011 and 2025[40] (See Exhibit 10). All of them are smaller units except Centralia. The total capacity for the 12 coal units is 3,308 MW, approximately 42 percent of this capacity is the Centralia units. In March of this year, after years of negotiation, TransAlta reached an agreement with the State of Washington to shutdown the first unit of Centralia by 2020 and the second unit by 2025. In exchange, TransAlta is allowed to sell coal power in-state which is currently prohibited by law. Hence, the decision involved political trade-offs.

[40] Source: Ventyx database as of June 16, 2011.

EXHIBIT 10

Announced Retirements of Coal Plants That Have Installed FGD

Plant	Online Date	Unit	MW	Planned Retirement Date	Age at Planned Retirement
AES Westover	1951	8	80.8	2011	60
AES Greenidge	1953	4	106.3	2011	58
Cane Run	1962	4	155	2015	53
	1966	5	168	2015	49
Centralia Complex	1972	BD21	688	2020	47
	1973	BD22	688	2025	51
Cherokee (CO)	1962	3	152	2014	52
	1968	4	352	2017	49
Cromby	1954	1	144	2011	57
Eddystone	1959	1	279	2011	52
Eddystone	1960	2	309	2012	52
Valmont	1964	5	186	2017	53
Total			3,308		

Note: At time of this analysis, AES Westover, AES Greenidge, Cromby 1 and Eddystone 1 have already been retired. Cherokee Unit 4 is planned to be converted to natural gas-fired.

VIII. NATURAL GAS VOLATILITY

Q. WHAT DOES SIERRA CLUB SAY ABOUT NATURAL GAS PRICE VOLATILITY?

A. Sierra Club testimony states that APS significantly overstates the potential for natural gas price volatility. Sierra Club testimony also states that a prudent utility can and should mitigate the risk of natural gas price volatility via long-term natural gas contracts and other hedging.

Q. WHAT IS YOUR REACTION TO SIERRA CLUB?

A. I have the following reactions:

- There is no basis for the claim that APS significantly overstates the potential for natural gas volatility.[41] APS uses the same discount rate for both coal and natural gas options. If it were to overstate the volatility, I would expect to see a higher risk adjusted discount rate for natural gas options or some other adjustment to the results or the decision criteria favoring coal. Rather, the company uses the same discount rates indicating the risks of coal and natural gas are the same. If Sierra Club's claim was accurate, I also would also not expect to see a conservatively low natural gas price, especially when it is combined with a conservatively high CO_2 price.
- Long-term natural gas contracts with prices that are fixed and financial hedging that achieve the same objectives are likely to incur the risk of mark-to-market collateral requirements. In light of the potential for natural gas market prices to have very large movements (*e.g.*, a hurricane in the Gulf, unexpected economic conditions), the impacts on the customers and the balance sheet of APS of mark-to-market collateral calls could be very large, even catastrophic. Thus, there are significant limits to natural gas price hedging that do not exist in coal supply.

[41] Sierra Club testimony dated May 31, 2011, page 3.

IX. REBUTTAL OF ACPA

Q. WHAT DOES THE ACPA SAY ABOUT THE PURCHASE OF FOUR CORNERS UNITS #4 AND #5?

A. The ACPA requests that APS conduct and report on a RFP for market based supply of power as a predicate for Commission action.

Q. WHAT IS YOUR REACTION?

A. I do not recommend any delays in the process that might jeopardize uniquely large cost savings to Arizona. The prospects for this RFP to provide an alternative that is competitive with the purchase of SCE's share are practically nil. My rationale for this conclusion is described in my earlier response to Sierra Club. The net value of such a transaction to APS and its customers is much larger than what can be realistically provided by a RFP. Also, I am concerned that a delay in the process could threaten a unique deal that promises large savings to APS customers. I have stated my concerns about delay earlier in my response to the Sierra Club.

X. CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. I disagree with the Sierra Club's conclusion that APS does not address the economic risks of operating Four Corners Units #4 and #5. In addition to responding directly to Sierra Club's points, I conducted my own analysis of the proposed transaction. My analysis concludes the potential to purchase SCE's share of Units #4 and #5 creates a unique opportunity to decrease APS customer costs and that this transaction deserves special attention and treatment. Also, I conclude:

- Sierra Club's assertions about the effect of age are not supported by evidence. Large coal unit availability is actually increasing. Indeed, the U.S. EPA assumes that 80 year lifetimes are achievable. The U.S. DOE makes similar assumptions. The age of Units #4 and #5 almost exactly equals the U.S. average age, and large investments are being made in existing units of similar ages. The units have attractive features compared to other U.S. coal power plants including large size, economies of scale, existing SO_2 scrubbers, and fabric filters.
- The net value of the transaction is very high at $712 million. This is net of the cost of the SCR and the $294 million payment to SCE. Even under the unrealistic assumption that there is absolute certainty that Units #4 and #5 will not retire regardless of whether the proposed transaction is consummated, the value is still high at $472 million.
- My estimate of value is moderately higher than that of APS for the same transaciton. ICF believes that APS uses conservatively high CO_2 prices for potential CO_2 regulations and conservatively low natural gas prices. However, this is partly offset by lower market prices for "pure" capacity in my analysis. This, in turn is associated with my assumption that NERC's forecast of peak electricity demand growth in the Desert Southwest is correct. This forecast and the similar forecast of APS are a fraction of pre-recession

historical peak electricity demand growth levels. If peak demand growth is higher than assumed, ICF's value would be higher than estimated and higher than APS's.

- Sierra Club's claim that the APS analysis is biased in favor of Units #4 and #5 and against natural gas is not correct. In some key parameters, *i.e.,* potential CO_2 and natural gas prices, APS makes conservative assumptions that, relative to ICF, bias the results against coal options, the opposite of what the Sierra Club suggests. Moreover, the risks are treated similarly by virtue of APS using the same discount rate for both natural gas and coal options.
- There is extremely little chance that any alternative would approach the cost savings potential of the proposed transaction. This includes a RFP directed at the competitive market. I would expect the results to have a net value closer to zero as the bids are expected to be close to the value. I conclude that in order to have higher value than the APS purchase of SCE's share of Units #4 and #5, owners of existing combined cycles would have to bid below [redacted]/kW, well below the lowest prices on record. Even under the unrealistic assumption that there is no risk whatsoever to Units #4 and #5 regardless of whether APS purchases SCE's share, the breakeven price is still extremely low at [redacted]/kW. These extremely low breakeven prices highlight the extent to which the proposed APS purchase of Units #4 and #5 is a special case.
- Failure to expeditiously implement the proposed APS purchase of SCE share creates risks that large cost savings for APS customers would be lost. APS customers would lose the cost savings from SCE's share of Units #4 and #5 and worse, Units #4 and #5 could retire and APS customers would lose the value of APS's current 231 MW interest in Units #4 and #5.
- The APS proposal has several elements that the Commission might find attractive, but which I did not address. The early retirement of Units #1 to #3 lowers CO_2 emissions, lowers existing power plant supply, and increase demand for the region's Independent

Power Producers' natural gas power plants. Rather, my analysis addresses cost savings from the proposed transaction versus alternatives. From the standpoint of minimizing customer costs, the recommendations of Sierra Club and ACPA regarding Units #4 and #5 should be rejected and the APS proposal approved.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

APPENDIX

EXHIBIT A-1
Four Corners Ownership Shares (MW)
Before Proposed APS Acquisition

Company	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Total
APS	170	170	220	115.5	115.5	791.0
SCE				369.6	369.6	739.2
PNM				100.1	100.1	200.2
SRP				77.0	77.0	154.0
El Paso Electric				53.9	53.9	107.8
TEP				53.9	53.9	107.8
Total	170	170	220	770.0	770.0	2,100.0

EXHIBIT A-2
Four Corners Ownership Shares (MW)
After Proposed APS Acquisition

Company	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Total
APS	0	0	0	485.1	485.1	970.2
SCE				0	0	0
PNM				100.1	100.1	200.2
SRP				77.0	77.0	154
El Paso Electric				53.9	53.9	107.8
TEP				53.9	53.9	107.8
Total	0	0	0	770.0	770.0	1,540.0

EXHIBIT A-3
Four Corners Ownership Shares (%)
Before Proposed APS Acquisition

Company	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Total
APS	100	100	100	15	15	37.7
SCE				48	48	35.2
PNM				13	13	9.5
SRP				10	10	7.3
El Paso Electric				7	7	5.1
TEP				7	7	5.1
Total	100	100	100	100	100	100

EXHIBIT A-4
Four Corners Ownership Shares (%)
After Proposed APS Acquisition

Company	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Total
APS	N/A	N/A	N/A	63	63	63
SCE				0	0	0
PNM				13	13	13
SRP				10	10	10
El Paso Electric				7	7	7
TEP				7	7	7
Total	N/A	N/A	N/A	100	100	100

ATTACHMENT JLR-1
JUDAH ROSE RESUME

JUDAH L. ROSE

EDUCATION

1982 M.P.P., John F. Kennedy School of Government, **Harvard University**

1979 S.B., Economics, **Massachusetts Institute of Technology**

EXPERIENCE

Judah L. Rose joined ICF in 1982 and currently serves as a Managing Director of ICF International. Mr. Rose has 30 years of experience in the energy industry. Mr. Rose's clients include electric utilities, financial institutions, law firms, government agencies, fuel companies, and IPPs. Mr. Rose is one of ICF's Distinguished Consultants, an honorary title given to three of ICF's 3,500 employees, and has served on the Board of Directors of ICF International as the Management Shareholder Representative.

Mr. Rose has supported the financing of tens of billion dollars of new and existing power plants and is a frequent counselor to the financial community.

Mr. Rose frequently provides expert testimony and litigation support. Mr. Rose has provided testimony in over 100 instances in scores of state, federal, international, and other legal proceedings.

Mr. Rose has also addressed approximately 100 major energy conferences, authored numerous articles published in Public Utilities Fortnightly, the Electricity Journal, Project Finance International, and written numerous company studies. Mr. Rose has also appeared in TV interviews.

Mr. Rose received a M.P.P. from the John F. Kennedy School of Government, Harvard University, and an S.B. in Economics from the Massachusetts Institute of Technology.

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30. “IPP Power Purchase Agreement,” confidential arbitration, April 2003.

29. “The Future of the Mohave Coal-Fired Power Plant”, California P.U.C., March 2003.

28. “Power Supply in the Pacific Northwest,” contract arbitration, December 5, 2002. CONFIDENTIAL

27. “Power Purchase Agreement Valuation”, Confidential Arbitration, October 2002.

26. “Cause No. 42145 - In support of PSI's petition for authority to acquire the Madison and Henry County plants, rebuttal testimony on behalf of PSI. Filed on 8/23/02.”

25. “Cause No. 42200 - in support of PSI's petition for authority to recover through retail rates on a timely basis. Filed on 7/30/02.”

24. “Cause No. 42196 - in support of PSI's petition for interim purchased power contract. Filed on 4/26/02.”

23. “Cause No. 42145 - In support of PSI's petition for authority to acquire the Madison and Henry County plants. Filed on 3/1/2002.”

22. “Analysis of an IGCC Coal Power Plant”, Minnesota state senate committees, January 22, 2002

21. "Analysis of an IGCC Coal Power Plant", Minnesota state house of representative committees, January 15, 2002

20. "Interim Pricing Report on New York State's Independent System Operator", New York State Public Service Commission (NYSPSC), January 5, 2001

19. "The need for new capacity in Indiana and the IRP process", Indiana Utility Regulatory Commission, October 26, 2000

18. "Damage estimates for power curtailment for a Cogen power plant in Nevada", August 2000. CONFIDENTIAL

17. "Valuation of a power plant in Arizona", arbitration, July 2000. CONFIDENTIAL

16. Application of FirstEnergy Corporation for approval of an electric Transition Plan and for authorization to recover transition revenues, Stranded Cost and Market Value of a Fleet of Coal, Nuclear, and Other Plants, Before PUCO, Case No. 99-1212-EL-ETP, October 4, 1999 and April 2000.

15. "Issues Related to Acquisition of an Oil/Gas Steam Power plant in New York", September 1999 Affidavit to Hennepin County District Court, Minnesota

14. "Wholesale Power Prices, A Cost Plus All Requirements Contract and Damages", Cajun Bankruptcy, July 1999. Testimony to U.S. Bankruptcy Court.

13. "Power Prices." Testimony in confidential contract arbitration, July 1998.

12. "Horizontal Market Power in Generation." Testimony to New Jersey Board of Public Utilities, May 22, 1998.

11. "Basic Generation Services and Determining Market Prices." Testimony to the New Jersey Board of Public Utilities, May 12, 1998.

10. "Generation Reliability." Testimony to New Jersey Board of Public Utilities, May 4, 1998.

9. "Future Rate Paths and Financial Feasibility of Project Financing." Cajun Bankruptcy, Testimony to U.S. Bankruptcy Court, April 1998.

8. "Stranded Costs of PSE&G." Market Valuation of a Fleet of Coal, Nuclear, Gas, and Oil-Fired Power Plants, Testimony to New Jersey Board of Public Utilities, February 1998.

7. "Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code." Market Value of Fleet of Nuclear, Coal, Gas, and Oil Power Plants, Rebuttal Testimony filed July 1997.

6. "Future Wholesale Electricity Prices, Fuel Markets, Coal Transportation and the Cajun Bankruptcy." Testimony to Louisiana Public Service Commission, December 1996.

5. "Curtailment of the Saguaro QF, Power Contracting and Southwest Power Markets." Testimony on a contract arbitration, Las Vegas, Nevada, June 1996.

4. "Future Rate Paths and the Cajun Bankruptcy." Testimony to the U.S. Bankruptcy Court, June 1997.

3. "Fuel Prices and Coal Transportation." Testimony to the U.S. Bankruptcy Court, June 1997.

2. "Demand for Gas Pipeline Capacity in Florida from Electric Utilities." Testimony to Florida Public Service Commission, May 1993.

1. "The Case for Fuel Flexibility in the Florida Electric Generation Industry." Testimony to the Florida Department of Environmental Regulation (DER), Hearings on Fuel Diversity and Environmental Protection, December 1992.

SELECTED SPEAKING ENGAGEMENTS

99. Rose, J.L., Vinson & Elkins Conference, Houston, TX, November 11, 2010.

98. Rose, J.L., Fundamentals of Electricity Transmission, EUCI, Crystal City, Arlington, VA, June 29-30, 2010.

97. Rose, J.L., Economics of PC Refurbishment, Improving the Efficiency of Coal-Fired Power Generation in the U.S., DOE-NETL, February 24, 2010.

96. Rose, J.L., Fundamentals of Electricity Transmission, EUCI, Orlando, FL, January 25-26, 2010.

95. Rose, J.L., CO_2 Control, "Cap & Trade", & Selected Energy Issues, Multi-Housing Laundry Association, October 26, 2009.

94. Rose, J.L., Financing for the Future – Can We Afford It?, 2009 Bonbright Conference, October 9, 2009.

93. Rose, J.L., EEI's Transmission and Market Design School, Washington, D.C., June 2009.
92. Rose, J.L., ICF's New York City Energy Forum - Market Recovery in Merchant Generation Assets, June 10, 2008.

91. Rose, J.L., Southeastern Electric Exchange – Integrated Resource Planning Task Force Meeting, Carbon Tax Outlook Discussion, February 21-22, 2008.

90. Rose, J.L., AESP, NEEC Conference, Rising Prices and Failing Infrastructure: A Bleak or Optimistic Future, Marlborough, MA, October 23, 2006.

89. Rose, J.L., Infocast Gas Storage Conference, "Estimating the Growth Potential for Gas-Fired Electric Generation," Houston, TX, March 22, 2006.

88. Rose, J.L., "Power Market Trends Impacting the Value of Power Assets," Infocast Conference, Powering Up for a New Era of Power Generation M&A, February 23, 2006.

87. Rose, J.L., "The Challenge Posed by Rising Fuel and Power Costs", Lehman Brothers, November 2, 2005.

86. Rose, J.L., "Modeling the Vulnerability of the Power Sector", EUCI – Securing the Nation's Energy Infrastructure, September 19, 2005

85. Rose, J.L., "Fuel Diversity in the Northeast, Energy Bar Association, Northeast Chapter Meeting, New York, NY, June 9, 2005.

84. Rose, J.L., "2005 Macquarie Utility Sector Conference", Macquarie Utility Sector Conference, Vail, CO, February 28, 2005.

83. Rose, J.L., "The Outlook for North American Natural Gas and Power Markets", The Institute for Energy Law, Program on Oil and Gas Law, Houston, TX, February 18, 2005.

82. Rose, J.L. "Assessing the Salability of Merchant Assets – What's on the Horizon?" Infocast – The Market for Power Assets, Phoenix, AZ, February 10, 2005.

81. Rose, J.L. "Market Based Approaches to Transmission – Longer-Term Role", National Group of Municipal Bond Investors, New York, NY, December 10, 2004.

80. Rose, J.L. "Supply & Demand Fundamentals – What is Short-Term Outlook and the Long-Term Demand? Platt's Power Marketing Conference, Houston, TX, October 11, 2004.

79. Rose, J.L. "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?, Infocast's Buying, Selling, and Investing in Energy Assets Conference, Houston, TX, June 24, 2004.

78. Rose, J. L. "After the Blackout – Questions That Every Regulator Should be Asking," NARUC Webinar Conference, Fairfax, VA, November 6, 2003.

77. Rose, J. L., "Supply and Demand in U.S. Wholesale Power Markets," Lehman Brothers Global Credit Conference, New York, NY, November 5, 2003.

76. Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?", Infocast's Opportunities in Energy Asset Acquisition, San Francisco, CA, October 9, 2003.

75. Rose, J.L., "Asset Valuation in Today's Market", Infocast's Project Finance Tutorial, New York, NY, October 8, 2003.

74. Rose, J.L., "Forensic Evaluation of Problem Projects", Infocast's Project Finance Workouts: Dealing With Distressed Energy Projects, September 17, 2003.

73. Rose, J.L., National Management Emergency Association, Seattle, WA, September 8, 2003.

72. Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?", Infocast's Buying, Selling & Investing in Energy Assets, Chicago, IL, July 24, 2003.

71. Rose, J.L., CSFB Leveraged Finance Independent Power Producers and Utilities Conference, New York, NY, "Spark Spread Outlook", July 17, 2003.

70. Rose, J.L., Multi-Housing Laundry Association, Washington, D. C., "Trends in U.S. Energy and Economy", June 24, 2003.

69. Rose, J.L., "Power Markets: Prices, SMD, Transmission Access, and Trading", Bechtel Management Seminar, Frederick, MD, June 10, 2003.

68. Rose, J.L., Platt's Global Power Market Conference, New Orleans, LA, "The Outlook for Recovery," March 31, 2003.

67. Rose, J.L., "Electricity Transmission and Grid Security", Energy Security Conference, Crystal City, VA, March 25, 2003.

66. Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?, Infocast's Buying, Selling & Investing in Energy Assets, New York City, February 27, 2003.

65. Rose, J.L., Panel Discussion, "Forensic Evaluation of Problem Projects", Infocast Conference, NY, February 24, 2003.

64. Rose, J.L., PSEG Off-Site Meeting Panel Discussion, February 6, 2003 (April 13, 2003).

63. Rose, J.L., "The Merchant Power Market—Where Do We Go From Here?" Center for Business Intelligence's Financing U.S. Power Projects, November 18-19, 2002.

62. Rose, J.L., "Assessing U.S. Regional And The Potential for Additional Coal-Fired Generation in Each Region," Infocast's Building New Coal-Fired Generation Conference, October 8, 2002.

61. Rose, J.L., "Predicting the Price of Power for Asset Valuation in the Merchant Power Financings, "Infocast's Product Structuring in the Real World Conference, September 25, 2002.

60. Rose, J.L., "PJM Price Outlook," Platt's Annual PJM Regional Conference, September 24, 2002.

59. Rose, J.L., "Why Investors Are Zeroing in on Upgrading Our Antiquated Power Grid Rather Than Exotic & Complicated Technologies," New York Venture Group's Investing in the Power Industry—Targeting The Newest Trends Conference, July 31, 2002.

58. Rose, J.L., Panel Participant in the Salomon Smith Barney Power and Energy Merchant Conference 2002, May 15, 2002.

57. Rose, J.L., "Locational Market Price (LMP) Forecasting in Plant Financing Decisions," Structured Finance Institute, April 8-9, 2002.

56. Rose, J.L., "PJM Transmission and Generation Forecast", Financial Times Energy Conference, November 6, 2001.

55. Rose, J.L., "U.S. Power Sector Trends", Credit Suisse First Boston's Power Generation Supply Chain Conference, Web Presented Conference, September 12, 2002.

54. Rose, J.L., "Dealing with Inter-Regional Power Transmission Issues", Infocast's Ohio Power Game Conference, September 6, 2001

53. Rose, J.L., "Where's the Next California", Credit Suisse First Boston's Global Project Finance Capital Markets Conference, New York NY, June 27 2001

52. Rose, J.L, "U.S. Energy Issues: What MLA Members Need to Know," Multi-housing Laundry Association, Boca Raton Florida, June 25, 2001

51. Rose, J.L., "How the California Meltdown Affects Power Development", Infocast's Power Development and Finance Conference 2001, Washington D.C., June 12, 2001

50. Rose, J.L., "Forecasting 2001 Electricity Prices" presentation and workshop, What to Expect in western Power Markets this Summer 2001 Conference, Denver, Colorado, May 2, 2001

49. Rose, J.L., "Power Crisis in the West" Generation Panel Presentation, San Diego, California, February 12, 2001

48. Rose, J.L., "An Analysis of the Causes leading to the Summer Price Spikes of 1999 & 2000" Conference Chair, Infocast Managing Summer Price Volatility, Houston, Texas, January 30, 2001.

47. Rose, J. L., "An Analysis of the Power Markets, summer 2000" Generation Panel Presentation, Financial Times Power Mart 2000 conference, Houston, Texas, October 18, 2000

46. Rose, J.L., "An Analysis of the Merchant Power Market, Summer 2000" presentation, Conference Chair, Merchant Power Finance Conference, Atlanta, Georgia, September 11 to 15, 2000

45. Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair, Merchant Plant Development and Finance Conference, Houston, Texas, March 30, 2000.

44. Rose, J.L., "Implementing NYPP's Congestion Pricing and Transmission Congestion Contract (TCC)", Infocast Congestion Pricing and Forecasting Conference, Washington D.C., November 19, 1999.

43. Rose, J.L., "Understanding Generation" Pre-Conference Workshop, Powermart, Houston, Texas, October 26-28, 1999.

42. Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair Merchant Plant Development and Finance Conference, Houston, Texas, September 29, 1999.

41. Rose, J.L., "Comparative Market Outlook for Merchant Assets" presentation, Merchant Power Conference, New York, New York, September 24, 1999.

40. Rose, J.L., "Transmission, Congestion, and Capacity Pricing" presentation, Transmission The Future of Electric Transmission Conference, Washington, DC, September 13, 1999.

39. Rose, J.L., "Effects of Market Power on Power Prices in Competitive Energy Markets" Keynote Address, The Impact of Market Power in Competitive Energy Markets Conference, Washington, DC, July 14, 1999.

38. Rose, J.L., "Peak Price Volatility in ECAR and the Midwest, Futures Contracts: Liquidity, Arbitrage Opportunity" presentation at ECAR Power Markets Conference, Columbus, Ohio, June 9, 1999.

37. Rose, J.L., "Transmission Solutions to Market Power" presentation, Do Companies in the Energy Industry Have Too Much Market Power? Conference, Washington, DC, May 24, 1999.

36. Rose, J.L., "Repowering Existing Power Plants and Its Impact on Market Prices" presentation, Exploiting the Full Energy Value-Chain Conference, Chicago, Illinois, May 17, 1999.

35. Rose, J.L., "Transmission and Retail Issues in the Electric Industry" Session Speaker, Gas Mart/Power 99 Conference, Dallas, Texas, May 10, 1999.

34. Rose, J.L., "Peak Price Volatility in the Rockies and Southwest" presentation at Repowering the Rockies and the Southwest Conference, Denver, Colorado, May 5, 1999.

33. Rose, J.L., "Understanding Generation" presentation and Program Chairman at Buying & Selling Power Assets: The Great Generation Sell-Off Conference, Houston, Texas, April 20, 1999.

32. Rose, J.L., "Buying Generation Assets in PJM" presentation at Mid-Atlantic Power Summit, Philadelphia, Pennsylvania, April 12, 1999.

31. Rose, J.L., "Evaluating Your Generation Options in Situations With Insufficient Transmission," presentation at Congestion Management conference, Washington, D.C., March 25, 1999.

30. Rose, J.L., "Will Capacity Prices Drive Future Power Prices?" presentation at Merchant Plant Development conference, Chicago, Illinois, March 23, 1999.

29. Rose, J.L., "Capacity Value – Pricing Firmness," presentation at Market Price Forecasting conference, Atlanta, Georgia, February 25, 1999

28. Rose, J.L., "Developing Reasonable Expectations About Financing New Merchant Plants That Have Less Competitive Advantage Than Current Projects," presentation at Project Finance International's Financing Power Projects in the USA conference, New York, New York, February 11, 1999.

27. Rose, J.L., "Transmission and Capacity Pricing and Constraints," presentation at Power Fair 99, Houston, Texas, February 4, 1999.

26. Rose, J.L., "Peak Price Volatility: Comparing ERCOT With Other Regions," presentation at Megawatt Daily's Trading Power in ERCOT conference, Houston, Texas, January 13, 1999.

25. Rose, J.L., "The Outlook for Midwest Power Markets," presentation to The Institute for Regulatory Policy Studies at Illinois State University, Springfield, Illinois, November 19, 1998.

24. Rose, J.L., "Developing Pricing Strategies for Generation Assets," presentation at Wholesale Power in the West conference, Las Vegas, Nevada, November 12, 1998.

23. Rose, J.L., "Understanding Electricity Generation and Deregulated Wholesale Power Prices," a full-day pre-conference workshop at Power Mart 98, Houston, Texas, October 26, 1998.

22. Rose, J.L., "The Impact of Power Generation Upgrades, Merchant Plant Developments, New Transmission Projects and Upgrades on Power Prices," presentation at Profiting in the New York Power Market conference, New York, NY, October 22, 1998.

21. Rose, J.L., "Capacity Value – Pricing Firmness," presentation to Edison Electric Institute Economics Committee, Charlotte, NC, October 8, 1998.

20. Rose, J.L., "Locational Marginal Pricing and Futures Trading," presentation at Megawatt Daily's Electricity Regulation conference, Washington, D.C., October 7, 1998.

19. Rose, J.L., Chairman's opening speech and "The Move Toward a Decentralized Approach: How Will Nodal Pricing Impact Power Markets?" at Congestion Pricing and Tariffs conference, Washington, D.C., September 25, 1998.

18. Rose, J.L., "The Generation Market in MAPP/MAIN: An Overview," presentation at Megawatt Daily's MAIN/MAPP – The New Dynamics conference, Minneapolis, Minnesota, September 16, 1998.

17. Rose, J.L., "Capacity Value – Pricing Firmness," presentation at Market Price Forecasting conference, Baltimore, Maryland, August 24, 1998.

16. Rose, J.L., "ICF Kaiser's Wholesale Power Market Model," presentation at Market Price Forecasting conference, New York, New York, August 6, 1998.

15. Rose, J.L., Campbell, R., Kathan, David, "Valuing Assets and Companies in M&A Transactions," full-day workshop at Utility Mergers & Acquisitions conference, Washington, D.C., July 15, 1998.

14. Rose, J.L., "Must-Run Nuclear Generation's Impact on Price Forecasting and Operations," presentation at The Energy Institute's conference entitled "Buying and Selling Electricity in the Wholesale Power Market," Las Vegas, Nevada, June 25, 1998.

13. Rose, J.L., "The Generation Market in PJM," presentation at Megawatt Daily's PJM Power Markets conference, Philadelphia, Pennsylvania, June 17, 1998.

12. Rose, J.L., "Market Evaluation of Electric Generating Assets in the Northeast," presentation at McGraw-Hill's conference: Electric Asset Sales in the Northeast, Boston, Massachusetts, June 15, 1998.

11. Rose, J.L., "Overview of SERC Power," opening speech presented at Megawatt Daily's SERC Power Markets conference, Atlanta, Georgia, May 20, 1998.

10. Rose, J.L., "Future Price Forecasting," presentation at The Southeast Energy Buyers Summit, Atlanta, Georgia, May 7, 1998.

9. Rose, J.L., "Practical Risk Management in the Power Industry," presentation at Power Fair, Toronto, Canada, April 16, 1998.

8. Rose, J.L., "The Wholesale Power Market in ERCOT: Transmission Issues," presentation at Megawatt Daily's ERCOT Power Markets conference, Houston, Texas, April 1, 1998.

7. Rose, J.L., "New Generation Projects and Merchant Capacity Coming On-Line," presentation at Northeast Wholesale Power Market conference, New York, New York, March 18, 1998.

6. Rose, J.L., "Projecting Market Prices in a Deregulated Electricity Market," presentation at conference: Market Price Forecasting, San Francisco, California, March 9, 1998.

5. Rose, J.L., "Handling of Transmission Rights," presentation at conference: Congestion Pricing & Tariffs, Washington, D.C., January 23, 1998.

4. Rose, J.L., "Understanding Wholesale Markets and Power Marketing," presentation at The Power Marketing Association Annual Meeting, Washington, D.C., November 11, 1997.

2. Rose, J.L., "Determining the Electricity Forward Curve," presentation at seminar: Pricing, Hedging, Trading, and Risk Management of Electricity Derivatives, New York, New York, October 23, 1997.

3. Rose, J.L., "Market Price Forecasting In A Deregulated Market," presentation at conference: Market Price Forecasting, Washington, D.C., October 23, 1997,

1. Rose, J.L., "Credit Risk Versus Commodity Risk," presentation at conference: Developing & Financing Merchant Power Plants in the New U.S. Market, New York, New York, September 16, 1997.

SELECTED PUBLICATIONS

Rose, J.L. and Surana, S. "Oil Price Increases, Yield Curve Inversion may be Indicators of Economic Recession." Oil and Gas Financial Journal, Volume 7, Issue 6, June 2010

Rose, J.L. and Surana, S. "Forecasting Recessions and Investment Strategies." World-Generation, June/July 2010, V.22, #3.

Rose, J.L., "Should Environmental Restrictions be Eased to Allow for the Construction of More Power Plants? The Costco Connection, April 2001.

Rose, J.L., "Deregulation in the US Generation Sector: A Mid-Course Appraisal", Power Economics, October 2000.

Rose, J. L., "Price Spike Reality: Debunking the Myth of Failed Markets", *Public Utilities Fortnightly,* November 1, 2000.

Rose, J.L., "Missed Opportunity: What's Right and Wrong in the FERC Staff Report on the Midwest Price Spikes," *Public Utilities Fortnightly,* November 15, 1998.

Rose, J.L., "Why the June Price Spike Was Not a Fluke," *The Electricity Journal*, November 1998.

Rose, J.L., S. Muthiah, and J. Spencer, "Will Wall Street Rescue the Competitive Wholesale Power Market?" *Project Finance International*, May 1998.

Rose, J.L., "Last Summer's "Pure" Capacity Prices – A Harbinger of Things to Come," *Public Utilities Fortnightly,* December 1, 1997.

Rose, J.L., D. Kathan, and J. Spencer "Electricity Deregulation in the New England States," *Energy Buyer*, Volume 1, Issue 10, June-July 1997.

Rose, J.L., S. Muthiah, and M. Fusco, "Financial Engineering in the Power Sector," *The Electricity Journal,* Jan/Feb 1997.

Rose, J.L, S. Muthiah, and M. Fusco, "Is Competition Lacking in Generation? (And Why it Should Not Matter)," *Public Utilities Fortnightly,* January 1, 1997.

Mann, C. and J.L. Rose, "Price Risk Management: Electric Power vs. Natural Gas," *Public Utilities Fortnightly,* February 1996.

Rose, J.L. and C. Mann, "Unbundling the Electric Capacity Price in a Deregulated Commodity Market," *Public Utilities Fortnightly,* December 1995.

Booth, William and J.L. Rose, "FERC's Hourly System Lambda Data as Interim Bulk Power Price Information," *Public Utilities Fortnightly,* May 1, 1995.

Rose, J.L. and M. Frevert, "Natural Gas: The Power Generation Fuel for the 1990s." Published by Enron.

EMPLOYMENT HISTORY

ICF Resources Incorporated	Managing Director	1999-Present
	Vice President	1996-1999
	Project Manager	1993-1996
	Senior Associate	1986-1993
	Associate	1982-1986