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Transcript Exhibit(s)

Arizona Corporation Commission
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Docket #(s): E-01345A-11-0224

Exhibit #: AIC1, AIC2, AECC/Noble/Kroger 1, AECC/Noble/Kroger 2, APS1-APS13, RUCO1-RUCO5, S1-S16, S18-S20, SC1, SC2, Walmart 1, Walmart 2

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To: Docket Control

Date: August 8, 2014

Re: APS / Four Corners Rate Rider
E-01345A-11-0224
August 4 - 6, 2014, Volumes I through III, Concluded

STATUS OF ORIGINAL EXHIBITS

EXHIBITS FILED WITH DOCKET CONTROL

Arizona Investment Council (AIC Exhibits)

AIC-1 and AIC-2

AECC / Noble / Kroger (ANK Exhibits)

ANK-1 and ANK-2

Arizona Public Service (APS Exhibits)

APS-1 through APS-13

1802 North 7th Street, Phoenix, AZ 85006 • 602.258.1440 (T) • 602.258.2062 (F)
Toll Free 1.800.262.DEPO • Toll Free AZ 1.800.537.DEPO • www.coashandcoash.com

Residential Utility Consumer Office (RUCO Exhibits)

RUCO-2 through RUCO-5

Sierra Club (SC Exhibits)

SC-1 and SC-2

Staff (S Exhibits)

S-1 through S-16, S-18 through S-20

Wal-Mart (Wal-Mart Exhibits)

Wal-Mart-1 and Wal-Mart-2

EXHIBITS RETURNED TO PARTIES

Arizona Public Service (APS Exhibits)

APS-14 Withdrawn

Residential Utility Consumer Office (RUCO Exhibits)

RUCO-1 Not offered

CONFIDENTIAL EXHIBITS

Please note: All confidential exhibits were retained by the Hearing Division, including the confidential portions redacted during the hearing from Exhibits APS-10 and APS-11.

Arizona Public Service (APS Exhibits)

APS-13CF

Sierra Club (SC Exhibits)

SC-1CF

Staff (S Exhibits)

S-17CF

Copy to: Teena Jibilian, ALJ
All parties present during the hearing

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB STUMP, Chairman
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

EXHIBIT
AIC-1
ADMITTED

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPAN FOR A HEARING TO DETERMINE THE FAIR VALUEOF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	Docket No. E-01345A-11-0224

GALLAGHER & KENNEDY, P.A.
2575 E. CAMELBACK ROAD
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(602) 530-8000

Direct Testimony

of Gary Yaquinto

on Behalf of

Arizona Investment Council

June 19, 2014

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GALLAGHER & KENNEDY, P.A.
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I. QUALIFICATIONS

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

A. Gary M. Yaquinto. I am President and CEO of the Arizona Investment Council ("AIC"). Our offices are located at 2100 North Central Avenue, Phoenix, Arizona 85004.

Q. Please summarize your educational background and professional experience.

A. I earned B.S. and M.S. Degrees in Economics in 1974 from Arizona State University, as well as an MBA from the University of Phoenix in 2005. From 1975 to 1977, I was employed by the State of Wyoming as an economist responsible for evaluating the economic, fiscal and demographic effects of resource development in Wyoming. From 1977 to 1980, I was Chief Research Economist for the Arizona House of Representatives and from 1980 to 1984, I was employed as an economist in the consulting industry. Since 1984, I have worked in various capacities in government and the private sector in the area of utility regulation, including positions with the Commission's Utilities Division Staff, a competitive local exchange telephone carrier and as a consultant. I also served as the Chief Economist at the Arizona Attorney General's Office from 2003-2005 and as the Director of the Governor's Office of Strategic Planning and Budgeting from 2005-2006. I became AIC's President in December of 2006.

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II. ARIZONA INVESTMENT COUNCIL ("AIC")

Q. What is the Arizona Investment Council and what is its mission?

A. The AIC is a non-profit association organized under Chapter 501(c)(6) of the Internal Revenue Code. AIC's membership includes about 6,000 people – many of whom are debt and equity investors in Arizona utility companies and other Arizona businesses.

AIC advocates on its members' behalf, primarily before regulatory bodies as well as the Legislature to enlarge and maximize their influence on public policies and government actions that impact investors, their investments and their investment decisions.

AIC works with the Commission and policymakers generally to find ways to support investment in Arizona's essential backbone infrastructure, as well as improvements to, or remediation of, existing facilities. This aspect of our mission is complementary to our core advocacy of investor interests.

III. TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony supports the application of Arizona Public Service Company for the Four Corners Rate Rider. The process for this rider was agreed to by the parties and authorized by the Commission in APS' last general rate case. In support of its request, APS' application follows the form and, as well, provides the substance agreed to by the more than 20 settling parties in Section 10 of that case's Settlement Agreement. It was then approved by the Commission in Decision No. 73183. The parties agreed to and the

Commission authorized this process so the Company could timely secure rates related to the rate base and expense effects of its acquisition of Southern California Edison's share of Four Corners Units 4 and 5 as well as its closure of Units 1-3. As a signatory to that agreement, my testimony supports APS' compliance filing.

Q. Did you also participate in the negotiations that led to APS' 2011 rate case settlement agreement?

A. Yes. AIC was an intervenor in that case. I filed Direct Testimony in accordance with the procedural schedule. We also participated in the discussions and negotiations among the parties which led to the settlement agreement.

Q. Did you sign the settlement agreement on behalf of AIC?

A. I signed the agreement and also offered testimony in support of it.

Q. Please provide more detail on the settlement agreement provisions which concern this filing.

A. Section 10.2 of the settlement agreement states:

> [T]his rate case shall remain open for the sole purpose of allowing APS to file a request, no later than December 31, 2013, that its rates be adjusted to reflect the proposed Four Corners transaction, should the Commission allow APS to pursue the acquisition and should the transaction thereafter close. Specifically, APS may within ten (10) business days after any Closing Date but no later than December 31, 2013 file an application with the Commission seeking to reflect in rates the rate base and expense effects associated with the acquisition of SCE's share of Units 4 and 5, the rate base and expense effects associated with the retirement of Units 1-3, and any cost deferral authorized in Docket No. E-01345A-10-0474. APS shall also be permitted to seek authorization to amend the PSA Plan of

Administration to include in the PSA the post-acquisition Operations and Maintenance expense associated with Four Corners 1-3 as a cost of producing off system sales until closure of Units 1-3 provided that such costs do not exceed off-system sales revenue in any given year. APS' rates shall be adjusted only if the Commission finds the Four Corners transaction to be prudent.

Q. Mr. Yaquinto, has APS met the conditions the signatories agreed to and the Commission approved as conditions precedent to making this filing?

A. Yes. The Company's filing in support of the rate case rider states that APS acquired SCE's interest in Four Corners on December 30, 2013 and it has now closed Units 1, 2 and 3. Commensurate with that acquisition, APS filed its rate rider application in accordance with Section 10.2 of the settlement agreement and Decision No. 73138.

APS is requesting the rate relief associated with its acquisition as Staff, RUCO, the AIC and many other parties agreed and as the Commission ordered in Decision No. 73183. However, the Company is not seeking to amend its PSA Plan of Administration regarding post-acquisition O&M costs because Units 1, 2 and 3 have already been closed. That being the case, amendments to the PSA for this purpose – although authorized – are not needed.

Q. Why are these provisions of the settlement agreement and the decision approving it important to the Company's investors?

A. As APS witness Guldner explains, without the ability to seek timely rate relief related to this acquisition, the Company's earnings will suffer and, I'd add, its credit ratings certainly could be impacted as a result. The settling parties recognized those impacts would be further exacerbated by the Settlement Agreement's rate "stay out" provision to mid-2015 and the companion bar on a general rates increase at any time prior to July 1, 2016. Those are the primary reasons why we, the Company, Staff, RUCO and many other parties supported this process in relation to APS' acquisition of Units 4 and 5. By making this filing to adjust rates related to the transaction, the Company could agree to a long general rates increase moratorium, but also be able to (1) minimize the earnings erosion that would otherwise result from the stay out, (2) support its earnings profile in the interim and (3) avoid negative earnings and ratings impacts for both investors and customers. In short, this process is producing the result intended by the parties in the Settlement Agreement and by the Commission in Decision No. 73138.

Q. Do you have a recommendation for the Commission?

A. Yes. I recommend the Commission approve APS' request for the Four Corners rate rider.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB STUMP, Chairman
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

EXHIBIT
AC-2
ADMITTED

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	Docket No. E-01345A-11-0224

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Surrebuttal Testimony

of Gary Yaquinto

on Behalf of

Arizona Investment Council

July 21, 2014

4316993v2/18762-0009

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I. INTRODUCTION

Q. Mr. Yaquinto, did you previously file Direct Testimony on AIC's behalf in support of Arizona Public Service Company's ("APS" or the "Company") request for a Four Corners Rate Rider?

A. Yes, I did. I pointed out that APS' Application in this Docket was consistent with the provisions of Section X of the Settlement Agreement agreed to by the parties and authorized by the Commission in the Company's last rate case decision, No. 73183 (the "Decision"). I also stressed the importance of Commission approval of this Four Corners Rate Rider. The Commission's Staff and RUCO supported this process and the Joint Signatories to the Settlement Agreement identified it as a "material" factor in order for "APS to remain financially healthy for customers to benefit from high quality service and for APS to achieve Arizona's energy goals."[1]

Q. Please restate what the Commission authorized APS to seek in this filing.

A. In approving the Settlement Agreement, the Commission held open the rate case:

> [F]or the sole purpose of allowing APS...to file an application with the Commission seeking to reflect in rates the rate base and expense effects associated with the acquisition of SCE's share of [the Four Corners] Units 4 and 5, the rate base and expense effects associated with Units 1-3 and any cost deferral authorized in Docket No. E-01345A-10-0474.

In summary, the Commission authorized this process to (1) strengthen rate stability in support of another Settlement Agreement term, i.e., "a four year rate case stay out, in

[1] Decision, p. 31, l. 24-p. 32, l. 5.

which APS agreed not to raise base rates as a result of any…filing prior to July 1, 2016";[2] (2) minimize regulatory lag; and (3) expedite timely recovery of costs. To accomplish each of those goals, the AIC urges the Commission to approve the Company's Application and requests.

II. RESPONSE TO SIERRA CLUB, UTILITIES DIVISION STAFF AND RUCO TESTIMONIES

Q. Have you reviewed Mr. Hausman's Direct Testimony on behalf of the Sierra Club?

A. Yes, I have. Mr. Hausman disputes the "benefits to ratepayers from the [Four Corners] acquisition relative to other resource options…." He recommends the Commission deny APS' request and re-file a more detailed analysis.

Q. What is AIC's response?

A. Given the Sierra Club's opposition to coal-fired generating resources in general, I was not surprised it would oppose APS' acquisition of Southern California Edison's interests in the coal-fired Four Corners plant. As for his analysis, AIC did not perform its own economic analysis of the transaction, so I cannot comment directly on the merits of Mr. Hausman's review.

I note, however, Company witness James Wilde's discussion on this subject. In his rebuttal testimony, he states that Sierra Club criticisms of the ratepayer benefits which will flow from the transaction are unfounded and points out that ACC Staff's Consultant

[2] Decision, p. 10.

agrees the Four Corners acquisition does, in fact, provide significant benefits to customers:

> The inputs used and analysis performed by APS...support a conclusion by this Commission that this Transaction provides significant benefits to Arizona customers...just as Staff's consultant also concluded.[3]

Q. Did you review the rebuttal testimonies of Messrs. Guldner and Snook and Ms. Blankenship on APS' updated revenue requirements calculation of $65.44 million, as well as their responses to the Staff and RUCO positions that revenue requirements should be reduced by $8.39 million and $16.24 million, respectively?

A. Yes, I have reviewed the APS testimonies and the testimonies of Staff and RUCO.

Q. Do you have any comments on the revenue requirement positions of the respective parties?

A. Yes. APS' methodology for calculating the revenue requirement utilizes the proper rate base and rate of return components reflected in the Commission's instructions in Decisions No. 73130 and 73183 in arriving at the $65.44 revenue requirement.

However, both the Staff and RUCO approaches depart from the ratemaking treatment contemplated in Decision No. 73183, although in different ways.

---

[3] Wilde Rebuttal, p. 6, ll. 14-17.

Q. Please explain the differences and why Staff and RUCO have used incorrect methods to arrive at their estimates of revenue requirement.

A. Decision No. 73130, regarding the accounting treatment of cost deferrals related to APS' acquisition, specifies that "the documented debt cost of acquiring SCE's interest in Units 4 and 5"[4] be used in calculating the deferrals. APS correctly utilized the cost of debt of 4.725 percent in calculating the deferral component of the revenue requirement. Both Staff and RUCO agree with the deferral amounts and the cost of debt used in calculating the amount of deferred costs, so there is no dispute on this component of the revenue requirement.

However, both Staff and RUCO use incorrect methods to calculate the rate base treatment of Units 4 and 5 as contemplated in Decision No. 73183. In doing so, both RUCO and Staff fail to apply proper ratemaking concepts to arrive at a fair value rate of return on rate base, which includes Units 4 and 5.

APS witness Snook, in his rebuttal testimony, provides the mathematical basis for calculating the proper return on the Units 4 and 5 assets in his critique of the analyses performed by Staff and RUCO. Mr. Snook correctly calculates the return as if the addition of Units 4 and 5 was part of the original rate case, which was, in fact, held open in Decision No. 73183 for the express purpose of rate-basing these assets once the transaction was completed. As Mr. Snook points out, the weighted cost of capital of 8.33 percent found in Decision 73183 is the correct value to apply to Units 4 and 5's

[4] Decision No. 73130, p. 37, ll. 8-9.

original cost rate base, just as it was utilized in the rate case for the Company's total original cost rate base.

In contrast, the Staff analysis simply applies the fair value rate of return of 6.09 percent determined in Decision No. 73183 to the original cost rate base value of Units 4 and 5. This is incorrect, because the fair value rate of return used by Staff reflects a blended rate, which combines the weighted cost of capital of 8.33 percent on OCRB with the much lower return rate of 1 percent on the "incremental fair value rate base," which is a proxy measure of the replacement value for the assets to arrive at FVROR.

Q. In APS' calculation of the revenue requirement, did it include an incremental fair value rate base component?

A. No. According to Mr. Snook's testimony, APS' revenue requirement was calculated without a value ascribed to incremental fair value rate base.

Q. If APS had included the incremental fair value rate base component coupled with a 1 percent return attached to it, what would be the revenue requirement?

A. Based on the estimated value of RCND in Mr. Snook's testimony, it would have <u>added</u> approximately $4 million more to the revenue requirement.

Q. Did Staff's calculation of revenue requirement include a consideration of incremental fair value of the Units 4 and 5 assets?

A. No.

Q. Turning to RUCO's position, is its application of the marginal cost of debt to determine the revenue requirement for rate basing Units 4 and 5 appropriate?

A. No. RUCO's use of the marginal cost of debt in calculating the revenue requirement for Units 4 and 5 is a misinterpretation of Decision No. 73183 and results in an egregious misuse of proper ratemaking methods. RUCO mistakes a directive from an accounting order related to <u>cost deferrals</u> in Decision No. 73130 as a reason to preclude the Company from earning <u>the return on its investment</u> to which it's entitled in the rate case.

As I stated previously in my testimony, Decision No. 73183 was kept open for the express purpose of including the costs related to APS' acquisition of SCE's share of Four Corners Units 4 and 5. Accordingly, these assets should be included in rate base as if they were part of that original rate case. This means the same weighted cost of capital for Units 4 and 5 should be used as was applied in the rate case for the Company's total original cost rate base.

III. CONCLUSION

Q. Mr. Yaquinto, do you have a recommendation for the Commission?

A. Yes. I recommend the Commission approve APS' request as presented for the Four Corners Rate Rider.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT
ASCC/Noble/
Kroger - 1
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

In the Matter of the Application of Arizona	)	
Public Service Company for a Hearing to	)	
Determine the Fair Value of the Utility	)	
Property of the Company for Ratemaking	)	Docket No. E-01345A-11-0224
Purposes, to Fix a Just and Reasonable	)	
Rate of Return Thereon, to Approve Rate	)	
Schedules Designed to Develop Such Return	)	

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport-McMoRan Copper & Gold Inc.,

Arizonans for Electric Choice & Competition

Noble Americas Energy Solutions and

The Kroger Co.

June 19, 2014

DIRECT TESTIMONY OF KEVIN C. HIGGINS

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DIRECT TESTIMONY OF KEVIN C. HIGGINS

INTRODUCTION

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

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

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

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

A. My testimony is being sponsored by Freeport-McMoRan Copper & Gold, Inc., Arizonans for Electric Choice and Competition ("AECC"), The Kroger Co. ("Kroger"), and Noble Americas Energy Solutions, LLC ("Noble Solutions"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1] Kroger is one of the largest grocery chains in the United States and a participant in APS's Schedule AG-1 program, described further below. Noble Solutions is a retail energy supplier that serves over 15,000 commercial and industrial end-use customers in 16 states, the District of Columbia, and Baja California, Mexico and also is a Generation Service Provider operating under the terms of Arizona Public Service Company's ("APS") Schedule AG-1.

Q. Please describe your professional experience and qualifications.

[1] Henceforth in this testimony, Freeport-McMoRan Copper & Gold Inc. and AECC collectively will be referred to as "AECC."

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you testified before this Commission in other dockets?

A. Yes. I have testified in a number of proceedings before this Commission, including the generic proceeding on retail electric competition (1998),[2] the hearings on APS's 1999 Settlement Agreement (1999),[3] the hearings on the Tucson Electric Power Company's ("TEP") 1999 Settlement Agreement (1999),[4] the Arizona Electric Power Cooperative, Inc.'s transition charge hearings (1999),[5] the Commission's Track A proceeding (2002),[6] the APS adjustment mechanism

[2] Docket No. RE-00000C-94-0165.
[3] Docket Nos. RE-00000C-94-0165, E-01345A-98-0471, and E-01345A-98-0473.
[4] Docket Nos. RE-00000C-94-0165, E-01933A-97-0772, and E-01933A-97-0773.
[5] Docket No. E-01773A-98-0470.
[6] Docket Nos. E-00000A-02-0051; E-01345A-01-0822; E-00000A-01-0630; E-01933A-02-0069; E-01933A-98-0471.

proceeding (2003),[7] the Arizona ISA proceeding (2003),[8] the APS 2004 rate case (2004),[9] the Trico Electric Cooperative, Inc. 2004 rate case (2005),[10] the TEP 2004 rate review (2005),[11] the APS 2006 interim rate proceeding (2006),[12] the APS 2006 rate case (2006),[13] TEP's request to amend Decision No. 62103 (2007),[14] the TEP 2007 rate case (2008),[15] the APS 2008 rate case (2008),[16] the APS 2011 rate case (2011-12),[17] the TEP 2011 Energy Efficiency Plan (2012),[18] and the TEP 2012 rate case (2012).[19]

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in approximately 170 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also participated in various Pricing Processes conducted by the Salt River Project Board of Directors and have filed affidavits in proceedings at the Federal Energy Regulatory Commission.

[7] Docket No. E-01345A-02-0403.
[8] Docket No. E-00000A-01-0630.
[9] Docket No. E-01345A-03-0437.
[10] Docket No. E-01461A-04-0607.
[11] Docket No. E-01933A-04-0408.
[12] Docket No. E-01345A-06-0009.
[13] Docket No. E-01345A-05-0816.
[14] Docket No. E-01933A-05-0650.
[15] Docket No. E-01933A-07-0402.
[16] Docket No. E-01345A-08-0172.
[17] Docket No. E-01345A-11-0224.
[18] Docket No. E-01933A-11-0055.
[19] Docket No. E-01933A-12-0291.

OVERVIEW AND CONCLUSIONS

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

A. My testimony addresses the applicability to customers served under Rate Schedule AG-1 of the Four Corners Adjustment rider proposed by APS.

Q. What are your primary conclusions and recommendations?

A. I disagree with APS's proposal to apply the Four Corners Adjustment rider to a portion of the bills paid by customers taking service under Rate Schedule AG-1. Charging AG-1 customers for Four-Corners-related costs does not make sense conceptually and also is inconsistent with both the 2012 Settlement Agreement in APS' 2011 rate case, as approved by the Commission in this docket on May 24, 2012, and the APS tariff.

Properly exempting AG-1 customers from the Four Corners Adjustment rider would cause the rate in the rider to increase by only 0.02%, causing it to go from 2.22% to 2.24%. Thus, correcting the APS proposal to make it consistent with the 2012 Settlement Agreement and the APS tariff would not have an appreciable impact on other customers.

FOUR CORNERS ADJUSTMENT RIDER

Q. What is the Four Corners Adjustment rider?

A. The Four Corners Adjustment rider, or Adjustment Schedule FCA, is the mechanism proposed by APS to recover the incremental costs associated with APS's acquisition and operation of Southern California Edison Company's share of Units 4 and 5 of the Four Corners power plant. The proposed rider is presented in Attachment EAB-9, Schedule 5, attached to the direct testimony of APS witness Elizabeth Blankenship. It is proposed to be a 2.22% surcharge applied to the base rates of all customers to which the rider is applicable, i.e., it would be applied to the customer's monthly billed amount, excluding all other adjustments, sales tax, regulatory assessment and franchise fees. This surcharge is intended to recover the estimated $62.53 million incremental annual revenue requirement associated with the Four Corners acquisition.

Q. Is the design of this recovery mechanism governed by any previous agreements approved by the Commission?

A. Yes. Section 10.3 of the 2012 Settlement Agreement approved by the Commission in this docket on May 24, 2012 provides that, among other things, the recovery mechanism for approved Four Corners incremental costs would be an adjustment rider that recovers the rate base and non-PSA ("Power Supply Adjustor") related expenses associated with any Four Comers acquisition on an equal percentage basis across all rate schedules.

Q. Are AECC, Kroger, and Noble Solutions signatories to the 2012 Settlement Agreement?

A. Yes.

Q. Did you personally participate in the negotiation of the 2012 Settlement Agreement?

A. Yes, I did.

Q. In your opinion, is Adjustment Schedule FCA as proposed by APS consistent with all the provisions of the Settlement Agreement?

A. No. In principle, I support the use of the equal percentage rider proposed by APS. However, I disagree with APS's proposal to apply this rider to a portion of the bills paid by customers taking service under Rate Schedule AG-1. Charging AG-1 customers for Four-Corners-related costs does not make sense conceptually and is inconsistent with both the 2012 Settlement Agreement and the APS tariff.

Q. What is Rate Schedule AG-1?

A. Rate Schedule AG-1 is an experimental rate rider that was proposed by APS in its 2011 rate case and was implemented (as revised through settlement negotiations) pursuant to the terms of the 2012 Settlement Agreement. Rate Schedule AG-1 is available to a limited amount of load on APS Rate Schedules E-32, E-34, and E-35. It provides for alternative generation buy-through service whereby APS customer participants arrange a power purchase from a third-party Generation Service Provider that is facilitated by APS through its tariff. This alternative buy-through generation is utilized for the AG-1 customers in lieu of APS's own generation supply. Accordingly, except for certain specified transition-type charges, and a charge for generation reserves, AG-1 customers do not pay for APS generation service.

Q. What transition-type charges were assessed to AG-1 customers?

A. AG-1 customers were subject to the Historical Component of the PSA for the first twelve months of their AG-1 service because the cost of that component had been incurred on their behalf. AG-1 customers also were required to compensate APS for the cost of unwinding their pro rata share of fuel supply hedges. But, except for these transition-type charges, and a charge for generation reserves, AG-1 customers are expressly exempt from APS's generation charges.

Q. What is APS proposing with respect to the applicability of the Four Corners Adjustment rider to AG-1 customers?

A. As explained in the direct testimony of APS witness Jeffrey Guldner, the Company is proposing to exempt AG-1 customers from the application of the Four Corners Adjustment rider to the buy-through generation portion of AG-1 customers' bills, but is proposing to apply the surcharge to the non-generation portion of their bills, i.e., the non-generation portion of Schedules E-32, E-34, or E-35, whichever is applicable.

Q. Please explain your disagreement with APS's proposed approach.

A. At a conceptual level, APS's approach is unreasonable because the Four Corners Adjustment rider is entirely a generation charge, and AG-1 customers are purchasing the entirety of their AG-1 generation supply through non-APS sources. Thus, it is not reasonable for AG-1 customers to be assigned the cost of this APS generation resource, particularly when it is clear that the structure of the AG-1 rate exempts AG-1 customers from paying for all other APS generation resources.

Q. Why doesn't the partial exemption from the Four Corners Adjustment rider proposed by APS for AG-1 customers adequately address your concerns?

A. The partial exemption proposed by APS, i.e., exempting only the generation portion of AG-1 customer bills, does not adequately address my concerns precisely because it is only a partial exemption. Even if the surcharge is restricted to the non-generation portion of AG-1 customer bills, the upshot of APS's proposal is that AG-1 customers would be forced to pay for APS generation costs even though these customers are purchasing the entirety of their

AG-1 generation supply from non-APS sources. Moreover, APS's proposal is inconsistent with both the 2012 Settlement Agreement as a whole and APS's tariff.

Q. Please explain. How is APS's proposal inconsistent with the 2012 Settlement Agreement as a whole?

A. Attachment J to the 2012 Settlement Agreement is the AG-1 rate schedule negotiated by the parties. On page 4 of the attachment, under the "Rates" heading, it states: "All provisions, charges and adjustments in the customer's applicable retail rate schedule will continue to apply except as follows:…." The very first exception listed states: "The generation charges will not apply;"

It is clear in this very first exception that a fundamental feature of the AG-1 rate schedule negotiated by the parties to the 2012 Settlement Agreement is that AG-1 customers are not intended to pay for APS generation charges. The limited exceptions to this principle (which were discussed above) are expressly spelled out in the rate section of Attachment J. Paying a surcharge for Four Corners generation costs is not among the exceptions listed.

I further note that the statement, "The generation charges will not apply" is a general reference to generation charges; that is, "generation charges" is in lower case and does not refer to a specific charge in the tariff; thus, it should be read to include all generation charges, including the proposed Four Corners Adjustment rider, unless expressly stated otherwise.

Q. How is APS's proposal inconsistent with the Company's tariff?

A. After the approval of the 2012 Settlement Agreement by the Commission, Attachment J was incorporated into the APS tariff. Thus, the language stating that generation charges do not apply to AG-1 customers is now part of the approved tariff. Consequently, APS's proposal to charge AG-1 customers for Four Corners generation service is inconsistent with its tariff.

Q. Is your proposal to exempt AG-1 customers from the Four Corners Adjustment rider consistent with Section 10.3 of the 2012 Settlement Agreement, which requires the Four Comers Adjustment rider to recover the costs on an equal percentage basis across all rate schedules?

A. Yes, it is. Under my proposed treatment, the Four Corners Adjustment rider would be structured as an equal percentage surcharge applied to all rate schedules, including Schedules 32, 34, and 35, consistent with Section 10.3 of the 2012 Settlement Agreement. The exemption for AG-1 would simply be applied to the *individual customers* taking service under the AG-1 rider for the portion of their service provided pursuant to AG-1.

Q. Does exempting the individual customers entirely from the Four Corners Adjustment rider cause the equal percentage rider to be higher than it would be under APS's proposal?

A. Yes, by a very small amount. According to information provided by APS in the technical conference conducted February 19, 2014, the full exemption of AG-1 customers from the Four Corners Adjustment rider would cause the rider to increase by only 0.02%, causing it to go from 2.22% to 2.24%, or about 2 cents per month for a typical customer with a base energy bill of $125 per month. Thus, correcting the APS proposal to make it consistent with the 2012 Settlement Agreement and the APS tariff would not have an appreciable impact on other customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
AECC/Noble/
Kroger - 2
ADMITTED

In the Matter of the Application of Arizona	)	
Public Service Company for a Hearing to	)	
Determine the Fair Value of the Utility	)	
Property of the Company for Ratemaking	)	Docket No. E-01345A-11-0224
Purposes, to Fix a Just and Reasonable	)	
Rate of Return Thereon, to Approve Rate	)	
Schedules Designed to Develop Such Return	)	

Surrebuttal Testimony of Kevin C. Higgins

on behalf of

Freeport-McMoRan Copper & Gold Inc.,

Arizonans for Electric Choice & Competition,

Noble Americas Energy Solutions, LLC, and

The Kroger Co.

July 18, 2014

SURREBUTTAL TESTIMONY OF KEVIN C. HIGGINS

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SURREBUTTAL TESTIMONY OF KEVIN C. HIGGINS

INTRODUCTION

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

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

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. Are you the same Kevin C. Higgins who previously filed direct testimony in this proceeding addressing the proposed Four Corners Adjustment Rider?

A. Yes, I am. My testimony is being sponsored by Freeport-McMoRan Copper & Gold, Inc., Arizonans for Electric Choice and Competition ("AECC"),[1] The Kroger Co. ("Kroger"), and Noble Americas Energy Solutions, LLC ("Noble Solutions").

OVERVIEW AND CONCLUSIONS

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

A. My surrebuttal testimony responds to the rebuttal testimony of Arizona Public Service Company ("APS") witness Leland R. Snook concerning the

[1] Henceforth in this testimony, Freeport-McMoRan Copper & Gold Inc. and AECC collectively will be referred to as "AECC."

applicability to customers served under Rate Schedule AG-1 of the Four Corners Adjustment rider proposed by APS.

Q. Please summarize your surrebuttal testimony.

A. I continue to disagree with APS's proposal to apply the Four Corners Adjustment rider to a portion of the bills paid by customers taking service under Rate Schedule AG-1. Mr. Snook's characterization of APS's proposal as a "middle ground" does not make it correct, reasonable or consistent with the 2012 Settlement Agreement approved by the Commission in this docket.

RESPONSE TO MR. SNOOK

Q. How has APS responded to the arguments you have made regarding the applicability of the Four Corners Adjustment rider to AG-1 customers?

A. Mr. Snook responds to my arguments on pages 9-10 of his rebuttal testimony. Mr. Snook justifies APS's proposal to charge AG-1 customers for Four Corners costs as being a "middle ground" between levying the percentage surcharge against AG-1 customers' total bill (inclusive of AG-1 generation service) versus not charging AG-1 customers at all for Four Corners costs, as I have argued is appropriate. Mr. Snook further maintains that "the Settlement made no distinction between the generation component of a rate schedule and the other components of base rates" and therefore APS proposed to assess the Four Corners Surcharge on each element of base rates for each rate schedule.

Q. What is your response to Mr. Snook?

A. I agree that APS's proposal is a sort of "middle ground": it sits in between my proposal on the one hand and an extreme proposition (to charge AG-1 customers a surcharge for APS's Four Corners costs as a mark-up on their generation costs paid to third-party providers) that no party to this proceeding has advocated. Simply being "in between" these two positions does not make APS's proposal correct, reasonable, or consistent with the 2012 Settlement Agreement. Rather, it is important to view the appropriate treatment of AG-1 customers within the full context of the 2012 Settlement Agreement, which as I have explained in my direct testimony, expressly exempts these customers from APS's generation charges.

Further, I disagree with Mr. Snook's characterization that the 2012 Settlement Agreement made no distinction between the generation component of a rate schedule and the other components of base rates. As I noted in my direct testimony, Attachment J to the 2012 Settlement Agreement, which is the AG-1 rate schedule negotiated by the parties, states: "All provisions, charges and adjustments in the customer's applicable retail rate schedule will continue to apply except as follows:…." The very first exception listed states: "The generation charges will not apply." Based on the plain reading of this provision, it is apparent that the 2012 Settlement Agreement intended to exempt AG-1 customers from generation charges generally – base rates as well as any additional generation charges added through a rider, unless expressly stated otherwise. APS's proposal, irrespective of whether it is a sort of "middle ground," is inconsistent with this basic tenet of the Settlement Agreement.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

DIRECT TESTIMONY OF JEFFREY B. GULDNER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-0224

December 30, 2013

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TESTIMONY OF JEFFREY B. GULDNER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-0224)

I. <u>INTRODUCTION</u>

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

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

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I joined APS in 2004 as Director of Regulatory Compliance and then assumed responsibility for federal regulation and policy. I was named to my present position in 2012. Prior to joining APS, I was a partner in the Phoenix office of Snell & Wilmer LLP, where I practiced energy and public utility law. That practice specifically focused on electric utility rate and regulatory matters, including general rate cases, power plant and transmission line siting, energy project finance, and utility mergers. Before practicing law, I served as a Surface Warfare Officer in the United States Navy. My education includes a B.A. in political science from the University of Iowa and a J.D., *magna cum laude*, from Arizona State University.

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

A. I outline the Company's Application and explain its relationship both to the current Docket, which is simply an extension of the last APS general rate proceeding, and to the 2012 Arizona Corporation Commission ("Commission") decision authorizing APS to proceed with the acquisition of Southern California Edison Company's ("SCE") share of Four Corners Units 4 and 5 ("FC 4-5") and granting APS a deferral of certain costs associated with that acquisition prior to a final decision on the Company's present Application. *See* Decision Nos. 73183 (May 24, 2012) and 73130 (April 24, 2012). These two Commission decisions, taken together, form the basis for the Company's request as set forth in its Application. Finally, I discuss some of the developments in 2013 that have delayed the closing of the FC 4-5 transaction and why the transaction continues to be a benefit for both our customers and Arizona.

II. <u>SUMMARY</u>

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. Including APS's incremental investment in SCE's share of FC 4-5 in rates, along with the ability to defer certain costs pursuant to Decision No. 73130, were important components of the Settlement agreed to by APS in December 2011 and approved by Decision No. 73183 ("Settlement"). These authorizations permitted the Company to agree to a four-year base rate stay out and to the other concessions that APS made in the process of negotiating the Settlement in that proceeding.

Decision No. 73130, which preceded the approval of the 2012 Settlement by one month, determined the Company had proven each element of the exhaustive set of criteria established by the Commission in 2005 as prerequisites to be met before APS could acquire an interest in an existing generating facility (in this case, the incremental portion of FC 4-5). *See* Decision No. 67744 (April 5, 2005). As I will discuss later, these are precisely the same criteria typically considered when deciding the prudency of a power plant investment.

Finally, I address some of the challenges APS had to overcome to consummate this transaction with SCE and explain how the delay in the final closing of the sale, which had been anticipated a year earlier, has affected the revenue and customer bill impact of this acquisition.

III. CONNECTION OF PRESENT APPLICATION TO DECISION NO. 73183

Q. HOW DID THE 2012 RATE SETTLEMENT AND DECISION NO. 73183 ADDRESS THE COMPANY'S THEN-PENDING ACQUISITION OF SCE'S INTEREST IN FC 4-5?

A. In Section 10.2 of the Settlement and again in Decision No. 73183, the Commission stated that:

> [T]his rate case shall remain open for the sole purpose of allowing APS to file a request, no later than December 31, 2013, that its rates be adjusted to reflect the proposed Four Corners transaction, should the Commission allow APS to pursue the acquisition and should the transaction thereafter close. Specifically, APS may within ten (10) business days after any Closing Date but no later than December 31, 2013, file an application with the Commission seeking to reflect in rates the rate base and expense effects associated with the acquisition of SCE's share of Units 4 and 5, the rate base and expense effects associated with the retirement of Units 1-3, and any cost deferral authorized in Docket No. E-01345A-10-0474. APS shall also be permitted to seek authorization to amend the PSA Plan of Administration to include in the PSA the post-acquisition Operations and Maintenance expense associated with Four Corners Units 1-3 as a cost of producing off system sales until closure of Units 1-3, provided that such costs do not exceed off-system sales revenue in any given year. APS's rates shall be adjusted only if the Commission finds the Four Corners transaction to be prudent.

In this Application, APS is seeking to include in rates "the rate base and expense effects associated with the acquisition of SCE's share of [FC] Units 4 and 5, the rate base and expense effects associated with the retirement of [FC] Units 1-3 and any cost deferral authorized in Docket No. E-01345A-10-0474." The Company is not requesting the PSA modification referenced above for reasons I will discuss.

Q. WHY WAS SECTION 10.2 OF THE SETTLEMENT IMPORTANT TO THE COMPANY?

A. The concept of keeping the 2011-12 general rate case docket open to recover the incremental costs of owning and operating SCE's share of FC 4-5 and the deferrals authorized by Decision No. 73130 originated from Staff's rate case testimony. It was critical to the Company's ability to accept the overall terms of the Settlement that this concept be included in the final agreement. This was the case for two principle reasons.

The first was to minimize the rate impact of the cost deferrals on APS customers. If costs had continued to accumulate through at least mid-2016, they would have been many times higher and the rate impact on APS customers correspondingly many times greater.

The second reason is because APS knew the cost deferrals permitted by Decision No. 73130 were less than the full cost of owning and operating SCE's share of FC 4-5 due to the lack of any equity return and the inability to compound the debt component of the return. This earnings shortfall could not, absent the provision of the Settlement and Decision No. 73183 quoted above, be addressed until the middle of 2016 at the earliest. Further, APS knew that other provisions agreed to in the Settlement, such as AG-1 and an under-compensatory Lost Fixed Cost Recovery mechanism, would progressively erode Company earnings over time. Thus, it was vital to have a way of minimizing the earnings impact of the FC 4-5 acquisition by means of the instant proceeding.

IV. RELEVANCE OF DECISION NO. 73130

Q. WHY DID APS FILE THE APPLICATION THAT RESULTED IN DECISION NO. 73130?

A. Decision No. 67744 imposed certain restrictions on the Company's ability to construct or acquire an ownership interest in additional generating capacity. Except in certain circumstances not applicable here,[1] that Decision requires that the Commission expressly pre-approve "the acquisition of a unit or interest in a generating unit from any merchant or utility generator" with an in-service date prior to January 1, 2015. *See* Decision No. 67744 (Finding of Fact 33).

The Decision also sets forth the criteria APS needed to address when seeking such approval:

a) The Company's specific unmet needs for additional long-term resources;

b) The Company's efforts to secure adequate and reasonably-priced long-term resources from the competitive wholesale market to meet these needs;

c) The reasons why APS believes those efforts have been unsuccessful, either in whole or in part;

[1] Several exceptions to the need to seek prior Commission authorization are identified in Decision No. 67744. These include renewable resources, distributed generation less than 50 MW, temporary generation, etc. *See* Decision No. 67744 at Attachment A, Paragraph 74.

d) The extent to which the request to self-build generation is consistent with any applicable Company resource plans and competitive resource acquisition rules or orders resulting from the workshop/rulemaking proceeding described in paragraph 79; and

e) The anticipated life-cycle cost of the proposed self-build option in comparison with suitable alternatives available from the competitive market for a comparable period of time.

See Decision No. 67744 at Appendix A, Paragraph 75.

The Company also requested an accounting order allowing it to defer for later recovery the costs of owning and operating the SCE interest in FC 4-5, as well as costs associated with closing down FC Units 1-3 between the time of acquisition/closure and when those costs were actually reflected in retail electric rates.

Q. DID THE COMMISSION FIND THAT APS HAD SATISFIED EACH OF THE ABOVE CRITERIA WITH REGARD TO ITS ACQUISITION OF SCE'S INTEREST IN FC 4-5?

A. Yes. *See* Decision No. 73130 at 28.

Q. DID THE COMMISSION FIND THAT SUCH ACQUISITION WAS "PRUDENT?"

A. Decision No. 73130 specifically reserved any finding of "prudence." But the criteria identified in Decision No. 67744 for exceptions to the so-called "self-build moratorium" -- criteria the Commission found APS to have satisfied in Decision No. 73130 -- are exactly those that, in my experience, this and other regulatory agencies have considered when determining that a new generation resource investment was prudent.

Q. IS THERE ANY COMMISSION REGULATION THAT ADDRESSES THE PRUDENCE OF A UTILITY'S INVESTMENT IN PLANT TO SERVE THE PUBLIC?

A. Yes. A.A.C. R14-1-103(A)(3)(l) states that "prudently invested" means investments that are "reasonable and not dishonest or obviously wasteful." The regulation goes on to state that "all investments shall be presumed to have been prudently made," and that this presumption can only be overcome by "clear and convincing evidence" to the contrary.

Q. DID OTHER AFFECTED PARTIES COMMENT FAVORABLY UPON THIS TRANSACTION?

A. Yes. As noted by the Commission in Decision No. 73130, the Residential Utility Consumers Office ("RUCO") strongly supported APS's acquisition of SCE's interest in FC 4-5:

> RUCO also agreed that APS' proposed transaction significantly reduces carbon dioxide and other pollutant emissions; it "preserves the diversity of APS' current generation portfolio while tempering the Company's exposure to volatile natural gas prices;" it maintains the mix of reliable baseload energy; and it "saves hundreds of jobs and millions of dollars of revenue that are critical to the Navajo Nation and local economy."

See Decision No. 73130 at 12.

Decision No. 73130 went on to say: "RUCO believes that the proposed transaction is in the best interest of ratepayers and provides numerous economic and environmental benefits." *Id.* at 23.

Q. WHY DID IT TAKE SO LONG TO CLOSE THIS TRANSACTION?

A. There have been numerous challenges along the road to closing this transaction. BHP decided it would discontinue its coal operations once the original contract with FC expired in 2016. The Navajo Nation successfully negotiated the purchase of the coal operations at FC, but that took time. Several of the participants, including APS, were occupied for several months with other regulatory issues that delayed the closing, and most recently, El Paso Electric Company ("El Paso") notified APS of its unwillingness to sign the 2016 Coal Supply Agreement. All through these ups and downs, APS remained staunchly committed to the transaction for the very same reasons cited by the Commission in Decision No. 73130: fuel diversity, economic benefit to the Navajo Nation and Arizona communities near FC, and customer benefit over the anticipated remaining life of FC 4-5.

Q. ARE THOSE REASONS STILL VALID TODAY?

A. Yes. Fuel diversity is more important than ever with the increasing reliance of the entire electric industry on natural gas. FC is still as vital to the Navajo Nation's economy and to those communities surrounding the plant. And, despite generally lower gas prices, the SCE interest in FC 4-5 is forecast to provide long-term value to APS customers.

Q. WHY IS APS NOT SEEKING TO MODIFY THE PSA TO ACCOUNT FOR CONTINUED OPERATION OF FC UNITS 1-3, AS AUTHORIZED BY DECISION NO. 73183?

A. APS is required to shut down Units 1-3 as part of the EPA negotiations by January 1, 2014. Therefore, APS will retire Units 1-3 before year end. The changes to the PSA discussed in the FC section of the 2012 Settlement are, thus, no longer necessary.

V. REVENUE AND BILL IMPACT

Q. WHAT IS THE ADDITIONAL REVENUE REQUESTED BY THE COMPANY AND WHAT WILL BE THE IMPACT ON CUSTOMERS?

A. APS Witness Elizabeth Blankenship's Testimony describes the details of the revenue requirement calculation. At a high level, the decrease in the purchase price ($7.5 million per month since October 2012) has more than offset some higher operating costs and leftover costs attributable to closing Units 1-3 earlier than had been anticipated in early 2012. Thus, the revenue requirement of approximately $70 million that had been estimated at the time of the Settlement's approval in Decision No. 73183 has been reduced to $62.53 million. The slightly over 3% bill impact projected in 2012 is now approximately 2.0%.[2] A sample bill analysis is attached to my Testimony as Attachment JBG-1. This Attachment also satisfies Section 10.3 of the Settlement Agreement's requirement to file a typical bill analysis (Schedule 7) under present and filed rates.

Q. HOW WILL THIS PERCENTAGE INCREASE BE APPLIED?

A. The percentage increase will be applied as an equal percentage to the base rate portion of customers' bills as contemplated by the Settlement. APS requests that this percentage increase be applied to the "APS" portion of an AG-1 customer's bill, but not to the portion representing a pass through of charges from such customer's Alternative Generation Provider. Also, E-36XL customers should be treated similar to AG-1 customers due to their unique customer profile.

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[2] Note that the Rider schedule attached to APS Witness Blankenship's Testimony shows the percentage increase of 2.22%. The difference between that number and the 2% referenced in my Testimony above is that the Rider is applied to only the base rate portion of a customers' bill. However it is important to a customer to know the total bill impact, which is why the 2% bill impact is included in my testimony.

Q. WHAT EFFECTIVE DATE IS APS PROPOSING FOR THE RATE RIDER TO BE IMPLEMENTED?

A. APS has assumed that the Rider will become effective on July 1, 2014 for purposes of calculating the deferral. As noted in APS Witness Elizabeth Blankenship's testimony, if the Rider is implemented after that date, there will be additional cost deferrals to recover. The Settlement directed parties to use "good faith" efforts to process the Rider within a "reasonable time," and APS believes this proceeding should be concluded as soon as is possible to minimize the eventual impact on APS customers.[3]

VI. CONCLUSION

Q. WOULD YOU SUMMARIZE YOUR CONCLUSIONS ABOUT THE COMPANY'S PRESENT APPLICATION?

A. The Company's Application should be granted. Decisions Nos. 73130 and 73183 have been fully complied with, and there would appear to be no reason for any lengthy delay. APS's purchase of SCE's interest in FC 4-5 was and remains a good deal for Arizona, the Navajo Nation, and APS customers.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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[3] *See* Section 10.4 of the Settlement Agreement.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 7 - FOUR CORNERS RATE RIDER
Estimated Monthly Bill Impacts of Four Corners Adjustor

Residential (Average - All Rates)	Current Annual Average Monthly Bill [1]	Requested July 2014 Annual Average Monthly Bill [2]	Current Summer Monthly Bill	Requested July 2014 Summer Monthly Bill	Current Winter Monthly Bill	Requested July 2014 Winter Monthly Bill
Average kWh per Month	1,100	1,100	1,337	1,337	863	863
Base Rates	$ 123.90	$ 123.90	$ 161.07	$ 161.07	$ 86.72	$ 86.72
Four Corners Adjustment	$ -	$ 2.76	$ -	$ 3.58	$ -	$ 1.93
PSA - Forward Component	$ 1.41	$ 1.41	$ 1.71	$ 1.71	$ 1.10	$ 1.10
PSA - Historical Component	$ 0.31	$ 0.31	$ 0.37	$ 0.37	$ 0.24	$ 0.24
TCA	$ 7.12	$ 7.12	$ 8.65	$ 8.65	$ 5.58	$ 5.58
RES	$ 4.11	$ 4.11	$ 4.11	$ 4.11	$ 4.11	$ 4.11
DSMAC	$ 2.99	$ 2.99	$ 3.63	$ 3.63	$ 2.34	$ 2.34
LFCR	$ 0.28	$ 0.29	$ 0.36	$ 0.37	$ 0.20	$ 0.20
Total	$ 140.12	$ 142.89	$ 179.90	$ 183.49	$ 100.29	$ 102.22
Bill Impact		**$ 2.77**				
		1.98%				

Residential (Rate E-12)	Annual Average Monthly Bill [1]	Annual Average Monthly Bill [2]	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	691	691	780	780	602	602
Base Rates	$ 86.40	$ 86.40	$ 108.04	$ 108.04	$ 64.76	$ 64.76
Four Corners Adjustment	$ -	$ 1.92	$ -	$ 2.40	$ -	$ 1.44
PSA - Forward Component	$ 0.89	$ 0.89	$ 1.00	$ 1.00	$ 0.77	$ 0.77
PSA - Historical Component	$ 0.20	$ 0.20	$ 0.22	$ 0.22	$ 0.17	$ 0.17
TCA	$ 4.48	$ 4.48	$ 5.05	$ 5.05	$ 3.90	$ 3.90
RES	$ 4.11	$ 4.11	$ 4.11	$ 4.11	$ 4.11	$ 4.11
DSMAC	$ 1.88	$ 1.88	$ 2.12	$ 2.12	$ 1.64	$ 1.64
LFCR	$ 0.20	$ 0.20	$ 0.24	$ 0.25	$ 0.15	$ 0.15
Total	$ 98.16	$ 100.08	$ 120.78	$ 123.19	$ 75.50	$ 76.94
Bill Impact		**$ 1.92**				
		1.96%				

Commercial (Rate E-32, 0-20 kW)	Annual Average Monthly Bill [1]	Annual Average Monthly Bill [2]	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	1,430	1,430	1,575	1,575	1,285	1,285
Base Rates	$ 202.30	$ 202.30	$ 232.85	$ 232.85	$ 171.75	$ 171.75
Four Corners Adjustment	$ -	$ 4.49	$ -	$ 5.17	$ -	$ 3.81
PSA - Forward Component	$ 1.83	$ 1.83	$ 2.01	$ 2.01	$ 1.64	$ 1.64
PSA - Historical Component	$ 0.40	$ 0.40	$ 0.44	$ 0.44	$ 0.36	$ 0.36
TCA	$ 3.58	$ 3.58	$ 3.94	$ 3.94	$ 3.22	$ 3.22
RES	$ 14.68	$ 14.68	$ 16.17	$ 16.17	$ 13.19	$ 13.19
DSMAC	$ 3.89	$ 3.89	$ 4.28	$ 4.28	$ 3.49	$ 3.49
LFCR	$ 0.45	$ 0.46	$ 0.52	$ 0.53	$ 0.39	$ 0.39
Total	$ 227.13	$ 231.63	$ 260.21	$ 265.39	$ 194.04	$ 197.85
Bill Impact		**$ 4.50**				
		1.98%				

ARIZONA PUBLIC SERVICE COMPANY
Schedule 7 - FOUR CORNERS RATE RIDER
Estimated Monthly Bill Impacts of Four Corners Adjustor

Commercial (Rate E-32, >20 kW)	Current: Annual Average Monthly Bill [1]	Requested July 2014: Annual Average Monthly Bill [2]	Current: Summer Monthly Bill	Requested July 2014: Summer Monthly Bill	Current: Winter Monthly Bill	Requested July 2014: Winter Monthly Bill
Average kWh per Month	62,238	62,238	68,381	68,381	56,094	56,094
Base Rates	5,977.26	5,977.26	7,044.20	7,044.20	4,910.31	4,910.31
Four Corners Adjustment	-	132.70	-	156.38	-	109.01
PSA- Forward Component	79.48	79.48	87.32	87.32	71.63	71.63
PSA - Historical Component	17.43	17.43	19.15	19.15	15.71	15.71
TCA	165.94	165.94	177.69	177.69	154.18	154.18
RES	152.49	152.49	152.49	152.49	152.49	152.49
DSMAC	189.52	189.52	202.94	202.94	176.09	176.09
LFCR	13.16	13.43	15.37	15.68	10.96	11.18
Total	6,595.28	6,728.25	7,699.16	7,855.85	5,491.37	5,600.60
Bill Impact		**$ 132.97**				
		2.02%				

Commercial (Rate E-32 M)	Annual Average Monthly Bill [1]	Annual Average Monthly Bill [2]	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	62,238	62,238	68,381	68,381	56,094	56,094
Base Rates	6,431.49	6,431.49	7,407.75	7,407.75	5,455.22	5,455.22
Four Corners Adjustment	-	142.78	-	164.45	-	121.10
PSA- Forward Component	79.48	79.48	87.32	87.32	71.63	71.63
PSA - Historical Component	17.43	17.43	19.15	19.15	15.71	15.71
TCA	165.94	165.94	177.69	177.69	154.18	154.18
RES	152.49	152.49	152.49	152.49	152.49	152.49
DSMAC	189.52	189.52	202.94	202.94	176.09	176.09
LFCR	14.07	14.36	16.09	16.42	12.05	12.29
Total	7,050.42	7,193.49	8,063.43	8,228.21	6,037.37	6,158.71
Bill Impact		**$ 143.07**				
		2.03%				

Commercial (Rate E-32 L)	Annual Average Monthly Bill [1]	Annual Average Monthly Bill [2]	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	290,507	290,507	314,925	314,925	266,089	266,089
Base Rates	24,709.54	24,709.54	29,456.69	29,456.69	19,962.38	19,962.38
Four Corners Adjustment	-	548.57	-	653.94	-	443.20
PSA- Forward Component	370.98	370.98	402.16	402.16	339.80	339.80
PSA - Historical Component	81.34	81.34	88.18	88.18	74.50	74.50
TCA	607.71	607.71	674.34	674.34	541.08	541.08
RES	152.49	152.49	152.49	152.49	152.49	152.49
DSMAC	694.07	694.07	770.16	770.16	617.97	617.97
Total	26,616.13	27,164.70	31,544.02	32,197.96	21,688.22	22,131.42
Bill Impact		**$ 548.57**				
		2.06%				

ARIZONA PUBLIC SERVICE COMPANY
Schedule 7 - FOUR CORNERS RATE RIDER
Estimated Monthly Bill Impacts of Four Corners Adjustor

Industrial (Rate E34/35)	Current: Annual Average Monthly Bill [1]	Requested July 2014: Annual Average Monthly Bill [2]	Current: Summer Monthly Bill	Requested July 2014: Summer Monthly Bill	Current: Winter Monthly Bill	Requested July 2014: Winter Monthly Bill
Average kWh per Month	3,581,412	3,581,412	3,729,201	3,729,201	3,433,622	3,433,622
Base Rates	$ 249,125.86	$ 249,125.86	$ 259,882.57	$ 259,882.57	$ 238,369.15	$ 238,369.15
Four Corners Adjustment	$ -	$ 5,530.60	$ -	$ 5,769.39	$ -	$ 5,291.80
PSA - Forward Component	$ 4,573.47	$ 4,573.47	$ 4,762.19	$ 4,762.19	$ 4,384.74	$ 4,384.74
PSA - Historical Component	$ 1,002.80	$ 1,002.80	$ 1,044.18	$ 1,044.18	$ 961.41	$ 961.41
TCA	$ 8,618.22	$ 8,618.22	$ 9,090.63	$ 9,090.63	$ 8,145.81	$ 8,145.81
RES	$ 3,335.00	$ 3,335.00	$ 3,335.00	$ 3,335.00	$ 3,335.00	$ 3,335.00
DSMAC	$ 6,395.98	$ 6,395.98	$ 6,746.57	$ 6,746.57	$ 6,045.38	$ 6,045.38
Total	$ 273,051.33	$ 278,581.93	$ 284,861.14	$ 290,630.53	$ 261,241.49	$ 266,533.29
Bill Impact		**$ 5,530.60**				
		2.03%				

Notes:
(1) Bill excludes regulatory assessment charge, taxes and fees. Adjustor levels in effect as of December 19, 2013.
(2) Adjustor levels in effect as of December 20, 2013
(3) Includes PSA rate effective February 1, 2014

EXHIBIT
APS-2
ADMITTED

REBUTTAL TESTIMONY OF JEFFREY B. GULDNER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-0224

July 3, 2014

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REBUTTAL TESTIMONY OF JEFFREY B. GULDNER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-0224)

I. <u>INTRODUCTION</u>

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

A. My name is Jeffrey B. Guldner. I am Senior Vice President of Public Policy for Arizona Public Service Company ("APS"). My business address is 400 N. 5th Street, Phoenix, Arizona, 85004.

Q. DID YOU SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, my Direct Testimony was filed on December 30, 2013.

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

A. I address the authorization granted to APS by the Arizona Corporation Commission ("Commission") in Decision No. 73183 (May 24, 2012). That Decision allowed APS to "reflect in rates the rate base and expense effects associated with the acquisition of Southern California Edison's ("SCE") share of Units 4 and 5, the rate base and expense effects associated with the retirement of Units 1-3, and any cost deferral authorized in Docket No. E-01345A-10-0474." I also address the deferral of certain costs associated with that acquisition per Decision No. 73130 (April 24, 2012). Finally, I discuss the Fair Value Rate of Return ("FVROR") that has a long foundation in Arizona and explain why the Four Corners transaction continues to be a benefit for both our customers and Arizona.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. APS's acquisition of SCE's share of Four Corners Units 4 and 5 combined with the retirement of Units 1-3, as part of negotiations with EPA, benefits APS customers, the Navajo Nation and Arizona. Notwithstanding Sierra Club's anti-coal agenda, every other party in this case offering an opinion on this issue has concluded that APS's purchase of SCE's share of Four Corners Units 4 and 5 is a good investment for APS and its customers. In fact, other than Sierra Club, no party has disagreed with the purchase price, timing, need, benefit to customers or the prudency of the transaction. Commission Staff in particular has thoroughly reviewed all aspects of the transaction and agrees the purchase was appropriate in every respect.

Again, Sierra Club aside, the only significant disagreement among the parties originates either from a misinterpretation of Decision Nos. 73183 (the "Settlement Agreement") and 73130 (the "Four Corners Deferral Order") or from an erroneous assumption with regard to the appropriate FVROR. When those Orders are reasonably interpreted and the intent of the settling parties is taken into consideration (and the corresponding calculations are used to apply that intent, as shown in the Rebuttal Testimonies of APS Witnesses Beth Blankenship and Leland Snook), RUCO's and Staff's revenue requirement are essentially the same as APS's.

The FVROR as calculated by Staff Witness Dennis Kalbarczyk is not consistent with the Settlement or with Commission precedent, and results in a significant under-recovery of the cost of owning the newly acquired portion of Four Corners Units 4 and 5. As stated in the Company's Direct Testimony, the recovery method and the ability to defer certain costs pursuant to Decision No. 73130 were important components of the Settlement agreed to by APS and approved by Decision No. 73183. These authorizations were part of the reason APS agreed to the many concessions made in the process of negotiating the Settlement in that proceeding.

III. AGREEMENT AMONG THE PARTIES

Q. PLEASE SUMMARIZE THE COMPONENTS OF THE FOUR CORNERS TRANSACTION ON WHICH THE PARTIES IN THIS CASE AGREE.

A. All parties, with the exception of the Sierra Club (who suggests that ever more analysis is needed regarding the net present value of the transaction), agree that APS's acquisition of SCE's share of Units 4 and 5 (i) will provide needed baseload capacity for the future, (ii) will provide both economic and non-economic benefits for APS customers, the Navajo Nation and Arizona, (iii) was reasonably priced, and (iv) was timed prudently. In sum, no party has challenged the prudency of this transaction. Indeed, Staff's expert consultant James Letzelter concluded:

1. The additional 179 MW is both used and useful;
2. APS considered an appropriate range of resource options;
3. APS's economic analysis of the acquisition was sound;
4. The economics of the transaction favor APS customers;
5. The timing of the transaction was prudent;
6. The risks of the acquisition are offset by the expected favorable economics;
7. Several ancillary benefits add to the positive impact that the transaction will have for customers; and
8. Overall, the Four Corners transaction was prudent.

See Direct Testimony of Staff Witness J. Letzelter at page 3, lines 1-9.

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF THE POINTS OF DISAGREEMENT AMONG THE THREE PARTIES ADDRESSING REVENUE REQUIREMENTS.

A. As to the revenue requirement, there is really just one area of significant disagreement: What return should be applied to the acquired share of Four Corners and to the deferrals? For the reasons discussed below, this disagreement is based upon inaccurate assumptions or misapplication of the concept of FVROR in prior proceedings, and does not provide a basis to significantly reduce the $65.44 million updated revenue requirement for the Four Corners Rate Rider requested by APS. *See also* Rebuttal Testimony of APS Witnesses Blankenship and Snook.

Specifically, Staff Witness Kalbarczyk has misapplied the FVROR as determined in the Settlement Agreement. RUCO, on the other hand, does not use the concept of FVROR at all and has applied an incremental debt rate to calculate the revenue requirement, which is not consistent with either the Four Corners Deferral Order or the Settlement.

Q. WHAT ARE THE POSITIONS OF THE OTHER PARTIES?

A. The Sierra Club disagrees with many of the assumptions used to determine the net present value of the transaction to APS customers; certain large customers disagree with the application of the Four Corners Rate Rider to AG-1 customers. My testimony focuses on the disagreements raised by Staff and RUCO regarding the application of Decision Nos. 73130 and 73183. APS Witnesses Blankenship and Snook also address Staff and RUCO's positions in their Rebuttal Testimony. The Sierra Club's contentions are refuted primarily in the Rebuttal Testimony of APS Witness Wilde. The concerns of AG-1 customers are discussed in the Rebuttal Testimony of APS Witness Snook.

IV. RATE OF RETURN DISCUSSION

Q. WHAT WAS THE INTENT OF DECISION NO. 73130?

As discussed in my Direct Testimony, Decision No. 73130 determined the Company had satisfied the criteria imposed by Decision No. 67744 related to the "Self-Build Moratorium" and authorized an accounting order allowing APS to defer for later recovery the costs of owning and operating the SCE interest in Four Corners Units 4 and 5, as well as costs associated with the shutdown of Four Corners Units 1-3 between the time of acquisition/closure and when those costs were actually reflected in retail electric rates.

Q. DOES APS'S APPLICATION COMPLY WITH DECISION NO. 73130?

A. Yes, APS's Application complies with the requirements and intent of Decision No. 73130. *See* APS Witness Blankenship's Rebuttal Attachments EAB-20 and EAB-21 that demonstrate APS's compliance with the Decision.

Q. WHAT DOES SECTION 10.2 OF THE 2012 RATE CASE SETTLEMENT, DECISION NO. 73183, SAY?

A. In Section 10.2 of the Settlement and again in Decision No. 73183, the Commission stated that:

> [T]his rate case shall remain open for the sole purpose of allowing APS to file a request, no later than December 31, 2013, that its rates be adjusted to reflect the proposed Four Corners transaction, should the Commission allow APS to pursue the acquisition and should the transaction thereafter close. **Specifically, APS may within ten (10) business days after any Closing Date but no later than December 31, 2013, file an application with the Commission seeking to reflect in rates the rate base and expense effects associated with the acquisition of SCE's share of Units 4 and 5, the rate base and expense effects associated with the retirement of Units 1-3, and any cost deferral authorized in Docket No. E-01345A-10-0474,** APS shall also be permitted to seek authorization to amend the PSA

> Plan of Administration to include in the PSA the post-acquisition Operations and Maintenance expense associated with Four Corners Units 1-3 as a cost of producing off system sales until closure of Units 1-3, provided that such costs do not exceed off-system sales revenue in any given year. APS's rates shall be adjusted only if the Commission finds the Four Corners transaction to be prudent. [Emphasis added]

As stated in this section, it allows APS to seek to include in rates three distinct items: (1) the rate base and expense effects associated with the acquisition of SCE's share of Units 4 and 5; (2) the rate base and expense effects associated with the retirement of Units 1-3; and (3) any cost deferral (resulting in Decision No. 73130). APS fully complied with the intent of the Settlement Agreement. *See* Rebuttal Testimonies of APS Witnesses Snook and Blankenship.

Q. **DOES STAFF WITNESS DENNIS KALBARCZYK'S TESTIMONY COMPLY WITH DECISION NO. 73183 AND IS IT CONSISTENT WITH THE SETTLING PARTIES INTENT? IF NOT, PLEASE EXPLAIN.**

A. No. Mr. Kalbarczyk's recommendation is inconsistent with how the FVROR was calculated in the Settlement. As, shown in APS Witness Snook's testimony, if APS were to use Staff's recommended figures and calculate the rate of return consistent with the Settlement and past orders, the revenue requirement requested here would be equal to or greater than in APS's original filing.

Q. **DOES RUCO'S TESTIMONY COMPLY WITH DECISION NOS. 73130 AND 73183? IF NOT, PLEASE EXPLAIN?**

A. No, it does not. RUCO misapplied Decision No. 73130 by applying the marginal cost of debt used for the cost deferral per that Decision as the applicable going forward rate of return. That is a clear misreading of Decision No. 73130 and is not consistent with the Settlement established precedent concerning FVROR. *See* Rebuttal Testimony of Snook.

V. VALUE OF THE TRANSACTION

Q. YOUR DIRECT TESTIMONY DISCUSSED THE REASONS THAT APS WAS COMMITTED TO PROCEEDING WITH THIS TRANSACTION. DO THOSE REASONS CONTINUE TO APPLY TODAY?

A. Yes. APS remains committed to the Four Corners Power Plant, to this transaction and to obtaining proper rate treatment for the transaction. Four Corners provides needed fuel diversity to APS's generation portfolio that (like electric utilities across the country) is increasingly becoming more dependent upon natural gas. Although APS encountered several challenges and delays through the process of acquiring Units 4-5 and retiring Units 1-3, the facts still remain that Four Corners is vital to the Navajo Nation's economy and to those communities surrounding the plant, the environment will benefit from the retirement of the less efficient and older Units 1-3, and Four Corners Units 4-5 are forecast to provide long-term value to APS customers. As noted by Staff Witness James Letzelter, as well as RUCO, this transaction continues to provide substantial economic benefits to APS's customers, the Navajo Nation and Arizona and is anticipated to do so throughout the remaining life of the plant.

VI. CONCLUSION

Q. WOULD YOU SUMMARIZE YOUR CONCLUSIONS ABOUT THE COMPANY'S PRESENT APPLICATION?

A. The Company's Application should be granted. Notwithstanding Sierra Club, the only significant disagreement among the parties originates either from a misinterpretation of Decision Nos. 73183 and 73130 or from a misapplication of the FVROR. APS complied with both Orders and the purchase of SCE's interest in Four Corners Units 4-5 was and remains a good deal for APS customers, the Navajo Nation, and Arizona.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

APS Exhibit ___

Why Four Corners is a Good Purchase?

Good for Customers

- Maintains diverse resource portfolio
- Low cost baseload generating resource
- Preserves APS customers' existing investments in Four Corners
- Provides over $400M net present value benefit to customers

Good for the Navajo Nation and Local Economy

- Preserves jobs & tax revenue for the Navajo Nation and local community
- Four Corners and the mine employ 800 workers, 82% of whom are Navajo
- Four Corners and the mine have an estimated economic benefit to the area of $225 million

Good for the Environment

- Closing Units 1-3 and running the cleaner, more efficient Units 4-5 significantly reduces emissions by:
  - Particulates: 43%
  - Nitrogen oxides: 36%
  - Carbon dioxide: 30%
  - Mercury: 61%
  - Sulfur dioxide: 24%

See APS's Second Technical Conference materials filed on February 18, 2014

EXHIBIT
APS-3
ADMITTED

ARIZONA PUBLIC SERVICE COMPANY
TOTAL COMPANY
SUMMARY COST OF CAPITAL
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		Adjusted End of Test Year 12/31/2010			
Line No.	Invested Capital	Amount	%	Cost Rate	Weighted Cost
1.	Long-Term Debt	$3,382,856	46.06% (a)	6.38% (b)	2.94%
2.	Preferred Stock	-	0.00%	0.00%	0.00%
3.	Common Equity	3,961,248	53.94% (a)	10.00% (b)	5.39%
4.	Short-Term Debt	-	0.00%	0.00%	0.00%
5.	Total	$ 7,344,104	100.00%		8.33%

(a) Section 5.1 of the Settlement Agreement attached to Decision No. 73183 states that: A capital structure comprised of 46.06% debt and 53.94% common equity shall be adopted.

(b) Section 5.2 of the Settlement Agreement attached to Decision No. 73183 states that: A return on common equity of 10.0% and an embedded cost of debt of 6.38% shall be adopted.

EXHIBIT
APS-4
ADMITTED

EXHIBIT
APS-5
ADMITTED

REBUTTAL TESTIMONY OF LELAND R. SNOOK

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-0224

July 3, 2014

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REBUTTAL TESTIMONY OF LELAND R. SNOOK
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-0224)

I. INTRODUCTION

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

A. My name is Leland R. Snook. My business address is 400 North 5th Street, Phoenix, Arizona, 85004. I am Director of Rates and Rate Strategy for Arizona Public Service Company ("APS" or "Company"). I have management responsibility for all aspects relating to rates and pricing.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My background and experience are set forth in Appendix A to this Rebuttal Testimony.

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

A. The purpose of my Rebuttal Testimony is to address Staff Witness Dennis Kalbarczyk's testimony on the Fair Value Rate of Return ("FVROR") that Staff used to calculate the Four Corners revenue requirement. I also address RUCO Witness Robert Mease's use of incremental debt costs for that same purpose, although APS Witness Blankenship does so in greater detail. I will also discuss the testimony of the large customer groups and electric suppliers who oppose applying the Four Corners Rate Rider to AG-1 customers. Finally, I sponsor the bill impact analysis resulting from APS's updated revenue requirement calculation.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Staff Witness Mr. Kalbarczyk has applied the concept of FVROR inconsistently with (1) how FVROR was determined in the Settlement adopted by Decision No. 73183 (May 24, 2012), (2) the express language of the Settlement itself, and (3) prior Commission decisions on FVROR.

RUCO Witness Mr. Mease does not ever determine a FVROR. He simply takes the incremental debt cost used to calculate the Four Corners Deferral in Decision No. 73130 and misapplies it as a rate of return to determine the incremental revenue requirement for the Four Corners acquisition.

As to AG-1, APS proposed to apply the Four Corners Rate Rider to only a subset of the AG-1 customer bill: to the portion covering the services that APS provides and not to the portion representing a pass through of charges from such customer's Alternative Generation Providers. The "Large Customer Group" and "Actual or Potential AG-1 Suppliers"[1] object to this middle-ground proposal, wanting a complete exemption from the charge. One could as easily support this view as they could argue that the Four Corners charge should be assessed to the entire AG-1 customer bill, rather than simply a portion of it. APS's proposal achieves a reasonable balance and treats all customers eligible for AG-1 in a similar manner.

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[1] Freeport-McMoRan Copper & Gold, Inc., Arizonans For Electric Choice and Competition, The Kroger Co., WalMart Stores, Inc., and Sam's West, Inc. (collectively referred to as the "Large Customer Group"), along with Noble American Energy Solutions L.L.C., Constellation NewEnergy, Inc., Direct Energy, L.L.C., and Shell Energy North America L.P (collectively referred to as "Actual or Potential AG-1 Suppliers").

III. STAFF'S APPLICATION OF THE FVROR IS INCORRECT

Q. PLEASE DESCRIBE HOW STAFF WITNESS DENNIS KALBARCZYK CALCULATED HIS PROPOSED FVROR IN THIS MATTER.

A. Mr. Kalbarczyk did not calculate a FVROR to apply to the Fair Value of the Four Corners asset. Rather, he took the 6.09% return on Fair Value Rate Base ("FVRB") referenced in the Settlement and applied it to the Original Cost of the Four Corners acquisition.

Q. WHY IS APPLYING THE FVROR CALCULATED IN THE SETTLEMENT TO THE FOUR CORNERS ASSET INCORRECT?

A. Because doing so ignores the Settlement's express intent that the Rate Rider reflect the "rate base and expense" effects of the Four Corners acquisition. It results in a FVROR on the new Four Corners asset that is demonstrably incorrect both as a matter of mathematics and in the context of Commission precedent.

In Section 10 of the Settlement, the parties agreed to hold open the underlying rate case to allow APS to seek to add the Four Corners acquisition to rate base as if the new asset had been a part of the Company's original rate case filing. To recognize the "rate base and expense effects" of that addition as the Settlement requires, one cannot simply cut and paste the 6.09% FVROR calculated using the Company's Settlement-authorized rate base and apply it to the new acquisition as a stand-alone asset.

Q. WHY NOT?

A. FVROR is the output of a formula whose components will change as items are added to or subtracted from rate base. The exact formula is as follows:

$$\textbf{FVROR} = \frac{\underline{\textbf{[(WACC x Original Cost Rate Base) + (1\% x Fair Value Increment)]}}}{\textbf{Fair Value Rate Base}}$$

Most of the inputs to this formula will change as rate base changes:

- Fair Value Rate Base is calculated by adding the Original Cost Rate Base ("OCRB") to the "Reconstruction Cost New Less Depreciation" ("RCND") of that Original Cost number and dividing that sum by 2. Fair Value Rate Base will thus clearly change with the value of either the OCRB or the RCND rate base.

- The Fair Value Increment is calculated by subtracting from the OCRB the Fair Value Rate Base ("FVRB"). Again, that number will change as either rate base calculation changes.

- The only static numbers in the formula are the WACC of 8.33% used in the Settlement and the 1% return on the Fair Value Increment.

Without the Four Corners acquisition, the OCRB and FVRB authorized in the Settlement resulted in a FVROR that equaled 6.09%. *See* Figure A below. But both of those numbers change when the new Four Corners asset is added to rate base, as contemplated by the Settlement. It is simply a matter of mathematics.

The following chart walks through three calculations of the FVROR formula: one with the Original Settlement calculation, a stand-alone Four Corners acquisition calculation and the combination of the Settlement and the Four Corners acquisition.

Figure A: Settlement and Four Corners Revenue Requirement to Calculate the FVROR

		Settlement	Four Corners	Four Corners + Settlement
		(dollars in thousands)		
1.	OCRB	$ 5,662,998	$ 225,934	$ 5,888,932
2.	WACC	8.33%	8.33%	8.33%
3.	Resulting Operating Income (line 1 * line 2)	$ 471,728	$ 18,820	$ 490,548
4.	FVRB	$ 8,167,126	$ 225,934	$ 8,393,060
5.	Incremental FVRB Over OCRB, i.e. Fair Value Increment (line 4 - line 1)	$ 2,504,128	$ 0	$ 2,504,128
6.	Return on Fair Value Increment	1.00%	1.00%	1.00%
7.	Return on Fair Value Increment * Fair Value Increment (line 6 * line 5)	$ 25,041	$ 0	$ 25,041
8.	OCRB + FVRB Required Operating Income (line 3 + line 7)	$ 496,769	$ 18,820	$ 515,590
9.	FVROR (line 8 / line 4)	6.09%	8.33%	6.14%

Each of these calculations effectively recognize the 8.33% WACC and 1% return on Fair Value Increment used in the Settlement. The slight increase to the FVROR percentage in the Four Corners plus Settlement scenario is not caused by any enhanced return on that asset, but simply reflects how the math changed when the rate base changed. APS still recovers only an 8.33% WACC and earns only a 1% return on the Fair Value increment, the numbers already used in the Settlement.

Mr. Kalbarczyk's treatment, on the other hand, effectively prevents APS from realizing the cost of capital on its investment. The return that results from Mr. Kalbarczyk's recommendation is $8.3 million less than the actual "rate base effect" of the transaction shown in Figure A above and is thus inconsistent with that express Settlement requirement.

Q. ARE THE OCRB AND RCND FOR THE FOUR CORNERS ACQUISITION ACTUALLY THE SAME?

A. No. By its very definition, RCND for the newly acquired Four Corners plant would cost significantly more to reconstruct and build new than the acquisition price. For example, applying the RCND accepted in the rate case for the Company's pre-existing share of Four Corners scaled to the newly acquired portion of the plant would result in a RCND of $716 million. This number stands in sharp contrast to the OCRB of about $226 million and would make the FVRB of the Four Corners acquisition $471 million.

Q. WHAT EFFECT WOULD APPLYING AN ACTUAL RCND TO THE FOUR CORNERS ASSET HAVE HAD ON APS'S REQUEST IN THIS PROCEEDING?

A. If APS had done so, there would have been a meaningful difference between the FVROR and the WACC. In fact, doing so would have *reduced* the FVROR to 6.00% -- below the 6.09% FVROR noted in the Settlement. Ironically, however, the resulting change in FVRB would also have *increased* APS's request in this proceeding by over $4 million to $69.45 million.

If APS had applied a 6.09% FVROR to FVRB in that scenario, as Mr. Kalbarczyk argues is somehow required, rather than the 6.00% that results mathematically, the revenue request would have been even larger. *See* Rebuttal Attachment LRS-1 for the details of this calculation. These examples all show that the exact FVROR is asset-specific and the overall FVROR is the weighted sum of these asset-specific FVRORs. One cannot plug and play one FVROR value to a different mix of plant and expect a reasonable result.

Q. WHY DID APS ASSUME IN ITS DIRECT TESTIMONY THAT FAIR VALUE, ORIGINAL COST, AND RCND ARE ALL THE SAME FOR THE FOUR CORNERS ASSET?

A. APS made a simplifying assumption to reflect just the cost of acquiring Southern California Edison's ("SCE") share of the Four Corners Units 4 and 5 because the asset was new to APS.

Q. IS IT APPROPRIATE TO USE THE 6.09% FVROR DESCRIBED IN THE SETTLEMENT FOR THE FOUR CORNERS RATE BASE ADDITION SOUGHT HERE?

A. No. Because, as I indicated above, doing so effectively mixes apples and oranges. The FVROR is one number when focused on the Four Corners asset in isolation; it is a different number when calculated using the pre-Four Corners Settlement rate base; and it is yet a different number when one adds the Four Corners purchase to the Settlement rate base amount. As described above, the FVROR is not a static number and treating it as such will result in flawed revenue recovery. For example, when the new Four Corners asset is taken on its own, FVROR and WACC are actually the same number – in this case, 8.33%. Recall the formula:

$$\textbf{FVROR} = \frac{\textbf{[(WACC x Original Cost Rate Base) + (1\% x Fair Value Increment)]}}{\textbf{Fair Value Rate Base}}$$

As discussed above, Fair Value Rate Base is determined by adding OCRB and RCND and dividing that total by 2. However, because the asset is new to APS, the OCRB and RCND were assumed to be identical. This means that Fair Value Rate Base and Original Cost Rate Base were also deemed to be identical. For ease of illustration, I will refer to that Rate Base number as "Y." Recall also that the Fair Value Increment is the difference between Fair Value Rate Base and Original Cost Rate Base. In this case, Y-Y=0. Plugging each of these inputs into the Fair Value Rate of Return formula above makes clear that, for the Four Corners asset on its own, the FVROR and the WACC are also the same number:

FVROR = (WACC x Y) + (1% x 0) / Y

FVROR = (WACC x Y) / Y

FVROR = WACC

In this case, the WACC used in the Settlement is 8.33%. This means that the FVROR that should be applied to the Fair Value of the new Four Corners asset is also 8.33% - the precise number that APS used to calculate the revenue requirement in this proceeding. Arbitrarily applying a 6.09% value instead of 8.33% prevents APS from any opportunity of earning its WACC on the Four Corners asset, in violation of Section 5 of the Settlement Agreement.

Q. DOES MR. KALBARCZYK'S RECOMMENDATION CONFLICT WITH PRIOR ACC PRECEDENT?

A. Yes. The formula used to calculate FVROR in Decision No. 73183 was far from unique. To APS's knowledge, that formula has been used in almost every case since the Commission began to value a FVRB Increment. And even before that time, the Commission acknowledged that the FVROR must be sufficient to allow the utility to recover its WACC. In particular, the Commission recognized that

> "[t]he beginning point of our inquiry [concerning Fair Value Rate of Return] must be the cost of capital. It is difficult to imagine a situation in which a reasonable return on FVRB would yield *less* than the cost of capital which comprises that rate base.

In re Arizona Water Company, Decision No. 53537 (April 27, 1983) at 15 (emphasis in original).

Mr. Kalbarczyk's recommendation fails the above test of a "reasonable return on FVRB" by a wide mark, under-recovering the WACC associated with the Four Corners transaction by some $8.3 million per year.

IV. RUCO DOES NOT RECOMMEND AN ACTUAL FVROR

Q. DOES RUCO'S FVROR RECOMMENDATION SUFFER FROM THE SAME DEFICIENCIES AS STAFF'S?

A. As a practical matter, the answer is yes. However, RUCO does not represent that its proposal to use a 4.725% return for purposes of calculating an incremental revenue requirement produces a reasonable FVROR, as is required by law. Rather, RUCO interprets Decision No. 73130 (April 24, 2012) as somehow mandating the use of an incremental debt cost for this purpose. In reality, that Decision does not address how revenue requirements should be calculated for the Four Corners Transaction once that Transaction is reflected in rates, a point that APS Witness Blankenship underscores in her Rebuttal Testimony. Decision No. 73130 solely addressed the return to be accrued on the deferred costs during the deferral period, which APS presently is estimating to run from December 30, 2013 through November of 2014. APS's calculation of the deferrals associated with the Four Corners Transaction reflected that accrued return both in the original filing and in the Company's April 30th update. *See* Rebuttal Testimony of APS Witness Blankenship.

V. TREATMENT OF AG-1 CUSTOMERS

Q. HOW DID APS PROPOSE TO APPLY THE PERCENTAGE INCREASE IN ITS ORIGINAL APPLICATION?

A. APS proposed to apply the percentage increase as an equal percentage to the base rate portion of customers' bills as contemplated by the Settlement. APS requested the percentage increase be applied to the "APS" portion of an AG-1 customer's bill, but not to the portion representing a pass through of charges from such customer's Alternative Generation Provider. E-36XL customers were treated similarly to AG-1 customers due to their unique generation service requirements.

Q. DID ANY INTERVENOR ADDRESS THE APPLICATION OF THE RATE RIDER TO AG-1 CUSTOMERS? IF SO, PLEASE EXPLAIN THEIR POSITION.

A. Yes. Both the Large Customer Group and the Actual or Potential AG-1 Suppliers addressed assessing the Four Corners Rate Rider to AG-1 customers. Both stated that AG-1 customers should be completely excluded from the Four Corners Rate Rider because that charge is related to generation plant.

Q. DOES APS AGREE WITH THEIR PROPOSED TREATMENT?

A. No. The Settlement made no distinction between the generation component of a rate schedule and the other components of base rates, and APS has therefore proposed to assess the Four Corners Surcharge on each and every element of base rates for each rate schedule. However, APS was aware that AG-1, also approved in the Settlement, exempts AG-1 customers from paying the generation component of their underlying rate schedule. In an attempt to give both provisions meaning, APS filed the middle-ground approach discussed above.

Q. WHAT WOULD BE THE IMPACT OF THE COMMISSION ADOPTING THE POSITION OF THESE INTERVENORS?

A. As noted in Mr. Kevin Higgins' Testimony, the Four Corners Rate Rider would increase all other customer bills by approximately 0.02%, or $581,410.

VI. <u>BILL IMPACT</u>

Q. WHAT IS THE UPDATED REVENUE REQUIREMENT REQUESTED BY THE COMPANY AND WHAT WILL BE THE IMPACT ON CUSTOMERS?

A. APS Witness Blankenship's Testimony describes the details of the updated revenue requirement calculation, but APS is seeking recovery of $65.44 million or approximately 2.1% on the average residential customer bill.[2] A sample bill analysis is attached to my Testimony as Rebuttal Attachment 2. This Attachment also satisfies Section 10.3 of the Settlement Agreement's requirement to file a typical bill analysis (Schedule 7) under present and filed rates.

Q. WHAT IS APS PROPOSING AS THE EFFECTIVE DATE FOR THE RATE RIDER TO BE IMPLEMENTED?

A. APS has assumed that the Rider will become effective on December 1, 2014 for purposes of calculating the deferral. As noted in APS Witness Blankenship's testimony, if the Rider is implemented after that date, there will be additional cost deferrals to recover, although it is the Company's recommendation that any deferrals not captured in the Commission's final order in this matter be carried over until the Company's next general rate proceeding.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS ABOUT THE COMPANY'S REBUTTAL TESTIMONY.

A. Mr. Kalbarczyk application of the FVROR is inconsistent with how it was determined in the Settlement (Decision No. 73183), the language of the Settlement Agreement, and with prior Commission decisions on FVROR.

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[2] Note that the Rider schedule attached to APS Witness Blankenship's Testimony shows the percentage increase of 2.33%. The difference between that number and the 2.1% referenced in my Testimony above is that the Rider is applied to only the base rate portion of a customer's bill. However it is important to a customer to know the total bill impact, which is why the 2.1% bill impact is included in my testimony.

Mr. Mease simply takes the marginal debt cost from Decision No. 73130, which was intended to be used only to calculate the Four Corners Cost Deferral, and mistakenly applies it as a rate of return in determining the revenue requirement for the Four Corners acquisition.

Finally, the Company's proposal regarding the application of the Four Corners Surcharge to those services directly provided to AG-1 customers by APS, rather than the AG-1 customer's entire bill, achieves a reasonable balance of two different provisions of the Settlement. Moreover, it treats all customers eligible for AG-1 in a similar manner

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Appendix A

Statement of Qualifications

Leland R. Snook

Leland R. Snook is Arizona Public Service Company's Director, Rates and Rate Strategy. He has over 25 years' experience in the electric utility business as a utility professional. Mr. Snook holds a Bachelor of Science Degree in Electrical Engineering from Texas Tech University and is a registered professional electrical engineer in the state of Arizona.

Mr. Snook's areas of expertise include development and analysis of electric utility revenue requirements, modeling of cost of service, rate schedule design, embedded and marginal cost analysis and formulation of utility service policies. Mr. Snook has previously testified before the Arizona Corporation Commission on customer service contract and rate schedule matters.

Mr. Snook has held his current position at Arizona Public Service Company for approximately six years. Prior to assuming that position, he served as the Director of Federal Regulation for APS. Before joining APS, Mr. Snook had a twenty-two year career with Tucson Electric Power Company, where he served in various professional and leadership roles.

ARIZONA PUBLIC SERVICE COMPANY
FOUR CORNERS REVENUE REQUIREMENT CALCULATION
COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENTS
ACC JURISDICTION
ADJUSTED TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	Original Cost	RCND	Fair Value	Line No.
1.	Adjusted Rate Base per Settlement	$ 5,662,998	$ 10,671,253	$ 8,167,126	1.
2.	Four Corners Rate Base Pro Forma Adjustments	225,934	716,142	471,038	2.
3.	Adjusted Rate Base with Four Corners (line 1 + line 2)	5,888,932	11,387,395	8,638,164	3.
4.	Adjusted Operating Income per Settlement	496,769	496,769	496,769	4.
5.	Four Corners Income Statement Pro Forma Adjustments	(20,680)	(20,680)	(20,680)	5.
6.	Adjusted Operating Income with Four Corners (line 4 + line 5)	476,089	476,089	476,089	6.
7.	Current Rate of Return (Line 6 / Line 3)	8.08%	4.18%	5.51%	7.
8.	Required Operating Income (Line 9 * Line 3)	490,548	490,548	490,548	8.
9.	Required Rate of Return	8.33%	4.60%	6.01%	9.
10.	Adjusted Operating Income Deficiency (Line 8 - Line 6)	14,459	14,459	14,459	10.
11.	Gross Revenue Conversion Factor per Settlement	1.6566	1.6566	1.6566	11.
12.	Requested Increase in Base Revenue Requirements (Line 10 * Line 11)	$ 23,953	$ 23,953	$ 23,953	12.
13.	Fair Value Increment	41,483		45,497	13.
14.	Requested Increase in Base Revenue Requirements (Line 12 + Line 13)	$ 65,436		$ 69,450	14.
15.	Required Rate of Return with Fair Value			6.00%	15.

ARIZONA PUBLIC SERVICE COMPANY
Estimated Monthly Bill Impacts of Four Corners Adjustor

	Current	Requested December 2014	Current	Requested December 2014	Current	Requested December 2014
Residential (Average - All Rates)	Annual Average Monthly Bill [1]	Annual Average Monthly Bill [2]	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	1,100	1,100	1,337	1,337	863	863
Base Rates	$ 123.90	$ 123.90	$ 161.07	$ 161.07	$ 86.72	$ 86.72
Four Corners Adjustment	$ -	$ 2.89	$ -	$ 3.75	$ -	$ 2.02
PSA - Forward Component	$ 1.41	$ 1.41	$ 1.71	$ 1.71	$ 1.10	$ 1.10
PSA - Historical Component	$ 0.31	$ 0.31	$ 0.37	$ 0.37	$ 0.24	$ 0.24
TCA	$ 7.70	$ 7.70	$ 9.36	$ 9.36	$ 6.04	$ 6.04
RES	$ 4.11	$ 4.11	$ 4.11	$ 4.11	$ 4.11	$ 4.11
DSMAC	$ 2.03	$ 2.03	$ 2.47	$ 2.47	$ 1.59	$ 1.59
EIS	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.02	$ 0.02
LFCR	$ 1.33	$ 1.36	$ 1.70	$ 1.74	$ 0.95	$ 0.97
Total	$ 140.82	$ 143.74	$ 180.82	$ 184.61	$ 100.77	$ 102.81
Bill Impact		**$ 2.92**				
		2.07%				

Residential (Rate E-12)	Annual Average Monthly Bill [1]	Annual Average Monthly Bill [2]	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	691	691	780	780	602	602
Base Rates	$ 86.40	$ 86.40	$ 108.04	$ 108.04	$ 64.76	$ 64.76
Four Corners Adjustment	$ -	$ 2.02	$ -	$ 2.52	$ -	$ 1.51
PSA - Forward Component	$ 0.88	$ 0.88	$ 1.00	$ 1.00	$ 0.77	$ 0.77
PSA - Historical Component	$ 0.20	$ 0.20	$ 0.22	$ 0.22	$ 0.17	$ 0.17
TCA	$ 4.84	$ 4.84	$ 5.46	$ 5.46	$ 4.22	$ 4.22
RES	$ 4.11	$ 4.11	$ 4.11	$ 4.11	$ 4.11	$ 4.11
DSMAC	$ 1.28	$ 1.28	$ 1.44	$ 1.44	$ 1.11	$ 1.11
EIS	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.01	$ 0.01
LFCR	$ 0.93	$ 0.95	$ 1.14	$ 1.17	$ 0.71	$ 0.73
Total	$ 98.66	$ 100.70	$ 121.43	$ 123.98	$ 75.86	$ 77.39
Bill Impact		**$ 2.04**				
		2.07%				

Commercial (Rate E-32, 0-20 kW)	Annual Average Monthly Bill [1]	Annual Average Monthly Bill [2]	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	1,430	1,430	1,575	1,575	1,285	1,285
Base Rates	$ 202.38	$ 202.38	$ 233.37	$ 233.37	$ 171.39	$ 171.39
Four Corners Adjustment	$ -	$ 4.72	$ -	$ 5.44	$ -	$ 3.99
PSA - Forward Component	$ 1.83	$ 1.83	$ 2.01	$ 2.01	$ 1.64	$ 1.64
PSA - Historical Component	$ 0.40	$ 0.40	$ 0.44	$ 0.44	$ 0.36	$ 0.36
TCA	$ 3.73	$ 3.73	$ 4.11	$ 4.11	$ 3.35	$ 3.35
RES	$ 14.68	$ 14.68	$ 16.17	$ 16.17	$ 13.19	$ 13.19
DSMAC	$ 2.64	$ 2.64	$ 2.91	$ 2.91	$ 2.37	$ 2.37
EIS	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03
LFCR	$ 2.15	$ 2.19	$ 2.46	$ 2.51	$ 1.83	$ 1.87
Total	$ 227.84	$ 232.60	$ 261.50	$ 266.99	$ 194.16	$ 198.19
Bill Impact		**$ 4.76**				
		2.09%				

ARIZONA PUBLIC SERVICE COMPANY
Estimated Monthly Bill Impacts of Four Corners Adjustor

	Current	Requested December 2014	Current	Requested December 2014	Current	Requested December 2014
Commercial (Rate E-32, >20 kW)	Annual Average Monthly Bill [1]	Annual Average Monthly Bill [2]	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	7,182	7,182	7,752	7,752	6,612	6,612
Base Rates	$ 842.33	$ 842.33	$ 987.28	987.28	$ 697.38	$ 697.38
Four Corners Adjustment	$ -	$ 19.63	$ -	$ 23.00	$ -	$ 16.25
PSA- Forward Component	$ 9.17	$ 9.17	$ 9.90	$ 9.90	$ 8.44	$ 8.44
PSA - Historical Component	$ 2.01	$ 2.01	$ 2.17	$ 2.17	$ 1.85	$ 1.85
TCA	$ 19.48	$ 19.48	$ 22.03	$ 22.03	$ 16.93	$ 16.93
RES	$ 73.72	$ 73.72	$ 79.57	$ 79.57	$ 67.87	$ 67.87
DSMAC	$ 16.50	$ 16.50	$ 18.65	$ 18.65	$ 14.34	$ 14.34
EIS	$ 0.15	$ 0.15	$ 0.16	$ 0.16	$ 0.14	$ 0.14
LFCR	$ 9.16	$ 9.35	$ 10.65	$ 10.87	$ 7.67	$ 7.83
Total	$ 972.52	$ 992.34	$ 1,130.41	$ 1,153.63	$ 814.62	$ 831.03
Bill Impact		**$ 19.82**				
		2.04%				

Commercial (Rate E-32 M)	Annual Average Monthly Bill [1]	Annual Average Monthly Bill [2]	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	62,238	62,238	68,381	68,381	56,094	56,094
Base Rates	$ 6,431.10	$ 6,431.10	$ 7,407.24	7,407.24	$ 5,454.95	$ 5,454.95
Four Corners Adjustment	$ -	$ 149.85	$ -	$ 172.59	$ -	$ 127.10
PSA- Forward Component	$ 79.48	$ 79.48	$ 87.32	$ 87.32	$ 71.63	$ 71.63
PSA - Historical Component	$ 17.43	$ 17.43	$ 19.15	$ 19.15	$ 15.71	$ 15.71
TCA	$ 160.83	$ 160.83	$ 172.21	$ 172.21	$ 149.44	$ 149.44
RES	$ 256.60	$ 256.60	$ 256.60	$ 256.60	$ 256.60	$ 256.60
DSMAC	$ 136.17	$ 136.17	$ 145.81	$ 145.81	$ 126.53	$ 126.53
EIS	$ 1.31	$ 1.31	$ 1.44	$ 1.44	$ 1.18	$ 1.18
LFCR	$ 67.35	$ 68.78	$ 76.93	$ 78.57	$ 57.78	$ 58.99
Total	$ 7,150.27	$ 7,301.55	$ 8,166.70	$ 8,340.93	$ 6,133.82	$ 6,262.13
Bill Impact		**$ 151.28**				
		2.12%				

Commercial (Rate E-32 L)	Annual Average Monthly Bill [1]	Annual Average Monthly Bill [2]	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	290,507	290,507	314,925	314,925	266,089	266,089
Base Rates	$ 24,707.54	$ 24,707.54	$ 29,453.69	$ 29,453.69	$ 19,961.38	$ 19,961.38
Four Corners Adjustment	$ -	$ 575.69	$ -	$ 686.27	$ -	$ 465.10
PSA- Forward Component	$ 370.98	$ 370.98	$ 402.16	$ 402.16	$ 339.80	$ 339.80
PSA - Historical Component	$ 81.34	$ 81.34	$ 88.18	$ 88.18	$ 74.50	$ 74.50
TCA	$ 588.97	$ 588.97	$ 653.49	$ 653.49	$ 524.44	$ 524.44
RES	$ 513.20	$ 513.20	$ 513.20	$ 513.20	$ 513.20	$ 513.20
DSMAC	$ 498.69	$ 498.69	$ 553.32	$ 553.32	$ 444.05	$ 444.05
EIS	$ 6.10	$ 6.10	$ 6.61	$ 6.61	$ 5.59	$ 5.59
Total	$ 26,766.82	$ 27,342.51	$ 31,670.65	$ 32,356.92	$ 21,862.96	$ 22,328.06
Bill Impact		**$ 575.69**				
		2.15%				

ARIZONA PUBLIC SERVICE COMPANY
Estimated Monthly Bill Impacts of Four Corners Adjustor

Industrial (Rate E34/35)	Current Annual Average Monthly Bill [1]	Requested December 2014 Annual Average Monthly Bill [2]	Current Summer Monthly Bill	Requested December 2014 Summer Monthly Bill	Current Winter Monthly Bill	Requested December 2014 Winter Monthly Bill
Average kWh per Month	3,693,933	3,693,933	3,841,873	3,841,873	3,545,992	3,545,992
Base Rates	$ 251,228.00	$ 251,228.00	$ 262,539.00	$ 262,539.00	$ 239,917.00	$ 239,917.00
Four Corners Adjustment	$ -	$ 5,853.62	$ -	$ 6,117.16	$ -	$ 5,590.07
PSA - Forward Component	$ 4,717.15	$ 4,717.15	$ 4,906.07	$ 4,906.07	$ 4,528.23	$ 4,528.23
PSA - Historical Component	$ 1,034.30	$ 1,034.30	$ 1,075.72	$ 1,075.72	$ 992.88	$ 992.88
TCA	$ 7,433.21	$ 7,433.21	$ 7,796.73	$ 7,796.73	$ 7,069.69	$ 7,069.69
RES	$ 3,335.00	$ 3,335.00	$ 3,335.00	$ 3,335.00	$ 3,335.00	$ 3,335.00
DSMAC	$ 4,433.18	$ 4,433.18	$ 4,649.98	$ 4,649.98	$ 4,216.37	$ 4,216.37
EIS	$ 77.58	$ 77.58	$ 80.68	$ 80.68	$ 74.47	$ 74.47
Total	$ 272,258.42	$ 278,112.04	$ 284,383.18	$ 290,500.34	$ 260,133.64	$ 265,723.71
Bill Impact		**$ 5,853.62**				
		2.15%				

Notes:
(1) Bill excludes regulatory assessment charge, taxes and fees. Adjustor levels in effect as of June 1, 2014

EXHIBIT
APS-6
ADMITTED

REJOINDER TESTIMONY OF LELAND R. SNOOK

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-0224

July 28, 2014

<u>Revised August 5, 2014</u>

Table of Contents

REJOINDER TESTIMONY OF LELAND R. SNOOK ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (Docket No. E-01345A-11-0224)

I. INTRODUCTION

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

A. My name is Leland R. Snook. My business address is 400 North 5th Street, Phoenix, Arizona, 85004. I am Director of Rates and Rate Strategy for Arizona Public Service Company ("APS" or "Company"). I have management responsibility for all aspects relating to rates and pricing.

Q. DID YOU PREVIOUSLY SUBMIT TESTIMONY IN THIS PROCEEDING?

A. Yes, my Rebuttal Testimony was filed on July 3, 2014.

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

A. I address Staff Witness Dennis Kalbarczyk's continued insistence that it is appropriate to apply a Fair Value Rate of Return ("FVROR") calculated using a specific mix of rate base assets (2010 Test Year Rate Base) to a different mix of rate base assets, specifically one that includes both APS's acquisition of SCE's share of Four Corners Units 4 and 5 and the 2010 Test Year Rate Base. I then respond to RUCO Witness Robert Mease's argument justifying his use of an incremental debt return to calculate the revenue requirement for the above acquisition.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REJOINDER TESTIMONY.

A. Mr. Kalbarczyk's and Mr. Mease's FVROR recommendations share one thing in common; though both believe that the investment was prudent, neither would permit APS to recover the full costs of owning and operating the additional share of Four Corners Units 4 and 5 acquired from SCE. This stands in stark contrast to the regulatory treatment afforded the Company's already-existing ownership interest in precisely the same Four Corners Units 4-5 by both the 2012 Settlement adopted by the Commission in Decision No. 73183 (May 24, 2012) and in all previous APS rate proceedings since Four Corners 4-5 were included in the Company's rate base in the 1970s.

Mr. Kalbarczyk does not explain the inconsistency of his recommendation with prior Commission precedent on FVROR. And his analysis of the 6.09% FVROR appearing in the 2012 Settlement demonstrates a fundamental unfamiliarity with the concept of FVROR, as determined by the Commission in this and other dockets.

Mr. Mease has abandoned his argument that Decision No. 73130 (April 24, 2012) supports RUCO's position and no longer contends that limiting APS to an incremental debt return is some manner of "risk sharing." Rather RUCO now argues that unlike every other asset in the Company's rate base, we should attempt to directly assign portions of the Company's overall cost of capital to these specific assets, especially that portion that provides for the lowest possible revenue requirement.

III. STAFF'S FAIR VALUE RATE OF RETURN

Q. WHY DOES STAFF MAINTAIN THAT A 6.09% RETURN IS REASONABLE IN DETERMINING THE REVENUE REQUIREMENT IN THIS PROCEEDING?

A. Mr. Kalbarczyk never contended that it was reasonable – merely that it appeared in the 2012 Settlement and, in his opinion, cannot be changed in this proceeding even though we are significantly changing one of the critical inputs to the formula that determines FVROR.

Q. AT PAGE 4 OF HIS SURREBUTTAL, MR. KALBARCZYK TAKES ISSUE WITH HOW YOU CHARACTERIZED THE CALCULATION OF FVROR IN YOUR REBUTTAL. IS HE CORRECT?

A. He is correct that the formula used by Staff witness Ralph Smith in the underlying rate case that led to the 2012 Settlement used a weighted capital structure to determine FVROR. The Exhibit referenced by Mr. Kalbarczyk is shown as Attachment LRS-1-Rejoinder. As seen in Figure 1, I show the same calculation using the 1% return on the Fair Value Increment (discussed in my Rebuttal Testimony) and the 10% ROE from the 2012 Settlement, as well as the capital ratios from the 2012 Settlement:

Figure 1

Adjusted Test Year Capital Structure	**Amount**	**%**	**Cost Rate**	**Weighted Average**
Long-Term Debt	$ 3,382,856	46.06%	6.38%	2.94%
Common Equity	3,961,248	53.94%	10.00%	5.39%
TOTAL	$ 7,344,104	100.00%		8.33%

Capital Structure with Settlement 1.0% Return on FV Increment	**Amount**	**%**	**Cost Rate**	**Weighted Average**
Long-Term Debt	$ 2,608,377	31.94%	6.38%	2.04%
Common Equity	3,054,621	37.40%	10.00%	3.74%
FVRB Increment	2,504,128	30.66%	1.00%	0.31%
TOTAL	$ 8,167,126	100.00%		6.09%

As you can see, one gets to precisely the same number as I calculated starting on page 3 of my Rebuttal Testimony. If I include the rate base addition of the SCE share of Four Corners 4 and 5 (a rate base amount that neither Staff nor RUCO disputes) into the above equation using the exact same beginning amounts of debt, equity and Fair Value Increment as Staff Witness Smith, I get the following FVROR:

Figure 2

Capital Structure with Four Corners Included	**Amount**	**%**	**Cost Rate**	**Weighted Average**
Long-Term Debt	$2,712,442	32.32%	6.38%	2.06%
Common Equity	3,176,490	37.85%	10.00%	3.79%
FVRB Increment	2,504,128	29.84%	1.00%	0.30%
Total	$8,393,060	100.00%		6.14%

This is again the identical result as in my Rebuttal Testimony. So while it is true that one can determine FVROR either by taking revenue requirement and dividing it by FVRB or by treating the Fair Value Increment as a low cost (1% in this case) capital structure component, both lead to the same end result.

Bottom line, rate base, expenses and rate of return are <u>not</u> three wholly independent variables in determining revenue requirement as postulated by Mr. Kalbarczyk at the top of page 4 of his Surrebuttal. Rather, FVROR and rate base are interdependent variables given the existence of the Fair Value Increment and its ratemaking treatment in Arizona. This interdependence would not exist in an Original Cost Rate Base jurisdiction, which Mr. Kalbarczyk may be more familiar with than Arizona.

Q. MR. KALBARCZYK STATES THAT APS IS ASKING AN 8.33% RETURN ON THE FAIR VALUE OF THE ADDITIONAL SHARE OF FOUR CORNERS AND NOT 6.14%. IS HE CORRECT?

A. It depends on whether one is looking at the return on the Four Corners increment in isolation or as a component to the whole of APS's rate base, including the additional Four Corners investment. Whether the overall Company FVROR is 6.09% without the additional share of Four Corners Units 4 and 5 or 6.14% with them, these numbers are a composite of thousands of individual asset returns that are above or below those overall returns. For older assets with relatively large Fair Value Increments, the return is well below 6%. The newer an asset is (with a correspondingly lesser Fair Value Increment) the closer the return will be to the Weighted Average Cost of Capital of 8.33%. But as noted at page 5 of my Rebuttal, this provides APS not one cent more return on a dollar of its investment in the SCE share of Four Corners than on a dollar of its pre-existing share of Four

Corners or, for that matter, its thousands of other investments outside of Four Corners that comprised the Company's rate base in Decision No. 73183.

Q. MR. KALBARCZYK ARGUES I AM TRYING TO DENY THE COMMISSION DISCRETION IN DETERMINING FVROR? DO YOU AGREE?

A. No. The Commission exercises it discretion when it determines, after consideration of the evidence presented, all the inputs to either my formula as shown on page 7 of my Rebuttal Testimony or that referenced by Mr. Kalbarczyk at page 4 of his Surrebuttal Testimony. Thereafter, discretion is replaced by mathematics.

Q. MR. KALBARCZYK FURTHER TESTIFIES AT PAGE 7 OF HIS SURREBUTTAL THAT IF THE COMMISSION AGREES IT SHOULD CALCULATE FVROR FOR THE COMPANY'S ADDITIONAL INVESTMENT IN FOUR CORNERS UNITS 4 AND 5 IN THE SAME MANNER AS IT HAS FOR EVERY OTHER APS ASSET, INCLUDING THE COMPANY'S PRE-EXISTING INVESTMENT IN THE VERY SAME UNITS, THE COMMISSION SHOULD COMPREHENSIVELY RE-EXAMINE FVROR. DO YOU AGREE?

A. No. The 2012 Settlement language was very clear that this would not be another rate case and another opportunity to re-litigate ROE, operating expenses, or additional rate base other than Four Corners. While as we have seen here, the addition of this new Four Corners investment necessarily changes FVROR (and other ratemaking items such as property and income taxes), APS has asked to change no other element of Decision No. 73183. All APS has done in this case is to treat the new investment as though it were originally part of the 2010 TY rate case, precisely as the 2012 Settlement intended and urges the Commission to reject Mr. Kalbarczyk's suggestion otherwise.

IV. <u>RUCO'S DEBT RETURN ARGUMENT AND BILL IMPACT ANALYSIS</u>

Q. DOES RUCO CONTINUE TO CONTEND THAT DECISION NO. 73130 REQUIRES THE COMMISSION TO USE AN INCREMENTAL DEBT

RETURN TO DETERMINE REVENUE REQUIREMENTS IN THIS PROCEEDING.

A. No.

Q. IS RUCO STILL ARGUING THAT REDUCING THE RETURN ON THE PORTION OF FOUR CORNERS UNITS 4 AND 5 ACQUIRED FROM SCE TO LESS THAN HALF THAT APPLIED TO THE COMPANY'S PRE-EXISTING SHARE OF THOSE SAME UNITS IS APPROPRIATE AS SOME MANNER OF "RISK SHARING?"

A. It does not appear so. Mr. Mease does not raise that argument in his Surrebuttal Testimony, and RUCO conceded in response to a Company Data Request that such a proposal was unprecedented in this or any other jurisdiction. *See* Attachment LRS-2-Rejoinder.

Q. WHAT IS THE RATIONALE RUCO USES TO SUPPORT ITS POSITION?

A. As best as I can make out, RUCO is attempting to assign one specific debt issuance of the Company's overall capitalization to the newly acquired share of Four Corners Units 4 and 5. Fortuitously for RUCO, it is one of the lowest cost components of APS's capitalization – a debt issuance in early 2014. I doubt that if APS had issued equity in early 2014, Mr. Mease would be recommending a full equity return on the Company's incremental investment in Four Corners.

Q. TO YOUR KNOWLEDGE, HAS THE COMMISSION EVER DETERMINED REVENUE REQUIREMENTS USING A SPECIFIC SECURITY'S COST AS THE FVROR?

A. No.

V. <u>CONCLUSION</u>

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Both Staff's and RUCO's recommendations would result in APS being unable to recover the cost of owning and operating its newly-acquired share of Four Corners Units 4 and 5. The difference is one of degree, albeit an important degree. Capital costs are every bit as real as labor or materials costs – costs that neither Staff nor RUCO suggest APS not be able to fully recover. I would conclude by again quoting the Commission's own words from the Arizona Water Company Decision cited in my Rebuttal Testimony: "It is difficult to imagine a situation in which a reasonable return on FVRB would yield less than the cost of capital which comprises that rate base." In this case, I would suggest that it is more than simply "difficult to imagine," but outright impossible. Neither Staff nor RUCO has provided any rationale for a different conclusion.

Q. DOES THIS CONCLUDE YOUR REJOINDER TESTIMONY?

A. Yes.

Arizona Public Service Company
Capital Structure & Cost Rates

Docket No. E-01345A-11-0224
Schedule D
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Capital Source		Capitalization Amount	Capitalization Percent	Cost Rate	Weighted Avg. Cost of Capital
			(A)	(B)	(C)	(D)
	APS - Proposed					
1	Short-Term Debt	$	-			0.00%
2	Long-Term Debt	$	3,382,856	46.06%	6.38%	2.94%
3	Common Stock Equity	$	3,961,248	53.94%	11.00%	5.93%
4	Total Capital	$	7,344,104	100.00%		8.87%
	ACC Staff - Proposed					
5	Short-Term Debt	$	-			0.00%
6	Long-Term Debt	$	3,382,856	46.06%	6.38%	2.94%
7	Common Stock Equity	$	3,961,248	53.94%	9.90%	5.34%
8	Total Capital	$	7,344,104	100.00%		8.28%
9	Difference					-0.59%
10	Weighted Cost of Debt					2.94%
	ACC Staff - Proposed Fair Value Rate of Return - Alternative 1					
11	Short-Term Debt	$	-	0.00%	0.00%	0.00%
12	Long-Term Debt	$	2,608,502	31.94%	6.38%	2.04%
13	Common Stock Equity	$	3,054,497	37.40%	9.90%	3.70%
14	Capital financing OCRB	$	5,662,998			
15	Appreciation above OCRB not recognized on utility's books	$	2,504,128	30.66%	0% [a]	0.00%
16	Total capital supporting FVRB	$	8,167,126	100.00%		5.74%
	ACC Staff - Proposed Fair Value Rate of Return - Alternative 2					
17	Short-Term Debt	$	-	0.00%	0.00%	0.00%
18	Long-Term Debt	$	2,608,502	31.94%	6.38%	2.04%
19	Common Stock Equity	$	3,054,497	37.40%	9.90%	3.70%
20	Capital financing OCRB	$	5,662,998			
21	Appreciation above OCRB not recognized on utility's books	$	2,504,128	30.66%	1.00% [b]	0.31%
22	Total capital supporting FVRB	$	8,167,126	100.00%		6.05%

Notes and Source
Lines 1-4, APS filing D-1.
Line 15, Col.A:

23	Fair Value Rate Base	$	8,167,126	Schedule A
24	Original Cost Rate Base	$	5,662,998	Schedule A
25	Difference	$	2,504,128	

Difference is appreciation of Fair Value over Original Cost that is not recognized on the utility's books.

[a] The appreciation of Fair Value over Original Cost has not been recognized on the utility's books. Such off-book appreciation has not been financed by debt or equity capital recorded on the utility's books. The appreciation over Original Cost book value is therefore recognized for cost of capital purposes at zero cost.

[b] Per Staff witness David Parcell

RESIDENTIAL UTILITY CONSUMER OFFICE
Docket No. E-01345A-11-0224 – Four Corners Rate Rider
Response to APS Data Request No. 1

APS 1.1 Please provide all data responses sent in response to other parties' data requests in this docket from the time of the Four Corners Rate Rider filing (December 30, 2013). This is an ongoing request to be supplemented with the additional data responses.

RESPONSE RUCO has received no Data Requests from other parties to this Docket.

APS 1.2 Please provide all workpapers in their original format for your testimony in the Four Corners Rate Rider proceeding

RESPONSE See Attachment No. 1 to this Document

APS 1.3 Please provide all testimony you have submitted to a court or regulatory agency in the last 5 years pertaining to the economic evaluation for ratemaking purposes of an electric generating facility or any other electric utility property.

RESPONSE See the following PDF files attached:

Docket No. E-01933A-12-0291
(1) TEP Direct Testimony
(2) TEP Supplemental Direct
(3) TEP Rate Design

Docket No. E04204A-12-0504
(1) UNS Direct Testimony
(2) UNS Rate Design

APS 1.4 Please provide a citation to and a copy of any prior ACC decision that limit the return on a utility asset as a "risk-sharing" device.

RESPONSE I'm not aware of any decisions that the ACC has included a risk sharing device.

Fair Value Example with New and Old Plant

	Baghdad Town Site Distribution Substation (In Service 2008)	Ocotillo Steam Units (In Service 1960)
	(dollars in thousands)	
1. OCRB	$ 1,216	$ 7,631
2. WACC	8.33%	8.33%
3. Resulting Operating Income (line 1 * line 2)	$ 101	$ 636
4. RCND	$ 1,370	$ 184,591
5. FVRB ((line 1 + line 4) / 2)	$ 1,293	$ 96,111
6. Incremental FVRB Over OCRB, i.e. Fair Value Increment (line 5 - line 1)	$ 77	$ 88,480
7. Return on Fair Value Increment	1.00%	1.00%
8. Return on Fair Value Increment * Fair Value Increment (line 7 * line 6)	$ 1	$ 885
9. OCRB + FVRB Required Operating Income (line 3 + line 8)	$ 102	$ 1,520
10. FVROR (line 9 / line 5)	7.90%	1.58%

EXHIBIT
APS-7
ADMITTED

Settlement and Four Corners Revenue Requirement to Calculate the FVROR

See Page 5 of the Rebuttal Testimony of Leland R. Snook

	Settlement	Four Corners	Four Corners Plus Settlement
1. Original Cost Rate Base	$ 5,662,998	$ 225,934	$ 5,888,932
2. Required Rate of Return	8.33%	8.33%	8.33%
3. Required Operating Income (line 1 * line 2)	$ 471,728	$ 18,820	$ 490,548
4. Fair Value Rate Base	$ 8,167,126	$ 225,934	$ 8,393,060
5. Incremental Fair Value Rate Base Over OCRB (line 4 - line 1)	$ 2,504,128	$ -	$ 2,504,128
6. Fair Value Increment per Settlement	1.00%	1.00%	1.00%
7. Fair Value Increment * Incremental FVRB (line 5 * line 6)	$ 25,041	$ -	$ 25,041
8. OCRB + FVRB Required Operating Income (line 3 + line 7)	$ 496,769	$ 18,820	$ 515,590
9. Fair Value Rate of Return (line 8 / line 4)	6.09%	8.33%	6.14%

EXHIBIT
APS-8
ADMITTED

APS Exhibit ____

FVROR and ROE

An Example of Holding the FVROR Constant from the Settlement

	Settlement Capital Structure with Settlement 1.0% FV Increment	Amount	%	Cost Rate	Weighted Avg
1.	Long-Term Debt	$ 2,608,377	31.94%	6.38%	2.04%
2.	Common Equity	3,054,621	37.40%	10.00%	3.74%
3.	FVRB Increment	2,504,128	30.66%	1.00%	0.31%
4.	Total	$ 8,167,126	100.00%		6.09%

	Capital Structure with Four Corners Included with Settlement FVROR Held Constant	Amount	%	Cost Rate	Weighted Avg
5.	Long-Term Debt	$ 2,712,442	32.32%	6.38%	2.06%
6.	Common Equity	3,176,490	37.85%	9.85%	3.73%
7.	FVRB Increment	2,504,128	29.84%	1.00%	0.30%
8.	Total	$ 8,393,060	100.00%		6.09%

	Adjusted Test Year Capital Structure Using Held Constant ROE	Amount	%	Cost Rate	Weighted Avg
9.	Long-Term Debt	$ 3,382,856	46.06%	6.38%	2.94%
10.	Common Equity	3,961,248	53.94%	9.85%	5.31%
11.	Total	$ 7,344,104	100.00%		8.25%

EXHIBIT
tabbies
APS-9
ADMITTED

DIRECT TESTIMONY OF ELIZABETH A. BLANKENSHIP

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-0224

EXHIBIT
APS-10
ADMITTED

December 30, 2013

Table of Contents

DIRECT TESTIMONY OF ELIZABETH A. BLANKENSHIP
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-0224)

I. INTRODUCTION

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

A. My name is Elizabeth A. Blankenship. I am a Manager in the Revenue/Regulatory Accounting Department for Arizona Public Service Company ("APS" or "Company"), a subsidiary of Pinnacle West Capital Corporation ("Pinnacle West"). I am primarily responsible for the revenue and regulatory accounting, asset accounting, accounts receivable and cash control functions at Pinnacle West and APS. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science degree in Business with a major in Accounting from Arkansas State University in 1993. From 1993 to 2000, I was employed as an Accountant for two companies in the long-term healthcare service industry. I joined APS in October 2000 as a senior accountant and spent the past 13 years working for APS in the Financial Reporting Department, Accounting Operations Department, and most recently the Revenue/Regulatory Accounting Department.

Prior to my transition to the Revenue/Regulatory Accounting Department in September 2012, I was responsible for the fossil generation accounting functions at APS as the manager of that department. I am a Certified Public Accountant, a member of the Arizona Society of Certified Public Accountants and a member of the Edison Electric Institute's Property Accounting Committee.

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

A. The purpose of my testimony is to support the Company's request for the Four Corners Rate Rider ("Rider"), as defined in the APS Settlement Agreement approved by Decision No. 73183, (May 24, 2012). Specifically, my testimony describes the revenue requirement that APS is seeking to recover in the Rider, including the calculation and amortization of the Four Corners deferral that was authorized in Decision No. 73130 (April 24, 2012).

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. On November 22, 2010, in Docket No. E-01345A-10-0474, APS asked the Arizona Corporate Commission ("ACC" or "Commission") to (1) authorize the purchase of Southern California Edison's ("SCE") interest in Four Corners Units 4 and 5, (2) grant APS an accounting order authorizing cost deferral and facilitating the early retirement of Units 1-3. This request resulted in Decision No. 73130, which provided the necessary authorization to pursue the transaction and retire Units 1-3. The Decision also approved an accounting order that would allow the Company to defer for later recovery all non-fuel costs of owning, operating, and maintaining the acquired SCE's interest in Four Corners Units 4 and 5, associated facilities, as well as all unrecovered costs associated with Four Corners Units 1-3 and additional costs incurred in connection with the closure of Four Corners Units 1-3.[1]

Subsequent to the Four Corners filing, APS also entered into a Settlement Agreement ("Settlement") in its General Rate Case Filing (a 2010 Test Year was

[1] *See* Decision No. 73130 at 43.

used). Section 10.2 of the Settlement, which was approved by the Commission in Decision No. 73183, provides the following:

> [T]his rate case shall remain open for the sole purpose of allowing APS to file a request, no later than December 31, 2013, that its rates be adjusted to reflect the proposed Four Corners transaction, should the Commission allow APS to pursue the acquisition and should the transaction thereafter close. Specifically, APS may within ten (10) business days after any closing date but no later than December 31, 2013, file an application with the Commission seeking to reflect in rates the rate base and expense effects associated with the acquisition of SCE's share of Units 4 and 5, the rate base and expense effects associated with the retirement of Units 1-3, and any cost deferral authorized in Docket No. E-01345A-10-0474. APS shall also be permitted to seek authorization to amend the PSA Plan of Administration to include in the PSA the post-acquisition Operations and Maintenance expense associated with Four Corners Units 1-3 as a cost of producing off system sales until closure of Units 1-3, provided that such costs do not exceed off-system sales revenue in any given year. APS's rates shall be adjusted only if the Commission finds the Four Corners transaction to be prudent.

My testimony provides the revenue requirement needed to include the Four Corners Transaction ("Transaction") in base rates as contemplated in the Settlement and Decision No. 73183, including the deferral of costs approved in Decision No. 73130 until the Transaction is included in rates. Specifically, my testimony includes the calculation of the $62.53 million revenue requirement, including all rate base and income statement pro forma adjustments. Consistent with the Company's request in this filing, this revenue requirement assumes a rate effective date of July 1, 2014. Any delay in the rate effective date would increase the revenue requirement by approximately $0.5 million per month and increase the bill impact accordingly.

III. FOUR CORNERS RATE RIDER REVENUE REQUIREMENT AND SUPPORTING SCHEDULES

Q. WHAT IS THE IMPACT ASSOCIATED WITH THE TRANSACTION?

A. The Four Corners Rate Rider that APS seeks approval of in this proceeding recovers a $62.53 million annual revenue requirement. The Rider will be applied to all customers' bills on an equal percentage basis to the base rate portion of the bill, consistent with Section 10.3 of the Settlement Agreement.[2] The percentage applied to recover this amount is 2.22%. To compute the Rider, APS started with the approved Settlement adjusted 2010 Test Year and made pro forma adjustments to that starting point to reflect the acquisition of SCE's share of Four Corners Units 4 and 5. The Rider also reflects the retirement of Four Corners Units 1-3. APS will update any forecast and deferral information, as it becomes available throughout the proceeding, to reflect actual costs incurred for the acquired portion of Units 4 and 5 at the time the Rider goes into effect. To the extent that even these updated costs are different than those actually incurred through the rate effective date, APS proposes to deal with balance (plus or minus) in its next general rate case.

Q. SECTION 10.3 OF THE SETTLEMENT REQUIRED CERTAIN SCHEDULES TO BE FILED WITH THE APPLICATION OF THE RIDER. PLEASE DESCRIBE THE SCHEDULES.

A. The Settlement requires APS to file the following information with its application for a rate rider:

> Any filing seeking a rate adjustment pursuant to Section 10.2 shall include at a minimum the following schedules: (1) the most current APS balance sheet at the time of filing; (2) the most current APS income statement at the time of filing; (3) an earnings schedule that demonstrates that the operating income resulting from the rate adjustment does not result in a return on rate base in excess of that authorized by this Agreement in the period after the rate adjustment becomes effective; (4) a revenue requirement calculation, including the amortization of any deferred costs; (5) an adjustment

[2] *See* Direct Testimony of APS Witness Jeffrey Guldner for more information regarding the applicability of the Rider to rate schedules AG-1 and E-36XL.

rider that recovers the rate base and non-PSA related expenses associated with any Four Corners acquisition on an equal percentage basis across all rate schedules which shall not become effective before July 1, 2013; (6) an adjusted rate base schedule; and (7) a typical bill analysis under present and filed rates.

My testimony addresses each of the required schedules, except number 7, which is attached to the Direct Testimony of APS Witness Jeffrey B. Guldner.

- *Schedule 1: the most current APS balance sheet at the time of filing.* Attachment EAB-1 is the balance sheet as of September 30, 2013, the most recently available financial filing for the Company.

- *Schedule 2: the most current APS income statement at the time of filing.* Attachment EAB-2 is the income statement for the three and nine months ending September 30, 2013, the most recently available financial filing for the Company.

- *Schedule 3: an earnings schedule that demonstrates that the operating income resulting from the rate adjustment does not result in a return on rate base in excess of that authorized by this Agreement in the period after the rate adjustment becomes effective.*
  Attachment EAB-3 is a forecast of APS's earnings through 2015. As can be seen from the Attachment, APS's anticipated earnings do not exceed the 10% ROE authorized in the Settlement Decision. Please note that Schedule 3 is confidential and has been filed under seal for the Commission's confidential review.

- *Schedule 4: a revenue requirement calculation, including the amortization of any deferred costs.*

Attachment EAB-4 is the requested rate base increase for the Rider. The schedule shows the adjusted 2010 Test Year rate of return under ACC Jurisdiction, including the Four Corners Acquisition, of 8.33%. Again, this reflects no changes to the Test Year results used in Decision No. 73183, except for the transaction. Schedule 4 also shows the increase to ACC Jurisdictional Original Cost Rate Base ("OCRB") from the 2010 Test Year attributable to the Four Corners Transaction. The OCRB increases from $5,663 million to $5,881 million post-acquisition. This schedule is similar to an "A-1" Standard Filing Requirement ("SFR") provided in a rate case proceeding. In addition, I have attached support Schedules 4(a) through 4(d), which provide additional information regarding the adjustments to the Rider calculation. Each of the supplemental schedules is discussed below and its rate case SFR equivalent is identified for ease of reference.

- *Schedule 4(a): APS's adjusted balance sheet.*

  Attachment EAB-5 is similar to SFR schedule B-1. It shows the change in APS's rate base from the 2010 Test Year adjusted original cost rate base to an adjusted original cost rate base that includes Four Corners, in the total amount of $7,010 million Total Company and $5,881 million ACC Jurisdiction, using the same jurisdictional allocation factors accepted in Decision No. 73183.

- *Schedule 4(b): APS's rate base pro forma adjustments.*

  Attachment EAB-6 is equivalent to SFR schedule B-2. This Attachment shows each pro forma adjustment and describes the adjustment and its impact on rate base.

- *Schedule 4(c): APS's adjusted income statement.*
  Attachment EAB-7 is equivalent to SFR schedule C-1. It reflects the Company's adjusted operating income. Specifically, this schedule shows the operating income authorized in the Settlement and the effects on that operating income as a result of the Four Corners Transaction. The transaction produces a $550.0 million adjusted net income for Total Company and $477.2 million for ACC Jurisdiction.

- *Schedule 4(d): APS's income statement pro forma adjustments.*
  Attachment EAB-8 is similar to SFR schedule C-2. This Attachment shows each pro forma adjustment and describes the adjustment and its impact on the operating income.

- *Schedule 5: an adjustment rider that recovers the rate base and non-PSA related expenses associated with any Four Corners acquisition on an equal percentage basis across all rate schedules, which shall not become effective before July 1, 2013.*
  Attachment EAB-9 is the tariff sheet titled "Four Corners Adjustment" that shows the equal percentage base rate increase to be applied to all customers' bills to recover the non-fuel Four Corners acquisition costs. Please note that, upon Commission approval of the Rider, APS will file as a compliance item all of the Company's rate schedules adjustments necessary to reflect the Decision.

- *Schedule 6: an adjusted rate base schedule.*
  Schedule 6 is equivalent to Schedule 4(a) discussed previously and is provided as Attachment EAB-5.

- *Schedule 7: a typical bill analysis under present and filed rates.*

Please see the Direct Testimony of APS Witness Jeffrey Guldner.

IV. CALCULATION OF THE FOUR CORNERS REVENUE REQUIREMENT AND ASSOCIATED RATE RIDER

Q. PLEASE DESCRIBE HOW APS CALCULATED THE FOUR CORNERS RATE RIDER.

A. To calculate the rate rider, the annual revenue requirement increase was calculated as an equal percentage to be applied to all customer classes. In order to determine the annual revenue requirement, two major types of adjustments were made to the Test Year adjusted financial position of the Company: (1) rate base pro forma adjustments, and (2) income statement pro forma adjustments. My testimony is separated into two subsections to describe the individual pro forma adjustments in each category. The starting point for all adjustments was the adjusted 2010 Test Year, as approved by the Commission in the Settlement.

A. *Rate Base Pro Forma Adjustments*

Q. PLEASE SUMMARIZE THE RATE BASE PRO FORMA ADJUSTMENTS ASSOCIATED WITH THE TRANSACTION.

A. The collective purpose of the adjustments is to accurately reflect the Company's rate base resulting from the acquisition, adjusted for the deferral of the costs from the date of acquisition through the anticipated rate effective date of July 1, 2014, and are needed to accurately account for, and reflect in APS's financial records, the assets and liabilities that APS has acquired from SCE. The acquired assets and liabilities are initially recorded at fair value, but then they are adjusted to reflect the "expected activity" from the acquisition date of December 30, 2013 to a rate effective date of July 1, 2014. The "expected activity" includes items like depreciation and amortization that occur immediately following the acquisition date. Please note that the "fair value" I am referencing here is an accounting "fair value" rather than "fair value" rate base as typically discussed in Arizona rate case. In this instance, however, they are mathematically equivalent.

The remaining rate base adjustments show the allowable costs that are expected to be deferred from December 30, 2013 to June 30, 2014. The anticipated deferral costs include incremental operations and maintenance expense, depreciation expense, property tax, remaining unrecovered plant investment costs associated with Units 1-3 and a return of the most current cost of debt (5.25%) for the necessary investments made by APS regarding the Transaction.

1. Four Corners Fair Value Acquisition

Q. PLEASE DESCRIBE THE PRO FORMA ADJUSTMENT FOR THE FAIR VALUE ACQUISITION OF SCE'S SHARE OF UNITS 4 AND 5.

A. This adjustment reflects the purchase of SCE's share of Units 4 and 5. The adjustment includes four parts:

- gross utility plant amount of $860.1 million, which includes SCE's net book value of Units 4 and 5, plus the negotiated cash purchase price – the "fair value" of the plant;
- accumulated depreciation of the SCE's share of Units 4 and 5, which is a reduction to rate base in the amount of $554.2 million;
- decommissioning and coal liabilities which reduces rate base by $127.1 million to assume SCE's liability of the Units; and,
- acquired inventory of SCE's share of Units 4 and 5 which is $4.5 million.

The total adjustment results in an increase to rate base of $183.3 million. (*See* Attachment EAB-6, page 1, column C and Attachment EAB-10).

2. Four Corners Auxiliary Plant

Q. PLEASE DESCRIBE THE PURPOSE AND AMOUNT OF THE PRO FORMA ADJUSTMENT RELATED TO THE ADDITION OF THE AUXILIARY BOILER.

A. This pro forma adjustment includes in rate base the cost of constructing a new auxiliary boiler to be used during start-up operations for Units 4 and 5, once Units 1-3 are shut down. Previously, the boiler stationed at Unit 3 was used to start and support the operations of Units 4 and 5. With the shutdown of Units 1-3, Units 4 and 5 will require an independent auxiliary boiler to operate. This is the basis of this pro forma adjustment. A new auxiliary boiler was placed into service on April 17, 2013. APS's ownership share of that project, including its acquisition of SCE's share, is $11.3 million. The gross plant investment is offset by actual accumulated depreciation from the in-service date of the project to the acquisition date of SCE's share of Units 4 and 5 of $0.1 million and estimated accumulated depreciation during the deferral period of $0.2 million, for a total offset of $0.3 million. The net amount of these items results in a rate base pro forma adjustment of $11.0 million on a Total Company basis. *See* Attachment EAB-6 page 1, column E and Attachment EAB-11.

3. Four Corners Deferral Balance

Q. PLEASE SUMMARIZE THE DECISION THAT ALLOWED APS TO DEFER COSTS ASSOCIATED WITH THE ACQUISITION OF FOUR CORNERS.

A. In Commission Decision No. 73130, APS was granted an accounting order allowing APS to defer all non-fuel costs of owning, operating and maintaining its purchase of SCE's share of Units 4 and 5. The appropriate ordering paragraphs are excerpted below:

> IT IS FURTHER ORDERED that Arizona Public Service is authorized to defer for possible later recovery through rates, all non-fuel costs (as defined herein) of owning, operating and maintaining the acquired Southern California Edison interest in Four Corners Units 4 and 5 and associated

> facilities. Nothing in this Decision shall be construed in any way to limit this Commission's authority to review the entirety of the acquisition and to make any disallowances thereof due to imprudence, errors or inappropriate application of the requirements of this Decision.
>
> IT IS FURTHER ORDERED that Arizona Public Service Company shall reduce the deferrals by non-fuel operations and maintenance and property tax savings associated with the closure of Four Corners Unit 1-3.
>
> IT IS FURTHER ORDERED that Arizona Public Service Company is authorized to defer for possible later recovery through rates, all unrecovered costs associated with Four Corners Units 1-3 and additional costs incurred in connection with the closure of Four Corners Units 1-3. Nothing in this Decision shall be construed in any way to limit this Commission's authority to review either the unrecovered costs or additional costs incurred in connection with the closure of Four Corners Units 1-3 and to make any disallowances thereof due to imprudence, errors or inappropriate application of the requirements of this Decision.

Q. PLEASE EXPLAIN THE NON-FUEL COSTS OF OWNING, OPERATING AND MAINTAINING SCE'S INTEREST IN FOUR CORNERS UNITS 4 AND 5 AND ITS ASSOCIATED FACILITIES.

A. There are four basic categories of non-fuel costs explained below:

1) Operations and Maintenance (O&M)

APS used its 2014 budget information to estimate additional O&M costs associated with an increased ownership share in Units 4 and 5 and its related facilities. APS's 48% additional ownership share of Units 4 and 5 will result in APS being responsible for additional costs that can be deferred from the date of acquisition until the date on which the investment is included in customer rates. This deferral period was estimated to last for six months for the purpose of this adjustment. The deferral amount associated with operating and maintaining SCE's share of Units 4 and 5 and Common Facilities is $29.1 million. The amount to be deferred is reduced by the elimination of no longer incurred costs associated with Units 1-3, in the amount of $23.0 million, which will be closed down in conjunction with the acquisition of Units 4 and 5. Certain minimal residual operating costs of $0.3 million pertaining to Units 1-3 will continue despite the shutdown, such as the continuing lease payment.

In addition, upon the closure of Units 1-3, consistent with the deferral authorized in Decision No. 73130, inventory and capital investments related to Units 1-3 will be deferred. The inventory balance for Units 1-3 is $6.2 million and plant investments for Units 1-3 total $25.7 million. The majority of the plant investments related to Units 1-3 pertain to ash disposal and environmental mitigation of ash seepage. The net change in O&M results in a deferral amount of $38.3 million.

2) Book Depreciation and Amortization

Depreciation – Depreciation expense will be incurred on the net book value of APS's acquired share of Units 4 and 5 beginning on the date of acquisition and on the auxiliary boiler as discussed previously at page 9 in my testimony. The depreciation rate on this amount is based on the straight-line method using an end-of-life assumption of 2038, consistent with the end-of-life assumption for Units 4 and 5 used in the depreciation study used and approved in Decision No. 73183. It results in an increase to the deferral amount of $1.1 million. The additional depreciation expense associated with the auxiliary boiler, using the same depreciation rate, results in an increase in the deferral amount of $0.2 million.

Amortization – Upon acquiring SCE's additional 48% share of Four Corners Units 4 and 5 and the associated facilities, APS also assumed SCE's portion of the obligation to fund both plant decommissioning costs and the final coal reclamation liability. Both of these liabilities are recorded at the accounting fair value on the date of the acquisition. The liabilities associated with these book items will be adjusted annually to reflect the correct amount of annual amortization. The estimated amount of amortization related to the deferred decommissioning and final coal reclamation costs is $3.4 million. The net change to book depreciation and amortization results in a deferral amount of $4.7 million.

3) Property and Other Taxes

The deferral calculation also includes the Possessory Interest Tax ("PIT") and Business Activity Taxes ("BAT"), Navajo Nation taxes associated with the acquisition, as well as the increased New Mexico property taxes on the acquired portion of Units 4 and 5 and the auxiliary boiler, less the reduced property taxes for Units 1-3. The total property and other taxes included in the deferral is $3.2 million.

4) Deferred Debt Return

The increase in the rate base investment, including the auxiliary boiler, is $193 million. To calculate the Commission-approved debt return, APS applied the marginal cost of debt of 5.25% to the increase in rate base to determine the deferred debt return of $5.1 million.

Collectively, the sum of these four cost categories results in a Four Corners Deferral balance of $51.2 million Total Company, the ACC Jurisdiction amount is $49.5 million. APS will amortize the balance over 10 years, as discussed later in my testimony. *See* Attachment EAB-6, page 2, column G and Attachment EAB-12.

B. *Income Statement Pro Forma Adjustments*

1. Incremental Operation and Maintenance ("O&M") Expenses Related to the Acquisition

Q. PLEASE DESCRIBE THE PRO FORMA ADJUSTMENT FOR INCREMENTAL O&M EXPENSE RELATED TO THE ACQUISITION.

A. This adjustment used the 2010 test year income statement as a starting point and then reduced the pre-tax operating income by $5.6 million to reflect the increase in O&M related to SCE's share of Units 4 and 5. This adjustment is also reduced by the removal of Units 1-3 O&M expenses, less the residual site O&M expenses for Units 1-3. *See* Attachment EAB-8, page 1, column A and Attachment EAB-13.

Q. YOU MENTIONED A REDUCTION IN OPERATING INCOME IN YOUR LAST ANSWER. WHAT IS THE RELATIONSHIP BETWEEN CHANGES IN OPERATING INCOME AND INCREASED REVENUE REQUIREMENT?

A. A rate increase, reduced to its basics, reconciles what is referred to as the "required operating income" with the existing adjusted test year operating income by taking the difference between the two calculations of operating income and multiplying it by the revenue conversion factor. Required operating income is simply the rate base multiplied by the weighted cost of capital. If an adjustment resulting from the Transaction reduces the adjusted test year operating income, it increases the required revenue increase by that amount times the revenue conversion factor.

2. Incremental Property Tax and Other Tax Related to the Acquisition

Q. PLEASE DESCRIBE THE PRO FORMA ADJUSTMENT FOR INCREMENTAL PROPERTY TAX EXPENSE RELATED TO THE ACQUISITION.

A. Similar to the O&M expense adjustment, this pro forma seeks to include the additional property tax expense, as well as PIT and BAT taxes that result from

APS's acquisition of SCE's share of Units 4 and 5, which will be offset by the decrease in Units 1-3 property tax expense. The adjustment results in a reduction to pre-tax operating income of $6.4 million on a Total Company basis. S*ee* Attachment EAB-8, page 1, column C and Attachment EAB-14.

Q. IN SECTION 12 OF THE SETTLEMENT AGREEMENT, APS IS AUTHORIZED TO DEFER PROPERTY TAXES WHEN THE RATE RISES. DOES THAT PROPERTY TAX DEFERRAL HAVE AN EFFECT ON THIS PROPERTY TAX PRO FORMA ADJUSTMENT?

A. No. The Settlement authorized APS to defer property tax expenses resulting from a change in **Arizona** composite property tax rates. The Four Corners Power Plant is located in New Mexico and is additional property specifically contemplated to be recovered on an incremental basis by Section 10 of the Settlement;

3. Incremental Depreciation and Amortization Expense Related to the Acquisition

Q. PLEASE DESCRIBE THE PRO FORMA ADJUSTMENT FOR INCREMENTAL DEPRECIATION AND AMORITZATION EXPENSE RELATED TO THE ACQUISITION.

A. When APS acquires SCE's share of Units 4 and 5 there will be additional depreciation and amortization expense associated with the additional plant book value. Depreciation and amortization is calculated over the remaining life of the purchased asset. Since the SCE plant was not included in the Settlement, timing between the remaining life assumptions of SCE and APS resulted in a lower overall depreciation rate applied to the book value of the acquired assets to the benefit of APS's customers. The depreciation and amortization results in a pre-tax reduction to operating income of $13.2 million (*see* Attachment EAB-8, page 1, column E and Attachment EAB-15).

4. Incremental Final Coal Reclamation Expense Related to Acquisition

Q. PLEASE DESCRIBE THE PRO FORMA ADJUSTMENT FOR INCREMENTAL COAL RECLAMATION EXPENSE RELATED TO THE ACQUISITION.

A. This pro forma adjustment includes the additional coal reclamation expense that APS will incur for its acquired share of Units 4 and 5. Coal reclamation is the process by which the coal mine is restored to the contractually agreed upon condition. The increase in expense represents the additional costs that APS will incur when the plant is decommissioned and the mine site is reclaimed. The increase in coal reclamation expense results in a reduction to pre-tax operating income of $4.5 million (*see* Attachment EAB-8, page 2, column G and Attachment EAB-16).

5. Incremental Decommissioning Expense Related to Acquisition

Q. PLEASE DESCRIBE THE PRO FORMA ADJUSTMENT FOR INCREMENTAL DECOMMISSIONING EXPENSE RELATED TO THE ACQUISITION.

A. This pro forma adjustment includes the additional decommissioning expense that APS will incur for its acquired share of Units 4 and 5. The decommissioning of the plant happens when the plant is shut down. APS is responsible, under its lease agreement, for returning the plant site to its original conditional, as is reasonably possible. The increase in the expense represents the additional costs that APS will bear when the plant is decommissioned. The increase in decommissioning results in a reduction to pre-tax operating income of $3.1 million (*see* Attachment EAB-8, page 2, column I and Attachment EAB-17).

6. Amortization of the Four Corners Deferral Balance

Q. PLEASE DESCRIBE THE PRO FORMA ADJUSTMENT TO AMORTIZE THE FOUR CORNERS DEFERRAL.

A. The amortization of the deferral is the income statement side of the rate base pro forma adjustment of the same title. This adjustment takes the ACC jurisdiction rate base adjustment of $49.5 million and amortizes it over a 10-year period. The adjustment reduces the pre-tax operating income by $4.9 million per year for ten years. The deferred balance included in the revenue requirement is premised on a 6-month deferral. In the event this Four Corners Rate Rider proceeding is delayed beyond that expected implementation date, the deferral amortization would increase by approximately $0.3 million each month (*see* Attachment EAB-8, page 2, column K and Attachment EAB-18).

7. Interest / Income Tax Adjustment Related to Rate Base Pro Formas

Q. PLEASE DESCRIBE THE PRO FORMA ADJUSTMENT PERTAINING TO INTEREST AND INCOME TAXES.

A. This pro forma identifies the additional interest expense associated with the additional rate base related to the acquisition of SCE's share of Units 4 and 5. This additional interest expense reduces income taxes and results in an increase of after-tax operating income of $2.6 million. (*see* Attachment EAB-8, page 3, column M and Attachment EAB-19)

Q. DOES THAT CONCLUDE THE ADJUSTMENTS USED TO DERIVE THE RIDER?

A. Yes.

V. <u>CONCLUSION</u>

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. The calculation of the Rider and the deferral are consistent with Commission's Decision Nos. 73183 (Settlement Agreement) and 73130 (Four

Corners Acquisition). The Rider results in an average 2.22% increase to base rates applied on equal percentage basis to all customers.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)
(dollars in thousands)

	September 30, 2013	December 31, 2012
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	2,379,696	2,379,696
Retained earnings	1,899,375	1,624,237
Accumulated other comprehensive loss:		
Pension and other postretirement benefits	(38,281)	(39,503)
Derivative instruments	(26,155)	(49,592)
Total shareholder equity	4,392,797	4,093,000
Noncontrolling interests (Note 6)	145,624	129,483
Total equity (Note S-1)	4,538,421	4,222,483
Long-term debt less current maturities (Note 2)	2,657,901	3,035,219
Palo Verde sale leaseback lessor notes less current maturities (Note 6)	37,414	38,869
Total capitalization	7,233,736	7,296,571
CURRENT LIABILITIES		
Short-term borrowings	--	92,175
Current maturities of long-term debt (Note 2)	566,481	122,828
Accounts payable	243,470	215,577
Accrued taxes (Note 5)	178,349	116,700
Accrued interest	45,542	49,135
Common dividends payable	--	59,800
Customer deposits	77,254	79,689
Liabilities from risk management activities (Note 7)	53,468	73,741
Regulatory liabilities (Note 3)	88,409	88,116
Other current liabilities	152,392	145,326
Total current liabilities	1,405,365	1,043,087
DEFERRED CREDITS AND OTHER		
Deferred income taxes	2,337,320	2,133,976
Regulatory liabilities (Note 3)	798,226	759,201
Liability for asset retirements	364,635	357,097
Liabilities for pension and other postretirement benefits (Note 4)	901,146	1,017,556
Deferred investment tax credit	115,984	99,819
Liabilities from risk management activities (Note 7)	67,662	85,264
Customer advances	109,667	109,359
Coal mine reclamation	114,764	118,860
Unrecognized tax benefits (Note 5)	81,589	70,932
Other	145,707	150,820
Total deferred credits and other	5,036,700	4,902,884
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
TOTAL LIABILITIES AND EQUITY	$ 13,675,801	$ 13,242,542

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)
(dollars in thousands)

	September 30, 2013	December 31, 2012
ASSETS		
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	$ 14,594,129	$ 14,342,501
Accumulated depreciation and amortization	(5,097,804)	(4,925,990)
Net	9,496,325	9,416,511
Construction work in progress	605,987	565,716
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	126,092	128,995
Intangible assets, net of accumulated amortization	159,979	161,995
Nuclear fuel, net of accumulated amortization	140,356	122,778
Total property, plant and equipment	10,528,739	10,395,995
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Note 13)	612,640	570,625
Assets from risk management activities (Note 7)	26,046	35,891
Other assets	33,203	31,650
Total investments and other assets	671,889	638,166
CURRENT ASSETS		
Cash and cash equivalents	113,072	3,499
Customer and other receivables	426,425	274,815
Accrued unbilled revenues	132,555	94,845
Allowance for doubtful accounts	(3,768)	(3,340)
Materials and supplies (at average cost)	223,385	218,096
Income tax receivable	126,098	589
Fossil fuel (at average cost)	34,959	31,334
Deferred fuel and purchased power regulatory asset (Note 3)	37,383	72,692
Other regulatory assets (Note 3)	82,558	71,257
Deferred income taxes	538	74,420
Assets from risk management activities (Note 7)	22,741	25,699
Other current assets	35,983	37,077
Total current assets	1,231,929	900,983
DEFERRED DEBITS		
Regulatory assets (Note 3)	1,105,882	1,099,900
Unamortized debt issue costs	22,367	22,492
Income tax receivable (Note 5)	--	70,784
Other	114,995	114,222
Total deferred debits	1,243,244	1,307,398
TOTAL ASSETS	$ 13,675,801	$ 13,242,542

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)
(dollars in thousands)

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012
ELECTRIC OPERATING REVENUES	$ 1,151,535	$ 1,108,623
OPERATING EXPENSES		
Fuel and purchased power	350,953	302,894
Operations and maintenance	222,617	218,403
Depreciation and amortization	107,364	100,329
Income taxes	143,335	153,797
Taxes other than income taxes	43,015	36,255
Total	867,284	811,678
OPERATING INCOME	284,251	296,945
OTHER INCOME (DEDUCTIONS)		
Income taxes	4,123	3,170
Allowance for equity funds used during construction	5,569	5,708
Other income (Note S-2)	721	815
Other expense (Note S-2)	(4,615)	(3,352)
Total	5,798	6,341
INTEREST EXPENSE		
Interest on long-term debt	47,214	48,841
Interest on short-term borrowings	1,553	1,334
Debt discount, premium and expense	1,008	1,070
Allowance for borrowed funds used during construction	(3,235)	(3,830)
Total	46,540	47,415
NET INCOME	243,509	255,871
Less: Net income attributable to noncontrolling interests (Note 6)	8,555	8,040
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 234,954	$ 247,831

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(unaudited)
(dollars in thousands)

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012
NET INCOME	$ 243,509	$ 255,871
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Derivative instruments:		
Net unrealized loss, net of tax benefit of $95 and $47	(145)	(72)
Reclassification of net realized loss, net of tax benefit of $9,348 and $19,547	14,310	29,931
Pension and other postretirement benefits activity, net of tax (expense) of $(621) and $(568)	951	869
Total other comprehensive income	15,116	30,728
COMPREHENSIVE INCOME	258,625	286,599
Less: Comprehensive income attributable to noncontrolling interests	8,555	8,040
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 250,070	$ 278,559

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(unaudited)
(dollars in thousands)

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
ELECTRIC OPERATING REVENUES	$ 2,752,427	$ 2,606,458
OPERATING EXPENSES		
Fuel and purchased power	859,216	783,926
Operations and maintenance	668,319	640,596
Depreciation and amortization	317,338	300,997
Income taxes	241,347	233,679
Taxes other than income taxes	123,366	119,499
Total	2,209,586	2,078,697
OPERATING INCOME	542,841	527,761
OTHER INCOME (DEDUCTIONS)		
Income taxes	9,555	6,906
Allowance for equity funds used during construction	18,698	15,639
Other income (Note S-2)	3,012	2,343
Other expense (Note S-2)	(15,755)	(11,969)
Total	15,510	12,919
INTEREST EXPENSE		
Interest on long-term debt	140,978	150,416
Interest on short-term borrowings	4,950	5,283
Debt discount, premium and expense	3,001	3,182
Allowance for borrowed funds used during construction	(10,861)	(10,428)
Total	138,068	148,453
NET INCOME	420,283	392,227
Less: Net income attributable to noncontrolling interests (Note 6)	25,338	23,573
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 394,945	$ 368,654

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(unaudited)
(dollars in thousands)

	Nine Months Ended September 30, 2013	2012
NET INCOME	$ 420,283	$ 392,227
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX		
Derivative instruments:		
Net unrealized loss, net of tax benefit of $162 and $14,820	(247)	(22,693)
Reclassification of net realized loss, net of tax benefit of $15,471 and $34,367	23,684	52,625
Pension and other postretirement benefits activity, net of tax (expense) of $(798) and $(1,409)	1,222	2,158
Total other comprehensive income	24,659	32,090
COMPREHENSIVE INCOME	444,942	424,317
Less: Comprehensive income attributable to noncontrolling interests	25,338	23,573
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 419,604	$ 400,744

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4 - FOUR CORNERS REVENUE REQUIREMENT CALCULATION
COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENTS
ACC JURISDICTION
ADJUSTED TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		Settlement			Settlement (with Four Corners Acquisition)				
Line No.	Description	Original Cost	RCND	Fair Value	Four Corners Pro Forma Adjustments	Original Cost	RCND	Fair Value	Line No.
1.	Adjusted Rate Base	$ 5,662,998 (a)	$ 10,671,253	$ 8,167,126 (a)	$ 217,629 (b)	$ 5,880,627	$ 10,888,882	$ 8,384,755	1.
2.	Adjusted Operating Income	496,769	496,769	496,769	(19,617) (c)	477,152	477,152	477,152	2.
3.	Fair Value Adjustment Embedded in Operating Income	25,041	25,041	25,041		25,041	25,041	25,041	3.
4.	Adjusted Operating Income without Fair Value Adjustment (Line 2 - Line 3)	471,728	471,728	471,728		452,111	452,111	452,111	4.
5.	Current Rate of Return (Line 4 / Line 1)	8.33%	4.42%	5.78% (d)		7.69%	4.15%	5.39%	5.
6.	Required Operating Income (Line 7 * Line 1)	471,728	471,728	471,728		489,856	489,856	489,856	6.
7.	Required Rate of Return	8.33% (e)	4.42% (e)	5.78% (e)		8.33% (e)	4.50% (e)	5.84% (e)	7.
8.	Adjusted Operating Income Deficiency (Line 4 - Line 6)	-	-	-		37,745	37,745	37,745	8.
9.	Gross Revenue Conversion Factor (f)	1.6566	1.6566	1.6566		1.6566	1.6566	1.6566	9.
10.	Requested Increase in Base Revenue Requirements (Line 8 * Line 9)	-	-	-		62,529	62,529	62,529	10.
11.	2010 Adjusted Base Revenues (g)					$ 2,810,916	$ 2,810,916	$ 2,810,916	11.
12.	Percentage Base Rate Increase (Line 10 / Line 11)					2.22%	2.22%	2.22%	12.

Notes:
(a) *See* Decision No. 73183, page 46
(b) *See* Schedule 4.a, Column E, Line 21
(c) *See* Schedule 4.c, Page 2, Column B, Line 23
(d) APS was authorized a 6.09% rate of return on fair value, to tie to that number, Line 2 would be divided into Line 1, however for purposes of this schedule, the Fair Value Rate of Return was shown without the Fair Value Increment
(e) The Required Rate of Return for OCRB, RCND and Fair Value does not reflect any return on the difference between Fair Value Rate Base and Original Cost Rate Base, but is simply a mathematical derivation based upon the original cost rate of return.
(f) *See* Staff Witness Ralph Smith, Attachment RCS-2
(g) APS's total adjusted base revenue in the Settlement was $2,868,858, however, this Schedule adjusts the revenue received by AG-1 customers to exclude amounts now paid to alternative generation suppliers and to add applicable wire-related revenues for E-36XL. *See* APS Witness Jeffrey Guldner's testimony for more information.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4.a FOUR CORNERS RATE RIDER
SUMMARY OF ORIGINAL COST RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		Original Cost						
		Total Company			ACC			
Line No.	Description	Settlement (a) (A)	Four Corners Pro Forma (b) (B)	Adjusted Settlement (c) (C)	Settlement (d) (D)	Four Corners Pro Forma (e) (E)	Adjusted Settlement (f) (F)	Line No.
1.	Gross utility plant in service	$ 14,005,836	$ 922,646	$ 14,928,482	$ 11,866,173	$ 891,276	$ 12,757,449	1.
2.	Less: Accumulated depreciation & amortization	5,219,000	554,515	5,773,515	4,528,867	535,661	5,064,528	2.
3.	Net utility plant in service	8,786,836	368,131	9,154,967	7,337,306	355,615	7,692,921	3.
	Deductions:							
4.	Deferred income taxes	1,931,063	20,238	1,951,301	1,567,902	19,550	1,587,452	4.
5.	Investment tax credits	907	-	907	876	-	876	5.
6.	Customer advances for construction	121,645	-	121,645	121,645	-	121,645	6.
7.	Customer deposits	68,084	-	68,084	68,084	-	68,084	7.
8.	Pension and other postretirement liabilities	711,164	-	711,164	661,518	-	661,518	8.
9.	Liability for asset retirements	328,571	-	328,571	320,592	-	320,592	9.
10.	Other deferred credits	66,842	127,074	193,916	64,107	122,753	186,860	10.
11.	Coal mine reclamation	117,243	-	117,243	114,396	-	114,396	11.
12.	Unrecognized tax benefits	65,363	-	65,363	53,961	-	53,961	12.
13.	Regulatory liabilities	260,687	-	260,687	253,750	-	253,750	13.
14.	Total deductions	3,671,569	147,312	3,818,881	3,226,831	142,303	3,369,134	14.
	Additions:							
15.	Regulatory assets	822,177	-	822,177	746,508	-	746,508	15.
16.	Deferred debit income tax receivable	65,498	-	65,498	63,271	-	63,271	16.
17.	Other deferred debits	77,674	4,469	82,143	72,203	4,317	76,520	17.
18.	Decommissioning trust accounts	469,886	-	469,886	458,476	-	458,476	18.
19.	Allowance for working capital	233,778	-	233,778	212,065	-	212,065	19.
20.	Total additions	1,669,013	4,469	1,673,482	1,552,523	4,317	1,556,840	20.
21.	Total rate base	$ 6,784,280	$ 225,288	$ 7,009,568	$ 5,662,998	$ 217,629	$ 5,880,627	21.

Notes:
(a) *See* Schedule 4.b, Page 1, Column A
(b) *See* Schedule 4.b, Page 2, Column I
(c) *See* Schedule 4.b, Page 2, Column K
(d) *See* Schedule 4.b, Page 1, Column B
(e) *See* Schedule 4.b, Page 2, Column J
(f) *See* Schedule 4.b, Page 2, Column L

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4.b - FOUR CORNERS RATE RIDER
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		(1)		(2)		(3)	
		Settlement Test Year 12/31/2010		Four Corners Fair Value Acquisition		Four Corners Auxiliary Plant	
Line No.	Description	Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
1.	Gross Utility Plant in Service	$ 14,005,836	$ 11,866,173	$ 860,105	$ 830,861	$ 11,319	$ 10,934
2.	Less: Accumulated Depreciation & Amort.	5,219,000	4,528,867	554,229	535,385	286	276
3	Net Utility Plant in Service	8,786,836	7,337,306	305,876	295,476	11,033	10,658
4.	Less: Total Deductions	3,671,569	3,226,831	127,074	122,753	-	-
5.	Total Additions	1,669,013	1,552,523	4,469	4,317	-	-
6.	Total Rate Base	$ 6,784,280	$ 5,662,998	$ 183,271	$ 177,040	$ 11,033	$ 10,658
	WITNESS:			BLANKENSHIP		BLANKENSHIP	

(1) Rate base per Settlement Decision No. 73183. *See* page 46.

(2) Adjustment to rate base to reflect the increase in the accounting fair value associated with the increase of SCE's share of Units 4&5.

(3) Adjustment to rate base to reflect the cost of the auxiliary boiler required to run Units 4&5.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4.b - FOUR CORNERS RATE RIDER
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		(4) Four Corners Deferral Balance		(5) Total Four Corners Rate Base Pro Forma Adjustments		(6) Adjusted Settlement Test Year 12/31/2010	
Line No.	Description	Total Co. (G)	ACC (H)	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)
1.	Gross Utility Plant in Service	$ 51,222	$ 49,481	$ 922,646	$ 891,276	$ 14,928,482	$ 12,757,449
2.	Less: Accumulated Depreciation & Amort.	-	-	554,515	535,661	5,773,515	5,064,528
3	Net Utility Plant in Service	51,222	49,481	368,131	355,615	9,154,967	7,692,921
4.	Less: Total Deductions	20,238	19,550	147,312	142,303	3,818,881	3,369,134
5.	Total Additions	-	-	4,469	4,317	1,673,482	1,556,840
6.	Total Rate Base	$ 30,984	$ 29,931	$ 225,288	$ 217,629	$ 7,009,568	$ 5,880,627

WITNESS: BLANKENSHIP

(4) Deferred balance of operating costs associated with SCE's share of Units 4&5 and unrecovered costs associated Units 1-3, less savings from closure of Units 1-3. Deferral balance covers amounts deferred from December 2013 through June 2014.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4.c - FOUR CORNERS RATE RIDER
TOTAL COMPANY
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	Total Company: Settlement (A)	Total Company: Pro Forma Adjustments (a) (B)	Total Company: Settlement Results After Pro Forma Adjustments (C)	Line No.
	Electric Operating Revenues				
1.	Revenues from Base Rates	$ 2,952,324	$ -	$ 2,952,324	1.
2.	Revenues from Surcharges	-	-	-	2.
3.	Other Electric Revenues	136,849	-	136,849	3.
4.	Total	3,089,173	-	3,089,173	4.
	Operating expenses:				
5.	Electric fuel and purchased power	1,031,289	4,470	1,035,759	5.
6.	Operations and maintenance excluding fuel expenses	676,937	5,601	682,538	6.
7.	Depreciation and amortization	405,150	21,407	426,557	7.
8.	Income taxes	242,751	(17,588)	225,163	8.
9.	Other taxes	162,770	6,417	169,187	9.
10.	Total	2,518,897	20,307	2,539,204	10.
11.	Operating income	570,276	(20,307)	549,969	11.
	Other income (deductions):				
12.	Income taxes	-	-	-	12.
13.	Allowance for equity funds used during construction	-	-	-	13.
14.	Other income	-	-	-	14.
15.	Other expense	-	-	-	15.
16.	Total	-	-	-	16.
17.	Income before interest deductions	570,276	(20,307)	549,969	17.
	Interest deductions:				
18.	Interest on long-term debt	-	-	-	18.
19.	Interest on short-term borrowings	-	-	-	19.
20.	Debt discount, premium and expense	-	-	-	20.
21.	Allowance for borrowed funds used during construction	-	-	-	21.
22.	Total	-	-	-	22.
23.	Net income	$ 570,276	$ (20,307)	$ 549,969	23.

Notes:
(a) *See* Schedule 4.d, Page 3, Column O

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4.c - FOUR CORNERS RATE RIDER
ACC JURISDICTION
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	ACC Jurisdiction Settlement (A)	Pro Forma Adjustments (a) (B)	Settlement Results After Pro Forma Adjustments (C)	Line No.
	Electric Operating Revenues				
1.	Revenues from Base Rates	$ 2,868,858	$ -	$ 2,868,858	1.
2.	Revenues from Surcharges	-	-	-	2.
3.	Other Electric Revenues	121,013	-	121,013	3.
4.	Total	2,989,871	-	2,989,871	4.
	Operating expenses:				
5.	Electric fuel and purchased power	1,006,003	4,318	1,010,321	5.
6.	Operations and maintenance excluding fuel expenses	779,461	5,411	784,872	6.
7.	Depreciation and amortization	352,026	20,679	372,705	7.
8.	Income taxes	216,195	(16,990)	199,205	8.
9.	Other taxes	139,417	6,199	145,616	9.
10.	Total	2,493,102	19,617	2,512,719	10.
11.	Operating income	496,769	(19,617)	477,152	11.
	Other income (deductions):				
12.	Income taxes	-	-	-	12.
13.	Allowance for equity funds used during construction	-	-	-	13.
14.	Other income	-	-	-	14.
15.	Other expense	-	-	-	15.
16.	Total	-	-	-	16.
17.	Income before interest deductions	496,769	(19,617)	477,152	17.
	Interest deductions:				
18.	Interest on long-term debt	-	-	-	18.
19.	Interest on short-term borrowings	-	-	-	19.
20.	Debt discount, premium and expense	-	-	-	20.
21.	Allowance for borrowed funds used during construction	-	-	-	21.
22.	Total	-	-	-	22.
23.	Net income	$ 496,769	$ (19,617)	$ 477,152	23.

Notes:
(a) *See* Schedule 4.d, Page 3, Column P

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4.d - FOUR CORNERS RATE RIDER
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		(1)		(2)		(3)	
		Incremental Operation and Maintenance Expenses Related to the Acquisition (Based on 2010 Actuals)		Incremental Property Tax & Other Taxes Related to the Acquisition		Incremental Depreciation and Amortization Expense Related to the Acquisition	
Line No.	Description	Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	559	540	-	-	-	-
8.	Maintenance	1,223	1,182	-	-	-	-
9.	Subtotal	1,782	1,722	-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	13,226	12,776
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	3,819	3,689	-	-	-	-
13.	Other Taxes	-	-	6,417	6,199	-	-
14.	Total	5,601	5,411	6,417	6,199	13,226	12,776
15.	Operating Income Before Income Tax	(5,601)	(5,411)	(6,417)	(6,199)	(13,226)	(12,776)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	(5,601)	(5,411)	(6,417)	(6,199)	(13,226)	(12,776)
18.	Composite Income Tax Rate - 39.51%	(2,213)	(2,138)	(2,535)	(2,449)	(5,226)	(5,048)
19.	Operating Income (line 15 minus line 18)	$ (3,388)	$ (3,273)	$ (3,882)	$ (3,750)	$ (8,000)	$ (7,728)
	WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	

(1) Adjustment to Test Year operation expense to reflect the increased cost associated with SCE's portion of Units 4&5 and removal of APS's costs of Units 1-3. The latter costs are based on Test Year 2010 actuals.

(2) Adjustment to Test Year property tax values to reflect the increase in tax owed to the Navajo Nation and New Mexico due to the acquisition of SCE's share of Units 4&5.

(3) Adjustment to Test Year depreciation and amortization expense to reflect additional expenses associated with the SCE transaction.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4.d - FOUR CORNERS RATE RIDER
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(4) Incremental Final Coal Reclamation Expense Related to Acquisition Total Co. (G)	ACC (H)	(5) Incremental Decommissioning Expense Related to Acquisition Total Co. (I)	ACC (J)	(6) Amortization of Four Corners Deferral Balance Total Co. (K)	ACC (L)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	4,470	4,318	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(4,470)	(4,318)	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	-	-	3,059	2,955	5,122	4,948
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	-	-	3,059	2,955	5,122	4,948
15.	Operating Income Before Income Tax	(4,470)	(4,318)	(3,059)	(2,955)	(5,122)	(4,948)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	(4,470)	(4,318)	(3,059)	(2,955)	(5,122)	(4,948)
18.	Composite Income Tax Rate - 39.51%	(1,766)	(1,706)	(1,209)	(1,168)	(2,024)	(1,955)
19.	Operating Income (line 15 minus line 18)	$ (2,704)	$ (2,612)	$ (1,850)	$ (1,787)	$ (3,098)	$ (2,993)
	WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	

(4) Adjustment to reflect the amortization of SCE's share of coal reclamation through 2038.

(5) Adjustment to reflect the amortization of SCE's share of decommissioning through 2038.

(6) Deferred balance of operating costs associated with SCE's share of Units 4&5 and unrecovered costs associated Units 1-3, less savings from closure of Units 1-3. Deferral balance covers amounts deferred from December 30, 2013 through June 30, 2014, amortized over 10 years.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4.d - FOUR CORNERS RATE RIDER
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		(7)		(8)	
		Interest/Income Tax Adjustment Related to Rate Base Pro Formas		Total Income Statement Adjustments	
Line No.	Description	Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)
	Electric Operating Revenues				
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-
3.	Other Electric Revenues	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	4,470	4,318
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	(4,470)	(4,318)
	Other Operating Expenses:				
7.	Operations Excluding Fuel Expense	-	-	559	540
8.	Maintenance	-	-	1,223	1,182
9.	Subtotal	-	-	1,782	1,722
10.	Depreciation and Amortization	-	-	21,407	20,679
11.	Amortization of Gain	-	-	-	-
12.	Administrative and General	-	-	3,819	3,689
13.	Other Taxes			6,417	6,199
14.	Total	-	-	33,425	32,289
15.	Operating Income Before Income Tax	-	-	(37,895)	(36,607)
16.	Interest Expense	6,620	6,395	6,620	6,395
17.	Taxable Income	(6,620)	(6,395)	(44,515)	(43,002)
18.	Composite Income Tax Rate - 39.51%	(2,615)	(2,526)	(17,588)	(16,990)
19.	Operating Income (line 15 minus line 18)	$ 2,615	$ 2,526	$ (20,307)	$ (19,617)

WITNESS: BLANKENSHIP

(7) Adjustment to income taxes to reflect the increase in rate base associated with the purchase of SCE's share of Units 4-5.

aps

ADJUSTMENT SCHEDULE FCA
FOUR CORNERS ADJUSTMENT

APPLICATION

The Four Corners Adjustment Schedule ("FCA") shall apply to all retail Standard Offer service.

Schedule FCA recovers costs associated with investment and expenses for APS's purchase of Southern California Edison's share of Four Corners Generating Station Units 4 and 5 and associated facilities and retirement of APS Units 1, 2 and 3 as approved in Decision Nos. 73130 and 73183.

All provisions of the customer's current applicable rate schedule shall apply in addition to charges under this adjustment schedule. Schedule FCA shall be effective upon approval by the Arizona Corporation Commission without proration.

RATE

The FCA charge will be applicable to the customer's monthly billed amount, excluding all other adjustments, sales tax, regulatory assessment and franchise fees. The resulting charged amount shall not be less than zero. In addition, the charge shall not apply to:

- The generation service and imbalance service charges in Rate Rider Schedule AG-1
- The energy and ancillary service charge in Rate Schedule E-36 XL
- Credits for the purchase of excess generation under rate rider schedules EPR-2, EPR-6, and E-56R
- Voluntary charges under rate rider schedules GPS-1, GPS-2, and GPS-3

FCA charge	2.22%

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule 4.b, page 1, column C
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: Four Corners Fair Value Acquisition
Adjustment to rate base to reflect the increase in the accounting fair value associated with the increase of SCE's share of Unit 4 & 5

Line No.	Description	Total Company Amount
1.	Gross Utility Plant in Service	$ 860,105
2.	Less: Accumulated Depreciation and Amortization	554,229
3.	Net Utility Plant in Service	305,876
4.	Less: Total Deductions	127,074
5.	Total Additions	4,469
6.	**Total Rate Base**	**$ 183,271**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule 4.b, page 1, column E
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: Four Corners Auxiliary Plant
Adjustment to rate base to reflect the cost of the auxiliary boiler required to run Units 4 & 5.

Line No.	Description	Total Company Amount
1.	Gross Utility Plant in Service	$ 11,319
2.	Less: Accumulated Depreciation and Amortization	286
3.	Net Utility Plant in Service	11,033
4.	Less: Total Deductions	-
5.	Total Additions	-
6.	**Total Rate Base**	**$ 11,033**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule 4.b, page 2, column G
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: Four Corners Deferral Balance
Deferred balance of operating costs associated with SCE's share of Units 4&5 and unrecovered costs associated Units 1-3, less savings from closure of Units 1-3. Deferral balance covers amounts deferred from December 30, 2013 through June 30, 2014.

Line No.	Description		Total Company Amount
1.	Gross Utility Plant in Service	$	51,222
2.	Less: Accumulated Depreciation and Amortization		-
3.	Net Utility Plant in Service		51,222
4.	Less: Total Deductions		20,238
5.	Total Additions		-
6.	**Total Rate Base**	**$**	**30,984**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule 4.d, page 1, column A
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Incremental Operation and Maintenance Expenses Related to the Acquisition**
Adjustment to Test Year operation expense to reflect the increased cost associated with SCE's portion of Units 4&5 and removal of APS's costs of Units 1-3. The latter costs are based on Test Year 2010 actuals.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	5,601
7.	Depreciation and amortization	-
8.	Other taxes	-
9.	Total Operating Expenses	5,601
10.	**Operating Income (before income tax)**	**(5,601)**
11.	Current Income Tax Rate - 39.51%	(2,213)
12.	**Operating Income After Tax**	**$ (3,388)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule 4.d, page 1, column C
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Incremental Property Tax and Other Taxes Related to Acquisition**
Adjustment to Test Year property tax values to reflect the increase in tax owed to the Navajo Nation and New Mexico due to the acquisition of SCE's share of Units 4&5.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	-
8.	Other taxes	6,417
9.	Total Operating Expenses	6,417
10.	**Operating Income (before income tax)**	**(6,417)**
11.	Current Income Tax Rate - 39.51%	(2,535)
12.	**Operating Income After Tax**	**$ (3,882)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule 4.d, page 1, column E
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Incremental Depreciation and Amortization Expense Related to the Acquisition**
Adjustment to Test Year depreciation and amortization expense to reflect additional expenses associated with the SCE transaction.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	13,226
8.	Other taxes	-
9.	Total Operating Expenses	13,226
10.	**Operating Income (before income tax)**	**(13,226)**
11.	Current Income Tax Rate - 39.51%	(5,226)
12.	**Operating Income After Tax**	**$ (8,000)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule 4.d, page 2, column G
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Incremental Final Coal Reclamation Expense Related to Acquisition**
Adjustment to reflect the amortization of SCE's share of coal reclamation through 2038.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	4,470
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	-
8.	Other taxes	-
9.	Total Operating Expenses	4,470
10.	**Operating Income (before income tax)**	**(4,470)**
11.	Current Income Tax Rate - 39.51%	(1,766)
12.	**Operating Income After Tax**	**$ (2,704)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule 4.d, page 2, column I
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Incremental Decommissioning Expense Related to Acquisition**
Adjustment to reflect the amortization of SCE's share of decommissioning through 2038.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	3,059
8.	Other taxes	-
9.	Total Operating Expenses	3,059
10.	**Operating Income (before income tax)**	**(3,059)**
11.	Current Income Tax Rate - 39.51%	(1,209)
12.	**Operating Income After Tax**	**$ (1,850)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule 4.d, page 2, column K
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Amortization of Four Corners Deferral Balance**
Deferred balance of operating costs associated with SCE's share of Units 4&5 and unrecovered costs associated Units 1-3, less savings from closure of Units 1-3. Deferral balance covers amounts deferred from December 30, 2013 through June 30, 2014, amortized over 10 years.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	5,122
8.	Other taxes	-
9.	Total Operating Expenses	5,122
10.	**Operating Income (before income tax)**	**(5,122)**
11.	Current Income Tax Rate - 39.51%	(2,024)
12.	**Operating Income After Tax**	**$ (3,098)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule 4.d, page 3, column M
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Interest / Income Tax Adjustment Related to Rate Base Pro Formas**
Adjustment to interest expense and income taxes related to the increase in rate base associated with the purchase of SCE's share of Units 4&5, including the acquisition net book value, purchase adjustment, auxiliary boiler and deferral balance.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	-
8.	Other taxes	-
9.	Total Operating Expenses	-
10.	**Operating Income (before income tax)**	-
11.	Interest Expense	6,620
12.	Taxable Income	(6,620)
13.	Current Income Tax Rate - 39.51%	(2,615)
14.	**Operating Income After Tax**	**$ 2,615**

REBUTTAL TESTIMONY OF ELIZABETH A. BLANKENSHIP

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-0224

EXHIBIT
APS-4
ADMITTED

July 3, 2014

Table of Contents

REBUTTAL TESTIMONY OF ELIZABETH A. BLANKENSHIP
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-0224)

I. INTRODUCTION

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

A. My name is Elizabeth A. Blankenship. I am a Manager in the Revenue/Regulatory Accounting Department for Arizona Public Service Company ("APS" or "Company"). My business address is 400 North 5th Street, Phoenix, Arizona 85004.

Q. DID YOU SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, my Direct Testimony was filed on December 30, 2013.

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

The purpose of my Rebuttal Testimony is to provide the updated Four Corners Rate Rider revenue requirement with information through April 30, 2014, to review the revenue requirement calculations submitted by Staff and RUCO, and to address the cost of debt used by RUCO as its rate of return and a miscellaneous item raised by Staff.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. On December 30, 2013, APS purchased Southern California Edison's ("SCE") 48 percent share in Units 4 and 5. Subsequently, APS filed an application to request recovery of a $62.53 million annual revenue requirement through the Four Corners Rate Rider. APS updated the revenue requirement as of April 30, 2014 and is now requesting recovery of a $65.44 million annual revenue requirement. This increase is primarily related to the delay in the assumed rate effective date, which is described in more detail in Section III below. My testimony provides the updated revenue requirement needed to include the Four Corners Transaction ("Transaction") in base rates as contemplated in the Settlement and Decision No. 73183 (May 24, 2012). Specifically, my testimony includes the updated calculation of the $65.44 million revenue requirement, including all rate base and income statement pro forma adjustments. The revenue requirement assumes a rate effective date of December 1, 2014.

My testimony also reviews both Staff and RUCO witnesses' testimonies regarding the Four Corners Rate Rider revenue requirement. Specifically, I address RUCO Witness Mr. Mease's misinterpretation of Decision No. 73130 (April 24, 2012) to apply the marginal cost of debt to derive the revenue requirement.

III. UPDATED FOUR CORNERS RATE RIDER REVENUE REQUIREMENT

Q. DID APS UPDATE THE FOUR CORNERS RATE RIDER REVENUE REQUIREMENT FOR REBUTTAL TESTIMONY?

A. Yes. APS updated the revenue requirement with the most up-to-date information as of April 30, 2014, including the timing assumption of the deferral period, (which was extended to reflect the rate effective date of December 1, 2014). The updated revenue requirement and supporting schedules, including the detailed pro forma calculations, are attached to my testimony as Rebuttal Attachments EAB-1 through EAB-21. Please note that Attachment EAB-3 is confidential and will be provided pursuant to an executed Protective Agreement.

Q. PLEASE DESCRIBE THE MAJOR CHANGES IN THE REVENUE REQUIREMENT FROM APS'S DIRECT TESTIMONY.

A. The table below shows the main components driving the change in the revenue requirement from APS's original Application filed December 30, 2014:

	$ in millions
Original As Filed Revenue Requirement (12/30/13)	$62.53
Change in Deferral Period (6 months to 11 months)	2.86
All Other Changes	0.05
Updated Revenue Requirement (04/30/14)	**$65.44**

As the table above shows, lengthening the deferral period from the original assumption of June 30, 2014 to November 30, 2014 caused almost all of the change to the revenue requirement.

Q. **DOES APS ANTICIPATE UPDATING THE REVENUE REQUIREMENT THROUGHOUT THE REMAINDER OF THE PROCEEDING?**

A. Yes. APS will update the revenue requirement if there is a significant change, such as an adjustment to the deferral period.

Q. **DID APS PROVIDE THE UPDATED REVENUE REQUIREMENT TO THE OTHER PARTIES PRIOR TO THE SUBMISSION OF THEIR DIRECT TESTIMONY?**

A. Yes. On June 2, 2014, in response to a data request from Staff (Staff 39.16), APS provided the updated revenue requirement as of April 30, 2014, including the supporting schedules.

Q. **DID ANY OTHER PARTIES ADDRESS THE UPDATED REVENUE REQUIREMENT?**

A. Yes. Staff and RUCO both presented revenue requirement testimony. Both parties agreed with the pro forma adjustments that APS included in the Application.[1] RUCO's testimony reflects the April 30th update. Staff's testimony used some, but not all the updated data, but APS does not believe Staff opposes

[1] Staff Witness Dennis Kalbarczyk presented revenue requirement testimony. He updated the marginal cost of debt rate in his testimony to reflect APS's debt issuance. Mr. Kalbarczyk included the rate of 4.7% in his calculation, ~~which~~ was based on a rounded figure that APS provided in a discovery response. The correct rate is 4.725%, as can be seen in APS's calculations. APS believes Staff will accept using the correct full cost of debt of 4.725% in the deviation of the revenue requirement.

Yield to M

any of the April 30th updates. However, Staff and RUCO each proposed different methods to determine the rate of return – a topic that I will discuss in greater detail later in my testimony. APS Witness Snook also addresses this topic.

Q. WHAT WERE STAFF AND RUCO'S RECOMMENDATIONS TO THE REVENUE REQUIREMENT?

A. Staff proposed an $8.39 million revenue reduction to APS's updated revenue requirement.[2] Staff stated the Fair Value Rate of Return ("FVROR") of 6.09 percent calculated in the Settlement Agreement should have been applied to the Original Cost Rate Base ("OCRB") adjustments, rather than the Weighted Average Cost of Capital ("WACC") of 8.33 percent.

RUCO proposed a $16.24 million revenue requirement reduction. RUCO proposed using the marginal cost of debt rate of 4.725 percent as the rate of return instead of the 8.33 percent WACC. The table below summarizes the ACC jurisdictional revenue requirement adjustments that Staff and RUCO recommended, as well as APS's updated revenue requirement.

	Description	APS Revised Filing (4/30/14)	Staff Direct Testimony	RUCO Direct Testimony
			(dollars in millions)	
1.	Revenue Requirement Increase	$ 65.44	$ 57.05	$ 49.20
2.	Adjusted Rate Base	$225.93	$225.93	$225.93
3.	Debt Rate for Deferral	4.725%	4.70%	4.725%
4.	Rate of Return for Revenue Requirement	8.33%	6.09%	4.725%
5.	Percentage Rate Surcharge	2.33%	2.03%	1.50%
6.	Change in Revenue Requirement	-0-	-$ 8.39	-$ 16.24

[2] Staff's Direct Testimony used APS's originally-filed information as a starting point for their revenue requirement analysis. Because APS does not believe Staff opposes any of the April 30th updates, APS updated its testimony to reflect the most updated numbers.

Q. DOES APS AGREE WITH STAFF'S AND RUCO'S RECOMMENDATIONS?

A. No. APS disagrees with both Staff and RUCO with respect to the appropriate rate of return to apply to the rate base adjustments. APS does not believe that Staff applied the FVROR correctly for several reasons, as explained in the Rebuttal Testimony of APS Witness Leland R. Snook. APS believes that RUCO's application of the marginal cost of debt rate to the revenue requirement is inconsistent with Section 10.2 of the Settlement Agreement (Decision No. 73183) and the Four Corners Deferral Order (Decision No. 73130).

IV. RUCO'S COST OF DEBT RECOMMENDATION

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF RUCO WITNESS ROBERT MEASE'S TESTIMONY REGARDING HOW THE COST OF DEBT SHOULD BE APPLIED IN THE FOUR CORNERS RATE RIDER CALCULATION.

A. Mr. Mease's only point of disagreement centered on the rate of return that should be used to calculate the revenue requirement. To that end, Mr. Mease applied only the 4.725% cost of debt to determine the revenue requirement, rather than the WACC of 8.33%. This resulted in a proposal of a $49.20 million revenue requirement, reducing APS's calculation by $16.24 million. Mr. Mease points to the Decision No. 73130 (the Four Corners Deferral Order), specifically page 37, lines 7-9, as the basis for using the 4.725% cost of debt to determine the revenue requirement.

Q. DO YOU AGREE WITH RUCO'S APPLICATION OF THE DEBT RATE TO THE TOTAL FOUR CORNERS REVENUE REQUIREMENT?

A. No. Mr. Mease's proposal relies entirely on language that applies only to the deferral balance and not to all of the components that make up the $65.44 million revenue requirement in this proceeding.[3] Section 10.2 of the Settlement Agreement specifically allowed APS to seek to reflect in rates three buckets of items associated with Four Corners in this proceeding: (1) the rate base and expense effects associated with the acquisition of SCE's share of Units 4 and 5; (2) the rate base and expense effects associated with the retirement of Units 1-3; and (3) any cost deferral authorized in Docket No. E-01345A-10-0474 (resulting in Decision No. 73130). In regards to the debt rate to be applied to this deferral, Decision No. 73130 plainly required that APS could only defer "the documented debt cost of acquiring SCE's interest in Units 4 and 5." APS calculated the deferral consistent with this requirement, applying only the 4.725% documented cost of debt to the deferred costs. *See* Rebuttal Attachment EAB-20 at line 19. The revenue requirement of $65.44 million in this proceeding includes that debt-return only deferral balance.

Decision No. 73130 did not say or imply that the cost of debt should be used in place of the WACC on the entire asset when the plant was placed in rate base. The debt-only capital treatment was strictly limited to the deferral balance. RUCO, however, extends the reach of that debt-return only treatment to all *three* of the items that make up the revenue requirement for this asset – not just the deferral balance. In leaving the rate case open to adjust rates to reflect the Four Corners transaction, the Settlement intended to allow the Four Corners asset the same rate of return treatment as the other assets comprising rate base in the Settlement's 2010 adjusted Test Year. Reducing the rate of return on that asset from the 8.33% WACC to a 4.725% documented debt cost would be inconsistent with the Settlement.

[3] Decision No. 73130 states that the Commission approved "an accounting order ... that allows **deferral** of the non-fuel costs, except that we will include as "non-fuel costs" only the documented debt cost of acquiring SCE's interest in Units 4 and 5, and will not authorize any carrying charges on any **deferred costs**." [emphasis added]

Q. DID APS COMPLY WITH DECISION NO. 73130 IN ITS APPLICATION OF THE DEBT RATE TO DEFERRED COSTS?

Yes. APS included a specific pro forma adjustment titled "Four Corners Deferral Balance" that complied with Decision No. 73130 and used the documented debt cost of 4.725% (*see* Rebuttal Attachment EAB-20 at line 19) to determine the cost deferral to include in the Four Corners Rate Rider.

V. <u>MISCELLANEOUS ISSUE</u>

Q. DOES APS AGREE WITH STAFF WITNESS KALBARCZYK'S SUGGESTION ON PAGE 15, LINES 10-18 OF HIS DIRECT TESTIMONY TO MODIFY THE FOUR CORNERS RATE RIDER TARIFF SHEET LANGUAGE?

A. Yes. APS agrees to add a sentence to the Four Corners Rate Rider Tariff sheet to state that the Rate Rider "will only remain in effect until the conclusion of APS's next rate case." A redlined copy of the updated tariff sheet is provided as Rebuttal Attachment EAB-9.

VI. <u>CONCLUSION</u>

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. APS complied with the intent and language of both Decision Nos. 73130 and 73183 in determining the cost deferral and the ultimate revenue requirement in the Four Corners Rate Rider and therefore, Staff and RUCO's proposals should not be accepted. Lastly, the updated revenue requirement provided in my testimony reflects the most recent data and assumptions and should be used to determine the Four Corners Rate Rider.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)
(dollars in thousands)

	March 31, 2014	December 31, 2013
ASSETS		
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	$ 15,253,694	$ 15,196,598
Accumulated depreciation and amortization	(5,357,699)	(5,296,501)
Net	9,895,995	9,900,097
Construction work in progress	646,236	581,369
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	124,157	125,125
Intangible assets, net of accumulated amortization	144,291	157,534
Nuclear fuel, net of accumulated amortization	144,048	124,557
Total property, plant and equipment	10,954,727	10,888,682
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Note 13)	657,862	642,007
Assets from risk management activities (Note 7)	21,626	23,815
Other assets	34,411	33,709
Total investments and other assets	713,899	699,531
CURRENT ASSETS		
Cash and cash equivalents	103,400	3,725
Customer and other receivables	245,272	299,055
Accrued unbilled revenues	88,907	96,796
Allowance for doubtful accounts	(2,504)	(3,203)
Materials and supplies (at average cost)	223,401	221,682
Fossil fuel (at average cost)	36,496	38,028
Income tax receivable	289	135,179
Assets from risk management activities (Note 7)	16,951	17,169
Deferred fuel and purchased power regulatory asset (Note 3)	--	20,755
Other regulatory assets (Note 3)	76,317	76,388
Other current assets	45,176	39,153
Total current assets	833,705	944,727
DEFERRED DEBITS		
Regulatory assets (Note 3)	719,596	711,712
Unamortized debt issue costs	22,686	21,860
Other	114,437	114,865
Total deferred debits	856,719	848,437
TOTAL ASSETS	$ 13,359,050	$ 13,381,377

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)
(dollars in thousands)

	March 31, 2014	December 31, 2013
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	2,379,696	2,379,696
Retained earnings	1,823,914	1,804,398
Accumulated other comprehensive loss:		
Pension and other postretirement benefits	(29,747)	(30,313)
Derivative instruments	(20,364)	(23,059)
Total shareholder equity	4,331,661	4,308,884
Noncontrolling interests (Note 6)	154,915	145,990
Total equity (Note S-1)	4,486,576	4,454,874
Long-term debt less current maturities (Note 2)	2,920,614	2,671,465
Total capitalization	7,407,190	7,126,339
CURRENT LIABILITIES		
Short-term borrowings (Note 2)	--	153,125
Current maturities of long-term debt (Note 2)	540,424	540,424
Accounts payable	219,910	281,237
Accrued taxes (Note 5)	173,040	122,460
Accrued interest	47,207	48,132
Common dividends payable	--	62,500
Customer deposits	75,999	76,101
Deferred income taxes	21,951	2,033
Liabilities from risk management activities (Note 7)	19,907	31,892
Liabilities for asset retirements	25,536	32,896
Deferred fuel and purchased power regulatory liability	18,897	--
Other regulatory liabilities (Note 3)	116,903	99,273
Other current liabilities	118,934	130,774
Total current liabilities	1,378,708	1,580,847
DEFERRED CREDITS AND OTHER		
Deferred income taxes	2,355,237	2,347,724
Regulatory liabilities (Note 3)	783,702	801,297
Liabilities for asset retirements	344,708	313,833
Liabilities for pension and other postretirement benefits (Note 4)	405,597	476,017
Liabilities from risk management activities (Note 7)	29,106	70,315
Customer advances	115,033	114,480
Coal mine reclamation	208,183	207,453
Deferred investment tax credit	152,114	152,361
Unrecognized tax benefits (Note 5)	26,284	42,209
Other	153,188	148,502
Total deferred credits and other	4,573,152	4,674,191
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
TOTAL LIABILITIES AND EQUITY	$ 13,359,050	$ 13,381,377

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)
(dollars in thousands)

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
ELECTRIC OPERATING REVENUES	$ 685,545	$ 685,827
OPERATING EXPENSES		
Fuel and purchased power	249,786	230,679
Operations and maintenance	208,285	220,752
Depreciation and amortization	101,748	103,706
Income taxes	10,478	16,060
Taxes other than income taxes	45,613	39,768
Total	615,910	610,965
OPERATING INCOME	69,635	74,862
OTHER INCOME (DEDUCTIONS)		
Income taxes	1,210	2,332
Allowance for equity funds used during construction	7,442	6,864
Other income (Note S-2)	2,762	1,343
Other expense (Note S-2)	(5,056)	(6,296)
Total	6,358	4,243
INTEREST EXPENSE		
Interest on long-term debt	48,896	46,221
Interest on short-term borrowings	1,413	1,429
Debt discount, premium and expense	1,011	1,011
Allowance for borrowed funds used during construction	(3,770)	(3,990)
Total	47,550	44,671
NET INCOME	28,443	34,434
Less: Net income attributable to noncontrolling interests (Note 6)	8,925	8,392
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 19,518	$ 26,042

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(unaudited)
(dollars in thousands)

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
NET INCOME	$ 28,443	$ 34,434
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Derivative instruments:		
Net unrealized gain (loss), net of tax benefit (expense) of $(599) and $(38)	(421)	58
Reclassification of net realized loss, net of tax benefit of $1,323 and $3,300	3,116	5,052
Pension and other postretirement benefits activity, net of tax expense of $606 and $576	566	882
Total other comprehensive income	3,261	5,992
COMPREHENSIVE INCOME	31,704	40,426
Less: Comprehensive income attributable to noncontrolling interests	8,925	8,392
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 22,779	$ 32,034

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4 - FOUR CORNERS REVENUE REQUIREMENT CALCULATION
COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENTS
ACC JURISDICTION
ADJUSTED TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		Settlement			Settlement (with Four Corners Acquisition)				
Line No.	Description	Original Cost	RCND	Fair Value	Four Corners Pro Forma Adjustments	Original Cost	RCND	Fair Value	Line No.
1.	Adjusted Rate Base	$ 5,662,998 (a)	$ 10,671,253	$ 8,167,126 (a)	$ 225,934 (b)	$ 5,888,932	$ 10,897,187	$ 8,393,060	1.
2.	Adjusted Operating Income	496,769	496,769	496,769	(20,680) (c)	476,089	476,089	476,089	2.
3.	Fair Value Adjustment Embedded in Operating Income	25,041	25,041	25,041		25,041	25,041	25,041	3.
4.	Adjusted Operating Income without Fair Value Adjustment (Line 2 - Line 3)	471,728	471,728	471,728		451,048	451,048	451,048	4.
5.	Current Rate of Return (Line 4 / Line 1)	8.33%	4.42%	5.78% (d)		7.66%	4.14%	5.37%	5.
6.	Required Operating Income (Line 7 * Line 1)	471,728	471,728	471,728		490,548	490,548	490,548	6.
7.	Required Rate of Return	8.33% (e)	4.42% (e)	5.78% (e)		8.33% (e)	4.50% (e)	5.84% (e)	7.
8.	Adjusted Operating Income Deficiency (Line 4 - Line 6)	-	-	-		39,500	39,500	39,500	8.
9.	Gross Revenue Conversion Factor (f)	1.6566	1.6566	1.6566		1.6566	1.6566	1.6566	9.
10.	Requested Increase in Base Revenue Requirements (Line 8 * Line 9)	-	-	-		65,436	65,436	65,436	10.
11.	2010 Adjusted Base Revenues (g)					$ 2,810,916	$ 2,810,916	$ 2,810,916	11.
12.	Percentage Base Rate Increase (Line 10 / Line 11)					2.33%	2.33%	2.33%	12.

Notes:
(a) *See* Decision No. 73183, page 46
(b) *See* Schedule 4.a, Column E, Line 21
(c) *See* Schedule 4.c, Page 2, Column B, Line 23
(d) APS was authorized a 6.09% rate of return on fair value, to tie to that number, Line 2 would be divided into Line 1, however for purposes of this schedule, the Fair Value Rate of Return was shown without the Fair Value Increment
(e) The Required Rate of Return for OCRB, RCND and Fair Value effectively reflects a zero return on any difference between Fair Value Rate Base and Original Cost Rate Base, and is mathematically equivalent to the original cost rate of return
(f) *See* Staff Witness Ralph Smith, Attachment RCS-2
(g) APS's total adjusted base revenue in the Settlement was $2,868,858, however, this Schedule adjusts the revenue received by AG-1 customers to exclude amounts now paid to alternative generation suppliers and to add applicable wire-related revenues for E-36XL. *See* APS Witness Jeffrey Guldner's Direct Testimony for more information

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4.a FOUR CORNERS RATE RIDER
SUMMARY OF ORIGINAL COST RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		Original Cost						
		Total Company			ACC			
Line No.	Description	Settlement (a) (A)	Four Corners Pro Forma (b) (B)	Adjusted Settlement (c) (C)	Settlement (d) (D)	Four Corners Pro Forma (e) (E)	Adjusted Settlement (f) (F)	Line No.
1.	Gross utility plant in service	$ 14,005,836	$ 939,446	$ 14,945,282	$ 11,866,173	$ 907,506	$ 12,773,679	1.
2.	Less: Accumulated depreciation & amortization	5,219,000	555,872	5,774,872	4,528,867	536,973	5,065,840	2.
3.	Net utility plant in service	8,786,836	383,574	9,170,410	7,337,306	370,533	7,707,839	3.
	Deductions:							
4.	Deferred income taxes	1,931,063	27,247	1,958,310	1,567,902	26,321	1,594,223	4.
5.	Investment tax credits	907	-	907	876	-	876	5.
6.	Customer advances for construction	121,645	-	121,645	121,645	-	121,645	6.
7.	Customer deposits	68,084	-	68,084	68,084	-	68,084	7.
8.	Pension and other postretirement liabilities	711,164	-	711,164	661,518	-	661,518	8.
9.	Liability for asset retirements	328,571	-	328,571	320,592	-	320,592	9.
10.	Other deferred credits	66,842	127,074	193,916	64,107	122,753	186,860	10.
11.	Coal mine reclamation	117,243	-	117,243	114,396	-	114,396	11.
12.	Unrecognized tax benefits	65,363	-	65,363	53,961	-	53,961	12.
13.	Regulatory liabilities	260,687	-	260,687	253,750	-	253,750	13.
14.	Total deductions	3,671,569	154,321	3,825,890	3,226,831	149,074	3,375,905	14.
	Additions:							
15.	Regulatory assets	822,177	-	822,177	746,508	-	746,508	15.
16.	Deferred debit income tax receivable	65,498	-	65,498	63,271	-	63,271	16.
17.	Other deferred debits	77,674	4,633	82,307	72,203	4,475	76,678	17.
18.	Decommissioning trust accounts	469,886	-	469,886	458,476	-	458,476	18.
19.	Allowance for working capital	233,778	-	233,778	212,065	-	212,065	19.
20.	Total additions	1,669,013	4,633	1,673,646	1,552,523	4,475	1,556,998	20.
21.	Total rate base	$ 6,784,280	$ 233,886	$ 7,018,166	$ 5,662,998	$ 225,934	$ 5,888,932	21.

Notes:
(a) *See* Schedule 4.b, Page 1, Column A
(b) *See* Schedule 4.b, Page 2, Column I
(c) *See* Schedule 4.b, Page 2, Column K
(d) *See* Schedule 4.b, Page 1, Column B
(e) *See* Schedule 4.b, Page 2, Column J
(f) *See* Schedule 4.b, Page 2, Column L

ARIZONA PUBLIC SERVICE COMPANY
FOUR CORNERS RATE RIDER
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(1) Settlement Test Year 12/31/2010 Total Co. (A)	(1) Settlement Test Year 12/31/2010 ACC (B)	(2) Four Corners Fair Value Acquisition Total Co. (C)	(2) Four Corners Fair Value Acquisition ACC (D)	(3) Four Corners Auxiliary Plant Total Co. (E)	(3) Four Corners Auxiliary Plant ACC (F)
1.	Gross Utility Plant in Service	$ 14,005,836	$ 11,866,173	$ 858,942	$ 829,738	$ 11,541	$ 11,149
2.	Less: Accumulated Depreciation & Amort.	5,219,000	4,528,867	555,395	536,512	477	461
3	Net Utility Plant in Service	8,786,836	7,337,306	303,547	293,226	11,064	10,688
4.	Less: Total Deductions	3,671,569	3,226,831	127,074	122,753	-	-
5.	Total Additions	1,669,013	1,552,523	4,633	4,475	-	-
6.	Total Rate Base	$ 6,784,280	$ 5,662,998	$ 181,106	$ 174,948	$ 11,064	$ 10,688
	WITNESS:			BLANKENSHIP		BLANKENSHIP	

(1) See Rate base per Settlement Decision No. 73183, page 46

(2) Adjustment to rate base to reflect the increase in the accounting fair value associated with the increase of SCE's share of Units 4&5

(3) Adjustment to rate base to reflect the cost of the auxiliary boiler required to run Units 4&5

ARIZONA PUBLIC SERVICE COMPANY
FOUR CORNERS RATE RIDER
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(4) Four Corners Deferral Balance Total Co. (G)	ACC (H)	(5) Total Four Corners Rate Base Pro Forma Adjustments Total Co. (I)	ACC (J)	(6) Adjusted Settlement Test Year 12/31/2010 Total Co. (K)	ACC (L)
1.	Gross Utility Plant in Service	$ 68,963	$ 66,619	$ 939,446	$ 907,506	$ 14,945,282	$ 12,773,679
2.	Less: Accumulated Depreciation & Amort.	-	-	555,872	536,973	5,774,872	5,065,840
3	Net Utility Plant in Service	68,963	66,619	383,574	370,533	9,170,410	7,707,839
4.	Less: Total Deductions	27,247	26,321	154,321	149,074	3,825,890	3,375,905
5.	Total Additions	-	-	4,633	4,475	1,673,646	1,556,998
6.	Total Rate Base	$ 41,716	$ 40,298	$ 233,886	$ 225,934	$ 7,018,166	$ 5,888,932

WITNESS: BLANKENSHIP

(4) Deferred balance of operating costs associated with SCE's share of Units 4&5 and unrecovered costs associated Units 1-3, less savings from closure of Units 1-3. Deferral balance covers amounts deferred from December 30, 2013 through November 30, 2014

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4.c - FOUR CORNERS RATE RIDER
TOTAL COMPANY
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		Total Company			
Line No.	Description	Settlement (A)	Pro Forma Adjustments (a) (B)	Settlement Results After Pro Forma Adjustments (C)	Line No.
	Electric Operating Revenues				
1.	Revenues from Base Rates	$ 2,952,324	$ -	$ 2,952,324	1.
2.	Revenues from Surcharges	-	-	-	2.
3.	Other Electric Revenues	136,849	-	136,849	3.
4.	Total	3,089,173	-	3,089,173	4.
	Operating expenses:				
5.	Electric fuel and purchased power	1,031,289	4,499	1,035,788	5.
6.	Operations and maintenance excluding fuel expenses	676,937	5,601	682,538	6.
7.	Depreciation and amortization	405,150	23,359	428,509	7.
8.	Income taxes	242,751	(18,472)	224,279	8.
9.	Other taxes	162,770	6,418	169,188	9.
10.	Total	2,518,897	21,405	2,540,302	10.
11.	Operating income	570,276	(21,405)	548,871	11.
	Other income (deductions):				
12.	Income taxes	-	-	-	12.
13.	Allowance for equity funds used during construction	-	-	-	13.
14.	Other income	-	-	-	14.
15.	Other expense	-	-	-	15.
16.	Total	-	-	-	16.
17.	Income before interest deductions	570,276	(21,405)	548,871	17.
	Interest deductions:				
18.	Interest on long-term debt	-	-	-	18.
19.	Interest on short-term borrowings	-	-	-	19.
20.	Debt discount, premium and expense	-	-	-	20.
21.	Allowance for borrowed funds used during construction	-	-	-	21.
22.	Total	-	-	-	22.
23.	Net income	$ 570,276	$ (21,405)	$ 548,871	23.

Notes:
(a) *See* Schedule 4.d, Page 3, Column O

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4.c - FOUR CORNERS RATE RIDER
ACC JURISDICTION
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		ACC Jurisdiction			
Line No.	Description	Settlement (A)	Pro Forma Adjustments (a) (B)	Settlement Results After Pro Forma Adjustments (C)	Line No.
	Electric Operating Revenues				
1.	Revenues from Base Rates	$ 2,868,858	$ -	$ 2,868,858	1.
2.	Revenues from Surcharges	-	-	-	2.
3.	Other Electric Revenues	121,013	-	121,013	3.
4.	Total	2,989,871	-	2,989,871	4.
	Operating expenses:				
5.	Electric fuel and purchased power	1,006,003	4,346	1,010,349	5.
6.	Operations and maintenance excluding fuel expenses	779,461	5,412	784,873	6.
7.	Depreciation and amortization	352,026	22,565	374,591	7.
8.	Income taxes	216,195	(17,842)	198,353	8.
9.	Other taxes	139,417	6,200	145,617	9.
10.	Total	2,493,102	20,680	2,513,782	10.
11.	Operating income	496,769	(20,680)	476,089	11.
	Other income (deductions):				
12.	Income taxes	-	-	-	12.
13.	Allowance for equity funds used during construction	-	-	-	13.
14.	Other income	-	-	-	14.
15.	Other expense	-	-	-	15.
16.	Total	-	-	-	16.
17.	Income before interest deductions	496,769	(20,680)	476,089	17.
	Interest deductions:				
18.	Interest on long-term debt	-	-	-	18.
19.	Interest on short-term borrowings	-	-	-	19.
20.	Debt discount, premium and expense	-	-	-	20.
21.	Allowance for borrowed funds used during construction	-	-	-	21.
22.	Total	-	-	-	22.
23.	Net income	$ 496,769	$ (20,680)	$ 476,089	23.

Notes:
(a) *See* Schedule 4.d, Page 3, Column P

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4.d - FOUR CORNERS RATE RIDER
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(1) Incremental Operation and Maintenance Expenses Related to the Acquisition (Based on 2010 Actuals) Total Co. (A)	ACC (B)	(2) Incremental Property Tax & Other Taxes Related to the Acquisition Total Co. (C)	ACC (D)	(3) Incremental Depreciation and Amortization Expense Related to the Acquisition Total Co. (E)	ACC (F)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	559	540	-	-	-	-
8.	Maintenance	1,223	1,182	-	-	-	-
9.	Subtotal	1,782	1,722	-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	13,378	12,923
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	3,819	3,689	-	-	-	-
13.	Other Taxes	-	-	6,418	6,200	-	-
14.	Total	5,601	5,411	6,418	6,200	13,378	12,923
15.	Operating Income Before Income Tax	(5,601)	(5,411)	(6,418)	(6,200)	(13,378)	(12,923)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	(5,601)	(5,411)	(6,418)	(6,200)	(13,378)	(12,923)
18.	Composite Income Tax Rate - 39.51%	(2,213)	(2,138)	(2,536)	(2,450)	(5,286)	(5,106)
19.	Operating Income (line 15 minus line 18)	$ (3,388)	$ (3,273)	$ (3,882)	$ (3,750)	$ (8,092)	$ (7,817)
	WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	

(1) Adjustment to Test Year operation expense to reflect the increased cost associated with SCE's portion of Units 4&5 and removal of APS's costs of Units 1-3. The latter costs are based on Test Year 2010 actuals

(2) Adjustment to Test Year property tax values to reflect the increase in tax owed to the Navajo Nation and New Mexico due to the acquisition of SCE's share of Units 4&5

(3) Adjustment to Test Year depreciation and amortization expense to reflect additional expenses associated with the SCE transaction

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4.d - FOUR CORNERS RATE RIDER
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		(4)		(5)		(6)	
		Incremental Final Coal Reclamation Expense Related to Acquisition		Incremental Decommissioning Expense Related to Acquisition		Amortization of Four Corners Deferral Balance	
Line No.	Description	Total Co. (G)	ACC (H)	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	4,499	4,346			-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(4,499)	(4,346)	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense			-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization			3,085	2,980	6,896	6,662
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes					-	-
14.	Total	-	-	3,085	2,980	6,896	6,662
15.	Operating Income Before Income Tax	(4,499)	(4,346)	(3,085)	(2,980)	(6,896)	(6,662)
16.	Interest Expense						
17.	Taxable Income	(4,499)	(4,346)	(3,085)	(2,980)	(6,896)	(6,662)
18.	Composite Income Tax Rate - 39.51%	(1,778)	(1,717)	(1,219)	(1,177)	(2,725)	(2,632)
19.	Operating Income (line 15 minus line 18)	$ (2,721)	$ (2,629)	$ (1,866)	$ (1,803)	$ (4,171)	$ (4,030)
	WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	

(4) Adjustment to reflect the amortization of SCE's share of coal reclamation through 2038

(5) Adjustment to reflect the amortization of SCE's share of decommissioning through 2038

(6) Deferred balance of operating costs associated with SCE's share of Units 4&5 and unrecovered costs associated Units 1-3, less savings from closure of Units 1-3. Deferral balance covers amounts deferred from December 30, 2013 through November 30, 2014, amortized over 10 years

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4.d - FOUR CORNERS RATE RIDER
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(7) Interest/Income Tax Adjustment Related to Rate Base Pro Formas Total Co. (M)	ACC (N)	(8) Total Income Statement Adjustments Total Co. (O)	ACC (P)
	Electric Operating Revenues				
1.	Revenues from Base Rates	$ -		$ -	$ -
2.	Revenues from Surcharges	-		-	-
3.	Other Electric Revenues	-		-	-
4.	Total Electric Operating Revenues	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	4,499	4,346
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	(4,499)	(4,346)
	Other Operating Expenses:				
7.	Operations Excluding Fuel Expense	-	-	559	540
8.	Maintenance	-	-	1,223	1,182
9.	Subtotal	-	-	1,782	1,722
10.	Depreciation and Amortization			23,359	22,565
11.	Amortization of Gain	-	-	-	-
12.	Administrative and General	-	-	3,819	3,689
13.	Other Taxes			6,418	6,200
14.	Total	-	-	35,378	34,176
15.	Operating Income Before Income Tax	-	-	(39,877)	(38,522)
16.	Interest Expense	6,873	6,639	6,873	6,639
17.	Taxable Income	(6,873)	(6,639)	(46,750)	(45,161)
18.	Composite Income Tax Rate - 39.51%	(2,715)	(2,622)	(18,472)	(17,842)
19.	Operating Income (line 15 minus line 18)	$ 2,715	$ 2,622	$ (21,405)	$ (20,680)

WITNESS: BLANKENSHIP

(7) Adjustment to income taxes to reflect the increase in rate base associated with the purchase of SCE's share of Units 4-5.

aps

ADJUSTMENT SCHEDULE FCA
FOUR CORNERS ADJUSTMENT

APPLICATION

The Four Corners Adjustment Schedule ("FCA") shall apply to all retail Standard Offer service.

Schedule FCA recovers costs associated with investment and expenses for APS's purchase of Southern California Edison's share of Four Corners Generating Station Units 4 and 5 and associated facilities and retirement of APS Units 1, 2 and 3 as approved in Decision Nos. 73130 and 73183.

All provisions of the customer's current applicable rate schedule shall apply in addition to charges under this adjustment schedule. Schedule FCA shall be effective upon approval by the Arizona Corporation Commission without proration and will only remain in effect until the conclusion of APS's next rate case.

RATE

The FCA charge will be applicable to the customer's monthly billed amount, excluding all other adjustments, sales tax, regulatory assessment and franchise fees. The resulting charged amount shall not be less than zero. In addition, the charge shall not apply to:

- The generation service and imbalance service charges in Rate Rider Schedule AG-1
- The energy and ancillary service charge in Rate Schedule E-36 XL
- Credits for the purchase of excess generation under rate rider schedules EPR-2, EPR-6, and E-56R
- Voluntary charges under rate rider schedules GPS-1, GPS-2, and GPS-3

FCA charge 2.33%

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule 4.b, page 1, column C
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: Four Corners Fair Value Acquisition
Adjustment to rate base to reflect the increase in the accounting fair value associated with the increase of SCE's share of Unit 4 & 5

Line No.	Description	Total Company Amount
1.	Gross Utility Plant in Service	$ 858,942
2.	Less: Accumulated Depreciation and Amortization	555,395
3.	Net Utility Plant in Service	303,547
4.	Less: Total Deductions	127,074
5.	Total Additions	4,633
6.	**Total Rate Base**	**$ 181,106**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule 4.b, page 1, column E
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: Four Corners Auxiliary Plant
Adjustment to rate base to reflect the cost of the auxiliary boiler required to run Units 4 & 5.

Line No.	Description		Total Company Amount
1.	Gross Utility Plant in Service	$	11,541
2.	Less: Accumulated Depreciation and Amortization		477
3.	Net Utility Plant in Service		11,064
4.	Less: Total Deductions		-
5.	Total Additions		-
6.	**Total Rate Base**	**$**	**11,064**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule 4.b, page 2, column G
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: Four Corners Deferral Balance
Deferred balance of operating costs associated with SCE's share of Units 4&5 and unrecovered costs associated Units 1-3, less savings from closure of Units 1-3. Deferral balance covers amounts deferred from December 30, 2013 through November 30, 2014.

Line No.	Description	Total Company Amount
1.	Gross Utility Plant in Service	$ 68,963
2.	Less: Accumulated Depreciation and Amortization	-
3.	Net Utility Plant in Service	68,963
4.	Less: Total Deductions	27,247
5.	Total Additions	-
6.	**Total Rate Base**	**$ 41,716**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule 4.d, page 1, column A
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Incremental Operation and Maintenance Expenses Related to the Acquisition**
Adjustment to Test Year operation expense to reflect the increased cost associated with SCE's portion of Units 4&5 and removal of APS's costs of Units 1-3. The latter costs are based on Test Year 2010 actuals.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	5,601
7.	Depreciation and amortization	-
8.	Other taxes	-
9.	Total Operating Expenses	5,601
10.	**Operating Income (before income tax)**	**(5,601)**
11.	Current Income Tax Rate - 39.51%	(2,213)
12.	**Operating Income After Tax**	**$ (3,388)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule 4.d, page 1, column C
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Incremental Property Tax and Other Taxes Related to Acquisition**
Adjustment to Test Year property tax values to reflect the increase in tax owed to the Navajo Nation and New Mexico due to the acquisition of SCE's share of Units 4&5.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	-
8.	Other taxes	6,418
9.	Total Operating Expenses	6,418
10.	**Operating Income (before income tax)**	**(6,418)**
11.	Current Income Tax Rate - 39.51%	(2,536)
12.	**Operating Income After Tax**	**$ (3,882)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule 4.d, page 1, column E
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Incremental Depreciation and Amortization Expense Related to the Acquisition**
Adjustment to Test Year depreciation and amortization expense to reflect additional expenses associated with the SCE transaction.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	13,378
8.	Other taxes	-
9.	Total Operating Expenses	13,378
10.	**Operating Income (before income tax)**	(13,378)
11.	Current Income Tax Rate - 39.51%	(5,286)
12.	**Operating Income After Tax**	$ (8,092)

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule 4.d, page 2, column G
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Incremental Final Coal Reclamation Expense Related to Acquisition**
Adjustment to reflect the amortization of SCE's share of coal reclamation through 2038.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	4,499
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	-
8.	Other taxes	-
9.	Total Operating Expenses	4,499
10.	**Operating Income (before income tax)**	**(4,499)**
11.	Current Income Tax Rate - 39.51%	(1,778)
12.	**Operating Income After Tax**	**$ (2,721)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule 4.d, page 2, column I
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Incremental Decommissioning Expense Related to Acquisition**
Adjustment to reflect the amortization of SCE's share of decommissioning through 2038.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	3,085
8.	Other taxes	-
9.	Total Operating Expenses	3,085
10.	**Operating Income (before income tax)**	**(3,085)**
11.	Current Income Tax Rate - 39.51%	(1,219)
12.	**Operating Income After Tax**	**$ (1,866)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule 4.d, page 2, column K
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Amortization of Four Corners Deferral Balance**
Deferred balance of operating costs associated with SCE's share of Units 4&5 and unrecovered costs associated Units 1-3, less savings from closure of Units 1-3. Deferral balance covers amounts deferred from December 30, 2013 through November 30, 2014, amortized over 10 years.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	6,896
8.	Other taxes	-
9.	Total Operating Expenses	6,896
10.	**Operating Income (before income tax)**	**(6,896)**
11.	Current Income Tax Rate - 39.51%	(2,725)
12.	**Operating Income After Tax**	**$ (4,171)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule 4.d, page 3, column M
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Interest / Income Tax Adjustment Related to Rate Base Pro Formas**
Adjustment to interest expense and income taxes related to the increase in rate base associated with the purchase of SCE's share of Units 4&5, including the acquisition net book value, purchase adjustment, auxiliary boiler and deferral balance.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	-
8.	Other taxes	-
9.	Total Operating Expenses	-
10.	**Operating Income (before income tax)**	-
11.	Interest Expense	6,873
12.	Taxable Income	(6,873)
13.	Current Income Tax Rate - 39.51%	(2,715)
14.	**Operating Income After Tax**	**$ 2,715**

ARIZONA PUBLIC SERVICE COMPANY
Cost Deferral on 4C 4-5 With Financing Deferrals @ 100% x 5.25% Marginal LTD Rate , No Compounding
12/30/2013 Purchase Date of SCE's Share, Units 1-2-3 Shut Down 12/31/2013
($ in Millions)

		(a)	Jan. 2014 - November 2014[1] (b)	Annual Amount (c)
A.		Operation & Maintenance		
	1	Incremental Four Corners O&M Attributable to Additional 48% ownership of Units 4&5	46.890	51.153
	2	Incremental Four Corners O&M Attributable to Additional ownership of Common Facilities	6.388	6.969
	3	Unrecovered Inventory on Units 1-3	6.067	
	4	Unrecovered Plant Investment on Units 1-3 ($1.8M for Unrecovered Plant; $9.8M NBV for Ash Pond and $14.1M for Seepage Intercept)	29.346	
	5	Four Corners 1-3 on going and residual O&M (Estimated @ $.6M per year)	0.551	0.602
	6	Less: Four Corners Units 1-3 Test-Year O&M	42.176	46.010
	7	Net Change to Operation & Maintenance (Sum L1 thru L5 less L6)	$ 47.066	$ 12.714
B.		Book Depreciation and Amortization		
	8	Book Depreciation on Estimated SCE Book Basis of Acquired Portion	2.042	2.228
	9	Depreciation on Auxiliary Boiler	0.406	0.443
	10	Decommissioning on Acquired Portion	1.480	1.614
	11	Final Coal Reclamation on Acquired Portion	3.775	4.118
	12	Net Change to Book Depreciation and Amortization (Sum L8 thru L11)	$ 7.703	$ 8.402
C.		Property and Other Taxes		
	13	Possessory Interest and Business Activity Taxes on Acquired Portion	5.277	5.757
	14	Property Taxes on Acquired Portion	1.083	1.182
	15	Property Tax on Auxiliary Boiler	0.085	0.093
	16	Less: Property Taxes on Units 1-3	0.562	0.613
	17	Net Change to Property and Other Taxes (Sum L13 thru L15 less L16)	$ 5.883	$ 6.419
D.		Deferred Debt Return		
	18	Increase in Rate Base Investment at Acquisition (inc. Auxiliary Boiler)	$ 191.870	
	19	Marginal Cost of Debt	4.725%	
	20	Deferred Debt Return (Line 18 * Line 19 *.9167)	$ 8.311	
E.		Cost Deferral		
	21	Pre-Tax Cost Deferral Total Company (Line 7 + Line 12 + Line 17 + Line 20)	$ 68.963	
	22	ACC Share	96.6%	
	23	Pre-Tax Cost Deferral ACC Share	$ 66.619	
	24	Deferred Taxes	$ 26.321	
	25	After-Tax Cost Deferral ACC Share (Line 23 - Line 24)	$ 40.298	
	26	Cumulative Pre-Tax ACC Cost Deferrals at End of Period (Line 23)	$ 66.619	
	27	Cumulative After-Tax ACC Cost Deferrals at End of Period (Line 25)	$ 40.298	
	28	Annual ACC Jurisdiction Deferral Amortization Starting 7/1/2014 (Line 26 amortized over 10 years)	$ 6.662	
	29	Total Company Deferral Amortization (Line 28/.966)	$ 6.896	

[1] Deferral return & expenses prorated on six months.

ARIZONA PUBLIC SERVICE COMPANY
FOUR CORNERS REVENUE REQUIREMENT ANALYSIS
TEST YEAR ENDING 12/31/2010 (Settlement)
(Thousands of Dollars)

Line No.	A. RATE BASE[1]	TOTAL COMPANY	ACC JURISDICTION
1)	Four Corners Fair Value	$181,106	$174,948
2)	Four Corners Auxiliary Plant	$11,064	$10,688
3)	Four Corners Deferral Balance	$41,716	$40,298
4)	Total Rate Base	$233,886	$225,934
5)	Settlement Allowed Rate of Return @ 8.33%		
6)	Return on Rate Base (Line 4 * Line 5)	$19,483	$18,820
	B. COMPUTATION OF INCOME TAXES		
7)	Weighted Cost of Long Term Debt @ 2.94%		
8)	Tax Rate @ 39.51%		
9)	Income Taxes ((Line 5 - Line 7)(Line 4)(Line 8))/(1 - Line 8)	$8,234	$7,954
10)	Settlement Revenue Conversion Factor Adjustment	$144	$139
	C. EXPENSES[2]		
11)	Electric Fuel and Purchased Power	$4,499	$4,346
12)	Operations and Maintenance	$5,601	$5,411
13)	Depreciation and Amortization	$23,359	$22,565
14)	Other Taxes	$6,418	$6,200
15)	Total Expenses	$39,877	$38,522
	D. REVENUE REQUIREMENT @8.33%		
16)	RETURN, INCOME TAXES, and EXPENSES (Line 6 + Line 9 + Line 10 + Line 15)	$67,738	$65,436

[1]Attachment EAB-6, Schedule 4.b, Page 2 of 2
[2]Attachment EAB-7, Schedule 4.c, Page 2 of 2

EXHIBIT
APS-12

REBUTTAL TESTIMONY OF JAMES C. WILDE

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-0224

July 3, 2014

Table of Contents

REBUTTAL TESTIMONY OF JAMES C. WILDE
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-0224)

I. INTRODUCTION

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

A. My name is James C. Wilde. I am the Director of Resource Planning for APS. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science degree in Corporate Finance from Grand Canyon University and a Master of Business Administration from Grand Canyon University. I joined APS in 2003. Prior to being named Director of Resource Planning, I was the Director of Enterprise Risk Management.

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

A. I clarify the basis for the natural gas and carbon prices used by APS in its net present value calculations and address certain statements and questions raised by Sierra Club regarding APS's economic evaluation of its purchase of Southern California Edison's ("SCE") share of Four Corners Units 4 and 5 ("Transaction").

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Sierra Club Witness Dr. Hausman alleges APS's analysis of the benefits to APS customers of acquiring SCE's interest in Four Corners is flawed in four major aspects. Dr. Hausman's criticisms are simply wrong. The Company's assumptions are, in fact, on the conservative side for at least two of the four factors discussed by Dr. Hausman. Staff's own extensive review of the Transaction confirms the Company's economic analysis.

III. SIERRA CLUB CRITICISMS OF APS'S ECONOMIC ANALYSIS ARE INVALID

1. *Gas Prices*

Q. THE SIERRA CLUB QUESTIONS THE BASIS OF THE NATURAL GAS PRICES USED BY APS IN ITS NET PRESENT VALUE CALCUATION ("NPV") AND ALLEGES THAT THE NATURAL GAS PRICES ARE TOO HIGH IN LATER YEARS. PLEASE RESPOND TO THOSE CONCERNS.

A. First, it is important to note that the natural gas prices used by APS in this proceeding are the same as those used in the preparation of its 2014 Integrated Resource Plan ("IRP") and are based on the New York Mercantile Exchange ("NYMEX") forward market gas prices on September 30, 2013. The September 2013 NYMEX forward market prices go through 2025. Beyond 2025, the gas prices are escalated at a conservative rate of 2.14% for the duration of the analysis. In addition, to accurately reflect the "delivered" fuel prices to the APS system, APS added delivery costs to the forward curve. The delivery costs are approximately 10% of the basin price.

Second, the Report on a Review of the Arizona Public Service Company Four Corners Acquisition, prepared for the Commission by The Liberty Consulting Group, expressly found:

> [T]he natural gas prices used by APS are reasonable, and are actually conservatively low. . . .Accordingly, it is Liberty's view that actual gas prices may be higher than APS expects, making the benefit of the Four Corners acquisition even higher . . . ." (*See* Staff Direct Testimony of James Letzelter at Exhibit JCL-1, p. 9)

2. *Carbon Prices*

Q. DID APS USE DIFFERENT CO_2 VALUES IN ITS 2012 AND 2014 INTEGRATED RESOURCE PLANS, AS WELL AS THE TWO FOUR CORNERS DOCKETS, AS ALLEGED BY SIERRA CLUB?

A. Yes.

Q. WHY?

APS's assumptions regarding CO_2 costs have changed over time as additional information became available regarding proposed environmental legislation and the emerging California CO_2 allowance market. Accordingly, APS updated its analysis over time to reflect the evolving information.

During the years 2007-2010, many federal legislative proposals addressing climate change were under consideration and discussion by Congress. Although none were enacted, APS chose to include carbon costs in its 2010 Four Corners analysis. The costs used were based on legislative proposals at the time of $20/metric ton beginning in 2013 and escalating at 2.5% per year.

In 2011, APS engaged Charles River Associates ("CRA") to develop carbon emission prices for APS's 2012 IRP. APS used the prices provided by CRA in its 2012 IRP. For the 2012 IRP filing, APS incorporated the carbon cost recommendation provided by CRA on November 2011, in which carbon costs arose in 2019 at an assumed price of $12/metric ton (in 2011 dollars) and escalated annually at 5% above inflation after 2019. CRA's forecast was based on a review of the most recent legislative proposals at the time. Those prices, which were developed in 2011, reflected the beliefs at the time regarding proposed carbon legislation and costs.

Q. WOULD CRA'S CARBON PRICE FORECAST CHANGE THE VALUE OF THE FOUR CORNERS ACQUISITION?

No, not significantly. Even with using the CRA recommended pricing, the 2012 IRP still showed a nearly $400 million customer benefit for proceeding with the purchase of SCE's share of Four Corners Units 4 and 5.

Q. PLEASE CONTINUE.

A. After the Waxman-Markey and Kerry-Lieberman bills failed, discussion of federal Green House Gas legislation largely faded. Due to this lack of progress on the legislative front, updated carbon prices were needed for the 2014 IRP. Thus, in its 2014 IRP filing, APS reviewed carbon markets trading in California as well as in the East and incorporated projected carbon costs based on the actual trading price of CO_2 allowances in the California market as of September 24, 2013. These prices were materially higher than those prevailing in the East. APS used this same trading price in its 2014 IRP as the basis of its emissions prices in the calculation of the NPV of the Four Corners transaction in this docket.

In 2014, after the present Four Corners filing was made, the EPA proposed rules for greenhouse gas emissions for existing sources in the Clean Power Plan. While the proposal does not yet address power plants located on Indian Reservation Lands, it does provide a number of ways to "reduce emissions" from existing sources, including heat rate improvements, re-dispatch, renewable generation and energy efficiency. It is noteworthy that the Clean Power Plan does not propose a carbon market as one of its building blocks for reducing carbon intensity. In light of this, it appears that using any carbon price in the Four Corners analysis may yield a conservatively low estimate of the value of the Transaction.

Q. DID APS MAKE A UNIT CONVERSION ERROR IN ITS USE OF CRA'S CARBON PRICES AS SIERRA CLUB ALLEGES?

A. No, APS did not make a conversion error. As discussed above, APS did not use CRA's prices in the calculation of the $426 million benefit represented in this filing. APS did use CRA's price data in preparing the Company's 2012 IRP, but there was no conversion error made in that filing either.

3. *Operating Performance*

Q. THE SIERRA CLUB QUESTIONS THE ABILITY OF FOUR CORNERS TO OPERATE EFFICIENTLY TWO DECADES FROM NOW. WHAT IS THE BASIS FOR APS'S ASSUMPTION THAT FOUR CORNERS WILL BE ABLE TO RUN AT THE ANTICIPATED CAPACITY FACTOR OVER THE REMAINING LIFE OF THE PLANT?

A. The Sierra Club offers no evidence that, properly maintained, Units 4 and 5 could not continue to operate at current levels for the assumed life of the plants. Indeed, a historical look at the capacity factors of Units 4 and 5 shows exactly the opposite. 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. Consistent with APS's future projections, Units 4 and 5 have had capacity factors averaging approximately 80% over the last couple of decades. There is no reason to believe that, if the Units are properly maintained, this trend will not continue 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. Moreover, the projected costs of operating and maintaining Units 4 and 5 at that level of performance through 2038 have already been included in the Company's economic analysis.

4. *Capital Improvements*

Q. HAVE THE PROJECTED CAPITAL EXPENDITURES FOR YEARS 2014-2038 DECLINED AS CONTENDED BY THE SIERRA CLUB?

A. No. The Sierra Club is incorrect. The projected Four Corners Units 4-5 capital expenditures for years 2014-2038 increased by $166 million compared to the Company's 2010 filing. Despite this increase, however, the overall capital revenue requirement increase is quite small due to the $100 million decrease in purchase price due to the timing of the acquisition, as well as a decrease in APS's cost of capital since 2010.

IV. <u>CONCLUSION</u>

Q. WOULD YOU SUMMARIZE YOUR CONCLUSIONS ABOUT THE COMPANY'S PRESENT APPLICATION?

A. The criticisms alleged by the Sierra Club of APS's analysis of the benefits of this transaction are unfounded. The inputs used and analysis performed by APS were sound and reasonable and support a conclusion by this Commission that this Transaction provides significant benefits to Arizona customers and indeed, the entire state, just as Staff's Consultant also concluded.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

REJOINDER TESTIMONY OF JAMES C. WILDE

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-0224

July 28, 2014

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REJOINDER TESTIMONY OF JAMES C. WILDE
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-0224)

I. INTRODUCTION

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

A. My name is James C. Wilde. I am the Director of Resource Planning for APS. My business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY SUBMIT TESTIMONY IN THIS PROCEEDING?

A. Yes, my Rebuttal Testimony was filed on July 3, 2014.

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

A. I rebut certain unfounded allegations made by Sierra Club Witness Dr. Ezra Hausman in his Surrebuttal Testimony and explain in additional detail regarding the natural gas and carbon prices used by APS in its analysis.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REJOINDER TESTIMONY.

A. Dr. Hausman's assertion that APS has withheld information regarding the data and calculations used to conduct the net present value ("NPV") analysis of the Four Corners transaction is wholly without merit. The Company has provided all data and analyses necessary to evaluate the NPV of the transaction. Staff concurs with the result of these analyses, and no other intervenor has questioned that the transaction has a substantial positive economic benefit for APS customers.

III. <u>SIERRA CLUB'S CRITICISMS REGARDING APS'S GAS FORECAST ARE UNFOUNDED</u>

Q. HAS APS PROVIDED IN THESE PROCEEDINGS THE BASIS FOR THE NATURAL GAS PRICES AND FORECASTS USED BY APS TO CONDUCT ITS ANALYSIS OF THE NET PRESENT VALUE OF THIS TRANSACTION?

A. Yes.

Q. WHERE IS THAT INFORMATION PROVIDED?

A. Page two of my Rebuttal Testimony discusses both the data and methodology used to develop the gas forecasts relied upon in these proceedings as well as APS's 2014 Integrated Resource Plan ("IRP"). All data used to evaluate this transaction has been provided. As explained, APS's gas forecasts are based on NYMEX data adjusted for basis location (i.e. Jan Juan and Permian basins) and delivery charges. *See* APS's Response to Sierra Club's Data Request 4.1 and 1.22.

Q. SIERRA CLUB QUESTIONS THE NYMEX GAS PRICES PROVIDED BY APS BECAUSE THE PAGE STATES THAT THE SOURCE OF THE DATA IS "DATAMART." WHAT IS "DATAMART"?

A. DataMart is a proprietary database used by APS to compile natural gas market price curves. APS imports actual NYMEX forward natural gas fixed prices, as well as forward natural gas basis market prices, into DataMart from an electronic data feed, then APS adjusts those prices for the delivery cost to APS power plants.

IV. <u>SIERRA CLUB'S CRITICISMS REGARDING APS'S CARBON PRICES ARE UNFOUNDED</u>

Q. HAS APS PROVIDED IN THESE PROCEEDINGS THE BASIS FOR THE CARBON EMISSIONS PRICES AND FORECASTS USED BY APS TO CONDUCT ITS ANALYSIS OF THE NET PRESENT VALUE OF THIS TRANSACTION?

A. Yes.

Q. WHERE IS THAT INFORMATION PROVIDED?

A. On pages three and four of my Rebuttal Testimony I explain the carbon prices used by APS in its 2012 and 2014 IRPs, as well as the prices used in the original and current Four Corners proceedings. I also explain why those prices have varied over time. In addition, APS's Response to Sierra Club's Data Request 2.1 contains the actual emissions prices used and APS's Response to Sierra Club's Data Request 4.2 explains the source and precisely how APS calculated those prices.

Q. PLEASE AGAIN SUMMARIZE HOW APS CALCULATED THE CO_2 EMISSIONS COSTS USED IN THIS PROCEEDING.

A. APS used the actual trading price of CO_2 allowances in the California market as of September 24, 2013, escalated at 2.5% per year. APS's projected CO_2 emissions cost basis of $11.60/metric ton is consistent with the median price for California Air Resources Board Quarterly Auctions for 2016 Vintage Carbon Allowances. The Vintage Carbon Allowances median price varied from $11.10/metric ton to $11.86/metric ton.

Q. DR. HAUSMAN SUGGESTS ON PAGE 9 OF HIS SURREBUTTAL TESITMONY THAT THE COMPANY SHOULD CONDUCT ANALYSIS USING CHARLES RIVER ASSOCIATES' HIGHER CARBON EMISSIONS PRICES. HAS THE COMPANY CONDUCTED SUCH ANALYSIS?

A. Yes. In its 2014 IRP, APS used Charles River Associates ("CRA") 2011 carbon prices for its "High CO_2 Emission Cost Sensitivity." Those prices were produced in response to Sierra Club's Data Request 2.1.c at APS15330. Please note that the California carbon market prices I reference do not support the use of these higher carbon prices for the reasons explained in my Rebuttal Testimony. In addition, as I explained in my Rebuttal Testimony, APS used CRA carbon pricing in its 2012 IRP, which was the intent for engaging CRA in the first place. As I stated in my Rebuttal Testimony, the 2012 IRP showed a substantial customer benefit for proceeding with the purchase of SCE's share of Four Corners Units 4 and 5, even with using CRA's carbon pricing.

Q. WOULD THIS TRANSACTION STILL BENEFIT APS CUSTOMERS EVEN IF WE WERE TO ASSUME, FOR THE SAKE OF ARGUMENT, USE OF THE CRA CARBON EMISSIONS PRICES CONTAINED IN THE 2011 CRA STUDY?

A. Yes. In the "High CO_2 Emission Cost Sensitivity" mentioned above and reflected in APS15330, the transaction would still have an approximate $50M NPV benefit for APS customers.

Q. IN YOUR REBUTTAL TESTIMONY, YOU DISCUSS BRIEFLY THE POTENTIAL IMPACT OF THE PROPOSED CLEAN POWER PLAN REGULATION ON THE CARBON MARKET. CAN YOU PLEASE EXPAND ON THAT TESTIMONY?

A. Yes. On June 2, 2014, the Environmental Protection Agency ("EPA") released a proposed rule, referred to as the "Clean Power Plan" ("CPP") for states to regulate greenhouse gas emissions from existing fossil fuel-fired electric generating units ("EGUs") under Section 111(d) of the Clean Air Act. The proposed rule establishes state-specific emission rates for all affected EGUs in each state rather than nationally uniform emission rates. The CPP does not propose a carbon market, but instead proposes to allow states the option of using a variety of methods to improve carbon emissions intensity, including the addition of renewables and energy efficiency. At this time, it's unclear what role a carbon market would play, if any, with individual state utility plans, given the flexibility provided in the proposed standard.

V. <u>CONCLUSION</u>

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. The criticisms lodged by Sierra Club Witness Dr. Hausman in his Surrebuttal Testimony are unsupported by the record in this matter. APS has been forthright and transparent regarding the natural gas and carbon prices used in its analysis.

APS has provided the data and methodologies employed and substantiated its conclusion that the Four Corners transaction is prudent and in the best interest of APS's customers.

Q. DOES THIS CONCLUDE YOUR REJOINDER TESTIMONY?

A. Yes.

EXHIBIT
RUCO-2
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01345A-11-0224

At: Phoenix, Arizona

Date: January 27, 2012

Filed: January 30, 2012

REPORTER'S TRANSCRIPT OF PROCEEDINGS

VOLUME II
(Pages 148 through 386)

ARIZONA REPORTING SERVICE, INC.
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Prepared for:

COLETTE E. ROSS
Certified Reporter
Certificate No. 50658

revenue requirement that was adopted than the zero percent in the settlement and the zero percent in RUCO.

But what we have done as we've reset those fuel levels, you reset the PSA. So the credit that customers were seeing was going to cause a bill impact in whatever new rates went into effect on July 1 of 2012. What the parties said here is well, we can defer that impact, so we can push that into the winter so it's not going through the summer and do it in February when the PSA normally resets.

I think there's another advantage beyond just delaying that impact until later. You can then see what else happens that might offset that impact. And if gas prices continue to come down, or if we overcollect on fuel, those are all things that can offset that so that it may help make that impact less than it otherwise would be.

And Four Corners is an example. If the Four Corners transaction is approved and we pursue that, that has an impact later. It's all trade-off. So there's an impact later, but that can then reduce the impact of the fuel reset in 2013.

Q. Let's go to Navajo.

A. Four Corners.

Q. Four Corners, rather, Navajo land and Four Corners. First of all, I'm going to ask the question. I hope I'm not stepping on any -- if I'm stepping on anybody's, on another case, I don't want to. This is not an easy dialogue to have, and I would like to ask some questions, and I will be prohibited from asking some questions. I have to be careful about what I ask because I'm going to be a decision maker on this, so ultimate, one of the points of review for what you're doing.

Page 5, line 22 of your direct testimony discusses constructive rate treatment of Four Corners Units 1 and 5. I don't know if I can ask this question in this context, but can you explain this so I can understand what constructive rate treatment means?

A. I think I can, and I'll start by indicating that the settlement agreement addressed, addresses the ratemaking impacts if the Four Corners transaction moves forward. So there is a separate docket pending right now seeking Commission authorization through a waiver of the self-build moratorium and a deferral order to obtain that authorization. The settlement is very clear that says we're not judging what happens in that docket. That will occur or not occur independently of what happens in the settlement.

The challenge that was presented to the parties with the Four Corners transaction, and in particular with how the timeline on that unfolded --

Q. What is -- please fill me in, if you can, on the timeline and how the two cases are linked, but I can't really discuss them here in full because I don't want to make a record in the Four Corners case. But in a sense, it could be included, this conversation, if something comes up.

A. I understand. I still think it's within this docket and it's not crossing the line.

Q. Okay.

A. But the Four Corners transaction could close sometime in the fourth quarter of 2012.

Q. 2012. December?

A. Again, if it's approved, if other things happen that are not necessarily within the company's control -- we still have to get CPUC approval from California, for example.

So if all those events transpired, the problem that was presented with this rate case was that the transaction would close shortly after new rates would likely have been put into effect in this case. There's the ability, if it's deemed appropriate and if it's approved in the subsequent docket, the challenge is then how do you now get that plant in rates, or do you have

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-11-0224

EXHIBIT

RUCO-3

ADMITTED

SURREBUTTAL TESTIMONY

OF

LON HUBER

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 21, 2014

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INTRODUCTION

Q. Please state your name, position, employer and address.

A. Lon Huber. I am a special projects advisor for Arizona's Residential Utility Consumer Office ("RUCO"), located at 1110 W. Washington, Suite 220, Phoenix, AZ 85007.

Q. Please state your educational background and work experience.

A. I started working in the energy field in 2007 at a research institute housed within the University of Arizona. In 2010, I became the governmental affairs staffer for TFS Solar, an integrator based in Tucson. I was hired by Suntech America in 2011 as a Manager of Regional Policy where I served as the point person for the company in numerous US states. Next, I started working in economic development as a senior analyst for the Greater Phoenix Economic Council while also serving as a consultant for RUCO on energy issues. I joined RUCO as a full time employee in January 2014.

I obtained a Bachelor of Science Public Administration degree in Public Policy and Management from the University of Arizona in 2009. I also received a Masters of Business Administration from the Eller College of Management at the same university. My primary residence is in Tucson, Arizona.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to address the Four Corners Adjustment rider's applicability to customers served under the AG-1 Rate Schedule. In doing so, I respond to the testimonies of Mr. Higgens and Mr. Chriss.

Q. Please summarize your conclusion and recommendation.

A. My determination is that APS was overly generous to AG-1 customers regarding the manner at which they applied the proposed 2.22 percent Four Corners Adjustment rider. Therefore, I am proposing a more equitable allocation of costs that does not unfairly burden non AG-1 ratepayers.

OVERVIEW OF ISSUE

Q. Please provide a high-level overview of the issue at hand.

A. AG-1 is an experiential rate rider that provides a buy through mechanism for large commercial and industrial customers. The rider is capped at 200 MW and falls on top of the customer's underlying rate schedule, mostly supplanting the costs of electrical generation. The details of the rate rider were worked out during the settlement process and adopted as part of the settlement agreement in Decision No. 73183 "Settlement." In parallel, another provision in the settlement related to the potential acquisition of certain units at the Four Corners power plant and the allocation of those costs should the transaction be executed. The Four Corners Adjustment rider "FCA" is the proposed mechanism to allocate these costs in accordance to provision 10.3 in the

Settlement. Mr. Higgins and Mr. Chriss are seeking exemption for their clients on any and all costs associated with the Four Corners investment.

Q. Please provide comment on section 10.3 of the Settlement as it relates to your testimony.

A. Section 10.3 very clearly explains that the cost recovery rider will apply to all rate schedules. Specifically, part five of section 10.3 states the following: "(5) an adjustment rider that recovers the rate base and non-PSA related expenses associated with any Four Corners acquisition on an equal percentage basis across all rate schedules which shall not become effective before July 1, 2013. "

Q. Did you personally participate in the 2012 settlement process?

A. No I did not.

Q. Please comment on APS's proposed approach to the FCA.

A. Overall, APS properly applied the FCA to the various rate schedules in accordance with section 10.3 of the Settlement. In general, APS assessed the proposed 2.22 percent rider to all portions of the bill representing services provided by APS. This includes the non-generation related services of each rate schedule.

Q. Did the Company fully apply the Four Corners Adjustment rider to the services provided to AG-1 customers?

A. Not entirely.

Q. Please Explain.

A. APS is proposing to apply the Four Corner Rate Rider to only a subset of the AG-1 customer bill. From dialogue at the February 19th technical conference, roughly 70 percent of an AG-1 customer bill is shielded from the Four Corners investment. However, upon investigation into the FCA's applicability to AG-1 customers I noticed that APS did explicitly state that the Company would apply the FCA to the reserve capacity charge. Therefore, I recommend that the order make it clear that the FCA applies to the reserve capacity charge.

Q. Please describe the reserve capacity charge.

A. It is a generation related component within the AG-1 rate rider. The reserve capacity charge is about a $6.985 per kW month charge that is applied to 15 percent of the customer's billed kW.

Q. With the exception of the reserve capacity charge was APS's proposed treatment of AG-1 customers fair?

A. Yes, I believe APS was extremely fair and balanced and could have easily decided to assess the charge on the entire bill of an AG-1 customer.

Q. How do you address Mr. Higgens' and Mr. Chriss' claims that their clients should be completely exempted?

A. They appear to have a misunderstanding of the FCA. APS is applying the FCA on every element of base rates. AG-1 customers still have an underlying rate plan. It is important to note that the FCA is not applied to only the generation portion of a customer's bill. Further, the Settlement makes no connection between what type of asset the FCA is actually collecting costs for and the portion of the customer's bill it applies to. However, Mr. Higgens and Mr. Chriss are using a provision in the AG-1 rider schedule and inappropriately enlarging that clause to shield them from any and all costs associated from the Four Corners acquisition.

Q. Can you provide an example of this misunderstanding?

A. Mr. Higgens states the following: "...AG-1 customers would be forced to pay for generation costs even though these customers are purchasing the entirety of their AG-1 generation supply from non-APS source."[1] The fundamental misunderstanding is that the rider is not representing generation costs associated with the actual electricity production of the Four Corners power plant. The FCA largely represents the actual investment costs of the acquired units. The costs of this acquisition are to be spread equally across all rate plans. Another way to think about it is to entertain for a moment that the FCA

[1] Page seven of Mr. Higgens' direct testimony.

is recovering costs of constructing an administrative building. Would it not be fair to allocate the costs of this asset in the manner APS proposes?

If you follow through with the argument employed against applying the FCA to underlying rate design of AG-1 customers, one would have to argue that some of the employees in that building will be working on generation related projects; therefore, the costs can not apply to AG-1 customers.

Q. Please explain how Mr. Higgens and Mr. Chriss are misapplying a clause in the AG-1 rider schedule?

A. Mr. Higgens and Mr. Chriss point to a line on page four of attachment J in the 2012 settlement. Under the heading "Rates," it states: "All provisions, charges and adjustments in the customer's applicable retail rate schedule will continue to apply except as follows:..." One of those exceptions states "The generation charges will not apply."

What this clause is referring to is the generation portion of the customer's underlying rate design. Clearly, the actual generation costs of providing energy and power to the customer as specified in their underlining rate design is exempted from the AG-1 rate because the customer is procuring power elsewhere. The clause does not read that AG-1 customers will be exempted from the acquisition costs of generation related assets. Furthermore, APS is only applying those costs to services relating to the customer's underlying rate schedule not the larger pass through portion of bill.

RECOMMENDATION

Q. What does RUCO recommend on this issue?

A. I recommend that the FCA apply to AG-1 customers just as APS proposed but with the inclusion of the reserve capacity charge.

Q. Is it fair to AG-1 customers?

A. Yes. Again, this proposal is fair and could have been assessed on the entire bill. Contrary to Mr. Chriss' claims that the proposed FCA violates cost causation and matching principles, the suggested FCA aligns nicely with those principles in the context of the 2012 Settlement.

Q. Please explain.

A. AG-1 is meant to be a four year experimental rate. By claiming there is no benefit from the Four Corners investment to AG-1 customers assumes that this rate will go on in perpetuity. It also ignores the generation related component that APS charges within the AG-1 rider. Because this is a short term rate rider offering, APS must still plan their system with long term reliability and cost considerations in mind. This includes the reintroduction of AG-1 customers. In fact, it could be argued that the FCA should be applied to more than just 30 percent of an AG-1 customer's bill. According to Jeffrey

Guldner, AG-1 customers burden all other customers with around $20 million in fixed cost shifts.[2] Following the cost causation principle, as Mr. Chriss suggests, would dictate that this cost shift must be rectified as soon as possible.

Q. Does this conclude your testimony?

A. Yes it does.

[2] RUCO Electric Deregulation Workshop, August 27, 2013.

EXHIBIT
RUCO-4
ADMITTED

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-11-0224

SURREBUTTAL TESTIMONY

OF

ROBERT B. MEASE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 21, 2014

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INTRODUCTION

Q. Please state your name, position, employer and address.

A. My Name is Robert B. Mease. I am Chief of Accounting and Rates employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Have you previously provided testimony regarding this docket?

A. Yes. I filed direct testimony on this docket on June 19, 2014.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the Company's rebuttal comments that pertain to adjustments I recommended in my direct testimony.

RUCO'S PROPOSED ADJUSTMENT

Q. Can you please explain the adjustment(s) that RUCO recommended in its direct testimony?

A. Yes. In my direct testimony I recommended a reduction in the Company's overall rate of return of 3.61 percent (8.33 percent less 4.725 percent) resulting in a reduction in requested revenues of approximately $16.3 million. The 8.33 percent, as referenced, is the Company's overall rate of return allowed on its Original Cost Rate Base as approved in Decision No. 73183 and the 4.725 percent represents the cost of debt directly related to the acquisition of Units 4 and 5.

Q. What was APS's position on RUCO's proposed adjustment?

A. APS disagreed with my proposed adjustment. Ms. Elizabeth Blankenship's rebuttal testimony best describes APS's disagreement with my recommendation.

"Decision No. 73130 did not say or imply that the cost of debt should be used in place of the WACC on the entire asset when the plant was placed in rate base. The debt-only capital treatment was strictly limited to the deferral balance. RUCO, however, extends the reach of that debt-return only treatment to all three of the items that make up the revenue requirement for this asset – not just the deferral balance. In leaving the rate case open to adjust rates to reflect the Four Corners transaction, the Settlement <u>intended</u> to allow the Four Corners asset the same rate of return as the other assets comprising the rate base in the Settlement's 2010 adjusted Test Year. Reducing the rate of return on that asset from the 8.33% WACC to a 4.725% documented debt cost would be inconsistent with the settlement."[1]

Mr. Jeffrey Guldner's testimony also states that "RUCO misapplied Decision No. 73130 by applying the marginal cost of debt used for cost deferral per that Decision as the applicable going forward rate of return. That is a clear misreading of Decision No. 73130 and is not consistent with the Settlement established precedent concerning FVROR."[2]

Q. Did APS at any time discuss calculating the return on the acquisition adjustment at the current cost of debt?

A. Yes. In Data Request 39.14 Staff ask the following: Please explain why it would not be appropriate to use APS's cost of debt (Marginal or Embedded) as the return on the acquisition adjustment in this case. APS responded that "this would be inconsistent with the Settlement and Decision No. 73183 and prior Commission precedent interpreting the requirements of the Arizona Constitution. Specifically, the Commission

[1] APS Witness Elizabeth Blankenship's Rebuttal Testimony Page 6
[2] APS Witness Jeffrey Guldner's Rebuttal Testimony Page 6

has determined that APS is entitled to the opportunity to earn a fair value rate of return based on the weighted average cost of two components of the Company's rate base: (1) APS's weighted average cost of capital (including equity return of 10%) as applied to OCLD (8.33% on an after tax basis); and (2) 1% as applied to the fair value increment (FVRB-OCRB). In this case, the requested fair value increment is zero, leaving the appropriate after tax return at 8.33%." Mr. Guldner went on to say in responding to the data request that if APS doesn't receive recovery of its request that it would very likely be poorly received in the financial community given the Commission's previous approval of this transaction.

Q. The Staff's data request related to the return on the acquisition adjustment, not the rate of return on rate base. Can you explain the relationship between the two?

A. In the current application the rate base ~~utility plant in service ("UPIS~~") increase is $225 million and of this amount $252 million represents acquisition adjustment. So in other words, the amount of the adjustment is entirely related to the acquisition adjustment. In this case the rate base ~~UPIS~~ adjustment is the acquisition adjustment.

Q. Does RUCO have a response to the expected reaction of the financial community as discussed by Mr. Guldner?

A. No. I have no reason to question Mr. Guldner or his comments related to the financial community. However, when reviewing what Value Line has to say in its latest evaluation of Pinnacle West, included in its Investment Survey dated May 2, 2014, I note the following: **We have raised the Financial Strength rating of Pinnacle West from A to A+**. The fixed-charge coverage and common-equity ratio are high---well above average for the electric utility industry. Moreover, APS is very close to earning its allowed return on equity. **This high-quality stock is untimely but has a dividend yield that is slightly above the utility average.** However, with the recent price near the midpoint of our 2017-2019 Target Range, total return potential is unspectacular. (See Attachment A)

Q. How did APS fund the purchase price of Units 4 and 5 and other costs and expenses associated with this transaction?

A. "On January 10, 2014, APS issued $250 million of 4.70% unsecured senior notes that mature on January 14, 2044. The proceeds from the sale were used to repay commercial paper which was used to fund the purchase price and costs associated with the acquisition of SCE's 48% ownership interest in each of Units 4 and 5 of Four Corners and to replenish cash used to re-acquire two series of tax-exempt indebtedness."[3]

Q. So in essence the purchase of Units 4 and 5 was totally funded by debt and that no additional equity was necessary?

A. According to the Company's audited financial statements, this transaction was funded in total by short term debt and ultimately replaced by unsecured senior notes.

RUCO'S POSITION IN DOCKET NOS. 10-0274 AND 11-0224

Q. In the initial filing of Docket No. 10-0274, did RUCO agree that the closure of Units 1, 2 and 3 coupled with the purchase of Units 4 and 5 appeared to be a transaction that was in the public interest?

A. Yes. RUCO agreed that APS' analyses showed that the APS transaction saves APS' customers' money and has a lower bill impact than that of every likely alternative. RUCO also agreed that APS' proposed transaction significantly reduces carbon dioxide and other pollutant emissions; preserves the diversity of APS' current generation portfolio while tempering the Company's exposure to volatile natural gas prices, it maintains the mix of reliable base load energy; and it "saves hundreds of jobs and millions of dollars of revenue that are critical to the Navajo Nation and local economy.

[3] Pinnacle West Capital Corporation 2013 Annual Report Page 65

Q. In the settlement agreement testimony provided by RUCO in Docket No. 11-0224, did RUCO provide a summary of the benefits to the Company in settling this docket?

A. Yes. RUCO identified a number of benefits to the ratepayer in completing this transaction. However, RUCO's primary concern in that rate case was the continued improvement of APS's financial health that had been a concern in the prior rate case. As RUCO indicates in its testimony this settlement "provides them a rate rider for the Four Corners acquisition if that all should happen. And RUCO finds that extremely important for the Company's continued financial viability, because it will get plant in service into rate base in a more timely fashion. And according to the bill impact statement filed by APS on January 19th that showed the bill impact, we are looking at somewhere in 2013 an impact of around $2 to the average ratepayer for that Four Corners rate rider." [4]

Q. Since RUCO's testimony supported the rate case settlement agreement and the proposed inclusion of the plant in service in rate base, did RUCO's testimony include a specific rate of return on that new rate base item?

A. No. RUCO's testimony did not specifically identify an actual rate of return on the purchase of Units 4 and 5. Therefore the Commission has the ability to determine an appropriate rate of return on this transaction alone.

[4] RUCO's Settlement Testimony Page 1143, 1144

Q. What was the original purchase price for Units 4 and 5 and what was the purchase price once the transaction was completed?

A. The original purchase price was $294,000,000. The price was to be reduced by $7,500,000 for each month the project did not close with a final transaction date for completion of the project by December 31, 2013. After allowing for a fourteen month and twenty-nine day delay the final purchase price was reduced by $112,016,129.

RUCO'S CURRENT POSITION

Q. Is RUCO continuing to recommend that the rate of return on this transaction be computed using the cost of debt specifically identified to this purchase transaction?

A. Yes. I am continuing to recommend that the cost of debt be used in calculating the rate of return on the purchase of Units 4 and 5.

Q. Can you reply to Mr. Guldner's rebuttal testimony that "RUCO misapplied Decision No. 73130 by applying the marginal cost of debt used for cost deferral per that Decision as the applicable going forward rate of return? That is a clear misreading of Decision No. 73130 and is not consistent with the Settlement established precedent concerning FVROR.

A. I'm going to answer that by including a comment from Mr. Leland R. Snook's rebuttal testimony. His testimony states that "RUCO interprets

Decision No. 73130, (April 24, 2012) as somehow mandating the use of an incremental debt cost for this purpose. In reality, that Decision does not address how revenue requirements should be calculated for the Four Corners Transaction once that Transaction is reflected in rates." [5]

I'm going to agree with Mr. Snook's testimony. That decision does not identify how to calculate the revenue requirement. I would also add that in Decision No. 73183 (May 24, 2012) does not address how the revenue requirement is to be calculated. The Decision states that the acquisition of Units 4 and 5 is to be rate based, but does not define the rate of return to be applied to the purchase.

In addition, in reviewing Mr. Guldner's testimony in the rate case settlement proceedings on page 245, in replying to a question from Commissioner Newman "what constructive rate treatment means," part of his response stated that "The settlement is very clear that says we're not judging what happens in that docket."[6]

Q. Does RUCO look at the two dockets as being independent and that one doesn't take precedence over the other?

A. RUCO looks at the two dockets as being independent with the exception that Decision No. 73183 was left open in order to include the Four Corners

[5] Rebuttal testimony Mr. Snook, Docket No. 11-.224, this filing.
[6] Testimony of Mr. Guldner, Docket No. 11-0224, page 245

transaction at a future date. According to APS, each docket should be looked at as separate dockets.

Q. Does RUCO believe that its' primary concern for APS financial health has been improved since their settlement testimony in the last rate case Docket No. 11-0224?

A Yes. APS, per Value Line is a financially healthy utility and earning very close to its cost of equity, 9.7 percent in 2013. It is projected, by Value Line, to continue its earnings growth over the next two years; the financial strength as reported by Value Line was upgraded from A to A+; and a dividend yield that is slightly above average.

Q. Can you summarize RUCO's position on the filing?

A. RUCO is continuing to base its recommendation using the cost of debt as the rate of return in this filing. RUCO's position is based on the following: (1) Decision No. 73130 did not identify a specific rate of return and the cost of debt related to this transaction was used. The cost of debt was used by RUCO as the two dockets were to be decided independent of the other per the testimony of Mr. Guldner. (2) APS's financial stability has improved substantially since the last rate case settlement, and finally (3) the transaction was funded totally with debt with no additional equity required. For these reasons RUCO is continuing to recommend the reduction requested by APS by $16.23 million.

Q. Does this conclude your rebuttal testimony?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-11-0224

EXHIBIT
RUCO-5
ADMITTED

DIRECT TESTIMONY

OF

ROBERT B. MEASE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 19, 2014

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Arizona Public Service Company ("APS" or "Company") is the largest Class A electric utility and is principal operating subsidiary of Pinnacle West Capital Corporation. APS is an electric utility serving approximately 1.1 million retail customers throughout the state of Arizona. On November 22, 2010, APS filed with the Arizona Corporation Commission ("Commission") an application for authorization to purchase the generating assets from Southern California Edison ("SCE") at the Four Corners Power Plant. In addition, the Company's application requested an accounting order be authorized for the deferral of certain costs associated with the acquisition. On April 24, 2012, by Decision No. 73130, the Commission approved APS request to move forward with the purchase of SCE generating assets and also approved the Company's request for an accounting order authorizing the deferral of certain costs.

On June 1, 2011, APS filed an application requesting an increase in rates and for a determination and approval of a just and reasonable return. On May 24, 2012, by Decision No. 73183, the Commission approved a Settlement Agreement reached by most of the parties in the case. As part of the Settlement Agreement, the parties agreed to leave the docket open until December 31, 2013, for APS to file a request to adjust its rates to reflect the rate base and expense effects associated with the acquisition of SCE's interest in Four Corners Units 4 and 5, the retirement of Units 1, 2 and 3, as well as any cost deferral authorized in the Commission's Decision in the Four Corners Acquisition Docket.

On December 30, 2013, APS purchased SCE's 48 percent share in Units 4 and 5 and now request that the Commission approve a Four Corners rate rider to permit recovery of $62.52 million annual revenue requirement. (On May 17, 2014, the Company provided updated schedules and their request increased to $65.43 million) The revenue requirement reflects the cost associated with APS's acquisition of SCE's share of Units 4 and 5, the retirement of Four Corners Units 1, 2 and 3, and for the deferred costs authorized in Decision No. 73130.

While the Company is requesting $65.43 million in additional revenues RUCO in proposing additional revenues of $49.20 million.

INTRODUCTION

Q. Please state your name, position, employer and address.

A. My name is Robert Mease and I'm Chief of Accounting and Rates for the Residential Utility Consumers Office. ("RUCO") My business address in 1110 W. Washington Street, Suite 220, Phoenix, AZ.

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

A. Attachment 1, which is attached to this testimony, describes my educational background, work experience and regulatory matters in which I have participated. In summary, I joined RUCO in October of 2011. I graduated from Morris Harvey College in Charleston, WV and attended Kanawha Valley School of Graduate Studies. I am a Certified Public Accountant and currently licensed in the state of West Virginia. My years of work experience include serving as Vice President and Controller of Energy West, Inc. a public utility and energy company located in Great Falls, Montana. While with Energy West I had responsibility for all utility filings and participated in several rate case filings on behalf of the utility. As Energy West was a publicly traded company listed on the NASDAQ Exchange I also had responsibility for all filings with the Securities and Exchange Commission.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's proposals and conclusions regarding the "APPLICATION TO APPROVE FOUR CORNERS RATE RIDER," as filed by APS on December 30, 2013.

Q. Can you briefly discuss the history of this filing by APS and why the Company is applying for an increase in its rates without a general rate case filing?

A. On November 22, 2010 APS filed an application for Commission authorization to purchase the generating assets of Units 4 and 5 of the Four Corners plant owned by Southern California Edison ("SCE") in addition to the approval to close APS Four Corners Units 1, 2 and 3. Also included in the application was APS' request for an accounting order authorizing the deferral of certain costs related to both the purchase of Units 4 and 5 and the closure of Units 1, 2, and 3.

APS was also required to satisfy the conditions as outlined in Decision No. 67744 that required APS to obtain Commission authorization before APS acquires any unit or interest in a generating unit other than "the acquisition of temporary generation needed for system reliability, distributed generation of less than fifty MW per location, renewable resources, or the up-rating of APS generation" when the in-service date is prior to January 1, 2015.

On April 24, 2012 Decision No. 73130 was issued by the Arizona Corporation Commission approving both the purchase of the generating assets from SEC, the closure of Units, 1, 2, and 3 and the accounting order authorizing the deferral of the certain costs related to both the purchase and closure transactions. It was also determined during the course of the application review that APS had satisfied the conditions as outlined in Decision No. 67744.

ACCOUNTING ORDER

Q. Before we go any further can you explain the purpose of the accounting order as requested by APS?

A. The ACC Staff defines an accounting order as a "rate-making mechanism for use by regulatory authorities that provides regulated utilities the ability to defer costs that would otherwise be expensed using generally accepted accounting principles and provides for alternative rate-making treatment of capital costs and other costs via the creation of regulatory assets and liabilities."[1]

Q. Did RUCO agree that an accounting order should be granted in this case?

A. RUCO agreed that the circumstances warranted a variation from the usual ratemaking treatment of plant acquired between rate cases. RUCO disagreed with APS' request to earn a return on the deferred accounts, stating that it would be "simply guaranteeing the Company a return rather than providing it with an opportunity to recover that return via its operating efficiency."

Q. Was the accounting order requested by APS approved by the Commission authorizing the deferral of certain cost(s)?

A. Yes. "Accordingly, we believe an accounting order is appropriate that allows deferral of the non-fuel costs, except that we will include as "non-fuel costs" only the documented debt cost of acquiring SCE's interest in Units 4 and 5, and will not authorize any carrying charges on any deferred costs."[2]

---

[1] Decision No. 73130 Page 35 Lines 10 - 14
[2] Decision No. 73130, Page 37, Lines 7 thru 9

Q. Can you please define what "non-fuel costs" were identified in Decision No. 73130 that the Commission approved for deferral?

A. The "non-fuel costs" that are authorized for deferral include depreciation, amortization of the acquisition adjustment, decommissioning costs, operations and maintenance costs, property taxes, final coal reclamation costs, the documented debt costs of acquiring SCE's interest in Units 4 and 5, and miscellaneous other costs. APS estimated that the costs to wind down operations at Units 1 – 3 would be approximately $20 million and would be incurred between the acquisition date of Units 4 and 5 through 2016."[3]

Q. Did RUCO agree with APS that the proposed closure of Units 1 – 3 and the purchase of Units 4 and 5 was for the benefit of ratepayers and should move forward?

A. Yes. RUCO agreed that APS' analyses showed that the APS transaction saves APS' customers' money and "has a lower bill impact than that of every likely alternative. RUCO also agreed that APS' proposed transaction significantly reduces carbon dioxide and other pollutant emissions; "preserves the diversity of APS' current generation portfolio while tempering the Company's exposure to volatile natural gas prices," it maintains the mix of reliable base load energy; and it "saves hundreds of jobs and millions of dollars of revenue that are critical to the Navajo Nation and local economy."

[3] Decision No. 73130 Page 37 Footnote 122

Q. Did APS comply with Decision No. 73130 when submitting this application for recovery of costs related to the purchase of Units 4 and 5?

A. No. The Company did not calculate its authorized return on cost deferral's in accordance with Decision No. 73130. The decision specified that <u>only the documented debt cost of acquiring SCE's interest in Units 4 and 5 would be approved, and will not authorize any carrying charges on any deferred costs."</u>[4]

Q. Can you please explain how APS calculated its rate base and expense adjustments when submitting this application?

A. In the Company's filing of this application APS prepared all supporting schedules and calculated all rate base and expense adjustments resulting from the closure of Units 1, 2 and 3. The Company also prepared supporting schedules and identified specific adjustments for the purchase of Units 4 and 5. The Company then offset the rate base and expense amounts of Units 1, 2 and 3, that were closed in 2013, against the acquired rate base and projected expenses of Units 4 and 5, going forward, and the net adjustments were then used to increase the rate base that was approved in Decision No. 73183.

[4] Decision No. 73130, Page 37, Lines 7 thru 9

Q. After the Company made the offsetting rate base and expense adjustments what was their next step in calculating the increase in revenues?

A. The Company then carried forward the net adjustments to Schedule EAB-4, Four Corners Revenue Requirement Calculation, and completed the remaining line items to reflect a bottom line increase in revenues of $65.42.

Q. What did the Company use as a rate of return when calculating its final revenue increase?

A. The Company calculated its revenue increase at 8.33 percent as was authorized in Decision No. 73183. The authorized rate of return includes both an interest element as well as a return on equity. From RUCO's understanding of Decision No. 73130 only the documented debt cost of acquiring SCE's interest in Units 4 and 5 would be allowed for recovery and not the Company's authorized rate of return which also includes a return on equity.

Q. What is the documented cost of debt for the purchase of Units 4 and 5?

A. Per APS's latest filing of amended schedules the documented cost of debt was reduced from 5.25 percent to 4.725 percent.

Q. So is RUCO recommending a reduction in the calculation of a rate of return on the deferral of costs related to the purchase of Units 4 and 5?

A. Yes. RUCO is proposing a reduction in rate of return of 3.61 percent (8.33 percent less 4.725 percent) resulting in a reduction in revenues of approximately $16.3 million.

ACQUISITION ADJUSTMENT

Q. Mr. Mease, did the Company request an "acquisition adjustment" in its request for a change in rates resulting from this transaction?

A. Yes. An acquisition adjustment was requested in APS's original filing seeking approval to move forward with the acquisition on Units 4 and 5. The acquisition adjustment was approved by the Commission in Decision No. 10-0327. The Company's increase in rate base of $225.9 million is primarily related to the acquisition premium that APS is requesting.

Q. Can you please provide a definition of an acquisition adjustment?

A. An acquisition adjustment is "The difference between the price an acquiring company pays to purchase a target company and the net original cost of the target utility company's assets. An acquisition adjustment is the premium paid for acquiring a company more than its tangible assets or book value."

Q. Does the Commission have a specific policy addressing an acquisition adjustment when a utility company pays in excess of book value for another utility's assets?

A. There is no specific policy that I'm aware but there is a statement included in Staff's Data Request No. 39.3 to APS that reads as follows, "Staff's understanding of the general rule in Arizona is that the Commission does not permit recovery of an acquisition adjustment arising from the sale of assets barring extraordinary circumstances."

Q. Also in Data Request No. 39.3 APS was ask to explain what extraordinary circumstances exist that would justify the Commission's recognition of an acquisition adjustment in this case? What was APS response to this request?

A. APS responded as follows:

> Decision No. 73130 (April 24, 2012) established the Four Corners acquisition from SCE as an extraordinary circumstance that warranted both an exemption from the "self-built" moratorium imposed by the Commission in Decision No 67744 (April 5, 2005) and the "best practices" for resource acquisition later codified in the Commission's Resource Planning Rules. See A.A.C. R14-2-702(B) (5).
>
> The acquisition was also extraordinary in the level of customer benefit (over $400 million on a net present value basis), the ability to preserve APS's customers' existing benefits from the Company's pre-existing share of Four Corners 4 and 5, and the significant environmental benefit (specifically cited in Decision No. 73130 at pages 8 – 11) from the closure of Units 1 – 3 by the end of 2013. None of these benefits would have happened absent this transaction.

Q. Mr. Mease, I have one more question related to Staff Data Request No. 39.3. Part (b) of the request ask APS to please explain how this transaction would not likely have occurred without the acquisition adjustment. What was APS response to this request?

A. APS response to (b) as follows:

> The transaction could never have occurred absent the agreement by APS to pay a sufficient amount to compensate SCE for its exit of the facility prior to mid-2016. SCE would not have agreed to a selling price that placed it in a worse economic position than not selling, and even if SCE would have agreed to a contract that was financially irresponsible, the sale would never have received the necessary CPUC approval.
>
> And neither APS nor any other rational utility would agree to pay nearly $300 million for a plant and then write off five sixths of that investment less than a year later. The significant operational benefits from additional ownership of Four Corners 4 and 5 justifying APS' acquisition would all accrue to APS customers, leaving APS shareholders with nothing to show for management's good faith efforts to benefit customers but a staggering write off.

Q. **Based on the response by APS to part (b) of this request, does it appear that APS was certain in its answer that they, APS, would get approval to include an acquisition adjustment, otherwise, the purchase would not have occurred?**

A. Yes. By their response above I believe it's safe to make that assumption. However, as stated in the Conclusions of Law, Page 43, of Decision No. 73130, "IT IS FURTHER ORDERED that Arizona Public Service Company is authorized to defer for possible later recovery through rates, all non-fuel costs (as defined herein) of owning, operating, and maintaining the acquired Southern California Edison interest in Four Corners Units 4 and 5 and associated facilities. Nothing in this Decision shall be construed in any way to limit the Commission's authority to review the entirety of the acquisition and to make any disallowances thereof due to imprudence, errors or inappropriate application of the requirements of this Decision.

Q. Has anything come to your attention that would make you question APS's belief that the acquisition adjustment that they are requesting could be disallowed by the Commission?

A. Yes. When reviewing Pinnacle West Capital Corporation Notes to Consolidated Financial Statement, for the period ending December 31, 2013, page 100, discussing the Four Corners transaction we noted the following, "While we expect the ACC to approve the recovery of the acquisition adjustment, should recovery be disallowed, it will be reclassified from plant-in-service to goodwill subject to impairment testing."

In addition, in Mr. Guldner's direct testimony in the original filing for the approval to move forward with the purchase of Units 4 and 5, he states

> "And I guess it's my opinion that you clearly can argue about how you measure the return component. And for example, in the Palo Verde Unit 3 order, the return component that was authorized in that case was a debt-only return. And I think that's actually what the Company ask for was rather than have the three components of debt, equity and the tax gross-up, in that case the debt expense was deferred as the return component. And so I think it's fair to argue how you calculate that return component."

Q. What is APS requesting as an acquisition adjustment in this application?

A. After making all the accounting entries related to the purchase of SCE's interest in the Four Corners generating facilities Units 4 and 5 the Company is requesting an adjustment of $243.9 million.

Q. Does RUCO believe that there are specific risks, either operational or financial, associated with the purchase of Units 4 and 5?

A. Certainly there are risks involved in any business transaction of this magnitude but more specifically the relevant environmental risks associated with the Company's investment in coal operated facilities. These risks are generally well known and were discussed at length between the time the Company filed its application for the approval of the transaction and the final Decision authorizing the Company to move forward. While the purchase transaction as presented in the original application filed with, and agreed to, by the Commission in Decision No. 73130 was authorized to move forward the inherent risks remain the same or have compounded since the Company filed its original application for authorization to move forward.

Q. Can you discuss several of the risks that you are referring to in you previous answer?

A. Yes. As the Company stated in their response to RUCO Data Responses to Nos. 2.6 and 2.7, when asked. "Has APS identified and attempted to quantify potential risks from further EPA rulings that may impact the economics of Four Corners?

> Yes. As explained in their response RUCO DR 2.6, "The potential risks from further EPA rulings were identified in APS's 2014 Integrated Resource Plan ("IRP") – Chapter 3 & Section E. As further identified in their response to DR. 2.7 the Company responded as follows:
>
> <u>Uncertainty pertaining to regional haze regulations (BART)</u> – APS has assumed and included the installation costs of SCR controls in the analysis.
>
> <u>Uncertainty pertaining to National Ambient Air Quality Standard (NAAQS)</u> – Because the proposed ozone NAAQS were withdrawn by EPA and the agency has yet to establish new NAAQS for ozone, it is difficult to estimate the impact, if any, of new standards on the Four Corners evaluation.
>
> <u>Uncertainties pertaining to RCRA regulations</u> – Proposed regulations include two different scenarios – Subtitle C (hazardous) and Subtitle D (non-hazardous). For the Four Corners evaluation and all other studies, APS has assumed EPA will choose to regulate CCR under Subtitle D and has included cost estimates in the analyses. The Subtitle C option was not evaluated because APS does not believe CCRs to be hazardous waste, but APS estimates the CCR costs would be 20% higher than Subtitle C.
>
> <u>Uncertainty pertaining to Greenhouse gas (GHG)</u> - New source performance standards (NSPS) regulations – APS has included in its analysis the potential for carbon pricing in the form of three carbon price forecasts, see response to Staff 35.31 and 35.35
>
> <u>Uncertainty pertaining to Effluent limitation guidelines (ELG)</u> – Any revisions to the ELG would impact the discharge limits at Four Corners which may be faced with increased capital and O&M expenses to achieve and maintain compliance. This risk was not evaluated because the EPA is not expected to have a final rule until late 2015 and it is uncertain what, if any, impact will come from such regulation.

Q. Do you believe that the Company shareholders should share in the risks associated with the purchase of Units 4 and 5?

A. Yes. Other than the general business risks that are associated with any merger or acquisition, there are additional risks as identified above. The ratepayer should not have to bear the burden of assuming all risks in this transaction. By the Commission's authorizing for recovery in rates only the documented debt cost of acquiring SCE's interest in Units 4 and 5, the Commission recognizes that there is an inherent risk that should be shared between the ratepayer and Company shareholders.

Q. Is RUCO recommending that APS recover its acquisition costs?

A. Yes. RUCO did not take exception to an acquisition adjustment in APS original filing requesting Commission authorization to move forward with the purchase of Units 4 and 5 and has not changed its position in this filing. Decision No. 73130, shares the risk of this transaction between the Company and ratepayers, so RUCO continues to support the acquisition adjustment as was authorized in that decision.

Q. Does RUCO believe that the Commission will be establishing a policy on acquisition premiums based on its Decision No. 73130?

A. RUCO's position is that the Commission should approve the acquisition adjustment because the transaction is in the public interest and without it there may not have be a transaction. RUCO believes that in most cases an acquisition adjustment is unwarranted and such a policy favoring a premium on its face value would provide little motivation for a Company not to overpay. That is not an issue in this case.

RUCO'S RECOMMENDATIONS

Q. Can you please summarize what RUCO is recommending in this application?

A. RUCO is proposing a reduction in revenue requirements as requested by APS from $65.43 million to $49.20 million. The reduction of $16.23 million is due to APS's requesting a rate of return on rate base adjustments of 8.33 percent while RUCO is proposing that the return on the adjusted rate base of 4.725 percent.

APS Requested Revenue Increase	$ 65,436
RUCO's Recommended Revenue Increase	$ 49,198
RUCO's Recommended Reduction in Revenues	$ 16,238

(See Attachment 2)

RATE DESIGN

Q. Has RUCO update the rate design schedules, as were filed by the Company, based on its recommended increase in revenues?

A. Yes. See Attachment 3. Rates have been established using the same methodology as requested by APS. The percentage increase is being applied as an equal percentage to the base rate portion of customers' bills as was agreed to in the Settlement Agreement. The average monthly bill for APS residential customers will increase by approximately $2.17, representing a 1.5 percent increase in their monthly billing. (See Attachment 3)

Q. Mr. Mease, does this conclude your testimony?

A. Yes.

<u>ATTACHMENT 1</u>

ROBERT B. MEASE, CPA
Education and Professional Qualifications

EDUCATION

Bachelors Degree Business Administration / Accounting - Morris Harvey College.

Attended West Virginia School of Graduate Studies and studied Accounting and Public Administration

Attended numerous courses and seminars for Continuing Professional Educational purposes.

WORK EXPERIENCE

Controller
Knives of Alaska, Inc., Diamond Blade, LLC, and Alaska Expedition Company.

Financial Manager / CFO
All Saints Camp & Conference Center

Energy West, Inc.
Vice President, Controller

- Led team that succeeded in obtaining a $1.5 million annual utility rate increase
- Coached accountants for proper communication techniques with Public Service Commission, supervised 9 professional accountants
- Developed financial models used to negotiate an $18 million credit line
- Responsible for monthly, quarterly and annual financial statements for internal and external purposes, SEC filings on a quarterly and annual basis, quarterly presentations to Board of Directors and shareholders during annual meetings, coordinated annual audit
- Communication with senior management team, supervised accounting staff and resolved all accounting issues, reviewed expenditures related to capital projects
- Monitored natural gas prices and worked with senior buyers to ensure optimal price obtained

Junkermier, Clark, Campanella, Stevens
Consulting Staff

- Established a consulting practice that generated approximately $160k the first year of existence
- Prepared business plan and projections for inclusion in clients financing documents
- Prepared written reports related to consulting engagements performed
- Developed models used in financing documents and made available for other personnel to use
- Performed Profit Enhancement engagements
- Participated during audit of large manufacturing client for two reporting years

Prior to 1999, held various positions: TMC Sales, Inc. as **Vice President / Controller**, with American Agri-Technology Corporation as **Vice President / CFO** and with Union Carbide Corporation as **Accounting Manager. (Union Carbide was a multi-national Fortune 500 Company that was purchased by Dow Chemical)**

PROFESSIONAL AFFILIATIONS
Member - Institute of Management Accountants
Member - American Institute of CPA's
Member – Society of Utility and Regulatory Financial Analysts
Past Member –WV Society of CPA's and Montana Society of CPA's

RESUME OF RATE CASE AND REGULATORY PARTICIPATION WITH RUCO

Utility Company	Docket No.
Arizona Water Company (Eastern Group)	W-01445A-11-0310
Pima Utility Company	W-02199A-11-0329 et al.
Tucson Electric Power Company	E-01933A-12-0291
Arizona Water Company (Northern Group)	W-01445A-12-0348
UNS Electric	E-04204A-12-0504
Global Water	W-01212A-12-0309 et al.
LPSCO	SW-01428A-13-0042 et al.
Johnson Utilities	WS-02987A-13-0477

Attachment 2

Arizona Public Service Corporation
Docket No. E-01345A-11-0224
Test Year Ended December 31, 2010

REVENUE REQUIREMENT - REVISED
ACC JURISDICTIONAL - AS SUBMITTED BY COMPANY
(Thousands of Dollars)

		ORIGINAL SETTLEMENT				ADJUSTED SETTLEMENT WITH ACQUISITION		
LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) PRO FORMA ADJUSTMENTS	(E) RUCO ORIGINAL COST	(F) RUCO RCND	(G) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 5,662,998	$ 10,671,253	$ 8,167,126	$ 225,934	$ 5,888,932	$ 10,897,187	$ 8,393,060
2								
3	Adjusted Operating Income (Loss)	$ 496,769	$ 496,769	$ 496,769	$ (20,680)	$ 476,089	$ 476,089	$ 476,089
4								
5	Fair Value Adjustment Embedded in Operating Income	25,041	25,041	25,041		25,041	25,041	25,041
6								
7	Adjusted Operating Income (Ln 3 - Ln 5)	471,728	471,728	471,728		451,048	451,048	451,048
8								
9	Current Rate of Return (Ln 7 / Ln 1)	8.33%	4.42%	5.78%		7.66%	4.14%	5.37%
10								
11	Required Operating Income (Ln 1 x Ln 13)	$ 471,728	$ 471,728	$ 471,728		$ 490,548	$ 490,548	$ 490,548
12								
13	Required Rate of Return	8.33%	4.42%	5.78%		8.33%	4.50%	5.84%
14								
15	Adjusted Operating Income Deficiency	-	-	-		$ 39,500	$ 39,500	$ 39,500
16								
17	Gross Revenue Conversion Factor	1.6566	1.6566	1.6566		1.6566	1.6566	1.6566
18								
19	Requested Increase in Revenue Requirement (Ln 15 X Ln 17)	$ -	$ -	$ -		$ 65,436	$ 65,436	$ 65,436

Source of Schedule - Submitted by Company as Attachment EAB-4
(Revised on May 17, 2014 in Staff Data Request)

Arizona Public Service Corporation
Docket No. E-01345A-11-0224
Test Year Ended December 31, 2010

Schedule RBM-2
Page 1

COMPARISON OF REVENUE REQUIREMENTS - RUCO'S RECOMMENDATION

(Thousands of Dollars)

Line No		(A) TOTAL COMPANY	(B) ACC JURISDICTION	(C) TOTAL COMPANY WGT AVG COST OF CAPITAL	(D) TOTAL COMPANY DEBT RATE	(E) ACC JURISDICTION WGT AVG COST OF CAPITAL	(F) ACC JURISDICTION DEBT RATE
	FOUR CORNERS REVENUE REQUIREMENTS						
1	Four Corners Acquisition Units 4 and 5	$ 55,670	$ 53,777	$ 55,670	$ 55,670	53,777	$ 53,777
2	Four Corners Acquisition Adjustment	252,510	243,925	252,510	252,510	243,925	243,925
3	Four Corners Acquisition (Decommissioning Lia.)	(34,123)	(32,963)	(34,123)	(34,123)	(32,963)	(32,963)
4	Four Corners Acquisition (Coal Reclamation Lia.))	(92,951)	(89,791)	(92,951)	(92,951)	(89,791)	(89,791)
5	Four Corners Auxillary Plant	11,065	10,689	11,065	11,065	10,689	10,689
6	Four Corners Deferred Costs Units 1, 2 and 3	41,716	40,298	41,716	41,716	40,298	40,298
7		233,887	225,935	233,887	233,887	225,935	225,935
8							
9	Settlement Pre-Tax Weighted Avg Cost of Capital	11.856%	11.856%	11.856%	4.725%	11.856%	4.725%
10							
11	Return on Rate Base (with Rev. Conversion Factor Adj)	27,861	26,913	27,730	11,051	26,913	10,675
12							
13	EXPENSE ADJUSTMENTS						
14	Incremental O&M Expense Related to Acquisition	5,601	5,411	5,601	5,601	5,411	5,411
15	Incremental Property Tax & Other Taxes	6,419	6,201	6,419	6,419	6,201	6,201
16	Incremental Depreciation Expense	2,671	2,580	2,671	2,671	2,580	2,580
17	Amortization of Four Corners Acquisition Adj.	10,707	10,343	10,707	10,707	10,343	10,343
18	Amortization of Four Corners Deferral Balance (10 Years)	6,896	6,662	6,896	6,896	6,662	6,662
19	Final Coal Reclamation on Acquired Portion	4,499	4,346	4,499	4,499	4,346	4,346
20	Decommissioning on Acquired Portion	3,085	2,980	3,085	3,085	2,980	2,980
21		39,878	38,523	39,878	39,878	38,523	38,523
22							
23	TOTAL REVENUE REQUIREMENT	$ 67,739	$ 65,436	$ 67,608	$ 50,929	$ 65,436	$ 49,198
24							
25							
26							

Source of Schedule - Prepared from Data Responses provided by APS and RUCO workpapers

Attachment 3

Arizona Public Service Corporation
Docket No. E-01345A-11-0224
Test Year Ended December 31, 2010

Four Corners Rate Rider
Estimated Bill Impacts

Schedule RBM-3

Residential (Average - All Rates)	Current Annual Average Monthly Bills	Requested Jul-14 Annual Average Monthly Bills	Current Summer Monthly Bill	Requested Jul-14 Summer Monthly Bill	Current Winter Monthly Bill	Requested Jul-14 Winter Monthly Bill
Average kWh per Month	1,100	1,100	1,337	1,337	863	863
Base Rates	$ 123.90	$ 123.90	$ 161.07	$ 161.07	$ 86.72	$ 86.72
Four Corners Adjustment	$ -	$ 2.17	$ -	$ 2.82	$ -	$ 1.52
PSA - Forward Component	$ 1.41	$ 1.41	$ 1.71	$ 1.71	$ 1.10	$ 1.10
PSA - Historical Component	$ 0.31	$ 0.31	$ 0.37	$ 0.37	$ 0.24	$ 0.24
TCA	$ 7.12	$ 7.12	$ 8.65	$ 8.65	$ 5.58	$ 5.58
RES	$ 4.11	$ 4.11	$ 4.11	$ 4.11	$ 4.11	$ 4.11
DSMAC	$ 2.99	$ 2.99	$ 3.63	$ 3.63	$ 2.34	$ 2.34
LFCR	$ 0.28	$ 0.29	$ 0.36	$ 0.37	$ 0.20	$ 0.20
TOTAL	$ 140.12	$ 142.30	$ 179.90	$ 182.73	$ 100.29	$ 101.81
Bill Impact		$ 2.18		$ 2.83		$ 1.52
		1.55%		1.57%		1.51%

Residential (Average - All Rates)	Current Annual Average Monthly Bills	Requested Jul-14 Annual Average Monthly Bills	Current Summer Monthly Bill	Requested Jul-14 Summer Monthly Bill	Current Winter Monthly Bill	Requested Jul-14 Winter Monthly Bill
Average kWh per Month	691	691	780	780	602	602
Base Rates	$ 86.40	$ 86.40	$ 108.04	$ 108.04	$ 64.76	$ 64.76
Four Corners Adjustment	$ -	$ 1.51	$ -	$ 1.89	$ -	$ 1.13
PSA - Forward Component	$ 0.89	$ 0.89	$ 1.00	$ 1.00	$ 0.77	$ 0.77
PSA - Historical Component	$ 0.20	$ 0.20	$ 0.22	$ 0.22	$ 0.17	$ 0.17
TCA	$ 4.48	$ 4.48	$ 5.05	$ 5.05	$ 3.90	$ 3.90
RES	$ 4.11	$ 4.11	$ 4.11	$ 4.11	$ 4.11	$ 4.11
DSMAC	$ 1.88	$ 1.88	$ 2.12	$ 2.12	$ 1.64	$ 1.64
LFCR	$ 0.20	$ 0.20	$ 0.24	$ 0.25	$ 0.15	$ 0.15
TOTAL	$ 98.16	$ 99.67	$ 120.78	$ 122.68	$ 75.50	$ 76.63
Bill Impact		$ 1.51		$ 1.90		$ 1.13
		1.54%		1.57%		1.50%

Residential (Rates E-12, 0-20kW)	Current Annual Average Monthly Bills	Requested Jul-14 Annual Average Monthly Bills	Current Summer Monthly Bill	Requested Jul-14 Summer Monthly Bill	Current Winter Monthly Bill	Requested Jul-14 Winter Monthly Bill
Average kWh per Month	1,430	1,430	1,575	1,575	1,285	1,285
Base Rates	$ 202.30	$ 202.30	$ 232.85	$ 232.85	$ 171.75	$ 171.75
Four Corners Adjustment	$ -	$ 3.54	$ -	$ 4.08	$ -	$ 3.01
PSA - Forward Component	$ 1.83	$ 1.83	$ 2.01	$ 2.01	$ 1.64	$ 1.64
PSA - Historical Component	$ 0.40	$ 0.40	$ 0.44	$ 0.44	$ 0.36	$ 0.36
TCA	$ 3.58	$ 3.58	$ 3.94	$ 3.94	$ 3.22	$ 3.22
RES	$ 14.68	$ 14.68	$ 16.17	$ 16.17	$ 13.19	$ 13.19
DSMAC	$ 3.89	$ 3.89	$ 4.28	$ 4.28	$ 3.49	$ 3.49
LFCR	$ 0.45	$ 0.46	$ 0.52	$ 0.53	$ 0.39	$ 0.39
TOTAL	$ 227.13	$ 230.68	$ 260.21	$ 264.30	$ 194.04	$ 197.05
Bill Impact		$ 3.55		$ 4.09		$ 3.01
		1.56%		1.57%		1.55%

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Test Year Ended December 31, 2010

Four Corners Rate Rider
Estimated Bill Impacts

Schedule RBM-3

Commercial (Rate E-32, >20 kW)	Current Annual Average Monthly Bills	Requested Jul-14 Annual Average Monthly Bills	Current Summer Monthly Bill	Requested Jul-14 Summer Monthly Bill	Current Winter Monthly Bill	Requested Jul-14 Winter Monthly Bill
Average kWh per Month	62,238	62,238	68,381	68,381	56,094	56,094
Base Rates	$ 5,977.26	$ 5,977.26	$ 7,044.20	$ 7,044.20	$ 4,910.31	$ 4,910.31
Four Corners Adjustment	$ -	$ 104.62	$ -	$ 123.29	$ -	$ 85.94
PSA - Forward Component	$ 79.48	$ 79.48	$ 87.32	$ 87.32	$ 71.63	$ 71.63
PSA - Historical Component	$ 17.43	$ 17.43	$ 19.15	$ 19.15	$ 15.71	$ 15.71
TCA	$ 165.94	$ 165.94	$ 177.69	$ 177.69	$ 154.18	$ 154.18
RES	$ 152.49	$ 152.49	$ 152.49	$ 152.49	$ 152.49	$ 152.49
DSMAC	$ 189.52	$ 189.52	$ 202.94	$ 202.94	$ 176.09	$ 176.09
LFCR	$ 13.16	$ 13.43	$ 15.37	$ 15.68	$ 10.96	$ 11.18
TOTAL	$ 6,595.28	$ 6,700.17	$ 7,699.16	$ 7,822.76	$ 5,491.37	$ 5,577.53
Bill Impact		$ 104.89		$ 123.60		$ 86.16
		1.59%		1.61%		1.57%

Commercial (Rate E-32 M)	Current Annual Average Monthly Bills	Requested Jul-14 Annual Average Monthly Bills	Current Summer Monthly Bill	Requested Jul-14 Summer Monthly Bill	Current Winter Monthly Bill	Requested Jul-14 Winter Monthly Bill
Average kWh per Month	62,238	62,238	68,381	68,381	56,094	56,094
Base Rates	$ 6,431.49	$ 6,431.49	$ 7,407.75	$ 7,407.75	$ 5,455.22	$ 5,455.22
Four Corners Adjustment	$ -	$ 112.57	$ -	$ 129.66	$ -	$ 95.48
PSA - Forward Component	$ 79.48	$ 79.48	$ 87.32	$ 87.32	$ 71.63	$ 71.63
PSA - Historical Component	$ 17.43	$ 17.43	$ 19.15	$ 19.15	$ 15.71	$ 15.71
TCA	$ 165.94	$ 165.94	$ 177.69	$ 177.69	$ 154.18	$ 154.18
RES	$ 152.49	$ 152.49	$ 152.49	$ 152.49	$ 152.49	$ 152.49
DSMAC	$ 189.52	$ 189.52	$ 202.94	$ 202.94	$ 176.09	$ 176.09
LFCR	$ 14.07	$ 14.36	$ 16.09	$ 16.42	$ 12.05	$ 12.29
TOTAL	$ 7,050.42	$ 7,163.28	$ 8,063.43	$ 8,193.42	$ 6,037.37	$ 6,133.09
Bill Impact		$ 112.86		$ 129.99		$ 95.72
		1.60%		1.61%		1.59%

Residential (Rates E-12, 0-20kW)	Current Annual Average Monthly Bills	Requested Jul-14 Annual Average Monthly Bills	Current Summer Monthly Bill	Requested Jul-14 Summer Monthly Bill	Current Winter Monthly Bill	Requested Jul-14 Winter Monthly Bill
Average kWh per Month	290,507	290,507	314,925	314,925	266,089	266,089
Base Rates	$ 24,709.54	$ 24,709.54	$ 29,456.69	$ 29,456.69	$ 19,962.38	$ 19,962.38
Four Corners Adjustment	$ -	$ 432.48	$ -	$ 515.57	$ -	$ 349.39
PSA - Forward Component	$ 370.96	$ 370.96	$ 402.16	$ 402.16	$ 339.80	$ 339.80
PSA - Historical Component	$ 81.34	$ 81.34	$ 88.18	$ 88.18	$ 74.50	$ 74.50
TCA	$ 607.71	$ 607.71	$ 674.34	$ 674.34	$ 541.08	$ 541.08
RES	$ 152.49	$ 152.49	$ 152.49	$ 152.49	$ 152.49	$ 152.49
DSMAC	$ 694.07	$ 694.07	$ 770.16	$ 770.16	$ 617.97	$ 617.97
LFCR						
TOTAL	$ 26,616.11	$ 27,048.59	$ 31,544.02	$ 32,059.59	$ 21,688.22	$ 22,037.61
Bill Impact		$ 432.48		$ 515.57		$ 349.39
		1.62%		1.63%		1.61%

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Four Corners Rate Rider
Estimated Bill Impacts

Schedule RBM-3

Industrial (Rate E34 / E35)	Current Annual Average Monthly Bills	Requested Jul-14 Annual Average Monthly Bills	Current Summer Monthly Bill	Requested Jul-14 Summer Monthly Bill	Current Winter Monthly Bill	Requested Jul-14 Winter Monthly Bill
Average kWh per Month	3,581,412	3,581,412	3,729,201	3,729,201	3,433,622	3,433,622
Base Rates	$ 249,125.86	$ 249,125.86	$ 259,882.57	$ 259,882.57	$ 238,369.15	$ 238,369.15
Four Corners Adjustment	$ -	$ 4,360.36	$ -	$ 4,548.63	$ -	$ 4,172.09
PSA - Forward Component	$ 4,573.47	$ 4,573.47	$ 4,762.19	$ 4,762.19	$ 4,384.74	$ 4,384.74
PSA - Historical Component	$ 1,002.80	$ 1,002.80	$ 1,044.18	$ 1,044.18	$ 961.41	$ 961.41
TCA	$ 8,618.22	$ 8,618.22	$ 9,090.63	$ 9,090.63	$ 8,145.81	$ 8,145.81
RES	$ 3,335.00	$ 3,335.00	$ 3,335.00	$ 3,335.00	$ 3,335.00	$ 3,335.00
DSMAC	$ 6,395.98	$ 6,395.98	$ 6,746.57	$ 6,746.57	$ 6,045.38	$ 6,045.38
LFCR						
TOTAL	$ 273,051.33	$ 277,411.69	$ 284,861.14	$ 289,409.77	$ 261,241.49	$ 265,413.58
Bill Impact		$ 4,360.36		$ 4,548.63		$ 4,172.09
		1.60%		1.60%		1.60%

EXHIBIT
S-1
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

IN THE MATTER OF THE APPLICATION OF THE ARIZONA PUBLIC SERVICE COMPANY FOR A REQUEST TO APPROVE A FOUR CORNERS RATE RIDER AS DEFINED IN APPROVED SETTLEMENT AGREEMENT IN DECISION NO. 73183 TO ALSO INCLUDE AMORTIZATION OF RELATED DEFERRALS AUTHORIZED IN DECISION NO. 73130

DOCKET NO. E-01345A-11-0224

REDACTED

DIRECT

TESTIMONY

OF

JAMES LETZELTER

CONSULTANT

ON BEHALF OF THE STAFF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 19, 2014

TABLE OF CONTENTS

EXHIBITS

INTRODUCTION

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

A. My name is James Letzelter. I am an Executive Consultant with The Liberty Consulting Group ("Liberty"). My business address is: The Liberty Consulting Group, 279 North Zinns Mill Road, Suite H, Lebanon, PA 17042-9576.

Q. What is the purpose of your testimony?

A. I led Liberty's review of the analytics behind the Arizona Public Service Company acquisition of Four Corners Units 4 and 5 from Southern California Edison. Our goal was to:

- Evaluate the validity of the analytical approach, data and models
- Update or confirm the APS valuation
- Assess the need for capacity
- Assess acquisition timing
- Evaluate risks of the transaction
- Identify ancillary benefits of the transaction.

Q. Did you prepare a report containing your analysis of the Four Corners Transaction?

A. Yes. I directly performed the work reflected in the report, and I prepared the report addressing the findings and conclusions of that examination, which is included as Exhibit JCL-1. The purpose of my testimony is to present, and respond to questions regarding Exhibit JCL-1.

Q. Mr. Letzelter, briefly summarize your educational background and professional qualifications as they relate to the subject of your testimony.

A. I have been engaged as a consultant and manager in the electric utility industry since 1990. Before joining Liberty in 2011, I served with companies now part of Navigant Consulting (Research Management International and Metzler Associates) and PA Consulting (Theodore Barry & Associates and Hagler Bailly), Entergy Corporation, Platts Research and Consulting, and GenMetrix. I have assisted energy industry clients throughout the United States and Europe, and have worked on behalf of many utility regulatory authorities.

My background includes power market assessment, risk analysis and generating asset valuation. Over the course of my career, I have performed asset valuations on over ten billion dollars' worth of electric power generating facilities. Clients have used that work for negotiation, project development, mergers, acquisitions, due diligence, regulatory proceedings, and litigation.

I have a B.S.E.E. degree from Clarkson University and an M.B.A. degree from the State University of New York at Albany (SUNY). I have earned the designation of Certified Rate of Return Analyst.

Q. Have you prepared a more detailed summary of your background?

A. Yes. Exhibit JCL-2 provides it.

CONCLUSIONS

Q. **Please briefly summarize your findings and conclusions with respect to the Four Corners Transaction.**

A. Based upon my analysis, Liberty formed the following conclusions:

1. The additional 179 MW of capacity are used and useful.
2. APS considered an appropriate range of resource options.
3. APS's economic analysis of the acquisition was sound.
4. The economics of the transaction favor APS customers.
5. The timing of the transaction was prudent.
6. The risks of the acquisition are offset by the expected favorable economics.
7. Several ancillary benefits add to the positive impact that the transaction will have for customers.
8. Overall, the Four Corners transaction was prudent.

In summary, Liberty finds the acquisition of Four Corners to be reasonable and prudent, and calculated to provide benefits to APS customers.

Q. Does that conclude your direct testimony?

A. Yes, it does.

Direct Testimony of James Letzelter
Docket No. E-01345A-11-0224
Exhibit JCL-1

Report on a
Review of the Arizona Public Service Company
Four Corners Acquisition

Presented to the:

Arizona Corporation Commission

By:

THE LIBERTY CONSULTING GROUP

279 North Zinns Mill Road, Suite H
Lebanon, PA 17042-9576

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June 19, 2014

Table of Contents

I. Executive Summary

A. Background

This report summarizes the process and results of Liberty's review of the Arizona Public Service Company ("APS" or "Company") Four Corners Units 4 and 5 acquisition.

On December 30, 2013, APS finalized a transaction with Southern California Edison ("SCE") to acquire SCE's share of Four Corners Units 4 and 5, as authorized by Decision No. 73130. Decision No. 73130 also set a goal for APS to retire Units 1-3 by December 31, 2013, if it acquired SCE's shares of Four Corners 4 and 5. With this transaction, APS therefore retired 560 MW of the older, less efficient Units 1-3, and acquired 740 MW of the more efficient Units 4 and 5. These changes produce a net increase in APS capacity of approximately 179 MW. Table 1 displays the basic parameters of the units involved in this transaction and Units 1-3, including the before and after APS share[1], unit type (technology), heat rate, and capacity factor.[2]

Table 1: Four Corners Basic Parameters (APS portions, before and after acquisition)

Unit	Capability (MW)			Technology	Heat Rate	Capacity Factor
	Before	After	Delta			
Unit 1	170	-	(170)	Subcritical	11,222	71.0%
Unit 2	170	-	(170)	Subcritical	11,139	72.0%
Unit 3	220	-	(220)	Subcritical	10,765	74.0%
Unit 4	116	485	370	Supercritical	10,047	75.0%
Unit 5	116	485	370	Supercritical	9,964	76.0%
Total	791	970	179			

The Company based its decision to purchase SCE's share of Units 4 and 5 on its view of its needs for long-term baseload supply, the economic value of the acquisition, and its comparison with other alternatives. APS's analyses determined that the Net Present Value ("NPV") of the acquisition was a $425.6 million benefit, when compared with the next best alternative (new gas-fired generators). Benefit is defined as the difference in NPV of the total system cost under the acquisition option (as compared to the gas build or buy option).

B. Scope of Work

Liberty's assessment of the acquisition focused on: the validity of APS's analytical approach, data and models gathered and used, updating or confirming the APS valuation, assessing the need for more capacity, acquisition timing, risks, and ancillary benefits. Liberty interviewed key people at APS in person, engaged in a number of telephone conferences to secure information, and reviewed models and data provided by APS in response to written data requests.

[1] Due to rounding, some capability totals (MW) do not sum to the total of their rounded components.
[2] Heat rates and capacity factor are from SNL Financial LC from 2012, and are provided as an indication of unit efficiency and historical performance relative to that efficiency. SNL Financial is an established energy industry information service serving more than 5,000 companies and 100,000 users. Liberty Consulting Group is a licensed subscriber of SNL Financial.

C. Findings & Conclusions Summary

Liberty performed a review of the models, processes, and data that drove APS's decision to acquire Four Corners Units 4 and 5. We also examined uncertainties and risks associated with the asset and the regional power market. Liberty formed the following conclusions:

1. The additional 179 MW of capacity are used and useful.
2. APS considered an appropriate range of resource options.
3. APS's economic analysis of the acquisition was sound.
4. The economics of the transaction favor APS customers.
5. The timing of the transaction was prudent.
6. The risks of the acquisition are offset by the expected favorable economics.
7. Several ancillary benefits add to the positive impact that the transaction will make for customers.
8. Overall, the Four Corners transaction was prudent.

In summary, Liberty finds the acquisition of Four Corners to be reasonable and prudent, and calculated to provide benefit to APS customers.

II. Background & Scope of Work

A. Background

[redacted] This spurred APS's initiative to investigate the prospect of acquiring SCE's interest in Units 4 and 5.

On October 19, 2010, the Environmental Protection Agency ("EPA") proposed a Federal Implementation Plan that would require Four Corners to achieve emissions reductions required under the Clean Air Act's "Best Available Retrofit Technology" ("BART") provision. APS projected that bringing all five units at Four Corners into compliance could exceed $660 million in capital costs by 2016. The Company proposed an alternate plan in November 2010. It consisted of closure of Units 1, 2, and 3, which APS owned in their entirety, and purchase of the SCE 45 percent interests in Units 4 and 5. APS would also commit to the installation of selective catalytic reduction ("SCR") equipment on Units 4 and 5 by July 31, 2018.

Based on the opportunity to purchase SCE's share of Units 4 and 5 and the EPA requirements, APS identified four options for the future of Four Corners:

- Continued operation of Units 1, 2, and 3 with Units 4 and 5 shut down in 2016.
- Replacement of the APS interest in Four Corners with combined-cycle gas generation.
- Retirement of Units 1, 2, and 3 early and acquisition of SCE's interest in Units 4 and 5.
- Continued Operation of Units 1-3 with SCE's interest in Units 4 and 5 acquired by another party.

APS found that, considering the costs of installing the equipment required to meet BART, the third alternative would produce revenue requirements (on a net present value basis) of about $500 million less than those of combined cycle installation and $1 billion less than those of continued operation of Units 1, 2, and 3. A consultant for APS found an even greater advantage in APS's preferred alternative. APS also cited the major contribution that Four Corners makes to the economy of the Navajo Nation, due to the units' location and operation.

The other companies holding an interest in Units 4 and 5 all declined to exercise their rights of first refusal with respect to the SCE interest, so APS did not consider the fourth option a viable alternative.

B. Scope of Work

The scope of Liberty's examination of the Four Corners Closure/Acquisition included the following principal elements:

1. Determining the basis for "pursuing" the closure/acquisition plan
2. Updating if and as required the evaluation of the closure/acquisition plan to verify its prudence
3. Determining whether and when the net increase in capacity produced by the plan will be "used and useful."

III. Findings

A. Need for Capacity

APS made clear in its application to acquire SCE's ownership interest in Four Corners that economics, rather than an immediate need for power, principally drove its plan. The net impact after retiring Units 1, 2 and 3 and adding 740 MW of Units 4 and 5 would be to add 179 MW of capacity to the Company's supply portfolio. APS calculated that its 2014 capacity reserve of 32.2 percent would essentially double the 15 percent reserve margin required to meet reliability requirements.

Taken at face value, this level of reserves may appear hard to justify. APS's particular circumstances, however, need to be considered in addressing that concern. Liberty used the APS 2014 Integrated Resource Plan ("IRP") as a reference for supply and demand[3] to create three Reserve Margin Scenarios to investigate APS's need for resources (both current and future). We used the underlying data from Table 1 of the APS 2014 IRP (page 8), and adjusted it to calculate the reserve margins under these scenarios.

Use of a 15 percent reserve margin drove this assessment. APS has established this planning threshold to meet its loss of load probability criterion. We found this margin typical for the U.S. electric power industry, and is the default level used by the North American Electric Reliability Corporation ("NERC") for primarily thermal systems[4]. That margin equals the percent of total capacity (less non-dispatchable renewables) divided by the peak demand (less customer owned resources). Also worth noting is the Commission's 2012 IRP Decision requiring APS to perform additional studies to mitigate surplus capacity when total reserve margin exceeds 20 percent for more than two years.

1. Load Growth

The rate at which APS's peak load grows will affect the reserve margins produced by the Four Corner's transaction. Over the next five years, APS forecasts peak demand growth of 3.25 percent per year. This projection was developed by APS, and used in its IRP. As part of its analysis, Liberty reviewed the load forecast and key inputs. The APS load forecasting team provided detailed explanations and data to support the Liberty review.

[3] The 2014 IRP uses established values for future supply, and projected customer demand.
[4] NERC website: http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx

At this growth rate, APS's generation needs to increase by 265 MW per year in order to maintain its reserve margin. These increases exclude the effects of any energy efficiency and distributed energy initiatives. APS projects that energy efficiency and distributed energy efforts will offset 986 MW of this increase, leaving a projected 2014 through 2019 increase of 1,419 MW. APS expects to address a substantial portion of this balance with new natural gas resources. A lower than expected load forecast would be expected to produce reduced or deferred commitments for new combined cycle gas turbines ("CCGT").

2. Reserve Margin Scenarios

In reviewing the need for generating capacity resources, Liberty reviewed APS's supply and demand situation, and estimated reserve margins for the following three scenarios. It is worth noting that the system load was the same for each of these scenarios. The only difference between scenarios is related to APS generating capacity.

a. Reserve Margin Scenario 1: Acquire Four Corners Units 4 and 5 and retire Four Corners Units 1-3

This scenario represents the current outlook for APS' future load and resource needs, because it includes the closure of Units 1, 2 and 3 and the acquisition of the Units 4 and 5 share from SCE. It reflects the resource plan from the APS 2014 IRP. It is important to assess the annual reserve margin of this scenario, as it highlights the Company's current and future position based on the current plan. The other scenarios will be compared to this scenario.

As of the December 31, 2013, acquisition and closure date, APS increased its share of Units 4 and 5 by 740 MW (from 231 MW to 970 MW). At the same time, APS closed its 560 MW of Units 1, 2 and 3. The net impact of the transactions was to increase the size of APS's generating portfolio by 179 MW.

The annual reserve margins for all scenarios are displayed in Figure 1, with an overlay of the planning target reserve margin of 15 percent. It is very clear that in Scenario 1 (solid line) for the next three years (2014-16), APS has capacity well in excess of its needs. Over those three years, reserve margins are 34, 33, and 22 percent, respectively. On the surface, it would appear that the addition of 179 MW was not justified on the basis of these next three years. However, the subsequent years should be considered.

Over the subsequent seven years, the period of 2017-2023, the supply plan produces near-optimum annual reserve margins (noted by the close tracking of the Reserve Margin Scenario 1 line to the 15 percent target). Based on this outlook, Liberty finds that the IRP case is appropriate. While the first three years represent excess capacity, it diminishes at a reasonable rate (from a capacity planning and development perspective) through a fall in contracted resources and growth in APS load. The acquisition of Units 4 and 5 creates additional surplus capacity in the short term, but is necessary to maintain system integrity (as defined by reserve margin) in the long term.

b. Reserve Margin Scenario 2: Do not acquire Four Corners Unit 4 and 5 and do not retire Four Corners Units 1-3

This scenario represents the APS pre-acquisition portfolio, to shed light on the reserve margin implications of not acquiring the SCE share of Units 4 and 5. To assess this scenario, Liberty started with Scenario 1 (APS 2014 IRP) and adjusted it to remove the net impacts of the acquisition and closure of Units 1, 2 and 3.

The capacity situation in this case reflects a reduction in coal resources of 179 MW for the period of 2014-2018. This situation reflects the differential between the pre- and post-acquisition portfolios over that period. After 2018, the numbers are further reduced by another 231 MW to reflect the loss of APS's pre-existing 231

MW share of Units 4 and 5 (under the assumption that no APS purchase of the SCE share causes the plant to be shut).

The annual reserve margins under this scenario are displayed by the No Acquisition/Keep 1-3 line in Figure 1. As in Reserve Margin Scenario 1, the first years (2014-15) display rather high reserve margins of 31 percent, followed by a year in the target zone (at 19.0). In this scenario the reserve margin picture falls more quickly in line with target levels.

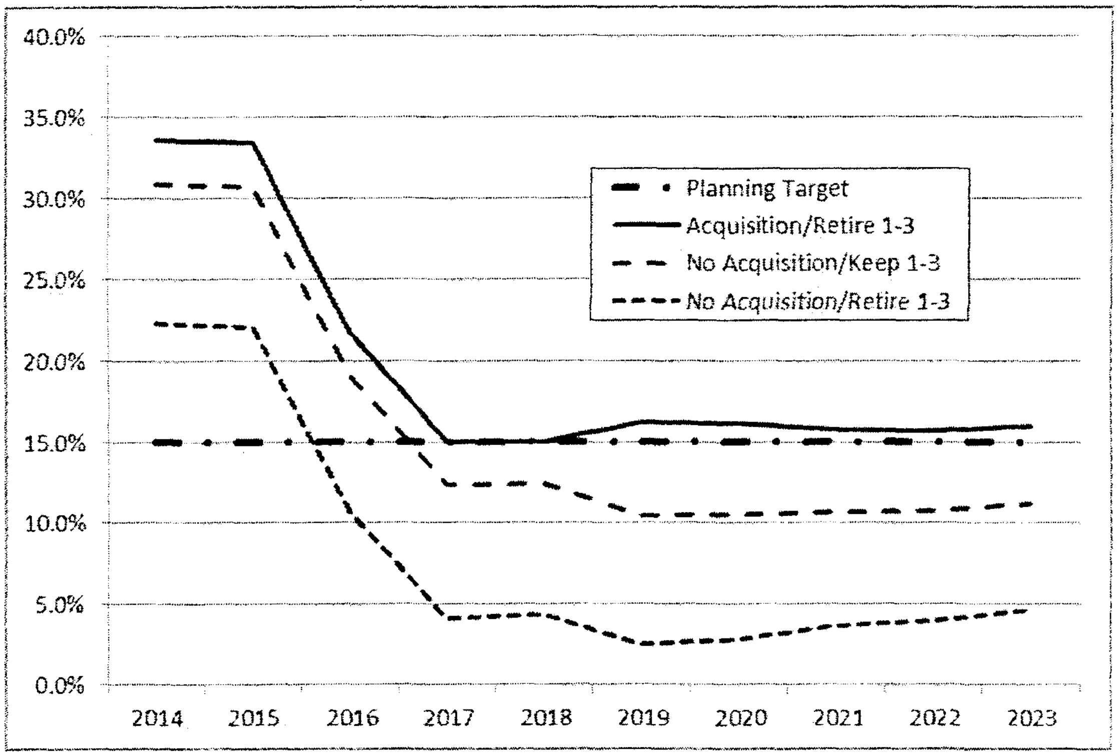
However, the situation changes significantly in the next seven years. During that time, based on Units 4 and 5 closing, the APS portfolio loses another 231 MW of coal capacity that represented its pre-existing share. Losing this 231 MW drives the reserve margins into the 10-12 percent range over this period, which is insufficient for system security. In short, not acquiring SCE's share of Units 4 and 5 would have had negative implications on the supply portfolio, from 2017 and beyond. Liberty concludes that the acquisition was helpful in maintaining integrity of the long-term supply plan.

c. Reserve Margin Scenario 3: Retire Four Corners 1-3 but do not acquire Four Corners Units 4 and 5

This scenario represents the closure of Units 1, 2 and 3 for economic reasons (due to emissions control capital requirements), with no acquisition of Units 4 and 5 or other resources. This event would result in 739 fewer MW through 2018, followed by the loss of an additional 231 MW after that due to the closure of APS's 231 MW of its pre-existing share of Units 4 and 5.

This scenario thus produces severe reserve margin impacts (bottom line in Figure 1). After 2015, reserve margins would plummet to dangerously low levels. What this scenario does, however, is highlight that additional resources would be absolutely required to maintain the APS system.

Figure 1: Reserve Margin Scenarios



B. Economic Analysis

APS based its economic analysis of the acquisition on the NPV of total system production costs. For each of the alternatives considered, APS calculated an NPV. The Company began with production model runs and simulations, made with the support of tools common in the industry (***Promod*** and ***Strategist***). Outputs from these models then fed a series of custom, ***MS Excel***-based financial models. Liberty reviewed the process, models and data used for the analyses, focusing on the key inputs and the Excel-based models.

1. Options Considered

APS considered only two alternatives to be completely viable, in light of the need for closure of Units 1, 2 and 3:

- Acquire SCE's interest in Units 4 and 5
- Build or buy new gas generation.

The key to the options considered was the need for baseload generation. Utilities serve their load with a variety of resources from various asset classes (commonly referred to as baseload, intermediate/cycling, and peaking). Typically, at least 30-40 percent of a utility's generation capacity is comprised of baseload resources. In order to maintain this level of baseload capacity upon closure of Four Corners Units 1, 2 and 3, new baseload generation was required.[5] Baseload resources are typically coal and nuclear facilities, or newer, high efficiency (low heat rate) gas-fired combined cycle units. Accordingly, the APS analysis focused on the NPV

[5] APS's baseload under each Reserve Margin Scenario identified in Figure 1 is as follows: Acquisition/Retire 1-3 (13% nuclear and 21% coal); No Acquisition/Keep 1-3 (13% nuclear and 20% coal); and No Acquisition/Retire 1-3 (13% nuclear and 13% coal).

differential between the two available baseload options: the Four Corners Units 4 and 5 acquisition and new gas combined cycle, augmented by simple-cycle gas turbines for additional (non-baseload) capacity.

Energy efficiency measures and distributed resources play a role in meeting resource requirements as well, as shown in the reserve margin tables in *Section A: Need for Capacity*. These are already included in the resource plans.

2. Model Integrity

Liberty reviewed the Excel-based models, including the inputs from the Promod and Strategist system inputs. The model was designed to calculate the annual cost of total system generation under the two options (acquire Units 4 and 5 versus build or buy new gas facilities). The model calculates the annual capital (fixed carrying charges), variable costs (fuel and variable O&M), fixed O&M, CO_2 emissions, transmission costs, and other costs. The horizon for the study was 25 years, covering the period from 2014 through 2038. The stream of annual system costs for each option was discounted to provide an NPV.

Liberty reviewed the analysis spreadsheets to verify that: a) the approach was sound from a resource cost calculation perspective, b) the calculations were based on appropriate flow of data, and c) the specific formulas and algorithms used were correct. This review found the financial analysis approach to have been appropriate. We observed no gaps or errors in the models or in their application.

3. Data Integrity

The data used to drive the APS analysis were comprised of many components (e.g., capital, fuel, variable O&M, fixed O&M, emissions, etc.). The production-related data were used in **Promod** to produce projections of output and costs for each option, to be added to the fixed cost components in the APS spreadsheet model. The data used by APS in this analysis are the same as that used in the Company's 2014 IRP. Liberty therefore used this document to review the data.

Of the many data elements, it was determined by APS (and confirmed by Liberty) that the forecasts of natural gas costs and the cost of CO_2 emissions proved to be the critical variables. These two key drivers are assessed in greater detail and are the basis for our valuation adjustments and probabilistic valuation of the acquisition.

4. Gas Data

The delivered cost of gas operates as a principal driving factor in the gas build or buy scenario. On the one hand, lower gas prices give advantage to the gas build or buy. On the other hand, high gas prices favor the coal-fired Four Corners Units 4 and 5 acquisition option.

Liberty reviewed the APS gas input prices APS used in its analysis. The base case produced the Company's calculation of $425.6 million in *net present value benefit*. This benefit is defined as the difference in net present value of the total system cost under the acquisition option (as compared to the gas build or buy option).

Liberty's view of gas prices was based on the Energy Information Administration ("EIA") 2014 Annual Energy Outlook ("AEO") report. To develop this view, we used the EIA projection for Henry Hub, added to it the basis differential to the San Juan Hub, and then added to that the location-specific transportation adder for APS gas generation. The Liberty view is compared to the gas data from the APS analysis, for base, high and low cases, as shown in Figure 2. It also includes an expected, probability-adjusted "@Risk" value to be discussed later in this report.

Figure 2: Comparison of APS Gas Prices to EIA Gas Prices

[redacted]

We found that the natural gas prices used by APS are reasonable, and are actually conservatively low. For each case (base, low, and high), the EIA-based prices are notably higher than the corresponding forecast that APS used in its analysis. Accordingly, it is Liberty's view that actual gas prices may be higher than APS expects, making the benefit of the Four Corners acquisition even higher, as addressed later in this report.

5. CO_2 Emissions Cost Data

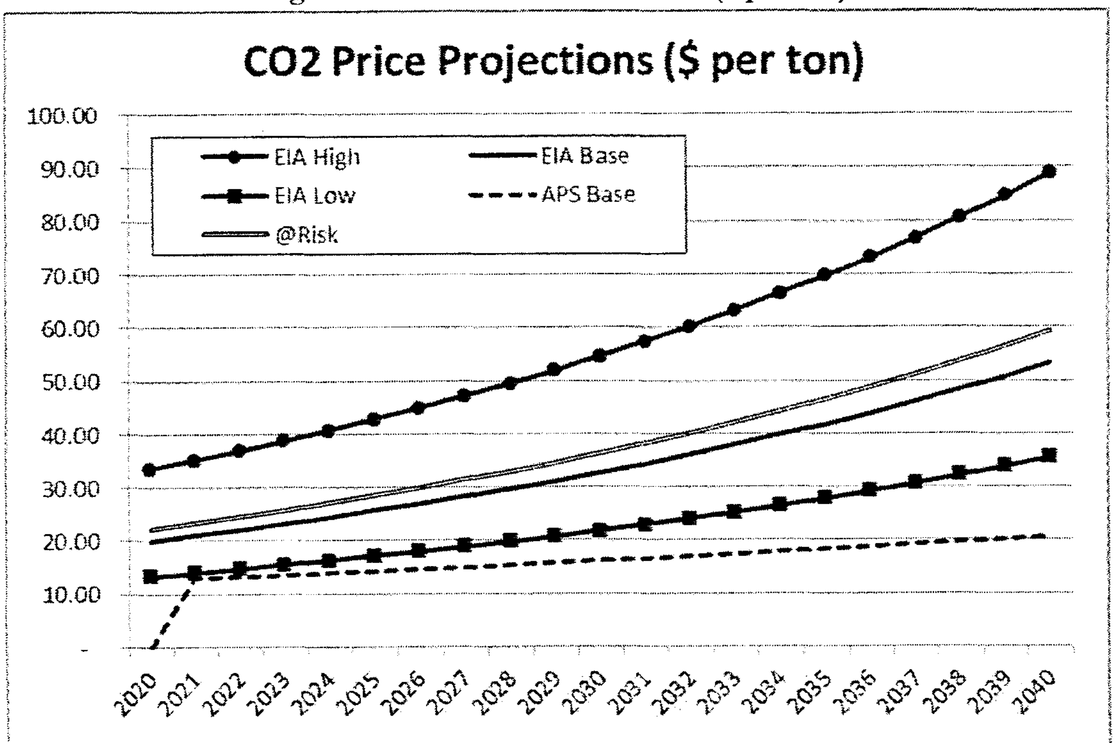
APS accounted for the potential changes in CO_2 regulation by imposing per-ton cost on its fossil fuel-fired units. There exists a high level of uncertainty in the future cost of CO_2 emissions, as shown by the very wide range of potential costs forecast by industry experts. Carbon presents a primary risk factor for fossil-fuel fired generating assets, particularly coal units. These facilities typically produce on the order of one ton of CO_2 per MWh (depending on unit heat rate). This level of output translates to a $/MWh dispatch cost impact equivalent to the $/ton CO_2 cost that is realized.

On June 2, 2014, the EPA proposed a draft rule requiring a 30 percent reduction in CO_2 emissions (nationwide) from existing power plants by 2013 (based on 2005 emission levels) and a 25 percent reduction by 2020.[6] This long-anticipated announcement now defines proposed reduction levels, which will result in varied predictions of the ultimate cost. However, at this point, there is no firm pricing available, meaning that there remains great uncertainty about the impact of CO_2 regulation on coal plant viability.

[6] Due to its location on tribal land, the EPA proposal does not specifically apply to Four Corners. This does not exclude Four Corners from CO_2 reductions, but affects the implementation plan process. That there remains a need to address goals and requirements for some facility locations does not in our view suggest the use of different assumptions about the exposure faced by Four Corners.

In light of this uncertainty, Liberty reviewed a number of public sources to compare them to the projections used by APS. Ultimately, Liberty compared the APS prices with those used by the EIA in its AEO. This EIA source is the same one we used in addressing the gas price projections discussed in the previous section. The APS and EIA prices are compared in Figure 3, as well as the probability-adjusted "@Risk" values used later in this report:

Figure 3: Carbon Cost Predictions ($ per ton)



Based on this comparison to the EIA's projections, Liberty considers the APS numbers to be insufficiently conservative (*i.e.*, too low for analysis purposes). The result is to underestimate the negative impacts to the Four Corners acquisition option. This, in turn, leads to the conclusion that more conservative (higher) CO_2 projections by APS could materially reduce the expected benefit of the acquisition.

6. Valuation Adjustment

The APS assessment calculated NPV for both the acquisition and gas build or buy options. As mentioned above, Liberty found the APS results appropriate in design and execution. Liberty has, however, adjusted this valuation to reflect differing views of the two primary drivers (gas prices and CO_2 costs). Liberty found that:

- It is proper to use *gas prices* higher than APS expects, resulting in a *higher* value for the acquisition benefits.
- It is proper to use *CO_2 prices* higher than APS expects, resulting in a *lower* value for the acquisition benefits.

To perform an adjustment for these two opposing factors, Liberty isolated both the cost and quantity of system-wide gas consumption and CO_2 emissions under each resource option, and calculated the annual cost differential of each. We then discounted the results back to calculate the NPV of benefits. Finally, we applied the resulting adjustment to the APS valuation of $425.6 million.

Figure 4 displays the total system gas consumption by APS for both resource options. The bottom area shows the gas burn as expected given the acquisition. The top area shows the increase in gas consumption by APS had the gas build or buy option been chosen instead. This delta (top area) is the quantity basis that is multiplied by the gas price adjustment to calculate the impact of the gas price adjustment on the acquisition benefit.

Figure 4: APS Gas Consumption

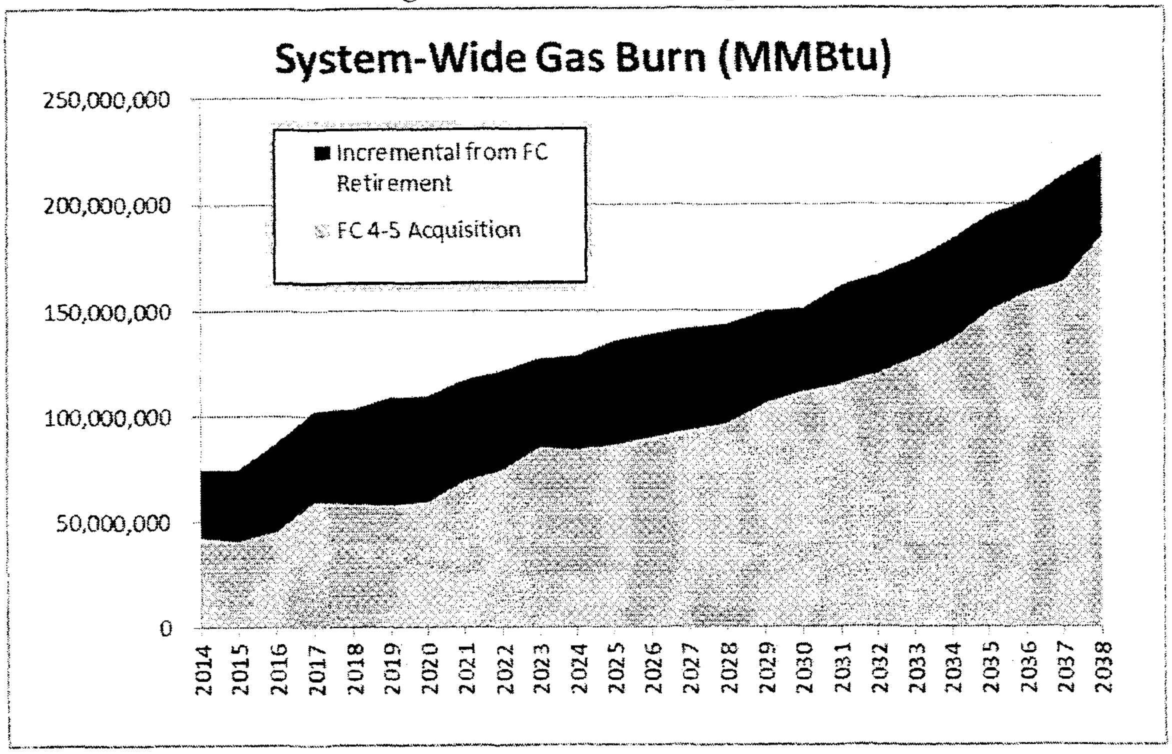
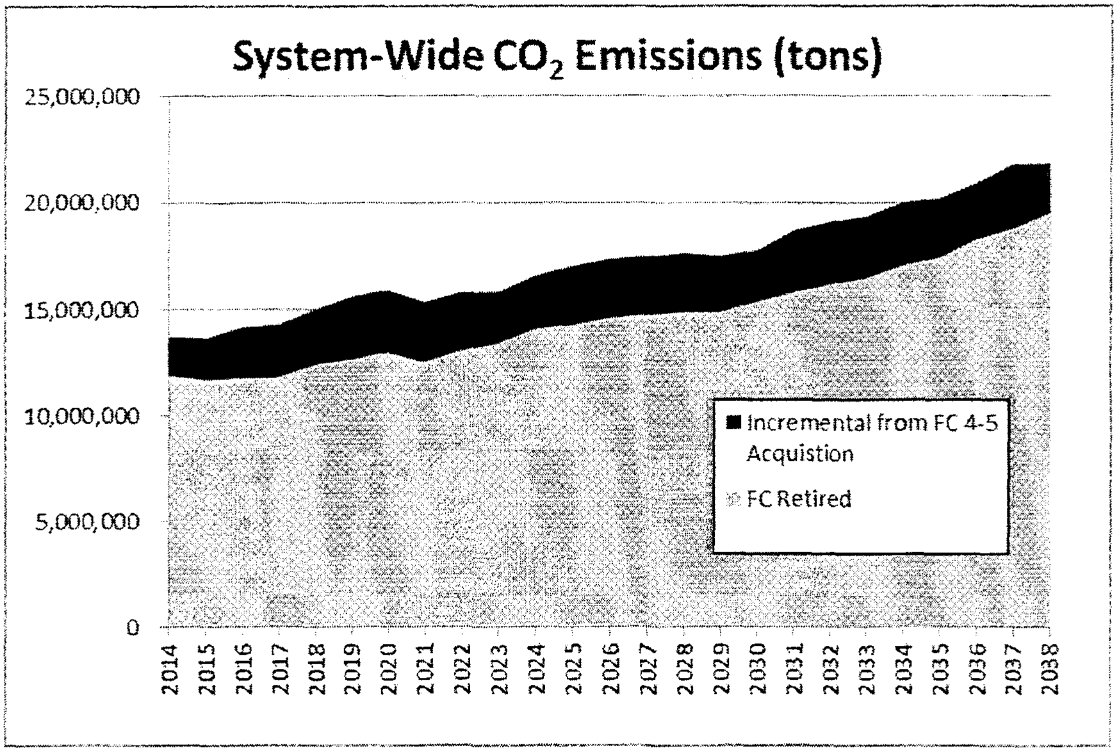


Figure 5 displays the total system CO_2 emissions by APS for both resource options. The bottom area shows the CO_2 emissions under the gas build or buy scenario. The top area shows the increase in CO_2 emissions by APS under the acquisition scenario. This delta (top area) shows the quantity basis that is multiplied by the CO_2 price adjustment to calculate the impact of the CO_2 price adjustment on the acquisition benefit.

Figure 5: APS Gas Consumption



Given the high uncertainty in gas prices and very uncertain future of CO_2 costs, Liberty engaged in a stochastic approach to perform the valuation adjustment. In doing so, Liberty was able to consider a range of inputs for gas prices and CO_2 costs, model each of those with a probability function, run a simulation, and capture the probabilistic range of results.

Key to this exercise is the development of input probability functions for the key drivers. Based on our experience, Liberty chose to use a triangle function for each parameter, which calls for the input of a low, base, and high value for each data element. Liberty chose the following for its input functions:

Parameter	Low	Base	High
Gas Price	EIA Low	APS Base	EIA High
CO_2 Cost	EIA Low	EIA Base	EIA High

The gas price scenarios referred to in the table, and the resulting expected value of the probability function, can be found in Figure 2. The CO_2 cost scenarios referred to in the table, and the resulting expected value of the probability function, can be found in Figure 3.

Liberty used the @Risk model to run a simulation of ~~10,000~~ 100,000 iterations of the probability inputs defined above. The result was a range of possible outcomes for the NPV of the benefit of the acquisition option. The results are displayed graphically in Figure 6.

Figure 6: Probability Distribution of Acquisition Benefit

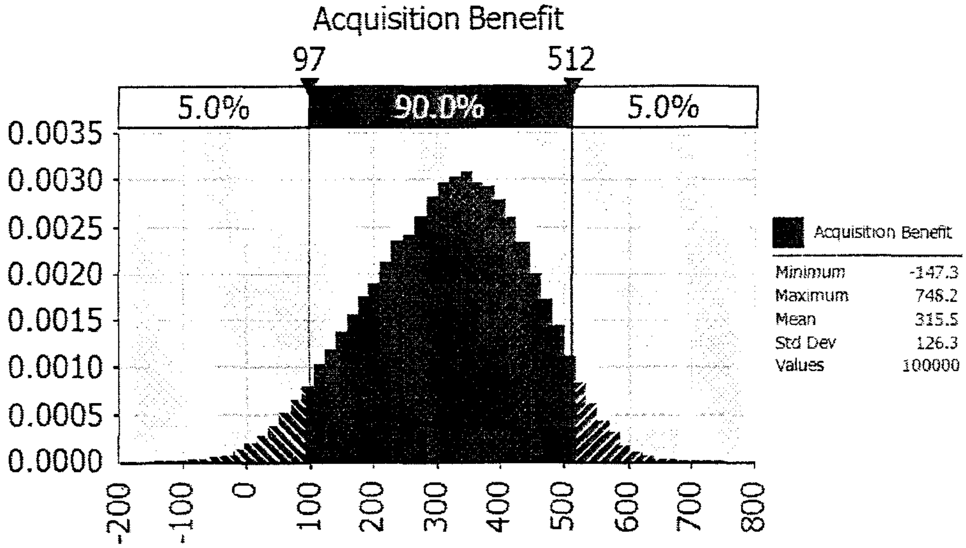


Figure 6 shows the probability weighted (expected) outcome of the acquisition to be $315.5 million, in comparison to the $425.6 million expected by APS. The results are lower, but still significantly favorable. The primary driver of the decrease is related to CO_2 cost, the negative impacts of which are somewhat offset by higher gas prices than those expected by APS.

The acquisition benefit ranges widely, from a negative (cost) of $147 million to a positive benefit (savings) of $748 million. These figures represent the extreme (low probability) ends of the spectrum. The 90 percent confidence interval of the analysis produces benefits that range from $97 million to $512 million.

C. Acquisition Timing

[redacted] SCE and APS settled on a price of $294 million, subject to an adjustment that reduced the value by $7.5 million per month for a closing after October 2012. The purchase price represented an ambivalence point for SCE, at which replacement power could be purchased in lieu of the production from Four Corners. Ultimately, a closing date of December 31, 2013, produced a cash purchase price of $181 million.

APS provided several reasons for its acquisition date, which we questioned, given that delaying the acquisition would have resulted in a lower acquisition price.

1. Closing of Four Corners Units 1 through 3 (EPA), $1 Billion

APS faced either committing to install SCR for NO_x control on Units 1 through 3, or shutting down the units by January 2014. The economic analyses clearly indicated that SCR was not a viable option for these units, which therefore should be closed. Closure would cause APS a loss of 560 MW. Purchasing the SCE portion of Four Corners would add 740 additional MW from Units 4 and 5, resulting in a net gain in capacity of 179 MW, instead of losing the 560 MW net loss of baseload generation.

2. Protect existing interest in Units 4 and 5

Without a buyer for SCE's share of Units 4 and 5, the existing APS share of Units 4 and 5 was at risk of closure. Additionally, because SCE was already determined to be rid of its share, it could not be expected to take a robust long-term outlook on planning and spending for the units. APS had been planning for a future well beyond 2016. Moreover, had APS not committed to purchasing the SCE portion when it did, it would have needed to start planning and spending for unit decommissioning, which would have had to begin in July of 2016.

3. SCR commitment and lead time

In order to continue operation of Units 4 and 5, APS had to commit to install SCR on both units. Installing SCR in time to meet its EPA deadlines required APS to move forward with planning for SCR construction—and incurring capital expenditures—as early as Quarter 2 of 2014. As such, APS viewed the earliest reasonable acquisition date as best in light of the need to spend for SCR. Otherwise, APS risked investing in SCR for an asset that may not be acquired by them or may not continue to operate at all.

4. Replacement of high cost sources with lower cost Units 4 and 5

While extending the closure resulted in a $7.5 million monthly price reduction, cost savings from holding the increased share of Units 4 and 5 served as an offset. To calculate the offset, Liberty considered two components:

[redacted]

- The total energy savings for both components of this analysis totals $1.93 million per month.

Taking these operational savings into consideration, APS's net monthly savings for delaying the acquisition of Units 4 and 5 would have been $5.5 million.

D. Risk Analysis

This analysis considers and evaluates the risks associated with APS's retirement of Four Corners Units 1, 2 and 3 and the concurrent acquisition of SCE's ownership interest in Four Corners Units 4 and 5. The net effect of closure and acquisition was to add 179 MW to APS's generation portfolio in 2014.

Retirement of Units 1, 2 and 3 helped APS avoid investing in mandated environmental containment systems, and the transaction has produced economic benefit for its consumers as analyzed by APS. Despite a sound evaluation, there are continued risks that may mitigate or eliminate that calculated benefit, in addition to the quantifiable risks associated with gas prices and CO_2 costs.

Few capital intensive, long-term investments, especially in light of today's energy business environment, come without a material degree of risk exposure. Coal-fired generation is under great pressure, as low natural gas prices due to fracking have increasingly displaced coal as the "low" cost source of baseload generation. The addition of government-imposed costs for reducing carbon not only will inhibit future coal units, but also will shorten the lives of some of those now operating.

However, gas sources of supply (e.g., a CCGT) also impose risk. Shale gas has undoubtedly been a game changer in the United States, driving natural gas prices to a fraction of what they were just five years ago. Nevertheless, pipeline and storage constraints have rendered natural gas highly volatile as to price and delivery. During the 2013 – 2014 winter season, delivery to the Northeast was constrained, and prices rose to over $100/MMBtu as the temperatures in New York and New England plunged. A large number of pending applications for liquefied natural gas export facilities, particularly combined with the political dimensions of international supply dominated by countries like Russia, risks more convergence between U.S. and international gas prices than we have seen to date.

Other Risks

In addition to the quantifiable risks associated with the uncertainty of natural gas prices and CO_2 costs, Liberty identified and summarized other risks associated with the Four Corners transaction, as defined in Table 3:

Table 3: Summary of Other Risks

Risk Area	Status	Potential Exposure
Coal contract termination	Coal Contract Extension executed	Low risk as it appears likely that the Navajo Nation will receive DOI approval
Four Corners Land Lease – Dept. of Interior ("DOI") Approval Process	Lease executed with APS	Low probability that DOI would reject lease, but might modify
Decommissioning and Mine Reclamation	Draft Environmental Impact Statement filed with DOI by Navajo Nation	While expected to be unlikely, DOI could reject or modify terms.
Heavy metals mitigation	Lengthening regulations for coal plants as to mercury and other heavy metals	Potential for added mitigation costs, although APS claims that Units 4 & 5 will comply
Inexperience of Navajo Transitional Energy Company ("NTEC")	BHP operating mine until 2016; APS manages closely and has assigned a full time fuel operations expert to be on-site.	Potential risk of mine operation due to replacement of BHP
Competitive market driven power costs	Potential for added mitigation costs, although APS claims that Units 4	Lower than expected market prices that would have been available via purchased power agreements

	& 5 will comply	
Load forecasts	Lower than expected load forecast could result in additional surplus capacity.	Risk to APS is low as further reduction in PPAs could offset lower growth and/or delay in planned 1,010 MW of gas generation

E. Ancillary Benefits

In addition to the economic benefits of the Four Corners acquisition, Liberty observed other benefits related to APS's acquisition of Four Corners Units 4 and 5. They include:

- Retention of approximately 800 jobs at the plant and mine
- Lease and right of way on Navajo land
- Protection of APS's pre-existing 15 percent of Four Corners Units 4 and 5
- Fuel diversity—not depending more on gas
- Closing Units 1 through 3 results in major reductions in Mercury, particulates, NO_x, SO_2 and CO_2.

IV. Conclusions

Based on the findings from our review of the process, data, and models, Liberty makes the following conclusions:

1. The additional 179 MW are both used and useful.
2. APS considered its reasonably available resource options.
3. The economic analysis of the acquisition was sound.
4. The economics of the transaction are favorable to APS customers.
5. The timing of the transaction was prudent.
6. The risks of the acquisition are more than offset by the expected favorable economics.
7. Several ancillary benefits add to the positive impact that the transaction will have for customers.
8. Overall, the Four Corners transaction was prudent.

In summary, Liberty finds that the acquisition of Four Corners to be reasonable and prudent, and calculated to provide benefit to APS customers.

James Letzelter

Areas of Specialization

Jim Letzelter is a leader in management consulting to the energy industry with over 24 years of experience. Jim specializes in power generation issues, including power market assessment, risk analysis, power plant valuation and acquisitions. He has led consulting teams on a variety of strategic, operational, regulatory and restructuring proceedings, and has supported a variety of successful merger, acquisition and development initiatives. Jim has a bachelor's degree in electrical engineering from Clarkson University and an M.B.A. from the State University of New York at Albany. He was a Lead Consultant in Liberty's audit of the procurement practices for fuel and purchased power of Entergy Mississippi, Inc. for the Mississippi Public Service Commission. Jim also led the effort by Liberty to evaluate the viability of PSNH's fossil fuel-fired generating stations.

Representative Experience

Risk Analysis & Asset Portfolio Assessment

- **Arcadia Wind**—Recently developed a sophisticated financial risk analysis model used by the client to bid on power project RFPs and to acquire capital from equity investors. Currently engaged with the company to provide ongoing risk modeling and overall financial and market intelligence support.
- **NextEra**—Developed a custom market intelligence tool to extract data from an industry standard forecasting package to meet the specific needs of energy traders. Currently engaged in an enhanced assignment to provide yet more market intelligence to the organization.
- **Nebraska Public Power District**—Performed a comprehensive risk analysis on the issue of nuclear plant life extension (NUPLEX) for the client's asset. Developed a risk management simulation tool to manage data and produce projections of future plant profitability under varying market, cost and regulatory scenarios. The work product was successfully employed by the client to make an informed decision on a major investment.
- **PSEG Power**—Developed and implemented a risk analysis and risk management tool for dealing with the uncertainty of emissions regulations. Implemented the model for the client and successfully led the organization through the maze of issues, including capital allocations, plant operations and investments that they faced.

Power Price Forecasting & Market Assessment

- **Investment Bank Syndicate**—Provided critical power market assessments for use in a major energy bankruptcy case. On behalf of the official creditor's committee, provided power price forecasts, power market assessments, fuel market reviews and power plant financial assessments. Work product was successfully used in litigation.

- **GE Power Systems**—Performed power market assessments for a major turbine manufacturer. Developed forecasts of energy, capacity, and ancillary service prices to be used to define the place in the market for an emerging turbine technology.
- **BNP Paribas**—Provided a detailed, comprehensive market assessment of global power markets to review the market for power generation turbines. With substantial investment in turbine manufacturers, the consortium relied on the expertise to make changes to their investment portfolios and shore up risk-plagued securities.
- **Bluewater Wind**—Provided market price forecasts to be utilized in the development and acquisition of power plants. Included forecasts of energy, capacity and ancillary services prices.

Generation & Transmission Operations

- **Bluewater Wind**—Provided a renewable power developer with consulting support on placement of assets with respect to transmission topography. Study used to select connection points and predict bus-level power prices.
- **Arcadia Wind**—Performed an assessment of transmission constraints for use in an asset valuation study. Used transmission constraint information to predict long-term power price implications, and the ability to move power to alternative markets.
- **NextEra**—Developed a power market price model based on dispatch costs, including transmission constraints and costs.

Asset Valuation, Acquisition & Development Support

- **PSEG Power**—Provided comprehensive power plant acquisition support. Managed market assessment process, provided asset valuations, defined acquisition price and assisted in property tax negotiations. Also highlighted the value of the asset with respect to asset re-powering opportunities.
- **PSEG Power**—Led the analytical efforts behind the acquisition of portions of three nuclear power plants. Included market comparables assessment, decommissioning fund valuation, and materials and supplies inventory valuation.
- **PSEG Power**—Provided a comprehensive financial and market analysis of re-powering opportunities for the client's older asset base. Included detailed assessment of market conditions and expected returns for various re-powering opportunities.
- **NextEra**—Successfully developed and deployed software to determine generating asset intrinsic and extrinsic value. Program utilizes probabilistic market price output from AURORA. Program also develops equilibrium market pricing for long-term time frame.
- **Dairyland Power Co-Op**—Provided a thorough asset valuation study to assess the impact of market uncertainties and financing parameters on the organization's asset values. Successfully provided the client with recommendations for potential divestiture and regulatory initiatives.
- **PSEG Power**—Provided a massive market assessment in support of a corporate power plant acquisition initiative. Included development of a detailed financial and valuation model for the client to use in future asset acquisition studies.

- **GE Power Systems**—Provided a power market assessment and financial analysis to assess the viability of a new class of combined cycle units for the U.S. power markets. Included a comprehensive scenario analysis of fuel prices, load growth, emissions regulations and transmission constraints.

Model Implementation, Validation & Development

- **NextEra**—Developed a custom interface for the AURORA electric power market model to seamlessly integrate within the client's analytical framework. Included data development and model validation, and custom report development.
- **NextEra**—Managed the overall process for transitioning the resource planning and forecasting department to AURORA. Included full data development, training, interface development, testing and validation. Successfully converted the business process to an AURORA-based system.
- **NextEra**—Developed a customized power price forecasting tool to provide acquisition and development support, restructuring support and general corporate financial forecasts. Developed data sets for the model and provided training and validation.

Emissions Control Analysis

- **PSEG Power**—Developed an enterprise-wide strategy for managing emissions constraints for the generating asset portfolio. Developed a probabilistic assessment model to consider plant operations, emission rates, control technology options, market forces and potential and existing emissions constraints. Deliverables resulted in a cohesive strategy and lobbying campaign for favorable regulations.
- **PSEG Power**—Performed a risk analysis of greenhouse gas regulation impacts on a potential fossil-fired asset portfolio acquisition. Deliverables included a detailed assessment of financial and asset value implications of various regulatory scenarios.
- **PSEG Power**—Provided an assessment of emissions regulations impacts on potential asset acquisitions. Included a market assessment of abatement technology costs and operating parameters, and a review of potential emissions regulations scenarios.

Regulatory & Litigation Support

- **BG&E**—Performed a gas cost of service study to be used in a major rate case. Developed a proprietary model for cost allocation and financial implications.
- **Entergy/MP&L**—Developed a custom ROE Calculation model to be used in rate-setting. The model captured highly complex algorithms into a manageable user interface. The model was approved by the state utility regulator and was successfully implemented.
- **PSEG Power**—Provided litigation support in a major utility restructuring proceeding. The project including development of exhibits, preparation of witnesses, developing testimony and cross-examination, and performing power market analyses.

Venture Capital & Emerging Technology Support

- **Arcadia Wind**—Provided analytical support for overall corporate development and acquisition of investment capital.
- **Thermal Energy International**—Provided comprehensive support for commercialization of a newly patented NO_x control technology. The project included a detailed market assessment, development of a financial analysis tool for customer proposals, acquisition of venture capital and strategic planning for the company. All aspects of the project were highly successful.

Basic Generation Services Auctions

- For the **Maryland PSC**, Mr. Letzelter oversaw several Basic Generation Service (BGS) auctions covering a multitude of time periods and utility service territories. The work entailed developing Bid Forms for bidders to submit with detailed price parameters; pre-qualification of bidders based on security and credit; and monitoring and oversight of the utility staff during bid period.
  The work also entailed developing a detailed and comprehensive pre-auction market report and setting a bandwidth of acceptable bids based on market conditions. Mr. Letzelter also provided the Commission with a detailed report and presentation on results and provided testimony and other hearing support.
- For the **Pennsylvania PUC**, Mr. Letzelter oversaw the auction for Basic Generation Service (BGS). As auction monitor, he was responsible for pre-qualifying bidders and to open bids and select winners. He developed and implemented a custom web-based bid system to replace previously used paper/faxed forms. The implementation was highly successful. Mr. Letzelter also provided the Commission with a detailed report and presentation on results and provided testimony and other hearing support.
- For the **Delaware PSC**, lead consultant for Liberty's current service as Independent Monitor of Delmarva Power & Light. The project includes a review of pre-bid communications, announcements to bidders, and website review. Monitored the receipt of all bids. Produced reports and presentation for commission and provided follow-up consulting support and testimony.

Education

Master of Business Administration (M.B.A.)—State University of New York at Albany, Concentration in Finance.

Bachelor of Science in Electrical Engineering (B.S.E.E.)—Clarkson University, Concentration in Power System Engineering.

Key Publications & Presentations

- Quoted extensively in major news publications, including BusinessWeek, Chicago Tribune, Miami Herald, LA Times, etc., related to the Northeast blackout of 2003
- "U.S. Power Markets Overview: An Issues Overview and Enhanced View of Eastern Markets," May 6, 2008, Gerson Lehman Group speaker sponsorship
- "Economics of Coal-Fired Generation," March 2007, Goldman Sachs private speaker sponsorship
- "Power Risk Management: Environmental Economics," 2007, Goldman Sachs private speaker sponsorship
- "Predicting Long-Term Energy Prices with OptQuest: The GenMetric Model," May 3, 2006, Crystal Ball User Conference
- "Using the Efficient Frontier," January 18, 2006, Internationally-broadcast Web Conference sponsored by Decisioneering
- "Building the Perfect Generation Portfolio," September 2005, Public Utilities Fortnightly
- "Finding the Efficient Frontier: Power Plant Portfolio Assessment," June 13, 2005, Crystal Ball User Conference
- "The Efficient Frontier and Power Plant Portfolio Analysis," September 2004, EPIS Electric Market Forecasting Conference
- "Power Asset Transactions: Regulatory Risks," June 24, 2004, Infocast Buying Selling & Investing in Energy Assets 2004
- "Power Generation Asset Valuation," June 17, 2004, Crystal Ball User Conference
- "Assessing Risk in a Changing Market," March 29, 2004, Platts Global Power Markets
- "Our Energy Future," January 14, 2004, NET 2004 Conference
- "Our Transmission Future," January 14, 2004, NET 2004 Conference
- "Models Matter: The Art of LMP," November 6, 2003, Platts Electric Market Design Conference
- "Risk Management Panel Discussion" Moderator, September 2002, EPIS Electric Market Forecasting Conference, Skamania, WA
- "Venture Capital" Panel Moderator, December 3, 2001, Strategic Research Institute Energy Investor's Summit
- "Leveraging AURORA: Modeling New Resource Development," November 13, 2001, EPIS Electric Market Forecasting Conference
- "Optimizing Emissions Compliance: Emerging Technologies & Multi-Pollutant Regulation," July 26, 2001, Coal-GEN 2001
- Letzelter, James C., Public Utilities Fortnightly, "The New Venture Capitalists: Utilities Go Shopping For Deals," December 2000
- "Power Plant Emissions: Modeling Market Implications," September 22, 2000, EPIS Electric Market Forecasting Conference
- "Emissions Modeling for Optimum Compliance," July 1999, Infocast SIP Call Conference
- Letzelter, James C., Public Utilities Fortnightly, "Surviving the SIP Call: Fossil Plant Economics Under NO_x Control," May 1, 1999

- "Managing Emission Limit Changes: Challenges & Opportunities," January 29, 1999, CBI Merchant Plant Conference
- Letzelter, James C., Power Finance & Risk, "The Impact of NO_x Limits on U.S. Energy Markets," January 11, 1999
- "Valuation of Electric Generating Assets," May 27, 1998, Gas Daily Conference
- Letzelter, James C. and Axelrod, Howard A., Resource Magazine, "Risk Analysis in Resource Planning," Summer 1992 issue

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

IN THE MATTER OF THE APPLICATION OF THE ARIZONA PUBLIC SERVICE COMPANY FOR A REQUEST TO APPROVE A FOUR CORNERS RATE RIDER AS DEFINED IN APPROVED SETTLEMENT AGREEMENT AT DECISION NO. 73183 TO ALSO INCLUDE AMORTIZATION OF RELATED DEFERRALS AUTHORIZED IN DECISION NO. 73130	DOCKET NO. E-01345A-11-0224

DIRECT

TESTIMONY

OF

DENNIS M. KALBARCZYK

CONSULTANT

ON BEHALF OF THE STAFF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 19, 2014

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Dennis M. Kalbarczyk. My business address is 910 Piketown Road, Harrisburg, Pennsylvania 17112.

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

A. I am the principal of Utility Rate Resources, and work frequently with the Liberty Consulting Group, Inc., ("Liberty"). Liberty has been engaged by the Utilities Division ("Staff") of the Arizona Corporation Commission ("ACC" or "Commission") in the review of the Arizona Public Service Company's ("APS" or "Company") application for approval of a Four Corners Rate Rider ("Rider"). This application was contemplated by two Commission Decisions: 1) Decision No. 73138 (May 24, 2012) which approved a settlement agreement in APS's last rate case providing for possible rate treatment related to any acquisition by APS of Southern California Edison's ("SCE") share of Four Corners Units 4 and 5; and 2) Decision No. 73130 (April 24, 2012) which authorized associated cost deferrals, as part of APS's application for authorization for the purchase of generating assets from SCE. In brief, the Rider would include the revenue requirement associated with APS's: (1) acquisition of the SCE interest in Four Corners Units 4 and 5; and (2) recovery of the cost deferrals authorized in Decision No. 73130.

Q. Have you prepared a detailed summary of your qualification?

A. Yes. Exhibit DMK-2 provides it.

Q. What is the purpose of your testimony?

A. I am addressing, on behalf of Staff, APS's revenue requirement request and the associated Rider designed to recover that revenue requirement, as submitted by APS witnesses Jeffrey B. Guldner and Elizabeth A. Blankenship. Mr. James Letzelter of Liberty addresses the prudence of the transaction and related issues on behalf of Staff.

II. INTRODUCTION AND BACKGROUND

Q. Briefly state your understanding of the nature of this proceeding.

A. In Decision No. 73183, the settlement agreement approved by the Commission provided for the rate case to be held open for the sole purpose of allowing APS to file a request, no later than December 31, 2013, for adjustment of its rates to reflect the proposed Four Corners transaction. On December 30, 2013, APS filed an application with the Commission, requesting an overall revenue increase of approximately $62,529,000, in order to recover the costs associated with its acquisition of the interest of SCE in Four Corners Units 4 and 5. APS also requests a revenue increase due to its acquisition of an auxiliary boiler, and associated operating costs not currently reflected in rates. The APS application also seeks recovery of costs associated with the closure and retirement of Units 1-3 and the removal of certain expenses currently being recovered through ACC-approved rates, but that will no longer be incurred as a result of these generating facility acquisitions. Mr. Guldner's testimony provides a general overview of the application and Commission Decision Nos. 73130 and 73183. Ms. Blankenship's testimony provides support for the development of the overall revenue requirement proposed by APS and for the associated change in rates.

Q. Please state your understanding of the requested change in rates.

A. APS seeks approval of an acquisition-related surcharge to be billed to its customers in addition to billing its currently approved retail rates. This Rider would consist of a 2.22 percent monthly surcharge to be applied to revenues billed under existing rates, effective as of July 1, 2014. Ms. Blankenship's testimony at Attachment EAB-9, Schedule 5, discusses the application of the proposed Rider. Mr. Guldner's testimony describes the typical bill impact by customer class, should the Rider be approved as filed.

III. SUMMARY OF RECOMMENDATIONS

Q. How did APS calculate the proposed revenue requirements?

A. APS based its request on the historic test year data used in its last rate case, making adjustments on a pro forma basis to reflect known and measurable changes to plant-in-service and accumulated reserves for depreciation to determine net book value. APS also included an acquisition adjustment, which it reflected in the value of rate base that it attributes to APS's acquired interest in Four Corners Units 4 and 5. These values are not reflected in APS's current rates. The sum of the net book value and the acquisition adjustment is the value that APS proposes to add to its rate base as the fair value of Units 4 and 5.

APS based its annual depreciation and amortized amounts for these two values upon a 24-year remaining life. APS is also seeking recovery of associated operating costs, and made adjustments on a pro forma basis to reflect known and measurable changes to the operating expenses associated with Units 4 and 5 that current rates do not reflect. APS also calculated costs associated with the closure and retirement of Units 1, 2, and 3. These costs comprise remaining book value and closing cost, which APS proposes to amortize over a 10-year period. The APS revenue requirement and surcharge calculation also considered changes in income taxes.

Q. Briefly explain your understanding of the deferrals authorized by the Commission in Decision No. 73130.

A. Commission Decision No. 73130 authorized an accounting order allowing APS to defer the non-fuel costs associated with APS's acquisition of SCE's interest in Units 4 and 5 and the retirement of Units 1-3. Decision No. 73130 at footnote 122, on page 37, described the "non-fuel costs" authorized for deferral as: depreciation, amortization of the acquisition adjustment, decommissioning costs, operations and maintenance costs, property taxes, final coal reclamation costs, the documented debt costs of acquiring SCE's interest in Units 4 and 5, and miscellaneous other costs. The footnote also referenced estimated Units 1-3 wind down costs that would be incurred between the acquisition date of Units 4 and 5 through 2016.

Q. Please summarize Liberty's overall review process.

A. Liberty undertook the following work tasks in reviewing APS's proposed revenue requirement and associated surcharge:

- Reviewing the testimony submitted with the application
- Reviewing supporting schedules and workpapers submitted with application
- Testing supporting schedules and workpapers for reasonableness and accuracy
- Reviewing and verifying the calculation of the revenue requirement
- Reviewing and verifying the calculation of the Rider
- Reviewing and verifying the impact on the overall rate of return before and after the Rider
- Reviewing the proposed Rider's structure and administration.

As part of our review and verification process, Liberty interviewed responsible representatives of APS, submitted more than 100 data requests, and conducted an on-site visit to test the accuracy and reasonableness of information supporting APS's calculation of the revenue requirement underlying the Rider.

Liberty was able to identify and verify the accuracy of all key elements comprising the $62,529,000 proposed revenue requirement and the proposed 2.22 percent monthly Rider surcharge.

Q. Does Liberty recommend approval of the $62.53 million revenue requirement and the 2.22 percent monthly Rider surcharge as-filed?

A. No. Liberty does not agree with APS's use of 8.33 percent as a fair value rate of return on rate base. APS included an 8.33 percent return on the proposed rate base value of Units 4 and 5.

Decision No. 73183 adopts a Fair Value Rate of Return ("FVROR") of 6.09 percent, which is applied to APS's fair value rate base. We consider that rate to be the proper determinant of the return on fair value rate base, which would include the acquisition adjustment.

Q. Describe the nature of, reasons for, and amount of the acquisition adjustment proposed by APS.

A. APS proposes to include a $255 million acquisition adjustment, which reflects the premium the Company paid above the net book value of the asset acquired.[1] In our experience, traditional ratemaking generally does not allow inclusion of acquisition adjustments as a rate base element when determining an overall revenue requirement.

The settlement agreement adopted in Decision No. 73183 did not expressly address the ratemaking treatment for the acquisition adjustment proposed by APS. Decision No. 73130, however, did acknowledge the possibility for recognizing an acquisition adjustment in rates.

[1] A net rate base value of $127,629,000 results when associated Asset Retirement Obligations and Coal Reclamation costs of $34,123,498 and $92,950,926, respectively, are removed from rate base consideration, as APS appropriately reflected in its Schedule 4.b, Column C of Ms. Blankenship's testimony.

Q. What is your understanding of the ACC's approach with respect to allowing recovery of acquisition adjustments?

A. It is my understanding that the Commission includes acquisition premiums in rate base only under limited extraordinary circumstances. Further, the Commission has determined in the past that, "if a party believes that an acquisition adjustment is necessary to bring about an efficiency-enhancing transaction, it should come to the Commission and establish at the very least: (1) the transaction will not likely occur but for an acquisition adjustment; (2) that operational efficiencies will likely result from the transaction; and (3) in a subsequent rate case, that operational efficiencies resulted from the transaction."[2]

Q. Does Liberty believe that the circumstances of the Four Corners transaction meet these criteria?

A. Yes. We believe that the transaction reasonably satisfies these criteria, and makes rate recognition of the acquisition premium appropriate.

Decision No. 73130 authorized APS to proceed with the transaction. APS explained that exceptional circumstances warranted an exemption from the "self-build" moratorium imposed by the Commission in Decision No. 67744 (April 7, 2005). APS also stated that the transaction would provide good value for customers and that it would require a significant investment. APS requested Commission approval to defer costs related to the transaction for recovery as part of a subsequent proceeding. The Commission determined that it was reasonable to authorize such a deferral, subject to later examination for prudence, errors, or inappropriate application of the requirements of Decision No. 73130.

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[2] See In the Matter of the Joint Application of Black Mountain Gas Company and SemStream Arizona Propane, L.L.C. for Approval of the Transfer of the Black Mountain Page Division and Related Assets to SemStream Arizona Propane, L.L.C., Consolidated Docket Nos. G-03703A-06-0694 and G-20471A-06-0694.

Our review has concluded that the transaction was reasonable, prudent, timely, and remains expected to provide good value for customers, and did require significant investment. We also believe that it is reasonable to conclude that the ability to recover actual costs (which include the acquisition premium) reflects a necessary and proper inducement for entry into a transaction that has value for customers.

We therefore believe that the unique circumstances of the acquisition, the results that it will provide for customers, and Decision No. 73130's prior recognition of the potential for rate recognition of the acquisition adjustment combine to warrant inclusion of the acquisition premium in the proposed Rider.

Q. What then, does Liberty recommend with respect to the acquisition adjustment?

A. Given Liberty's conclusion that the acquisition was reasonable, prudent, and appropriately timed, we believe that the acquisition adjustment should be included in rate base, at a 6.09 percent FVROR. This approach will require a downward adjustment to the jurisdictional revenue requirement in the amount of $8,151,604 to $54,377,396 from $62,529,000 million and, would reduce the surcharge rate by 0.29 of a percentage point, reducing the proposed monthly surcharge rate to 1.93 percent.

Q. Are there unique circumstances associated with this Acquisition Adjustment that should be considered by the Commission?

A. Yes, to wit:

- Significant policy changes in another state (California) presented APS with a need to respond to uncertainties about the future viability of its interests in a fairly short period of time;

- Environmental requirements applicable across the five Four Corners units caused APS to face significant compliance costs for units with differing economic characteristics and costs (and therefore value to customers);
- The circumstances also provided APS with a unique opportunity to rearrange its ownership position through unit retirements and share acquisitions outside the traditional self-build and market solicitation approaches;
- Delays in pursuing the non-traditional approach made available to APS would risk higher fuel and purchased power costs for customers, and produce an ownership structure whose members had differing interests and objectives for a group of assets that APS still viewed as a long term contributor to its system;
- The non-traditional opportunities available to APS enabled the company to make an acquisition on terms estimated to provide substantial positive value to customers when compared with the available alternatives.

Q. Although this is an Acquisition Adjustment per the National Association of Regulatory Utility Commissioners and/or GAAP, does Staff believe this Acquisition Adjustment gives rise to different considerations than when Utility A purchases all or part of Utility B at more than book value and Utility A will take over service of Utility B's customers?

A. Other than that both are classified as an Acquisition Adjustment, they should not be considered the same. APS's purchase in this case is simply a purchase of additional capacity, not of a service area or customers that it will serve. This purchase should be considered in light of the factors previously discussed. In the case of Utility A purchasing Utility B for more than book value, the Commission should consider the benefits, if any, that the customers of Utility B will receive in exchange for being served by Utility A if Utility A will be asking for an increase in rates simply to cover the added cost of the Acquisition Adjustment.

Q. Why does Liberty disagree with APS's proposed return component applicable to the rate base component of the proposed Rider?

A. The result of Decision No. 73183 was the application of a FVROR of 6.09 percent to APS's fair value rate base. We thus believe that this rate comprises the appropriate one for application to APS's Four Corner's fair value rate base when determining the surcharge rate.

Ms. Blankenship's testimony at page 8 states that the assets APS has acquired were initially recorded at fair value. She observed that the "fair value" she is referring to is an accounting "fair value" rather than "fair value" rate base as typically discussed in Arizona rate cases. Nevertheless, she acknowledges that the two measures are mathematically equivalent in this case.

Schedule 4, Line 6, of Ms. Blankenship's testimony shows that the increase to APS's required operating income ($18,128,500) is the same under all three methods for measuring rate base (Original Cost, RCND, and Fair Value). This amount is based upon the $217,629,000 increased rate base value multiplied by a constant 8.33 percent rate of return. APS's responses to data requests indicated minor changes to the as-filed rate base values. The changes produce a slightly lower adjusted rate base value of $217,352,003.

Applying the fair value rate of return of 6.09 percent on APS's fair value rate base produces required operating income of $13,236,737 ($217,352,003 x 6.09 percent), which is $4,891,763 less than the $18,128,500 sought by APS. We therefore consider APS's proposed revenue requirement to be overstated by approximately $8,151,604 ($4,891,763 times the 1.6566 tax gross-up factor). Dividing the approximately $8,151,604 by the $2,810,916,000 of 2010 Base Revenues (from line 11 of Schedule 4) produces a 0.29 of a percentage point reduction to the APS-proposed 2.22 percent monthly surcharge. A monthly surcharge of 1.93 percent results from this adjustment.

Q. What is your view of the remaining elements of the revenue requirement calculation proposed by APS?

A. Liberty generally found that APS has accurately calculated and appropriately supported the other revenue requirement elements it has proposed. There are, however, some exceptions. APS has provided estimates for some cost items included in the Four Corners Units 4 and 5 revenue requirement. Liberty also understands that some costs related to the closure and retirement of Units 1-3 may increase if the proceeding is not finalized by the proposed effective date of July 1, 2014.

Liberty has requested that APS continue to provide updates to its cost estimates as actual data becomes available. Liberty believes it is proper and important to update the surcharge rate calculation as more current data becomes available during the remainder of this proceeding.

IV. RATE BASE ELEMENT DETAILS

Q. What are the major rate base elements APS has claimed in this proceeding?

A. As shown in the table below, APS's rate base claim includes three major elements: a) acquisition of SCE's interest in Units 4 and 5 having an approximate $52 million net book value (original cost value less accumulated depreciation as of December 31, 2013); b) $8,623,930 for auxiliary boiler; and c) a $254,787,014 acquisition adjustment to reflect the amount paid that exceeds the net book value of the asset acquired.[3]

For the reasons discussed earlier, Liberty believes that the Commission should recognize the acquisition adjustment as a rate base value in this proceeding. The revenue requirement

[3] The table reflects an adjusted rate base value of $217.352 million based upon APS's data request responses. Those responses change the as-filed $217.629 million rate base value by $277,000. APS's data request responses further indicated that the as-filed operating expenses of $19.617 million would be reduced to $19.588 million (for a difference of approximately $29,000).

determination, however, should be based upon the FVROR of 6.09 percent, rather than APS's proposed 8.33 percent.

Four Corners Pro Forma Rate Base	Amount
Plant in Service:	
Acquired Plant	$605,364,014
Acquisition Adjustment	254,787,393
Auxiliary Boiler-Plant	8,623,930
Auxiliary Boiler-Startup Steam Supply	2,694,978
Deferred Cost-O&M Expense (12/30/13 - 6/30/14)	38,252,000
Deferred Cost-Depr & Amort Expense (12/30/13 - 6/30/14)	4,694,000
Deferred Cost-Property Taxes (12/30/13 - 6/30/14)	3,208,000
Deferred Cost-Debt Return (12/30/13 - 6/30/14)	4,533,268
Total Plant in Service	**$922,157,582**
Accumulated Depreciation:	
Acquired Plant	$-539,326,651
SCE Additional Reserve (9/1/13 - 12/31/13)	-14,738,975
APS Additional Reserve (1/1/14 - 6/30/14)	-1,088,271
Cost of Removal Reserve	916,566
Boiler Depreciation (5/1/13 - 6/30/14)	-286,000
Total Accumulated Depreciation	**$-554,523,331**
Plus Deferred Debits:	
Plant, Materials & Operating Supplies	$4,468,827
Total Deferred Debits	**$4,468,827**
Less Deferred Credits:	
Deferred Taxes	$-20,026,580
Asset Retirement Obligation Liability	-34,123,498
Other Deferred Credits (Including Coal Reclamation)	-92,950,926
Total Deferred Credits	**$-147,101,004**
Total Company Rate Base	**$225,002,074**
APS Allocation Rate	96.60%
APS Rate Base	**$217,352,003**

We are still in the process of examining the potential removal from base rates of any rate base costs associated with Units 1-3.

V. OTHER REVENUE REQUIREMENT REVIEW DETAILS

Q. How did APS determine the $62.53 million annual revenue deficiency and the resulting 2.22 percent monthly surcharge?

A. The Company's filing computed the incremental Rate Base impact of the Four Corners acquisition to be approximately $217,629,000. The Company also computed the incremental annual operating expenses associated with operating the Four Corners acquisition to be $19,617,000. To compute the $62,529,000 revenue deficiency, the Company applied its proposed 8.33 percent rate of return and the revenue conversion factor approved by the Commission in the last rate case. The Company computed the 2.22 percent monthly surcharge by dividing the $62,529,000 revenue requirement by the 2010 Adjusted Base Revenues from its last rate case.

As I noted earlier, APS's as-filed $217,629,000 and $19,617,000 of rate base and operating expense values should be reduced to $217,352,003 and $19,587,962, respectively based upon information provided in responses to data requests. We also recommend that the required revenue requirement be based upon the Commission authorized 6.09 percent FVROR. The table below provides a summary of the revenue requirement and surcharge rates based upon APS's as-filed amounts and the updated revenue requirement needs when considering the slightly lower operating expenses and required return on the lower rate base value at the Commission authorized 6.09 percent FVROR. Liberty's proposed adjustments produce a $54,377,396 revenue requirement and 1.93 percent monthly surcharge rate. These adjustments generate reductions of $8,151,604 to the revenue requirement and 0.29 of a percentage point to the monthly surcharge rate.

Item	APS As-Filed Pro Forma Adjustments	Liberty Proposed
Adjusted Rate Base	$217,629,000	$217,352,003
Adjusted Operating Income	-19,617,000	-19,587,962
Current Rate of Return	-9.01%	-9.01%
Rate of Return	8.33%	6.09%
Required Return	$18,128,500	$13,236,737
Operating Income Deficiency	$37,745,500	$32,824,699
Gross Revenue Conversion Factor	1.6566	1.6566
Total Revenue Deficiency	**$62,529,000**	**$54,377,396**
2010 Adjusted Base Revenues	$2,810,916,000	$2,810,916,000
Percentage Rate Surcharge	**2.22%**	**1.93%**
Change in Revenue Deficiency		**($8,151,604)**
Change in % from As-Filed		**(0.29%)**

Q. Please explain how the Company accounted for the Four Corners acquisition on its books.

A. The book value (cost less accumulated depreciation) of the acquired plant is approximately $60,778,500 (which includes $8,623,930 for the auxiliary boiler). In addition to this amount, the Company added approximately $12,963,000 for the cost of other assets related to the Four Corners acquisition. The Company then deducted approximately $147,355,000 for the estimated cost of assumed liabilities (*e.g.*, asset retirement obligations, coal reclamation, accounts payable) related to the Four Corners acquisition. The table below shows that this calculation produces a net book value for all recorded assets and liabilities of approximately $-73,613,500. The cash price that the Company has paid for SCE's share of Units 4 and 5 is approximately $181,127,000. Therefore, the difference between the cash price paid of $181,127,000 and the book value of the acquired assets and liabilities of $-73,613,500 represents an acquisition adjustment of approximately $254,787,393, which the next table shows.

Item	Four Corners Accounting
Plant Net Book Value (Cost less Accumulated Depreciation)	$60,778,500
Plus Materials & Supplies, Prepaid Expenses	12,963,000
Less Assumed Liabilities and Deferred Credits	-147,355,000
Net Book Value of all Assets & Liabilities	**$-73,613,500**
Acquisition Adjustment	$254,741,000
Cash Price Paid	**$181,127,000**

Q. **Was Liberty able to verify the cost components of the acquisition of Units 4 and 5 and of the retirement of Units 1-3?**

A. Yes. Liberty traced all costs associated with the acquisition of Units 4 and 5 to the source records of SCE and to the books of APS. Liberty was also able to trace the costs associated with the retirement of Units 1, 2, and 3 to APS's books and records.

Q. **Does Liberty consider the amortization rates proposed by the Company reasonable?**

A. Yes. The Company has proposed to amortize the cost deferrals authorized in Decision No. 73130 over a 10-year period. Liberty believes that a 10-year period properly balances the cost impact of these items with the financing costs. Liberty therefore found the 10-year amortization period reasonable for amortizing these costs.

The Company has also proposed to amortize the decommissioning and reclamation costs of Units 4 and 5 over a 24-year period coinciding with the expected life of the plant. Liberty considers matching the amortization period with the expected production period reasonable for amortizing these costs.

Q. Will approval of the Four Corners surcharge allow the Company to earn beyond its authorized rate of return set by the Commission in the last rate case?

A. No, based on our analysis of the matter. Liberty has reviewed the Company's earnings reports for the past three years. APS's effective rate of return is below its authorized rate of return. The proposed Four Corners surcharge only allows it to earn a return on the newly acquired assets at the same return approved in the last rate case. The surcharge by itself should therefore not allow the Company to exceed its authorized rate of return.

VI. FOUR CORNERS ADJUSTMENT RIDER

Q. Does Liberty have any concerns regarding the language of the Four Corners Tariff Rider proposed by the Company?

A. Yes. The tariff contains no provision for suspension, should APS earn beyond its authorized rate of return. However, the surcharge Rider is only intended to remain in effect until the Company's next rate case, which may be filed in 2015. Therefore, the safeguards normally found in this type of tariff may not be required here. Nevertheless, at a minimum, the tariff language should be amended to make explicit that the Four Corners Rider shall only remain in effect until the Company's next rate case, if the intention was to only utilize the Rider until the impact of the acquisition would be reflected in base rates.

Q. Does that conclude your direct testimony?

A. Yes, it does.

Direct Testimony of Dennis M. Kalbarczyk
Docket No. E-01345A-11-0224
Exhibit DMK-1

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTY-SIXTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
FOUR CORNERS RATE RIDER
DOCKET NO. E-01345A-11-0224
APRIL 8, 2014

Staff 36.20: Refer to the Company's Workpaper EAB-3, Page 2. Please provide the source and support for the property tax rate of 2.451%.

Response: The 2.451% property tax rate was an estimate of the average composite property tax rate for New Mexico at the time the schedule was prepared. APS's actual 2013 New Mexico Composite Property Tax Rate was 2.434%. See APS15312 for the calculation and support for the actual rate of 2.434%. APS will reflect this modification its Rebuttal Testimony.

Witness: Beth Blankenship

Arizona Public Service Company

New Mexico - 2013 Compostie Property Tax Rate

			[A]	[B] / [A]	[B]
Tax Year	**Full Value**	**Tax Value %**	**Taxable Value**	**Tax Rate**	**Amount Due**
2013	200,110,328	33.33%	66,703,376	2.434%	1,623,581

41G87403 MHG4052 1970 NEW 10 X 55 FOUR CORNERS POWER PLANT P0085001

2013 TAX BILL

SAN JUAN COUNTY TREASURER
100 S. OLIVER, STE 300
AZTEC, NEW MEXICO 87410
OFFICE HOURS:
7:00 am to 5:30 pm
MON Thru THUR
CLOSED FRIDAY'S
Phone: **(505) 334-9421**
On-line payment: go to www.sjcounty.net
Credit cards not accepted over the phone.
Drop box located on east side of building for your convenience

51702 T166 P1 ******AUTO**ALL FOR AADC 852
ARIZONA PUBLIC SERVICE CO   00007159
1622
PO BOX 53999
PHOENIX AZ 85072-3999

☐ IF THIS BOX IS CHECKED, YOUR MORTGAGE COMPANY HAS REQUESTED YOUR TAX BILL FOR PAYMENT. PLEASE KEEP THIS BILL FOR YOUR RECORDS.

TAX BILL NUMBER: 00007159

THE FIRST HALF PAYMENT IS DUE: November 10, 2013
TO AVOID INTEREST AND PENALTY CHARGES, PAYMENT MUST BE POSTMARKED BY: December 10, 2013

NR PROPERTY CLASSIFICATIONS
RS = RESIDENTIAL NR = NON-RESIDENTIAL

THE SECOND HALF PAYMENT IS DUE APRIL 10, 2014
TO AVOID INTEREST AND PENALTY CHARGES, PAYMENT MUST BE POSTMARKED BY: MAY 10, 2014.

PROPERTY	FULL VALUE	TAXABLE VALUE
LAND		
IMPROVEMENTS		
PERSONAL PROPERTY		
MANUFACTURED HOMES	1866	622
LAND / IMPROVEMENTS		
LESS EXEMPTIONS		
TOTALS	1866 (B)	622 (C)

AGENCIES	TAX RATE	AMOUNT DUE
STATE	1.3600	0.85
COUNTY	8.5000	5.29
SCHOOL	9.3180	5.80
CITY	0.0000	0.00
COLLEGE	5.1000	3.17
TOTAL TAX RATE	24.2780	15.11

PRIOR TAXES, IF ANY, MUST BE PAID BEFORE ACCEPTING CURRENT YEAR PAYMENT.

YEAR	BILL NO.	TAX	INTEREST	PENALTY	AMOUNT DUE

Amount Due
Σ(A)'s = 1,623,581

Full Value
Σ(B)'s = 200,110,328

Taxable Value
Σ(C)'s = 69,703,376

EQUIPMENT FOR ELECTRIC GEN

2013 TAX BILL

SAN JUAN COUNTY TREASURER
100 S. OLIVER, STE 300
AZTEC, NEW MEXICO 87410
OFFICE HOURS:
7:00 am to 5:30 pm
MON Thru THUR
CLOSED FRIDAY'S
Phone: **(505) 334-9421**
On-line payment: go to www.sjcounty.net
Credit cards not accepted over the phone.
Drop box located on east side of building for your convenience

51704 T166 P1 ******AUTO**ALL FOR AADC 852
ARIZONA PUBLIC SERVICE CO 00085001
STATION 9505
PO BOX 53999
PHOENIX AZ 85072-3999

☐ IF THIS BOX IS CHECKED, YOUR MORTGAGE COMPANY HAS REQUESTED YOUR TAX BILL FOR PAYMENT. PLEASE KEEP THIS BILL FOR YOUR RECORDS.

TAX BILL NUMBER: 00085001

THE FIRST HALF PAYMENT IS DUE: November 10, 2013
TO AVOID INTEREST AND PENALTY CHARGES, PAYMENT MUST BE POSTMARKED BY: December 10, 2013

NR PROPERTY CLASSIFICATIONS
RS = RESIDENTIAL NR = NON-RESIDENTIAL

THE SECOND HALF PAYMENT IS DUE APRIL 10, 2014
TO AVOID INTEREST AND PENALTY CHARGES, PAYMENT MUST BE POSTMARKED BY: MAY 10, 2014.

PROPERTY	FULL VALUE	TAXABLE VALUE
LAND		
IMPROVEMENTS		
PERSONAL PROPERTY		
MANUFACTURED HOMES		
LAND / IMPROVEMENTS		
CENTRAL ASSESSED	198116406	66038736
LESS EXEMPTIONS		
TOTALS	198116406	66038736

AGENCIES	TAX RATE	AMOUNT DUE
STATE	1.3600	89,812.68
COUNTY	8.5000	561,329.26
SCHOOL	9.3180	615,348.94
CITY	0.0000	0.00
COLLEGE	5.1000	336,797.55
TOTAL TAX RATE	24.2780	1,603,288.43

PRIOR TAXES, IF ANY, MUST BE PAID BEFORE ACCEPTING CURRENT YEAR PAYMENT.

YEAR	BILL NO.	TAX	INTEREST	PENALTY	AMOUNT DUE

2013 TAX BILL

THIS TAX BILL IS THE ONLY NOTICE YOU WILL RECEIVE!
PLEASE CHECK NAME, ADDRESS AND PROPERTY DESCRIPTION CAREFULLY. IF INCORRECT, NOTIFY ASSESSOR'S OFFICE.

Parcel Number: 2-075-590-000-000

Legal: REAL ESTATE, PLANT IN SERVICE, CWIP, SEE CORPORATES
PAGES 5 & 6

ERNEST C. BECENTI JR
McKINLEY COUNTY TREASURER
207 WEST HILL AVENUE, SUITE 101
GALLUP, NEW MEXICO 87301-4715

ARIZONA PUBLIC SERVICE CO.
PO BOX 53999 STATION 9505
PHOENIX AZ 85072-3999

T71 P1 99 RN: 007
AC: C207559

TAXABLE VALUE IS 33 1/3% OF FULL VALUE

	FULL VALUE	TAXABLE VALUE
CORP - PUB. UTI	1,371,136	457,045
NET VALUE		457,045

PRINT THIS ACCOUNT NO. ON YOUR CHECK

ACCOUNT NO.: C207559

TOTAL AMOUNT: $ 15,252.52

FIRST HALF: $ 7,626.26

SECOND HALF: $ 7,626.26

IT IS THE RESPONSIBILITY OF THE PROPERTY OWNER TO INSURE PROPERTY TAXES ARE PAID. OWNERS WITH MORTGAGES SHOULD CONTACT LENDER TO DETERMINE RESPONSIBILITY FOR PAYMENT OF PROPERTY TAX.

INTEREST IS 1% PER MONTH ON DELINQUENT TAXES, IN ADDITION A 1% PENALTY WILL ALSO BE CHARGED ON EACH HALF.

DELINQUENT DATES

YEAR	TAX AMOUNT	INTEREST	PENALTY	TOTAL TAXES

PRIOR TAXES, IF ANY MUST BE PAID BEFORE ACCEPTING CURRENT YEAR PAYMENT.

HOW YOUR TAX DOLLAR IS BEING DISTRIBUTED

TAX RATE - $ PER THOUSAND		TAX DOLLAR AMOUNT
STATE DEBT SERVICE	1.360	621.58
COUNTY OPERATIONAL-NON RE	11.850	5,415.99
SCHOOL DISTRICT OPERATION	0.500	228.52
SCHOOL DIST CAP IMPROVEME	2.000	914.09
GALLUP BRANCH COLLEGE - N	2.000	914.09
REHOBOTH CHRISTIAN HOSPIT	3.000	1,371.14
UNM GALLUP SPECIAL VOCATI	1.000	457.05
COUNTY DEBT SERVICE	0.000	0.00
SCHOOL DISTRICT DEBT SERV	8.332	3,808.10
GALLUP BRANCH DEBT SERVIC	3.330	1,521.96

ROAD 6675 FRUITLAND NM 87416 NR 22NR

EQUIPMENT FOR WATER ASSOCI
ATIONS

APS15312
Page 5 of 5

2013 TAX BILL

SAN JUAN COUNTY TREASURER
100 S. OLIVER, STE 300
AZTEC, NEW MEXICO 87410
OFFICE HOURS:

CLOSED FRIDAY'S
Phone: **(505) 334-9421**
On-line payment: go to www.sjcounty.net

ARIZONA PUBLIC SERVICE CO
PO BOX 53940
PHOENIX AZ 85072-3940

IF THIS BOX IS CHECKED, YOUR MORTGAGE COMPANY HAS REQUESTED YOUR TAX BILL FOR PAYMENT. PLEASE KEEP THIS BILL FOR YOUR RECORDS.

Drop box located on east side of building for your convenience

TAX BILL NUMBER **8005415**

THE FIRST HALF PAYMENT IS DUE:
TO AVOID INTEREST AND PENALTY CHARGES, PAYMENT MUST BE POSTMARKED BY:

NR PROPERTY CLASSIFICATIONS
RS = RESIDENTIAL NR = NON-RESIDENTIAL

THE SECOND HALF PAYMENT IS DUE APRIL 10, 2014
TO AVOID INTEREST AND PENALTY CHARGES, PAYMENT MUST BE POSTMARKED BY: MAY 10, 2014.

PROPERTY	FULL VALUE	TAXABLE VALUE
LAND		
IMPROVEMENTS		
PERSONAL PROPERTY	620920	206973
MANUFACTURED HOMES		
LAND / IMPROVEMENTS		
LESS EXEMPTIONS		
TOTALS	620920	206973

AGENCIES	TAX RATE	AMOUNT DUE
STATE	1.360	281.48
COUNTY	8.500	1,759.27
SCHOOL	9.318	1,928.57
CITY	0.000	0.00
COLLEGE	5.100	1,055.56
TOTAL TAX RATE	24.278	5,024.88

PRIOR TAXES, IF ANY, MUST BE PAID BEFORE ACCEPTING CURRENT YEAR PAYMENT.

YEAR	BILL NO.	TAX	INTEREST	PENALTY	AMOUNT DUE

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTY-SIXTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
FOUR CORNERS RATE RIDER
DOCKET NO. E-01345A-11-0224
APRIL 8, 2014

Staff 36.22: Refer to the Company's Workpaper EAB-4, Page 2. Please provide the source and support for the 5.25% rate used as the marginal cost of debt.

Response: In Workpaper EAB-4, page 2 the Company used the 5.25% rate based on the anticipated forecasted interest rate of the Company's next bond financing. APS issued debt at a 4.7% yield on January 7, 2014 to fund the purchase of SCE's share of Units 4 and 5 of Four Comers. APS is currently deferring costs at 4.7%. When APS updates the deferral calculation in Rebuttal Testimony the 4.7% debt rate will be used.

Witness: Beth Blankenship

Dennis M. Kalbarczyk
Educational and Professional Experience

I am the principal of Utility Rate Resources, and work frequently with the Liberty Consulting Group, Inc., ("Liberty").

I graduated in 1971 with a Bachelor of Science Degree in Accounting from Husson College (now Husson University), in Bangor, Maine. In 1969, I received an Associate in Art Degree in Accounting from Strayer College (now Strayer University), in Washington D.C. I am the principal of Utility Rate Resources, which was formed in October 1990. I have prepared over fifty rate case filings, which have included almost all key aspects of the ratemaking process, such as revenue requirement elements (revenues, operation & maintenance expenses, administrative and general expenses, taxes, depreciation and amortization expenses, and rate base valuation), rate of return, cost of service, rate design, and, other tariff rate design and rate rider matters.

I was employed by Drazen-Brubaker & Associates, Inc. from March 1988 to September 1990. I presented testimony and prepared financial statements necessary for applications for Certificates of Public Convenience before the Pennsylvania Public Utility Commission ("PA PUC"). Additionally, I was responsible for the preparation and filing of rate cases, and testified on behalf of utilities under PaPUC regulation. Prior to March 1988, I was employed by Metropolitan Edison Company, a subsidiary of First Energy, formerly GPU Energy and General Public Utilities. I spent three years in the utility's Rate Revenue Requirement Department as a Senior Financial Analyst. My responsibilities included the preparation, review, and analysis of financial reports, budgets, and management responsibility for rate and regulatory matters before the PaPUC.

From 1975 through 1985, I was employed by the PaPUC, serving primarily in the performance of financial and operations audits and in rate proceedings. I testified on revenue requirements matters in nearly all the major electric rate cases during my time at the PaPUC, and performed audits of electric, gas, and water companies for compliance with Commission regulations in the areas of energy cost, coal and gas contracts, and affiliated service contracts. I testified in Energy Cost Rate, Gas Cost Rate, and Coal Compliance proceedings. I actively participated in developing the Commission's first set of regulations on Fuel Procurement Policy and Procedures, Tariffs and Procedures on Energy Cost Rates for electric companies and Gas Cost Rates for gas companies, and designed computerized procedures for electric utilities to report fossil fuel purchases to the PaPUC. From 1972 to 1975 I held progressive degrees of responsibilities with Certified Public Accounting firms performing accounting, auditing and tax preparation duties.

I have specialized in the area of utility rate and economic consulting related to the financial aspects of public utility rates and regulation. My work has encompassed rate case filings, certificates of public convenience, expert testimony, and financial applications for funding by the Pennsylvania Infrastructure Investment Authority. I have participated in regulatory and legal proceedings concerning investor-owned and municipal utilities, have testified before governmental agencies and courts, and have represented utilities as well as consumers of utility services.

Since 2002, I have been providing senior level consulting services to Liberty, participating in an audit of electricity distribution service costs for inclusion in revenue requirement before the Illinois Commerce Commission, and serving as a team member on focused audits (for the New Jersey Board of Public Utilities) addressing financing, accounting, and affiliate charges of National Utilities Inc. (Elizabethtown Gas), South Jersey Gas, and New Jersey Natural Gas. I participated in Liberty's examinations of fuel adjustment mechanism costs and issues for staffs of the Arizona

Corporation Commission ("ACC") and the Nova Scotia Utility and Review Board ("NSUARB"). I also participated in Liberty's engagements to assist ACC Staff in the review of AEPCO's and the Southwest Transmission Cooperative, Inc. ("SWTC") applications for a general rate increase in the proceedings at Docket Nos. E-01773A-09-0472 and E-04100A-09-0496 pertaining to cost of service and rate design matters, respectively and testified to same. More recently in 2013, I assisted ACC Staff in the review of AEPCO's and SWTC's application for a general rate case filing in the proceedings at Docket Nos. E-01773A-12-0305 and E-04100A-12-0353 and I presented testimony pertaining to revenue requirement, and cost of service and rate design matters, respectively. I also participated with Liberty in Nova Scotia Power Incorporated's last two general rate increase filings, where I testified about revenue requirement matters.

I have testified in more than 70 rate and regulatory matters on behalf of state regulatory commissions, utilities, municipal authorities, and various consumer groups.

EXHIBIT
S-3
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

IN THE MATTER OF THE APPLICATION OF THE ARIZONA PUBLIC SERVICE COMPANY FOR A REQUEST TO APPROVE A FOUR CORNERS RATE RIDER AS DEFINED IN APPROVED SETTLEMENT AGREEMENT AT DECISION NO. 73183 TO ALSO INCLUDE AMORTIZATION OF RELATED DEFERRALS AUTHORIZED IN DECISION NO. 73130	DOCKET NO. E-01345A-11-0224

SURREBUTTAL

TESTIMONY

OF

DENNIS M. KALBARCZYK

CONSULTANT

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 21, 2014

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Dennis M. Kalbarczyk. My business address is 910 Piketown Road, Harrisburg, Pennsylvania 17112.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I previously submitted direct testimony on behalf of the Utilities Division ("Staff") of the Arizona Corporation Commission ("ACC" or "Commission") regarding the application of Arizona Public Service Company ("APS" or "Company") for approval of a Four Corners Rate Rider ("Rider") in this proceeding. My direct testimony addressed the appropriate calculation of the Rider as it relates to: (1) the rate base and expense effects associated with APS's acquisition of the Southern California Edison ("SCE") interest in Four Corners Units 4 and 5, (2) the rate base and expense effects associated with the retirement of Units 1-3; and (3) recovery of the cost deferrals authorized in Decision No. 73130.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to reply to rebuttal testimony of APS witnesses Jeffrey B. Guldner, Leland R. Snook and Elizabeth Blankenship regarding calculation of the Four Corners Rider; and to the rebuttal testimony of APS witness Snook, Walmart witness Steve W. Chriss and witness Kevin C. Higgins, who presents testimony on behalf of Freeport-McMoRan Copper & Gold Inc. ("Freeport-McMoRan"), Arizonans for Electric Choice & Competition ("AECC"), Noble Americas Energy Solutions ("Noble") and The Kroger Company ("Kroger"), regarding a rate design issue involving application of the Four Corners Adjustment Schedule to AG-1 customers. Finally, I will also comment on the updated revenue requirement and surcharge rate calculation provided by Ms. Blankenship.

Q. Do you agree with Mr. Guldner that there is primarily one significant issue in dispute

regarding the calculation of the Four Corners Rider?

A. Yes, that appears to be the case. APS advocates the use of the Weighted Average Cost of Capital ("WACC") of 8.33 percent as the return on fair value rate base; Staff advocates the use of the Fair Value Rate of Return of 6.09 percent as set forth in Section 5 of the Settlement Agreement approved by the Commission in Decision No. 73183; and the Residential Utility Consumer Office ("RUCO") recommends the use of the incremental cost of debt of 4.725% as the appropriate return.

Q. What difference in revenue requirement do these three different positions produce?

A. Ms. Blankenship summarizes the effects of the APS, Staff and RUCO positions on page 4 of her rebuttal testimony. APS's position results in an increase of $65.44 million; Staff's position results in an increase of $57.05 million; and RUCO's position results in an increase of $49.20 million. So, the Staff's proposal results in a revenue reduction of $8.39 million to APS's updated revenue requirement and RUCO's proposal results in a $16.24 million revenue reduction.

II. DISCUSSION OF ISSUES

Issue Relating to the Appropriate Rate of Return

Q. Have you reviewed the APS rebuttal testimony and proposed recommendations related to the appropriate rate of return?

A. Yes. APS's witnesses reject my proposed use of the FVROR of 6.09 percent, which is specifically set forth in Section 5 of the Settlement approved by the Commission in Decision No. 73183. The APS witnesses continue to recommend application of the 8.33 percent WACC to APS's fair value rate base. APS witnesses Blankenship, Guldner, and Snook address this matter. Referring to Section 10.2 of the Settlement, Mr. Snook (Rebuttal at p. 3) states that use of the 6.09% return on rate base "ignores the Settlement's express intent that the Rate Rider reflect the 'rate base and expense' effects of the Four Corners acquisition." I do not agree. It is well recognized in public utility setting that required revenues of the firm are equal to its rate base times its rate of return plus expenses. In this case, the Settlement contemplates changes to rate base and expenses in recognition of APS's acquisition of SCE's interest in Four Corners units 4 and 5. I believe that the rate base and expense effects of the acquisition have all been appropriately recognized. What APS appears to seek is a change to the third part of the formula as well, the rate of return, which was not contemplated in Section 10.2 of the Settlement.

Q. Doesn't Mr. Snook argue that FVROR is an output of a formula whose components will change with rate base additions or subtractions?

A. Yes. Mr. Snook argues that FVROR is simply the mechanical output of a formula whose components will change with rate base additions or subtractions. Thus, he opines that the FVROR must be recalculated, which here would produce equivalent FVRORs and WACCs; *i.e.*, 8.33 percent. He also argues that applying the 6.09 percent FVROR would contravene Section 5 of the Settlement Agreement. There are several flaws with this position, which I discuss below.

Q. What are those flaws?

A. Rather than a rate base issue, Staff's original testimony in this docket viewed the derivation of the FVROR as a financing and related capital structure issue. See Ralph Smith Direct Testimony, Attachment RCS-2, page 12 of 40. Thus, the addition of an asset should not necessarily mean that the WACC or FVROR must change to reflect each individual asset addition. If such a recalculation were desired, then all elements of the FVROR analysis should be reconsidered.

Q. What other problems do you see with Mr. Snook's position?

A. The Commission approved a Settlement Agreement in this case. The Agreement provides for a FVROR of 6.09 percent. I do not believe that recalculations are required for purposes of developing the appropriate FVROR or that a failure to do so contravenes Section 5 of the Settlement Agreement. To the contrary, recalculating the FVROR (to adopt a FVROR other than 6.09 percent) would appear to cancel the result achieved through Section 5 of the Settlement Agreement. That provision simply and clearly states that it adopts a fair value rate of return of 6.09 percent.[1]

Simply put, the 6.09 percent FVROR is not set forth as a value that results from a rote calculation, but as the appropriate fair value rate of return duly authorized under the Settlement Agreement. If one accepted Mr. Snook's contention that fair value rate of return is in all cases simply the by-product of a mathematical formula where the Commission does not have the ability or discretion to structure a return that is fair in any given case, the significant discretion afforded the Commission would be severely limited. But even if the FVROR were merely the by-product of a formula, a point with which I disagree, that would not change the fact that the FVROR was agreed to by the settling parties and ultimately approved by the Commission as one fixed point among many that led to a determination that the Settlement Agreement set forth a reasonable basis for disposing of the matter before the Commission.

Section 10, of the Settlement Agreement only makes reference to the rate base and expense effects associated with the transaction. As discussed above, I believe that those have been appropriately recognized.

[1] Decision No. 73183 at page 11.

Q. Do you have any other comments with regard to Mr. Snook's rebuttal testimony regarding the appropriate rate of return?

A. Yes. APS stated that the 'fair value' of this asset from an accounting 'fair value' perspective is in this case the same as the 'fair value' rate base concept typically discussed in Arizona rate cases; or at least that they "are mathematically equivalent." The price (including the acquisition adjustment paid by APS) is the product of an arm's length transaction and in Staff's opinion represents the best indicator of fair value for purposes of determining the revenue requirement in this case.

Mr. Snook's rebuttal testimony implies that the almost $226 million of rate base claimed for the total acquisition is the original cost rate base value. He goes on to indicate that recalculation to reflect reconstructed values would produce a much higher fair value than that of the original cost.

It is not correct to assert that APS's approximate $226 million of acquisition value for the referenced facilities reflects the original cost value. Rather, it reflects the fair value of the facilities as acquired by APS. As explained in my direct testimony, the approximate $226 million of rate base includes an acquisition adjustment. This adjustment reflects the fact that APS paid far in excess of the $52 million book value of Units 4 & 5. That $226 million also includes over $8 million for Southern California Edison's ("SCE") share of the new auxiliary boiler that recently went into service.

Q. What about Mr. Snook's comments about the use of RCND for this plant?

A. Mr. Snook poses the following question: "Why did APS assume in its Direct Testimony that fair value, original cost and RCND were all the same for the Four Corners Asset." Mr. Snook then states that "APS made a simplifying assumption to reflect just the cost of acquiring SCE share of the Four Corners Units 4 and 5 because the asset was new to APS." I agree with APS's Direct Testimony to the extent that fair value and RCND are the same in this case. The best indicator of fair value for this plant is the purchase price paid by APS in this case. Further, one cannot base reconstruction value upon the acquisition value of $226 million, which includes amounts paid far in excess of the book value of $52 million.

Q. Do you have any other concerns with use of the WACC of 8.33 percent as the return in this case?

A. Yes. From Figure A included on page 5 of Mr. Snook's testimony, adoption of APS's position would increase the FVROR from 6.09 percent to 6.14 percent. The plain language of the Settlement Agreement simply does not support this redetermination of FVROR from 6.09 percent to 6.14 percent or the application of the WACC of 8.33 percent to the fair value of this plant.

Q. What do you recommend if the Commission were to adopt APS's position?

A. If APS wants to update and recalculate the fair value rate of return for its acquisition of Four Corners Units 4 and 5, Staff believes that all aspects of the fair value rate of return should be subject to examination. In other words, APS derives significant benefit from the Rider, and its risk is reduced, which should be reflected in the equity component of its rate of return. Additionally, the debt component and the capital structure would also need to be reevaluated given APS has just recently obtained new debt financing.

APS's Updated Revenue Requirement and Surcharge Rate Calculation

Q. What is your opinion on the updated surcharge rate calculation amounts cited in the APS rebuttal testimony?

A. Ms. Blankenship updated APS's rate base and operating income claims to reflect known and measurable costs as of April 30, 2014. She proposed an adjusted jurisdictional rate base of approximately $225.93 million and operating income shortfall of approximately $20.680 million. These amounts produced an overall revenue requirement of approximately $65.436 million and would result in a 2.33 percent monthly increase to customers' bills. Her rebuttal testimony uses the same 8.33 percent WACC discussed above.

My direct testimony generally found that APS has accurately calculated and appropriately supported the other revenue requirement elements it has proposed (except for use of the 8.33% WACC rather than the 6.09% FVROR). My preliminary review of APS's updated amounts to reflect known and measurable changes as of April 30, 2014, leads to the same conclusions. The table below compares Staff's rate base value position in my direct testimony to the updated values provided by APS, which we accept.

Four Corners Pro Forma Rate Base	Amounts Projected To 6/30/14	Amounts Projected To 11/30/14
Plant in Service:		
Acquired Plant	$605,364,014	$606,431,941
Acquisition Adjustment	254,787,393	252,509,950
Auxiliary Boiler-Plant	8,623,930	8,793,031
Auxiliary Boiler-Startup Steam Supply	2,694,978	2,747,822
Deferred Cost-O&M Expense (12/30/13 to ----)	38,252,000	47,066,287
Deferred Cost-Depr & Amort Exp. (12/30/13 to ---)	4,694,000	7,703,000
Deferred Cost-Property Taxes (12/30/13 to ---)	3,208,000	5,883,000
Deferred Cost-Debt Return (12/30/13 to ----)	4,533,268	8,311,000
Total Plant in Service	**$922,157,582**	**$939,446,031**
Accumulated Depreciation:		
Acquired Plant	$-539,326,651	$-553,352,949
SCE Additional Reserve (9/1/13 - 12/31/13)	-14,738,975	
APS Additional Reserve (1/1/14 to ---)	-1,088,271	-2,042,193
Cost of Removal Reserve	916,566	

Boiler Depreciation (5/1/13 to ----)	-286,000	-476,562
Total Accumulated Depreciation	**$-554,523,331**	**$-555,871,704**
Plus Deferred Debits:		
Plant, Materials & Operating Supplies	$4,468,827	$4,633,133
Total Deferred Debits	**$4,468,827**	**$4,633,133**
Less Deferred Credits:		
Deferred Taxes	$-20,026,580	$-27,247,000
Asset Retirement Obligation Liability	-34,123,498	-34,123,498
Other Deferred Credits (Including Coal Reclamation)	-92,950,926	-92,950,926
Total Deferred Credits	**$-147,101,004**	**$-154,321,424**
Total Company Rate Base	**$225,002,074**	**$233,886,036**
APS Allocation Rate	96.60%	96.60%
APS Rate Base	**$217,352,003**	**$225,933,911**

Q. Describe how APS determined the updated jurisdictional $65.436 million annual revenue deficiency and the resulting 2.33 percent monthly surcharge, and describe Staff's proposed jurisdictional revenue deficiency and surcharge rate.

A. The methods relied upon for the calculations of the jurisdictional revenue deficiencies under the Company's and Staff's proposals did not change. The following table illustrates the resultant revenue deficiencies and surcharge rates based upon the rates of return proposed by APS and Staff.

Staff recommends that the Company's computed jurisdictional revenue deficiency of $65.436 million be reduced by $8.39 million to $57.05 million. The revised revenue deficiency therefore reduces the surcharge rate from 2.33 percent to 2.03 percent.

Item	APS Updated Pro Forma Adjustments	Liberty Updated Proposed
Adjusted Rate Base	$225,934,000	$225,934,000
Adjusted Operating Income	-20,680,000	-20,680,000
Current Rate of Return	-9.15%	-9.15%
Rate of Return	8.33%	6.09%
Required Return	$18,820,000	$13,759,381
Operating Income Deficiency	$39,500,000	$34,439,381
Gross Revenue Conversion Factor	1.6566	1.6566
Total Revenue Deficiency	**$65,436,000**	**$57,052,279**

2010 Adjusted Base Revenues	$2,810,916,000	$2,810,916,000
Percentage Rate Surcharge	**2.33%**	**2.03%**
Change in Revenue Deficiency		**($8,383,721)**

Q. Please summarize the changes to APS's adjusted operating income claim.

A. The APS initial as-filed jurisdictional operating income deficiency was $19.617 million, which it updated to $20.680 million. The next table summarizes the cost components at APS's claimed values, and summarizes the changes. The changes occurred in depreciation and amortization expenses and in income taxes. The change from a 6-month to 11-month time period projected for this proceeding (from June 30, 2014 to November 30, 2014) drives these changes.

Item	APS As-Filed Pro Forma Adjustments	APS Updated Pro Forma Adjustments	Change
Elec. Fuel & Purc. Pwr.	$4,318,000	$4,346,000	28,000
O&M Excl. fuel expenses	5,411,000	5,412,000	1,000
Depr. & Amort. Expenses	20,679,000	22,564,000	1,885,000
Income Taxes	-16,990,000	-17,842,000	-852,000
Other Taxes	6,199,000	6,200,000	1,000
Total Change	**$19,617,000**	**$20,680,000**	**$1,063,000**

Q. What is your view of the need for future review of APS's updated values?

A. I accept the updated values as provided by APS as of April 30, 2014, for purposes of calculating the surcharge rate for the instant proceeding.

AG-1 Rate Design Issue

Q. Have you reviewed the testimony of Walmart Witness Steve Chriss and Witness Kevin Higgins on behalf of Freeport-McMoRan, AECC, Kroger and Noble?

A. Yes. These are large AG-1 customers of APS who do not believe that the Four Corners Rate Rider should apply to them. As Witness Chriss describes it, AG-1 is a buy through rate for large commercial and industrial customers, which allows them to purchase generation service from a third party. These large customers do not believe that the Rider should apply to them since they do not take generation service from APS. They argue that only those ratepayers who take generation service from APS and will benefit from the acquisition of those assets should bear the costs. They further argue that APS's proposal to apply this to even the "APS" portion of their bills is a violation of the Settlement approved by the Commission.

Q. How is the surcharge applied?

A. According to Section 10.3 of the Settlement, the recovery mechanism would recover the rate base and non-PSA ("Power Supply Adjustor") related expenses associated with the Four Corners transaction on an equal percentage basis across all rate schedules. APS has proposed to apply the surcharge to only a portion of the bills paid by customers taking service under AG-1. As proposed by APS, the charge would apply only to the non-generation portion of AG-1 customers' bills.

Q. What is Staff's position with regard to the application of the surcharge rate to AG-1 customers?

A. Since APS proposes to apply the surcharge rate only to the non-generation portion of the AG-1 customer's bill, and not the portion representing a pass-through of charges from Alternative Generation Providers, Staff believes that this approach provides a reasonable balance of the interests of all customer concerns.

Q. Do you believe that APS's proposal is inconsistent with the Settlement approved by the Commission and with the Company's Tariff as Mr. Higgins and Mr. Chriss suggest?

A. No. With respect to the Settlement, had the parties intended to exclude AG-1 customers from the application of the surcharge, language could have easily been included in the relevant portions of the Settlement, but it was not. APS's application of the surcharge to only the APS portions of the AG-1 customers' bills is a reasonable result in light of the Settlement and the Company's Tariff.

Q. What impact would Mr. Higgins' and Mr. Chriss' proposal to exclude AG-1 customers entirely have on other customers?

A. Mr. Higgins notes that the rider would increase by approximately 0.02 percent, or about 2 cents per month, for a typical customer with a base energy bill of $125 per month.

Q. If the impact is so small, why is Staff opposed to Mr. Higgins' and Mr. Chriss' proposal?

A. Staff's objective is to achieve the appropriate balance between customer classes. We believe that APS's proposal in this case does that.

Units 1-3 Rate Base Issue

Q. What do you conclude with respect to rate base costs associated with Units 1-3?

A. My direct testimony noted that we were in the process of examining the potential removal from base rates of any rate base costs associated with Units 1-3. That review process is now complete. We are satisfied that the Company has demonstrated that these facilities have, in fact, been removed from rate base consideration, and are not reflected in current rates or in the proposed surcharge rate.

III. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. I recommend that the Commission:

- Reject APS's requested 8.33 percent return to be applied to the Four Corners fair value rate base.

- Accept Staff's direct testimony position that the appropriate rate of return associated with the development of the surcharge rate be the Fair Value Rate of Return ("FVROR") of 6.09 percent contained in the Settlement Agreement approved by the Commission in Decision No. 73183.
- Approve APS's updated cost values, including (1) rate base and expenses associated with the acquisition of SCE's share of Units 4 and 5; (2) the rate base and expense effects associated with the retirement of Units 1-3; and, (3) related cost deferrals provided for in Decision No. 73130 for purposes of calculating the surcharge rate.
- Approve a total jurisdictional revenue increase of no more than $57.05 million.
- Require that the Four Corners Adjustment Schedule include updated language agreed to by APS in order to make clear that the surcharge rate will only remain in effect until the conclusion of APS's next rate case.
- Make the surcharge rate applicable to customers as described in APS's proposed Four Corners Adjustment Schedule.
- Approve a surcharge rate of 2.03 percent.

Q. Does that conclude your direct testimony?

A. Yes, it does.

Arizona Public Service Company
Capital Structure & Cost Rates

Docket No. E-01345A-11-0224
Schedule D
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Capital Source		Capitalization Amount (A)	Capitalization Percent (B)	Cost Rate (C)	Weighted Avg. Cost of Capital (D)
	APS - Proposed					
1	Short-Term Debt	$	-			0.00%
2	Long-Term Debt	$	3,382,856	46.06%	6.38%	2.94%
3	Common Stock Equity	$	3,961,248	53.94%	11.00%	5.93%
4	Total Capital	$	7,344,104	100.00%		8.87%
	ACC Staff - Proposed					
5	Short-Term Debt	$	-			0.00%
6	Long-Term Debt	$	3,382,856	46.06%	6.38%	2.94%
7	Common Stock Equity	$	3,961,248	53.94%	9.90%	5.34%
8	Total Capital	$	7,344,104	100.00%		8.28%
9	Difference					-0.59%
10	Weighted Cost of Debt					2.94%
	ACC Staff - Proposed Fair Value Rate of Return - Alternative 1					
11	Short-Term Debt	$	-	0.00%	0.00%	0.00%
12	Long-Term Debt	$	2,608,502	31.94%	6.38%	2.04%
13	Common Stock Equity	$	3,054,497	37.40%	9.90%	3.70%
14	Capital financing OCRB	$	5,662,998			
15	Appreciation above OCRB not recognized on utility's books	$	2,504,128	30.66%	0% [a]	0.00%
16	Total capital supporting FVRB	$	8,167,126	100.00%		5.74%
	ACC Staff - Proposed Fair Value Rate of Return - Alternative 2					
17	Short-Term Debt	$	-	0.00%	0.00%	0.00%
18	Long-Term Debt	$	2,608,502	31.94%	6.38%	2.04%
19	Common Stock Equity	$	3,054,497	37.40%	9.90%	3.70%
20	Capital financing OCRB	$	5,662,998			
21	Appreciation above OCRB not recognized on utility's books	$	2,504,128	30.66%	1.00% [b]	0.31%
22	Total capital supporting FVRB	$	8,167,126	100.00%		6.05%

Notes and Source
Lines 1-4, APS filing D-1.
Line 15, CoLA:

23	Fair Value Rate Base	$	8,167,126	Schedule A
24	Original Cost Rate Base	$	5,662,998	Schedule A
25	Difference	$	2,504,128	

Difference is appreciation of Fair Value over Original Cost that is not recognized on the utility's books.

[a] The appreciation of Fair Value over Original Cost has not been recognized on the utility's books. Such off-book appreciation has not been financed by debt or equity capital recorded on the utility's books. The appreciation over Original Cost book value is therefore recognized for cost of capital purposes at zero cost.

[b] Per Staff witness David Parcell

EXHIBIT
ALL-STATE LEGAL®
S-4
ADMITTED

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTY-SEVENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
FOUR CORNERS RATE RIDER
DOCKET NO. E-01345A-11-0224
APRIL 17, 2014

Staff 37.2: Refer to Work Paper EAB-1, Page 6 of 9. Please provide a copy of the sales contract that provides for the terms outlined on this schedule.

Response: Attached as APS15360 is the requested "Purchase and Sale Agreement by and between Southern California Edison and Arizona Public Service". This document was also attached to Mark Schiavoni's Direct Testimony in the Four Corners Docket (E-01345A-10-0474).

Witness: Beth Blankenship

Execution Copy

PURCHASE AND SALE AGREEMENT

BY AND BETWEEN

SOUTHERN CALIFORNIA EDISON COMPANY,
a California corporation

and

ARIZONA PUBLIC SERVICE COMPANY,
an Arizona corporation

Dated as of

November 8, 2010

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PURCHASE AND SALE AGREEMENT

This **PURCHASE AND SALE AGREEMENT** is made as of November 8, 2010, by and between **SOUTHERN CALIFORNIA EDISON COMPANY**, a California corporation (**"Seller"**), and **ARIZONA PUBLIC SERVICE COMPANY**, an Arizona corporation (**"Purchaser"**).

BACKGROUND

A. Seller desires to sell to Purchaser certain assets, which constitute all of Seller's participation interests in the fossil fuel generating facility known as the Four Corners Power Plant and certain other facilities and assets associated therewith or ancillary thereto, and Purchaser desires to purchase these assets from Seller, all on the terms and conditions hereinafter set forth;

B. Seller and Purchaser are entering into this Agreement to evidence their respective duties, obligations and responsibilities;

NOW, THEREFORE, in consideration of the respective representations, warranties, covenants and agreements contained in this Agreement, Seller and Purchaser, intending to be legally bound, hereby agree as follows:

ARTICLE 1
DEFINITIONS

1.1 Defined Terms. The following terms when used in this Agreement (or in the Schedules and Exhibits to this Agreement) with initial letters capitalized have the meanings set forth below:

1.1.1 ACC. "ACC" means the Arizona Corporation Commission or its regulatory successor, as applicable.

1.1.2 Affiliate. **"Affiliate"** of a Person means any other Person that (a) directly or indirectly controls the specified Person; (b) is controlled by or is under direct or indirect common control with the specified Person; or (c) is an officer, director, employee, representative or agent or subsidiary of the Person. For the purposes of this definition, "control," when used with respect to any specified Person, means the power to direct the management or policies of the specified Person, directly or indirectly, whether through the ownership of voting securities, partnership or limited liability company interests, by contract or otherwise.

1.1.3 Agreement. **"Agreement"** means this Purchase and Sale Agreement, together with the Schedules and Exhibits hereto.

1.1.4 Ancillary Agreements. **"Ancillary Agreements"** means the Deed, the Bill of Sale, the Assignment and Assumption Agreement and any other agreement to be executed and delivered by the Parties under this Agreement.

1.1.5 **<u>Article</u>**. **"Article"** means a numbered article of this Agreement. An Article includes all the numbered sections of this Agreement that begin with the same number as that Article.

1.1.6 **<u>Assets</u>**. **"Assets"** has the meaning set forth in <u>Section 2.1</u>.

1.1.7 **<u>Assignment and Assumption Agreement</u>**. **"Assignment and Assumption Agreement"** means the assignment and assumption agreement between Seller and Purchaser, to be delivered at the Closing, in such form as shall be reasonably acceptable to Seller and Purchaser, pursuant to which Seller shall assign to Purchaser all of Seller's right, title and interest in and to the Facilities Contracts, certain intangible assets and certain other Assets, and Purchaser shall accept such assignments and assume the Assumed Liabilities.

1.1.8 **<u>Assumed Liabilities</u>**. **"Assumed Liabilities"** has the meaning set forth in <u>Section 2.3</u>.

1.1.9 **<u>Bill of Sale</u>**. **"Bill of Sale"** means the bill of sale from Seller to Purchaser, to be delivered at the Closing, in such form as shall be reasonably acceptable to Seller and Purchaser.

1.1.10 **<u>Business Day</u>**. **"Business Day"** means a day other than Saturday, Sunday or a day on which banks are legally closed for business in the State of Arizona.

1.1.11 **<u>California ISO</u>**. **"California ISO"** means the Independent System Operator described in Article 3 of Chapter 2.3 of Part 1 of Division 1 of the California Public Utilities Code.

1.1.12 **<u>Capital Expenditure</u>**. **"Capital Expenditure"** means any additions to or replacements of property, plant and equipment in accordance with any of the Facilities Contracts.

1.1.13 **<u>Carbon Emission Allowance</u>**. **"Carbon Emission Allowance"** means an Emission Allowance or authorization to emit one specified unit of carbon dioxide or, if applicable, another pollutant addressed under Environmental Laws to mitigate global warming or climate change.

1.1.14 **<u>Closing</u>**. **"Closing"** has the meaning set forth in <u>Section 3.1</u>.

1.1.15 **<u>Closing Date</u>**. **"Closing Date"** has the meaning set forth in <u>Section 3.1</u>.

1.1.16 **<u>Code</u>**. **"Code"** means the Internal Revenue Code of 1986, as amended.

1.1.17 **<u>Commercially Reasonable Efforts</u>**. **"Commercially Reasonable Efforts"** means efforts by a reasonable Person in the position of a Party which are designed to enable a Party to satisfy a condition to, or otherwise assist in the consummation of, the transactions contemplated by, or to perform its obligations under, this Agreement and which do not require the performing Party to expend any funds or assume liabilities other than expenditures and liabilities which are customary and reasonable in nature and amount for transactions like those contemplated by this Agreement.

1.1.18 Confidential Information. "Confidential Information" has the meaning ascribed to such term in the Confidentiality Agreement.

1.1.19 Confidentiality Agreement. "Confidentiality Agreement" means that certain Multiparty Confidentiality Agreement by and among Seller, Purchaser and the other Facilities Owners dated August 4, 2009.

1.1.20 CPUC. "CPUC" means the California Public Utilities Commission, or its regulatory successor, as applicable.

1.1.21 Decommissioning Report. "Decommissioning Report" means the Final Report Facility-Wide Indicative Demolition Cost Estimate for the Four Corners Power plant issued in December of 2009 by The Shaw Group Power Generation Services.

1.1.22 Deed. "Deed" means the special warranty deed as customarily used in the state where the Facilities are located pursuant to which Seller will convey all of its right, title and interest in the real property Assets sold to Purchaser under this Agreement, subject to Permitted Encumbrances.

1.1.23 Edison-Arizona Transmission Agreement. "Edison-Arizona Transmission Agreement" means that certain Transmission Agreement between Southern California Edison Company and Arizona Public Service Company executed July 20, 1966, as the same may be amended to the Closing Date.

1.1.24 Effective Date. "Effective Date" means the date on which this Agreement has been executed and delivered by the Parties.

1.1.25 Emission Allowance. "Emission Allowance" means an authorization to emit one specified unit of pollutant or Hazardous Substance from the Assets, which units are established by the Governmental Authority with jurisdiction over the Assets under (a) an air pollution control and emission reduction program designed to mitigate global warming or climate change or interstate or intrastate transport of air pollutants, (b) a program designed to mitigate environmental impairment of surface waters, watersheds, or groundwater or (c) any pollution reduction program with a similar purpose. Emission Allowances include allowances, as described above, including credits, regardless of whether the Governmental Authority establishing such allowances designates such allowances by a name other than "allowances." Except as specifically addressed in Sections 2.2(l) and 2.6 with respect to Carbon Emission Allowances and Section 2.2(k) with respect to SO_2 Emission Allowances, the amount of the Emission Allowances shall be all Emission Allowances granted to the Facilities or to Seller or Purchaser as a result of its or their ownership interests in the Facilities and in existence and not consumed as of the Effective Date or subsequently authorized in respect of the Assets, reduced by the Emission Allowances consumed in the operation of the Facilities between the Effective Date and the Closing Date in the ordinary course of business.

1.1.26 __Encumbrances__. **"Encumbrances"** means any and all mortgages, pledges, claims, liens, security interests, conditional and installment sales agreements, easements, activity and use restrictions and limitations, exceptions, rights-of-way, deed restrictions, defects of title, encumbrances, and charges of any kind.

1.1.27 __Environment__. **"Environment"** means all soil, real property, air, water (including surface waters, streams, ponds, drainage basins, washes and wetlands), groundwater, water body sediments, drinking water supply, stream sediments or land (including land surface or subsurface strata), fish, plants, wildlife and other biota or other environmental medium or natural resource.

1.1.28 __Environmental Condition__. **"Environmental Condition"** means the presence, Release or threatened Release to the Environment of Hazardous Substances, including any migration of Hazardous Substances through the Environment, at, to or from the Facilities or the Facilities Switchyard or the Navajo Mine regardless of when such presence, Release or threatened Release occurred or is discovered. As used in this Agreement, **"threatened Release"** shall have the meaning ascribed thereto by the Comprehensive Environmental Response, Compensation, and Liability Act (42 U.S.C. § 9607(a)).

1.1.29 __Environmental Laws__. **"Environmental Laws"** means all Federal, state, local and tribal civil and criminal laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders relating to the Environment or human health and welfare, as the same may be amended or adopted, including, without limitation, those relating to Releases or threatened Releases to the Environment or otherwise relating to the manufacture, processing, distribution, use, treatment, storage, Release, threatened Release, transport, disposal or handling of Hazardous Substances, including but not limited to, the Comprehensive Environmental Response, Compensation, and Liability Act (42 U.S.C. § 9601 *et seq.*), the Hazardous Materials Transportation Act (49 U.S.C. § 1801 et Seq.), the Resource Conservation and Recovery Act (42 U.S.C. § 6901 *et seq.*), the Federal Water Pollution Control Act (33 U.S.C. § 1251 *et seq.*), the Clean Air Act (42 U.S.C. § 7401 *et seq.*), the Toxic Substances Control Act (15 U.S.C. § 2601 *et seq.*), the Oil Pollution Act (33 U.S.C. § 2701 *et seq.*), the Emergency Planning and Community Right-to-Know Act (42 U.S.C. § 11001 *et seq.*), the Oil Pollution Act (33 U.S.C. Sec. 2701 *et seq.*), the Safe Drinking Water Act (42 U.S.C. Secs. 300f through 300j), the Occupational Safety and Health Act (29 U.S.C. Sec. 651 *et seq.*), or any similar laws of any Governmental Authority having jurisdiction over the site at which the Assets are located or otherwise applicable to the Assets.

1.1.30 __Excluded Assets__. **"Excluded Assets"** has the meaning set forth in __Section 2.2__.

1.1.31 __Excluded Liabilities__. **"Excluded Liabilities"** has the meaning set forth in __Section 2.4__.

1.1.32 __Exhibits__. **"Exhibits"** means the exhibits to this Agreement.

1.1.33 __Facilities__. **"Facilities"** means the "Four Corners Project," as that term is defined in the Facilities Co-Tenancy Agreement, as well those facilities defined by the following terms in the Facilities Co-Tenancy Agreement, to the extent they relate to the Four Corners Project, and to the extent such facilities exist, as of the Closing Date: "Existing New Facilities," "Existing Related Facilities," "Future New Facilities," and "Future Related Facilities."

1.1.34 Facilities Co-Tenancy Agreement. "**Facilities Co-Tenancy Agreement**" means that certain Four Corners Project Co-Tenancy Agreement executed as of July 19, 1966, by and among the Facilities Owners, as the same may be amended to the Closing Date.

1.1.35 Facilities Contracts. "**Facilities Contracts**" has the meaning set forth in Section 2.1(h).

1.1.36 Facilities Fuel Agreement. "**Facilities Fuel Agreement**" means the Four Corners Coal Supply Agreement, effective January 1, 2010, between BHP Navajo Coal Company and the Facilities Owners, as the same may be amended to the Closing Date.

1.1.37 Facilities Insurance Policies. "**Facilities Insurance Policies**" means all insurance policies carried by or for the benefit of the Facilities Owners with respect to the ownership, operation or maintenance of the Facilities or the Facilities Switchyard, including all liability, property damage, self insurance arrangements, retrospective assessments and business interruption policies in respect thereof.

1.1.38 Facilities Lease. "**Facilities Lease**" means the Indenture of Lease dated December 1, 1960 between the Navajo Tribe of Indians and Purchaser, as amended, supplemented and revised by the Supplemental and Additional Indenture of Lease executed as of July 6, 1966 between the Navajo Tribe of Indians and the Facilities Owners, and as further amended by the Amendment and Supplement No. 1 to the Supplemental and Additional Indenture of Lease dated April 25, 1985 between the Navajo Tribe of Nations and the Facilities Owners, as the same may be amended to the Closing Date.

1.1.39 Facilities Operating Agreement. "**Facilities Operating Agreement**" means that certain Four Corners Project Operating Agreement entered into as of May 15, 1969, by and among the Facilities Owners, as the same may be amended to the Closing Date.

1.1.40 Facilities Owner. "**Facilities Owner**" means each Person who, as of the relevant time, is a "Participant" under the Facilities Co-Tenancy Agreement, which, as of the date of this Agreement, means Purchaser, El Paso Electric Company, Public Service Company of New Mexico, Salt River Project Agricultural Improvement and Power District, Seller and Tucson Electric Power Company, in each case in such Person's capacity as a "Participant".

1.1.41 Facilities Switchyard. "**Facilities Switchyard**" means the 500 kv and 345 kv switchyards located at and adjacent to the Facilities.

1.1.42 FERC. "**FERC**" means the Federal Energy Regulatory Commission as established by the Department of Energy Organization Act of 1977, 42 U.S.C. § 7171, as amended, or its regulatory successor, as applicable.

1.1.43 **FIRPTA Affidavit**. "**FIRPTA Affidavit**" means the Foreign Investment in Real Property Tax Act Certificate and Affidavit of Seller, to be delivered at the Closing.

1.1.44 **Governmental Authority**. "**Governmental Authority**" means any federal, state, local or other government; any governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, police, regulatory or taxing authority or power; any court or governmental tribunal; and any Tribal Authority; but does not include Purchaser, Seller, any Affiliate thereof, or any of their respective successors in interest or any owner or operator of the Assets (if otherwise a Governmental Authority).

1.1.45 **Hazardous Substances**. "**Hazardous Substances**" means (a) any petroleum, asbestos, urea formaldehyde foam insulation and/or transformer or other equipment that contains polychlorinated biphenyls; (b) any chemical, material or substance defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "toxic pollutants," "contaminants," "pollutants" or "hazardous air pollutants," or words of similar meaning and regulatory effect, under any Environmental Law; and/or (c) any other chemical, material or substance that is listed or regulated under any Environmental Law because it poses a hazard to human health or welfare or the Environment.

1.1.46 **HSR Act**. "**HSR Act**" means the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended from time to time.

1.1.47 **Income Tax**. "**Income Tax**" means any Tax imposed by any Governmental Authority (a) based upon, measured by or calculated with respect to gross or net income, profits or receipts (including municipal gross receipt Taxes, capital gains Taxes and minimum Taxes) or (b) based upon, measured by or calculated with respect to multiple bases (including corporate franchise Taxes) if one or more of such bases is described in clause (a), in each case together with any interest, penalties or additions attributable to such Tax.

1.1.48 **Independent Accounting Firm**. "**Independent Accounting Firm**" means such nationally recognized, independent accounting firm as is mutually appointed by Seller and Purchaser for purposes of this Agreement.

1.1.49 **Initial Purchase Price**. "**Initial Purchase Price**" means Two Hundred Ninety-Four Million Dollars ($294,000,000).

1.1.50 **Knowledge**. The term "**Knowledge**" or similar phrases in this Agreement means: (a) in the case of Seller, the extent of the actual and current knowledge of Seller's officers, employees, and knowledgeable persons listed in Schedule 1.1.50(a) at the Effective Date (or, with respect to the certificate delivered pursuant to Section 8.6, the date of delivery of the certificate) without any implication of verification or investigation concerning such knowledge; (b) in the case of Purchaser, the extent of the actual and current knowledge of Purchaser's officers, employees and authorized agents listed in Schedule 1.1.50(b) at the Effective Date (or, with respect to the certificate delivered pursuant to Section 9.6, the date of delivery of the certificate) without any implication of verification or investigation concerning such knowledge; and (c) in the case of Operating Agent, the extent of the actual and current knowledge of Operating Agent's officers, employees and authorized agents listed in Schedule 1.1.50(c) at the date of this Agreement or at the Closing Date, as well as the Persons who, as of the date of this Agreement or as of the Closing, serve as the plant manager of the Facilities and the Person or Persons to whom the plant manager reports, without any implication of verification or investigation concerning such knowledge.

1.1.51 Landfill. **"Landfill"** means that certain landfill as identified in the sections labeled "LANDFILL" on the map attached as Exhibit A hereto.

1.1.52 Laws. "Laws" means all Federal, state, local and tribal civil and criminal laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders.

1.1.53 Material Adverse Effect. **"Material Adverse Effect"** means (x) any event, circumstance or condition materially impairing a Party's authority, right, or ability to consummate the transactions contemplated by this Agreement or the Ancillary Agreements, or (y) any change (or changes taken together) in, or effect on, the Assets that is materially adverse to the operations or physical condition of the Facilities and the Facilities Switchyard, taken as a whole, which exist as of the Closing, including an unscheduled shutdown that is materially adverse to the operations or physical condition of the Assets following the Closing, but excluding (a) any change (or changes taken together) generally affecting the international, national, regional or local electric industry as a whole and not affecting the Assets in any manner or degree materially different than other facilities like the Facilities, (b) any change (or changes) resulting from the international, national, regional or local markets for fuel used at the Facilities, (c) any change (or changes taken together) in the North American, national, regional or local transmission system, (d) any change (or changes taken together) to the extent constituting or involving an Excluded Asset or Excluded Liability, or (e) any change which is cured (including by the payment of money) before the earlier of the Closing or the termination of the Agreement under Section 10.1.

1.1.54 **Moenkopi Switchyard**. **"Moenkopi Switchyard"** means the 500-kV transmission switching station located at the Moenkopi Substation as defined in the Edison-Arizona Transmission Agreement.

1.1.55 Navajo Mine. **"Navajo Mine"** means the coal mine located on the Navajo Nation property that is operated by BHP Navajo Coal Company (**"BHP"**) and that supplies coal to the Facilities under the Facilities Fuel Agreement.

1.1.56 Operating Agent. **"Operating Agent"** means Arizona Public Service Company, as operating agent under the Facilities Co-Tenancy Agreement and the Facilities Operating Agreement, or its successor in interest.

1.1.57 **Operating Agent's Actuary**. **"Operating Agent's Actuary"** means the Person acting as the actuary for the Operating Agent with respect to the Facilities, or its successors or assigns, which at the time of this Agreement is Towers Watson & Co.

1.1.58 Party. "**Party**" means either Seller or Purchaser, as the context requires; "**Parties**" means, collectively, Seller and Purchaser.

1.1.59 Pension and OPEB Liabilities. "**Pension and OPEB Liabilities**" means the pension plan accumulated benefit obligation (ABO) and the other post-retirement benefit obligation (APBO) for the Operating Agent and its Affiliates determined in accordance with Statement of Financial Accounting Standards No. 87 (FAS 87), Statement of Financial Accounting Standards No. 106 (FAS 106) and Accounting Standards Codification 715, as amended.

1.1.60 Permitted Encumbrances. "**Permitted Encumbrances**" means (a) liens for Property Taxes and other governmental charges and assessments which are not yet due and payable, (b) all exceptions set forth in the Preliminary Title Report to the extent deemed approved by Purchaser under Section 6.10, (c) during the period prior to the Closing, the lien of Seller's Mortgage, (d) liens, encumbrances or title imperfections with respect to the Assets created by or resulting from the acts or omissions of Purchaser or Operating Agent, (e) liens, charges, claims, pledges, security interests, equities and encumbrances arising under the Facilities Contracts, or which will be and are discharged or released either prior to, or simultaneously with, the Closing, (f) the Assumed Liabilities, and (g) liens, charges, claims, pledges, security interests, equities and encumbrances that do not apply only and exclusively, to the interest of Seller but that also constitute liens, charges, claims, pledges, security interests, equities or encumbrances upon the interests of the other Facilities Owners in common and/or the Operating Agent, as agent for any of the Facilities Owners and that individually, or in the aggregate, do not constitute a Material Adverse Effect with respect to the Facilities or the Facilities Switchyard other than Material Adverse Effects of which the Operating Agent has Knowledge.

1.1.61 Person. "**Person**" means an individual, partnership, joint venture, corporation, limited liability company, trust, association or unincorporated organization, or any Governmental Authority.

1.1.62 PNW Plan Assets. "**PNW Plan Assets**" means the fair market value of the Operating Agent's and its Affiliates' investments in its retirement and other post-retirement plans listed on Schedule 1.1.62.

1.1.63 Preliminary Title Report. "**Preliminary Title Report**" has the meaning set forth in Section 6.10.

1.1.64 Property Tax. "**Property Tax**" means any Tax resulting from and relating to the assessment of real or personal property or a possessory interest in real or personal property by any Governmental Authority.

1.1.65 Purchase Price. "**Purchase Price**" has the meaning set forth in Section 3.2.

1.1.66 Purchaser. "**Purchaser**" has the meaning set forth in the introductory paragraph of this Agreement.

1.1.67 __Purchaser's Required Consents__. "**Purchaser's Required Consents**" means all consents specified in __Schedule 1.1.67__, which include the consent of any Person (other than a Governmental Authority) necessary for Purchaser's consummation of the transactions contemplated by this Agreement and the Ancillary Agreements, except where the failure to obtain such Person's consent would not have a Material Adverse Effect.

1.1.68 __Purchaser's Required Regulatory Approvals__. "**Purchaser's Required Regulatory Approvals**" means all approvals specified in __Schedule 1.1.68__, which include the approval of the purchase and sale contemplated hereby by (i) the ACC; (ii) the FERC under the Federal Power Act, which approval shall be without conditions or constraints that would limit Purchaser's ability to take delivery and deliver power from the Facilities for purposes of serving Purchaser's retail load or selling at wholesale on terms and conditions reasonably satisfactory to Purchaser; and (iii) any other Governmental Authority with general regulatory authority over Purchaser or the business and assets represented by the Assets and whose approval is required for Purchaser's consummation of the transactions contemplated by this Agreement and the Ancillary Agreements, except where the failure to obtain such Governmental Authority's approval would not have a Material Adverse Effect.

1.1.69 __Reclamation Report__. "**Reclamation Report**" means the Final Reclamation Closure Plan and Cost Estimate at the Navajo Mine for APS issued in August of 2010 by Marston & Marston, Inc.

1.1.70 __Release__. "**Release**" means any release, spill, leak, discharge, disposal of, pumping, pouring, emitting, emptying, injecting, leaching, dumping, depositing, dispersing, escaping or migration of a Hazardous Substance into, onto or through the Environment or within any building, structure, facility or fixture, including the abandonment or discarding of Hazardous Substances in barrels, drums, or other containers.

1.1.71 __Remediation__. "**Remediation**" means any action of any kind to address an Environmental Condition or Release or threatened Release or the presence of Hazardous Substances on or in the Environment relating to the Facilities, the Facilities Switchyard, the Navajo Mine or any other location at which Hazardous Substances or non-hazardous substances or materials generated or originating at the Facilities were transported, stored or disposed of, including the following: (i) monitoring, investigation, treatment, cleanup, containment, remediation, removal, mitigation, response or restoration work; (ii) obtaining any permits, consents, approvals or authorizations of any Governmental Authority necessary to conduct any such work; (iii) preparing and implementing any plans or studies for such work; (iv) obtaining a written notice, from a Governmental Authority with jurisdiction under applicable Environmental Laws that no material additional work is required by such Governmental Authority; (v) any response to or preparation for, any inquiry, order, hearing or other proceeding by or before any Governmental Authority with respect to any such Environmental Condition, Release or threatened Release or presence of Hazardous Substances, and (vi) any other activities reasonably determined by the Operating Agent of the Facilities or the Facilities Switchyard, as applicable, to be necessary or appropriate or required under Environmental Laws to address an Environmental Condition, the presence, Release or threatened Release of Hazardous Substances on or in the Environment at the Facilities, the Facilities Switchyard, the Navajo Mine or any other location at which Hazardous Substances or non-hazardous substances or materials generated or originating at the Facilities were transported, stored or disposed of.

1.1.72 <u>Schedules</u>. **"Schedules"** means the schedules to this Agreement.

1.1.73 <u>Section</u>. **"Section"** means a numbered section of this Agreement included within the Article that begins with the same number as that section.

1.1.74 <u>§ 323 Grants</u>. **"§ 323 Grants"** means one or more grants of rights-of-way and easements under the Act of February 5, 1948 (62 Stat. 17, 18, 25 U.S.C. § 323-328), the Act of March 3, 1879 (20 Stat. 394, 5 U.S.C. § 485), as amended, and the Acts of July 9, 1832, and July 27, 1868 (4 Stat. 564, 15 Stat. 228. 25 U.S.C. § 2) and such regulations promulgated thereunder, as are applicable, including 25 C.F.R. § 1.2 and 25 C.F.R. Part 169 granted to the Facilities Owners pursuant to the Facilities Lease, as the same may be amended in connection with the Facilities Lease amendments referenced in Section 8.14.

1.1.75 <u>Seller</u>. **"Seller"** has the meaning set forth in the introductory paragraph of this Agreement.

1.1.76 <u>Seller's Mortgage</u>. **"Seller's Mortgage"** means Seller's First Mortgage Bond Trust Indenture, dated as of October, 1923, as amended.

1.1.77 <u>Seller's Required Consents</u>. **"Seller's Required Consents"** means all consents specified in <u>Schedule 1.1.77</u>, which include the consent of the trustee under the Seller's Mortgage if required under the Seller's Mortgage, and any Person (other than a Governmental Authority) necessary for Seller's consummation of the transactions contemplated by this Agreement and the Ancillary Agreements, except where the failure to obtain such Person's consent would not have a Material Adverse Effect.

1.1.78 <u>Seller's Required Regulatory Approvals</u>. **"Seller's Required Regulatory Approvals"** means all approvals specified in <u>Schedule 1.1.78</u>, which include the approval of the purchase and sale contemplated hereby by (i) the CPUC, (ii) the FERC under the Federal Power Act, in form and substance reasonably satisfactory to Seller, (iii) the California ISO, and (iv) any other Governmental Authority with general regulatory authority over Seller or the business and assets represented by the Assets and whose approval is required for Seller's consummation of the transaction contemplated by this Agreement and the Ancillary Agreements, except where the failure to obtain such Governmental Authority's approval would not have a Material Adverse Effect.

1.1.79 <u>Seller's Share of Underfunded/Overfunded Pension and OPEB Liabilities</u>. **"Seller's Share of Underfunded/Overfunded Pension and OPEB Liabilities"** means the adjusted product of (i) Pension and OPEB Liabilities minus PNW Plan Assets, multiplied by (ii) the proportional share of Pension and OPEB Liabilities related to the Facilities as determined by the Operating Agent's Actuary, multiplied by (iii) an allocation percentage of 34.76%. This product shall reflect an adjustment whereby (a) amounts billed by the Operating Agent to Seller since 1982 related to Pension and OPEB Liabilities shall be assumed to have been invested in PNW Plan Assets since such billed amounts' respective years of payment, and (b) the Operating Agent and its Affiliates shall be deemed to have made contributions in respect of Pension and OPEB Liabilities at at least the same rate as the Facilities Owners, and such contributions shall be assumed to have been invested in PNW Plan Assets.

1.1.80 **Tax**. "**Tax**" means any federal, Tribal Authority, state, local or foreign income, gross receipts, license, payroll, employment, excise, severance, stamp, occupation, premium, windfall profits, environmental, (including taxes under Code Section 59A), customs duties, capital stock, franchise, profits, withholding, social security (or similar), unemployment, disability, real property (including assessments, fees or other charges based on the use or ownership of real property), personal property, transactional, use, transfer, registration, value added, alternative or add-on minimum, estimated tax, or other tax of any kind whatsoever, including any interest, penalty or addition thereto, whether disputed or not, including, without limitation, any item for which liability arises as a transferee or successor-in-interest.

1.1.81 **Tax Return**. "**Tax Return**" means any return, report, information return, declaration, claim for refund, or other document, together with all amendments and supplements thereto (including all related or supporting information), required to be supplied to any Governmental Authority responsible for the administration of Laws governing Taxes.

1.1.82 **Termination Agreement**. "**Termination Agreement**" means the agreement entered into on or about the Effective Date between Seller and Purchaser with respect to the termination of the Edison-Arizona Transmission Agreement.

1.1.83 **Third Party Claim**. "**Third Party Claim**" means a claim by a Person that is not a member of the Seller Group or the Purchaser Group, including any claim for the costs of conducting Remediation or seeking an order or demanding that a Person undertake Remediation.

1.1.84 **Transferable Permits**. "**Transferable Permits**" means all those permits relating to the Facilities or the Facilities Switchyard (and all applications pertaining thereto) which are transferable under applicable law from Seller to Purchaser with or without a filing with, notice to, or consent or approval of any Governmental Authority.

1.1.85 **Transfer Tax**. "**Transfer Tax**" means any sales Tax, transaction privilege Tax, transaction Tax, conveyance fee, use Tax, stamp Tax, stock transfer Tax or other similar Tax, including any related penalties, interest and additions thereto.

1.1.86 **Tribal Authority**. "**Tribal Authority**" means any sovereign nation recognized by the United States government, Indian tribe, or any governmental subdivision, agency, department, or instrumentality thereof with the authority to administer and collect Taxes, administer and enforce tribal laws and administer and enforce tribal agency processes.

1.2 Index of Other Defined Terms.

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1.3 <u>**Interpretation**</u>. In this Agreement, unless a clear contrary intention appears:

(a) the singular number includes the plural number and vice versa;

(b) reference to any Person includes such Person's successors and assigns but, if applicable, only if such successors and assigns are permitted by this Agreement, and reference to a Person in a particular capacity excludes such Person in any other capacity;

(c) reference to any gender includes each other gender;

(d) reference to any agreement (including this Agreement), document or instrument means such agreement, document or instrument as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof;

(e) reference to any Article, Section, Schedule or Exhibit means such Article, Section, Schedule or Exhibit to this Agreement, and references in any Article, Section, Schedule, Exhibit or definition to any clause means such clause of such Article, Section, Schedule, Exhibit or definition;

(f) "hereunder," "hereof," "hereto" and words of similar import are references to this Agreement as a whole and not to any particular Section or other provision hereof or thereof;

(g) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term;

(h) relative to the determination of any period of time, "from" means "from and including," "to" means "to but excluding" and "through" means "through and including;"

(i) reference to any law (including statutes and ordinances) means such law as amended, modified, codified or reenacted, in whole or in part, and in effect from time to time, including rules and regulations promulgated thereunder; and

(j) any agreement, instrument, insurance policy, statute, regulation, rule or order defined or referred to herein or in any agreement or instrument that is referred to herein means such agreement, instrument, insurance, policy, statute, regulation, rule or order as from time to time amended, modified or supplemented, including (in the case of agreements or instruments) by waiver or consent and (in the case of statutes, regulations, rules or orders) by succession of comparable successor statutes, regulations, rules or orders and references to all attachments thereto and instruments incorporated therein.

ARTICLE 2
PURCHASE AND SALE OF ASSETS

2.1 Transfer of Assets. Upon the terms and subject to the satisfaction of the conditions contained in this Agreement, at the Closing, Seller will sell, convey, assign, transfer and deliver to Purchaser and Purchaser will purchase and acquire from Seller, all of Seller's interest in the Facilities and the Facilities Switchyard, including Seller's undivided interest therein as a tenant in common, which Seller owns or to which Seller has rights by reason of any of the Facilities Contracts, free and clear of all Encumbrances other than Permitted Encumbrances, including, without limitation, Seller's interest in the following, but excluding all Excluded Assets (collectively, the "**Assets**"):

(a) **Real Property Rights**. The parcels of real property (or interests therein), if any, owned by Seller, or by the Operating Agent on behalf of Seller, as one of the Facilities Owners, relating to the Facilities or the Facilities Switchyard, together with all buildings, facilities and other improvements thereon and all appurtenances thereto, including all construction work in process (the **"Owned Real Property"**);

(b) **Leased Real Property**. The real property leasehold estates and the related lease or sublease agreements, if any, related to the Facilities or the Facilities Switchyard, together with all buildings, fixtures and real property improvements thereon and thereto, including all construction work in process (the **"Leased Property"**), including, without limitation, the items set forth on Schedule 2.1(b);

(c) **Rights-of-Way/Easements and Water Rights**. All rights-of-way, easements, grants and privileges (including all water rights) appurtenant to the Owned Real Property or the Leased Property, including, without limitation, the items set forth on Schedule 2.1(c);

(d) **Equipment**. All machinery, mobile or otherwise, equipment (including computer hardware and software and communications equipment), vehicles, tools, fixtures, furniture and furnishings, and other tangible personal property that (i) are not Inventory, (ii) are licensed, owned or leased by Seller, or the Operating Agent, on behalf of the Facilities Owners or on behalf of Seller, as one of the Facilities Owners, as of the Closing, and (iii) are related to, used, or useful, in the operation of the Facilities or the Facilities Switchyard, or are typically located at the Facilities, the Facilities Switchyard, the Navajo Mine or other locations or facilities which are owned, operated, maintained or under the control of the Operating Agent;

(e) **Fuel Inventory**. All coal under contract or in inventory relating to the operation of the Facilities located at or in transit to the Facilities (the **"Fuel Inventory"**);

(f) **Inventory**. The following items intended to be consumed at the Facilities or the Facilities Switchyard in the ordinary course of business: inventories of spare parts; maintenance, shop and office supplies; and other similar items of tangible personal property in existence as of the Closing, wherever located, excluding Fuel Inventory (the **"Inventory"**);

(g) **Emission Allowances**. All Emission Allowances, except for allowances which are to be retained by Seller pursuant to Section 2.2(k) or Section 2.2(l);

(h) **Facilities Contracts**. Subject to the receipt of necessary consents and approvals, the contracts, agreements, arrangements, licenses and leases of any nature, (i) to which Seller, in its capacity as a Facilities Owner, is a party, including, without limitation, the items set forth on Schedule 2.1(h), or (ii) to which the Operating Agent, on behalf of the Facilities Owners or on behalf of Seller, as one of the Facilities Owners, is a party, and by or to which Seller, the Facilities, or the Facilities Switchyard are bound or subject, in each case relating to the ownership, lease, maintenance or operation of the Facilities or the Facilities Switchyard (the **"Facilities Contracts"**); provided that Seller shall retain all rights under the Facilities Contracts with respect to any Excluded Assets or Excluded Liabilities;

(i) __Permits, Licenses, Etc__. Subject to the receipt of necessary consents and approvals, the Transferable Permits and any other permits, licenses, approvals, registrations, franchises, certificates, other authorizations and consents of Governmental Authorities relating to the ownership, lease, maintenance or operation of the Facilities or the Facilities Switchyard that, in each case, as of the Closing are in favor of the Facilities Owners, or the Operating Agent, as agent for the Facilities Owners, except for and to the extent that such licenses, permits, approvals, registrations, franchises, certificates, other authorizations and consents relate to Excluded Assets (the "**Facilities Permits**");

(j) __Documents__. The books, records, materials, documents, information, drawings, reports, operating data, operating safety and maintenance manuals, inspection reports, engineering design plans, blueprints, specifications, and procedures and similar items (i) located at and relating to the Facilities or the Facilities Switchyard or (ii) otherwise relating to the Facilities or the Facilities Switchyard and owned by the Facilities Owners in common or by the Operating Agent as agent for the Facilities Owners (the "**Facilities Documents**"); provided that Seller may retain, at its own expense, and may use subject to any confidentiality obligations that may apply to the Facilities Owners, copies of any Facilities Documents related to any Excluded Assets or Excluded Liabilities;

(k) __Third Party Warranties__. All unexpired, transferable warranties and guarantees from third parties with respect to the Facilities or the Facilities Switchyard or arising out of the Facilities Contracts or any contracts entered into thereunder, except to the extent they relate to Excluded Assets or Excluded Liabilities;

(l) __Intellectual Property__. All intangible assets of an intellectual property nature, including all patents and patent rights, trademarks and trademark rights, inventions, trade names and copyrights relating to the Facilities or the Facilities Switchyard, including the name of the Facilities and the Facilities Switchyard and all pending applications therefor, together with any trade secrets relating to the Facilities or the Facilities Switchyard, in each case that are owned in common by the Facilities Owners or by the Operating Agent as agent for the Facilities Owners;

(m) __Claims, Rights and Causes of Action__. All rights in, to and under (i) any claims, rights or causes of action against any third parties (including indemnification, contribution and insurance claims) relating to the Assets or the Assumed Liabilities, whether occurring prior to, on or after the Closing, if any, including any claims for refunds, prepayments, offsets, recoupment, insurance proceeds, condemnation awards, judgments and the like; whether received as payment or credit against future liabilities, and (ii) any actual or potential claim or cause of action as a Facilities Owner against the Operating Agent, whether known or unknown, contingent or accrued, arising prior to and in existence at the Closing, except in each case for Excluded Claims;

(n) __Prepayment__. Advance payments, prepayments, prepaid expenses, deposits and the like (i) made by Seller or the Operating Agent on Seller's behalf in the ordinary course of business prior to the Closing specifically with respect to the Facilities or the Facilities Switchyard, (ii) which exist as of the Closing and (iii) with respect to which Purchaser will receive the benefit after the Closing;

(o) **Insurance Proceeds**. The right to any proceeds from insurance policies to the extent covering the Assets or the Assumed Liabilities, except for Excluded Claims; and

(p) **Miscellaneous**. Any miscellaneous assets necessary, useful or used in or ancillary to operating the Facilities or the Facilities Switchyard and primarily utilized in connection therewith but not otherwise enumerated above, including, without limitation, the assets specified on Schedule 2.1(p), except for Excluded Assets, which in the ordinary course of business are typically located at the Facilities, the Facilities Switchyard, the Navajo Mine or other locations or facilities which are owned, operated, maintained or under the control of the Operating Agent or one of its Affiliates.

2.2 Excluded Assets. Nothing in this Agreement will constitute or be construed as conferring on Purchaser, and Purchaser is not acquiring, any right, title or interest of Seller in or to the following (the "**Excluded Assets**"), except to the extent Seller owns an interest in any such physical assets as a tenant in common with the other Facilities Owners, in which event such interests in such assets are Assets:

(a) the assets listed or described on Schedule 2.2(a), which are associated with the Assets but are specifically excluded from the sale;

(b) certificates of deposit, shares of stock, securities, bonds, debentures, evidences of indebtedness, and interests in joint ventures, partnerships, limited liability companies and other entities;

(c) all cash, cash equivalents, bank deposits, accounts and notes receivable (trade or otherwise), except for such assets on deposit with, or under the control of, the Operating Agent;

(d) any and all data and information pertaining to customers of Seller or its Affiliates;

(e) rights in, to and under all agreements and arrangements of any nature, which are not assigned to Purchaser under the terms of this Agreement, including any agreements for the sale by Seller of energy, capacity or ancillary services from the Facilities prior to the Closing, and any trade accounts receivable and all collateral, security arrangements, notes, bonds, and other evidences of indebtedness of and rights to receive payments arising out of or related to such sales, including any rights with respect to any third party collection procedures or any other actions or proceedings which have been commenced in connection therewith;

(f) rights arising under this Agreement or any instrument or document executed and delivered pursuant to the terms hereof;

(g) any and all books and records not described in Section 2.1(j);

(h) any rights in, to and under (i) any claims, rights or causes of action against any third parties (including indemnification, contribution and insurance claims) relating to the Excluded Assets or the Excluded Liabilities, whether occurring prior to, on or after the Closing, if any, including any claims for refunds, prepayments, offsets, recoupment, insurance proceeds, condemnation awards, judgments and the like; whether received as payment or credit against future liabilities and (ii) any actual or potential claim or cause of action as a Facilities Owner against the Operating Agent, whether known or unknown, contingent or accrued, arising prior to and in existence at the Closing relating to the Excluded Assets or the Excluded Liabilities (**"Excluded Claims"**);

(i) all privileged or proprietary books, records, materials, documents, information, drawings, reports, operating data, operating safety and maintenance manuals, inspection reports, engineering design plans, blueprints, specifications, and procedures and similar items not owned by the Facilities Owners in common or by the Operating Agent as agent for the Facilities Owners and any and all rights to use the same, including, without limitation, intangible assets of an intellectual property nature such as trademarks, service marks and trade names (whether or not registered), computer software that is proprietary to Seller, or the use of which under the pertinent license therefor is limited to operation by Seller or its Affiliates or on equipment owned by Seller or its Affiliates;

(j) the right to receive mail and other communications relating to any of the Excluded Assets or Excluded Liabilities, all of which mail and other communications shall be promptly forwarded by Purchaser to Seller;

(k) Emission Allowances for sulfur dioxide (SO_2) (**"SO_2 Emission Allowances"**) related to Seller's share of the Facilities that are of past vintage as of the Closing Date and either: (i) already distributed to Seller as of the Closing Date; or (ii) in excess of the amount needed to cover the Facilities' SO_2 emissions corresponding to Seller's ownership interest in the previous calendar year, but not yet distributed to Seller as of the Closing Date; and Seller's share of the proceeds from any United States Environmental Protection Agency auction of SO_2 Emission Allowances related to the Facilities occurring before the Closing Date, even if such proceeds have not yet been distributed as of the Closing Date;

(l) any Carbon Emission Allowances or rights thereto retained by Seller under Section 2.6;

(m) properties of Seller that are not used in the ownership or operation of the Assets, or that relate to the Excluded Liabilities; and

(n) any rights specifically excluded from the definition of the Assets under Section 2.1.

At any time or from time to time, up to ninety (90) days following the Closing, any and all of the Excluded Assets may be removed from the Facilities and the Facilities Switchyard by Seller (at no expense to Purchaser, but without charge by Purchaser for temporary storage), provided that Seller shall do so in a manner that does not unduly or unnecessarily disrupt normal business activities at the Facilities and the Facilities Switchyard, and provided further that Excluded Assets may be retained at the Facilities and the Facilities Switchyard to the extent permitted by easements, licenses, agreements or similar arrangements in favor of Seller.

2.3 Assumption of Liabilities. From and after the Closing, Purchaser will assume the following obligations and liabilities of Seller to the extent such obligations and liabilities relate to the Assets (the "**Assumed Liabilities**"):

(a) All liabilities or obligations (including, without limitation, any fines, penalties or costs imposed by a Governmental Authority) arising under Environmental Laws (whether such laws are enacted before or after the Closing Date), and all liabilities and obligations relating to Environmental Conditions or Hazardous Substances, in each case to the extent attributable to actions or failures to act occurring, or conditions first arising, after the Closing Date in connection with Purchaser's ownership of the Assets or the operation thereof or with respect to the Navajo Mine, including any threatened Releases that do not exist prior to the Closing Date;

(b) Except for the payment obligations pro-rated to Seller under Section 3.6, or as specifically contemplated under Section 2.4, all liabilities and obligations under all agreements, contracts, undertakings, and licenses assigned to Purchaser under this Agreement, including the Facilities Contracts, and the Transferable Permits in accordance with the terms thereof, except in each case to the extent such liabilities and obligations were incurred by Seller prior to the Closing Date;

(c) All liabilities and obligations of Seller with respect to decommissioning the Facilities and the Facilities Switchyard, including without limitation the dismantling and removal of the Facilities and the Facilities Switchyard and the restoration of their sites, as described in the Decommissioning Report (collectively, "**Decommissioning**"). Notwithstanding the foregoing, the Decommissioning liabilities and obligations assumed by Purchaser do not include Excess Decommissioning Costs which would otherwise constitute Retained Environmental Liabilities and do not include liabilities and costs identified in Section 2.4(j). "**Excess Decommissioning Costs**" mean, for any work included in the Decommissioning Report, the decommissioning costs related thereto arising from (i) changes in Environmental Laws after the Effective Date, or (ii) Remediation activities for Environmental Conditions not reflected in the cost estimate in the Decommissioning Report including, without limitation, any decommissioning activities related to Morgan Lake or for soil and subsurface Environmental Conditions, which, in either case, imposes additional costs on Purchaser in excess of the cost estimate, if any, for that work in the Decommissioning Report on an inflation adjusted basis;

(d) All costs of modifications to the Facilities or their operations or of supplemental environmental projects legally required to operate the Facilities after the Closing or agreed to by the Facilities Owners (other than the amount of any fines or penalties which would otherwise constitute Retained Environmental Liabilities that were avoided by the agreement to implement the supplemental environmental projects, which amount shall be (i) as specified in the related settlement, (ii) as agreed to by the Parties if such amount is not specified and (iii) as determined by the provisions of Section 11.10 if the amount is not specified and the Parties are unable to agree), whether or not the liabilities or obligations related to such costs are alleged, claimed, enforced, settled or paid for after the Closing Date, including without limitation the costs of any selective catalytic reduction technology or modifications to the Facilities related to the storage or handling of coal ash or other coal combustion residuals required to operate the Facilities after the Closing except, with respect to the storage or handling of coal ash or other coal combustion residuals, to the extent that such costs would have been required even if the Plant were to be shut down on or about July 6, 2016.;

(e) All other liabilities expressly allocated to Purchaser in the Agreement;

(f) Subject to Section 3.2(e) and Section 3.3(b), all of Seller's share of any liabilities or obligations of the Operating Agent or its Affiliates with respect to pensions or other post-employment benefits attributable to Operating Agent's operation of the Facilities;

(g) All Seller's obligations, if any, under the Facilities Contracts, (i) with respect to any Capital Expenditures that Seller cannot fund under California law, and (ii) to fund selective catalytic reduction technology if legally required to be installed at the Facilities; and

(h) All liabilities and obligations of Seller with respect to post-Closing reclamation and all final reclamation of the Navajo Mine, and the site comprising the same or on which the Navajo Mine exists or has existed as detailed in the Reclamation Report (collectively, "**Reclamation**"). Notwithstanding the foregoing, the Reclamation liabilities and obligations assumed by Purchaser do not include Excess Reclamation Costs which would otherwise constitute Retained Environmental Liabilities. "**Excess Reclamation Costs**" means, for any work included in the Reclamation Report, the reclamation costs related thereto arising from (i) changes in Environmental Laws after the Effective Date, or (ii) Remediation activities for Environmental Conditions not reflected in the cost estimate in the Reclamation Report which, in either case, imposes additional costs on Purchaser in excess of the cost estimate, if any, for that work in the Reclamation Report (as supplemented by the Cost Update) on an inflation adjusted basis. "**Cost Update**" means the Marston (Final Report) FCPP Reclamation Cost Table 2010 previously delivered by the Operating Agent to the Facilities Owners on September 21, 2010.

For the avoidance of doubt, Purchaser is not assuming any liabilities or obligations of any of the Facilities Owners other than Seller pursuant to this Agreement.

2.4 Excluded Liabilities. Purchaser shall not assume or be obligated to pay, perform or otherwise discharge any liabilities or obligations of Seller other than the Assumed Liabilities. All obligations and liabilities of Seller other than the Assumed Liabilities are referred to herein as the "**Excluded Liabilities**", all of which Excluded Liabilities shall remain the sole responsibility of Seller. The Excluded Liabilities include, without limitation, the following:

(a) Any liabilities or obligations of Seller in respect of any Excluded Assets or other assets which are not Assets and the ownership, operation and conduct of any business in connection therewith or therefrom;

(b) Any liabilities or obligations of Seller in respect of costs under Section 3.6 and Taxes attributable to the ownership, operation or use of Assets before the Closing Date (except for Taxes for which Purchaser is liable pursuant to Section 3.6) and any Taxes for which Seller is liable under Section 6.5;

(c) Except as otherwise specifically set forth in Section 2.3 herein, liabilities or obligations arising prior to the Closing Date under any of the agreements or contracts assumed by Purchaser, including the Facilities Contracts;

(d) Liabilities or obligations under any of the Facilities Contracts which would be included in the Assets but for the provisions of Section 3.7, unless Purchaser is provided with the benefits thereunder as contemplated by Section 3.7;

(e) Except as otherwise set forth in Section 2.4(i), any fines, penalties or costs, other than costs specified in Section 2.3(d), imposed by a Governmental Authority with respect to the Assets resulting from (i) an investigation, proceeding, request for information or inspection before or by a Governmental Authority pending or, to Seller's Knowledge, threatened prior to Closing, but only relating to actions or omissions or conditions existing prior to the Closing Date or (ii) violations of applicable law or illegal acts of Seller;

(f) Any liability of Seller arising out of a breach by Seller of any of its obligations under this Agreement, the Confidentiality Agreement or the Ancillary Agreements;

(g) Any obligation of Seller to indemnify any Person who is a member of the Purchaser Group pursuant to ARTICLE 7;

(h) Any costs or expenses for which Seller is liable under this Agreement;

(i) Seller's share of all liabilities or obligations (including, without limitation, any fines, penalties or costs imposed by a Governmental Authority) arising under Environmental Laws (whether such laws are enacted before or after the Closing Date), and all liabilities or obligations relating to Environmental Conditions or Hazardous Substances, to the extent attributable to actions or failures to act occurring, or conditions first arising, prior to the Closing Date in connection with Seller's ownership of the Assets or the operation thereof or with respect to the Navajo Mine, whether or not such liabilities and obligations are alleged, claimed, enforced, settled, or paid for after the Closing Date (the **"Retained Environmental Liabilities"**), but excluding all liabilities assumed by Purchaser under Section 2.3(c), Section 2.3(d) and Section 2.3(h), and related to any threatened Releases that do not exist prior to the Closing Date;

(j) Seller's share of the costs of Remediation or removal of the Landfill if the Facilities Owners are required to Remediate or remove such Landfill under Laws, the Facilities Lease or the § 323 Grants.

2.5 Control of Litigation.

(a) The Parties acknowledge and agree that, from and after the Closing Date, as between Seller and Purchaser, Seller shall be entitled exclusively to control, defend and settle any suit, action, proceeding or investigation arising out of or related to any Excluded Assets, Excluded Liabilities or Tax and related audit, appeals process or litigation for taxable periods occurring prior to the Closing Date, in each case, not involving claims against the Operating Agent or the other Facilities Owners, and Purchaser agrees to cooperate reasonably in connection therewith, it being understood that Purchaser shall not be required to incur any cost in connection with any such settlement but may be required to provide a release to a third party claimant in respect of the specific matters involved in such suit, action, proceeding or investigation; provided, however, that Seller shall reimburse Purchaser for all reasonable costs and expenses incurred in providing such cooperation to Seller and shall not unreasonably interfere with operations at the Facilities or the Facilities Switchyard.

(b) The Parties acknowledge and agree that, from and after the Closing Date, as between Seller and Purchaser, Purchaser shall be entitled exclusively to control, defend and settle any suit, action, proceeding or investigation arising out of or related to any Assets or Assumed Liabilities, in each case, not involving Excluded Assets or Excluded Liabilities, and Seller agrees to cooperate reasonably in connection therewith, it being understood that Seller shall not be required to incur any cost in connection with any such settlement but may be required to provide a release to a third party claimant in respect of the specific matters involved in such suit, action, proceeding, or investigation; provided, however, that Purchaser shall reimburse Seller for all reasonable costs and expenses incurred in providing such cooperation to Purchaser and shall not unreasonably interfere with Seller's operations.

(c) For suits, actions, proceedings, or investigations arising out of or related to both Excluded Assets and/or Excluded Liabilities, and Assets and/or Assumed Liabilities:

(i) For suits, actions, proceedings or investigations which are reasonably expected to result in costs and liabilities to Seller of less than two hundred fifty thousand dollars ($250,000) and in which Seller is not a named party, such matters shall be controlled and defended by the Operating Agent under the Facilities Operating Agreement, with Seller exercising the rights it retains under Section 2.1(h) through Purchaser and the costs thereof allocated between Seller and Purchaser in accordance with the allocation of Assumed Liabilities and Excluded Liabilities under this Agreement, provided that to the extent not already required by Seller's retention of rights it retains under Section 2.1(h):

(1) Purchaser shall keep Seller informed of material developments related to such suits, actions, proceedings or investigations in a timely manner;

(2) Seller's approval shall be required for any compromise or settlement of any liability or obligation of Seller, such approval not to be unreasonably withheld; and

(3) Seller's approval shall be required for any admission of liability or guilt in any civil or criminal matter, with such approval at Seller's sole discretion.

(ii) For all other suits, actions, proceedings or investigations, the Parties agree to coordinate with each other with respect to the defense thereof. Without limiting the foregoing, for suits, actions, proceedings or investigations in which Seller and Purchaser are named parties, Seller and Purchaser shall discuss the feasibility of having one counsel represent Seller and Purchaser.

2.6 Carbon Emission Allowances.

(a) To the extent that legislation and/or regulations creating and allocating Carbon Emission Allowances are adopted after the Effective Date, the Parties agree that Seller shall receive the Carbon Emission Allowances to which it would have been entitled if (i) the Facilities were operated through July 6, 2016 and (ii) Seller retained its current interest in the Facilities through that date. Accordingly:

(i) **Carbon Emission Allowances allocated by a Governmental Authority before July 6, 2016**: Seller will retain any Carbon Emission Allowances allocated to Seller, or attributable to a 48% share of the Units 4 and 5 at the Plant (**"Seller's Facilities Share"**), and Purchaser will surrender to Seller any such Carbon Emission Allowances attributable to Seller's Facilities Share, except that Seller will surrender to Purchaser or Purchaser will retain the Carbon Emission Allowances needed to cover the operation of Seller's Facilities Share from the Closing through July 6, 2016. After the Closing, Seller shall have no obligation to purchase any Carbon Emission Allowances if the amount of Carbon Emission Allowances allocated to Seller or attributable to Seller's Facilities Share is less than the amount needed to cover such operation;

(ii) **Carbon Emission Allowances allocated by a Governmental Authority after July 6, 2016 based on any pre-July 6, 2016 measurement period**: Seller will retain any Carbon Emission Allowances allocated to Seller, or attributable to Seller's Facilities Share, and Purchaser will surrender to Seller any such Carbon Emission Allowances attributable to Seller's Facilities Share; and

(iii) **Carbon Emission Allowances allocated by a Governmental Authority after July 6, 2016 based on a post-July 6, 2016 measurement period**: Seller will surrender to Purchaser or Purchaser will retain any such Carbon Emission Allowances.

(b) If, prior to July 6, 2016, Purchaser has the option of selecting a measurement period for Carbon Emission Allowances for the Facilities, then the Carbon Emission Allowances to be retained by or surrendered to Seller shall be calculated as if Purchaser had selected the measurement period which results in the highest amount of Carbon Emission Allowances retained by or surrendered to Seller.

2.7 California Capacity Rights. If the Closing Date occurs prior to October 1, 2012, Seller will have the month-by-month option to retain the capacity rights for the Seller's Facilities Share for purposes of satisfying the requirements of California's Resource Adequacy program for each month from the Closing Date until October 1, 2012. Seller may exercise such option by providing Purchaser with twenty days advanced prior written notice of the exercise of such option for each such month; provided that with respect to the month in which the Closing Date occurs, if Seller has not been able to provide twenty days advanced prior written notice, Seller shall be deemed not to have exercised such option. In no event shall Purchaser have any obligation to secure replacement capacity or any other remedy in the event the Facilities are not operating at full capacity. For any month after the Closing Date for which Seller retains the capacity rights for Seller's Facilities Share, Purchaser shall, and shall have the exclusive authority to, submit or cause to be submitted all bids, including but not limited to supply bids for energy, self-schedules and self-provision of ancillary services for Seller's Facilities Share in the California ISO day-ahead market, hour-ahead scheduling process and real-time market, as required for Seller to satisfy the requirements of California's Resource Adequacy program. All revenues produced from such bids and self-schedules from the day-ahead market, hour-ahead scheduling process, real-time market and other revenues (including but not limited to revenues from ancillary services, the integrated forward market and residual unit commitment) related to Seller's Facilities Share flowing from mechanisms other than the capacity market shall accrue to Purchaser. If the energy is called for, Purchaser will deliver such energy to the Moenkopi

Switchyard. Any wheeling costs for energy delivery incurred by Seller for delivery of energy from the Moenkopi Switchyard to the middle of the Colorado River will be netted from Purchaser's market energy revenues.

ARTICLE 3
CLOSING

3.1 **Closing**. The closing of the sale of the Assets to, and the assumption of the Assumed Liabilities by, Purchaser (the "**Closing**") will take place at the offices of Arizona Public Service Company, 400 North Fifth Street, Phoenix, Arizona 85004, at 10:00 a.m. local time on the first day of the first full month following the date on which the conditions set forth in ARTICLE 8 and ARTICLE 9 have been either satisfied or waived by the Party for whose benefit such conditions precedent exist, or if such day is not a Business Day, on the next succeeding Business Day, or on such other date and at such other place as the Parties may mutually agree. The time and date of Closing is hereinafter called the "**Closing Date.**" Notwithstanding anything in this Agreement to the contrary, the Closing shall be deemed to have taken place at 12:01 a.m., Fruitland, New Mexico prevailing time, on the Closing Date, or if the Closing Date is not the first day of the month because such day is not a Business Day, on the first day of the month.

3.2 **Purchase Price**. At or, as applicable, after, the Closing, the Initial Purchase Price shall be adjusted, without duplication, to account for the following items and Closing Adjustments, and Post-Closing Adjustments, as set forth in Section 3.3, the sum of which is hereinafter referred to as the "**Purchase Price**":

(a) **Prorations**. The Initial Purchase Price shall be adjusted to account for the items prorated as of the Closing Date pursuant to Section 3.6.

(b) **Capital Expenditures**. Subject to Section 6.6, the Initial Purchase Price will be increased by an amount equal to (i) the aggregate Capital Expenditures funded by Seller during 2010 and 2011 in excess of its share of the aggregate 2010 and 2011 capital budgets for the Facilities approved by the Facilities Owners, plus (ii) Capital Expenditures funded by Seller during 2012 and thereafter, until the Closing Date, in each case minus the amount of any depreciation Seller incurred as a result of such Capital Expenditures through the Closing Date; provided, however, that any costs or expenditures for which Seller is responsible under Section 2.4(i), or which are made on an emergency basis to address actual or anticipated equipment failures that would adversely affect the operating capacity of the Facilities prior to Closing and are economically viable to Seller ("**Emergency Capital Expenditures**"), will not increase the Initial Purchase Price; provided further that, with respect to Emergency Capital Expenditures made in 2012 and thereafter, Seller has received appropriate regulatory approval of cost recovery for such Emergency Capital Expenditures. For purposes of the foregoing, an Emergency Capital Expenditure will be considered economically viable if the net benefits to Seller associated with making the repair up to the Closing Date exceed the net costs to Seller associated with making the repair. This provision is intended only to address potential adjustments to the Initial Purchase Price, and is not intended to modify the parties' rights and obligations under the Facilities Contracts.

(c) **Timing of Closing**. If the Closing Date is prior to October 1, 2012, the Initial Purchase Price shall be increased by Seven Million Five Hundred Thousand Dollars ($7,500,000) for each month between the Closing Date and October 1, 2012 and if the Closing Date is after October 1, 2012, the Initial Purchase Price shall be decreased by Seven Million Five Hundred Thousand Dollars ($7,500,000) for each month between October 1, 2012 and the Closing Date.

(d) **California Capacity Rights**. If Seller exercises its option under Section 2.7, the Initial Purchase Price shall be decreased by Three Million Dollars ($3,000,000) per month for each month for which Seller exercises its option to retain such capacity rights.

(e) **Pension and OPEB Liabilities.** If Seller's Share of Underfunded/Overfunded Pension and OPEB Liabilities is greater than $0, the Initial Purchase Price shall be decreased by such amount, otherwise the Initial Purchase Price shall be increased by the absolute value of such amount, in each case, determined as of the Closing Date pursuant to Section 3.3(b).

3.3 Pre-Closing and Post-Closing Adjustments.

(a) At least thirty (30) calendar days prior to the Closing Date, Purchaser, with the assistance and participation of, and in consultation with, Seller, shall prepare and deliver to Seller an estimated closing statement (the "**Estimated Closing Statement**") that shall set forth Purchaser's best estimate of all estimated adjustments to the Initial Purchase Price required by Section 3.2 (the "**Estimated Adjustment**"). Within ten (10) calendar days after the delivery of the Estimated Closing Statement by Purchaser to Seller, Seller may object in good faith to the Estimated Adjustment in writing. If Seller objects to the Estimated Adjustment within such ten (10) day period, the Parties shall attempt to resolve their differences by negotiation. If the Parties are unable to do so prior to the Closing Date (or if Seller does not object to the Estimated Adjustment), the Initial Purchase Price shall be adjusted (the "**Closing Adjustment**") at the Closing by the amount of the Estimated Adjustment not in dispute. The disputed portion shall be resolved in accordance with the provisions of Section 3.3(b) and paid as part of any Post-Closing Adjustment to the extent required by Section 3.3(b).

(b) Within sixty (60) days after the Closing Date, Purchaser, with the assistance and participation of, and in consultation with, Seller shall prepare and deliver to Seller a final closing statement (the "**Post-Closing Statement**") that shall set forth all adjustments to the Initial Purchase Price proposed by Purchaser to be required by Section 3.2(a) through 3.2(e) not previously effected by the Closing Adjustment (the "**Proposed Post-Closing Adjustment**"); provided that if any adjustments to be made pursuant to Section 3.2(d) cannot be made within sixty (60) days after the Closing Date, the Parties agree that additional Post-Closing Statements can be subsequently prepared to address such adjustments. To the extent applicable, the Post-Closing Statement shall be prepared using the same accounting principles, policies and methods as the Operating Agent has historically used in connection with the calculation of the items reflected on such Post-Closing Statement. Without limiting the generality of the foregoing, for matters covered by Section 3.2(e), the discount rate and other assumptions used to determine Pension and OPEB Liabilities as reflected in the Post-Closing Statement shall be selected using the same methodology historically used for selecting the discount rate and assumptions for

Pinnacle West Capital Corporation's consolidated fiscal year-end calculations reported in its audited financial statements. Within thirty (30) days after the delivery of the Post-Closing Statement by Purchaser to Seller, Seller may object in good faith to the Proposed Post-Closing Adjustment in writing, stating in reasonable detail its objections thereto. Purchaser and Seller agree to cooperate to exchange information used to prepare the Post-Closing Statement and information relating thereto. If Seller objects to the Proposed Post-Closing Adjustment, the Parties shall attempt to resolve such dispute by negotiation. If the Parties are unable to resolve such dispute within thirty (30) days after any objection by Seller, the Parties shall appoint the Independent Accounting Firm, which shall, at Seller's and Purchaser's joint expense, review the Proposed Post-Closing Adjustment and determine the appropriate adjustment to the Purchase Price, if any, within thirty (30) days after such appointment. The Parties agree to cooperate with the Independent Accounting Firm and provide it with such information as it reasonably requests to enable it to make such determination. For purposes of this Section 3.3(b) and wherever the Independent Accounting Firm is retained to resolve a dispute between the Parties, the Independent Accounting Firm may determine the issues in dispute following such procedures, consistent with the language of this Agreement, as it deems appropriate to the circumstances and with reference to the amounts in issue. No particular procedures are intended to be imposed upon the Independent Accounting Firm, it being the desire of the Parties that any such disagreement shall be resolved as expeditiously and inexpensively as reasonably practicable. The Independent Accounting Firm shall have no liability to the Parties in connection with such services except for acts of bad faith, willful misconduct or gross negligence, and the Parties shall provide such indemnities to the Independent Accounting Firm as it may reasonably request. The finding of such Independent Accounting Firm shall be binding on the Parties hereto. Upon determination of the appropriate adjustment (the "**Post-Closing Adjustment**") by agreement of the Parties or by binding determination of the Independent Accounting Firm, the Party owing the difference shall deliver such amount to the other Party no later than two (2) Business Days after such determination, in immediately available funds or in any other manner as reasonably requested by the payee.

3.4 **Payment**. Any cash payments required by this Agreement shall be paid in U.S. dollars in immediately available funds. The recipient of such funds will designate the account or accounts to which the funds will be wire transferred.

3.5 **Allocation of Purchase Price**. The Parties will file all Tax Returns consistently with the allocation of the Purchase Price determined in accordance with this Section 3.5. The allocation of the Purchase Price (including any portion of the Assumed Liabilities if applicable) will be negotiated by the Parties in accordance with Applicable Tax Law (as defined below). Purchaser shall propose and deliver to Seller a preliminary allocation among the Assets of the Purchase Price and such other consideration to be paid to Seller pursuant to this Agreement (an "**Allocation**") sufficiently far in advance of the Closing to allow the Final Pre-Closing Allocation referred to below to be determined prior to the Closing. The Allocation shall be consistent with Code Section 1060 ("**Applicable Tax Law**") and the regulations thereunder and in a manner which facilitates Property Tax reporting and shall separately allocate Assets in the Facilities Switchyard. Seller shall within thirty (30) days thereafter propose any changes to the Allocation. Within thirty (30) days following delivery of such proposed changes, Purchaser shall provide Seller with a statement of any objections to such proposed changes, together with a reasonably detailed explanation of the reasons therefor. If Purchaser and Seller are unable to resolve any disputed objections within ten (10) days thereafter, such objections shall be referred to the Independent Accounting Firm, which shall determine the Allocation (including any valuations). The Independent Accounting Firm shall be instructed to deliver to Purchaser and Seller a written determination of the proper allocation of such disputed items within twenty (20) Business Days from the date of engagement. Such determination shall be final, conclusive and binding upon the Parties for all purposes, and the Allocation shall be so adjusted (the allocation, including the adjustment, if any, to be referred to as the **"Final Pre-Closing Allocation"**). Within thirty (30) days of the determination of the Post-Closing Adjustment, the Parties shall agree to the adjustments to the Final Pre-Closing Allocation (**"Final Allocation"**). The fees and disbursements of the Independent Accounting Firm attributable to any Allocation shall be shared equally by Purchaser and Seller. Purchaser and Seller agree to timely file Internal Revenue Service Form 8594, and all Tax Returns, in accordance with such Allocation or Final Allocation, as the case may be, and to report the transactions contemplated by this Agreement for Federal Income tax and all other tax purposes in a manner consistent with the Allocation or Final Allocation, as the case may be. Purchaser and Seller agree to promptly provide the other Parties with any additional information and reasonable assistance required to complete Form 8594, or compute Taxes arising in connection with (or otherwise affected by) the transactions contemplated hereunder.

3.6 <u>Prorations.</u>

(a) Purchaser and Seller agree that, except as otherwise specifically provided in this Agreement, all of the budgeted, ordinary, and recurring items normally charged to the Facilities Owners, including those listed below (but not including any Income Taxes and Transfer Taxes), relating to the business and operation of the Assets, shall be prorated and charged as of the Closing Date, without any duplication of payment under the Facilities Contracts, with Seller liable to the extent such items relate to any time period prior to the Closing Date, and Purchaser liable to the extent such items relate to periods commencing with the Closing Date (measured in the same units used to compute the item in question, otherwise measured by calendar days):

(i) Property Taxes having a lien date in the same calendar year as the Closing Date, provided, however, with respect to any Property Taxes imposed by a Tribal Authority, such Property Taxes shall be prorated based upon that portion of the calendar year starting with the date of expiration of any applicable tax waiver and ending with the last day of the calendar year of the Closing Date;

(ii) Retrospective adjustments and policyholder distributions for the applicable period during which the Closing occurs with respect to Facilities Insurance Policies included in the Assets occurring within twelve (12) months of Closing or ninety (90) days after the year-end following the Closing, whichever occurs first; and

(iii) Operating and maintenance expenses incurred in any period prior to the Closing Date (not including Capital Expenditures) in the nature of the expenses shown on <u>Schedule 3.6(a)(iii)</u> but only to the extent that the amount of such expenses are determined within twelve (12) months of Closing or ninety (90) days after the year-end following the Closing, whichever occurs first.

(b) In connection with the prorations referred to in Section 3.6(a), in the event that actual figures are not available at the Closing Date, the proration shall be based upon the respective amounts accrued through the Closing Date or paid for the most recent year or other, appropriate period for which such amounts paid are available. All prorated amounts shall be recalculated and paid to the appropriate Party within sixty (60) days after the date that the previously unavailable actual figures become available. Seller and Purchaser shall furnish each other with such documents and other records as may be reasonably requested in order to confirm all proration calculations made pursuant to this Section 3.6.

3.7 No Assignment if Breach. To the extent that Seller's rights under any of the Facilities Contracts to be transferred to Purchaser hereunder may not be assigned without the consent of another Person which consent has not been obtained, this Agreement shall not constitute an agreement to assign the same if an attempted assignment would constitute a breach thereof or be unlawful, and Purchaser and Seller shall cooperate and each use Commercially Reasonable Efforts to obtain any such required consent(s) as promptly as possible. Seller and Purchaser agree that if any consent to an assignment of any of the Facilities Contracts to be transferred hereunder shall not be obtained or if any attempted assignment would be ineffective or would impair Purchaser's rights and obligations under the applicable Facilities Contracts so that Purchaser would not in effect acquire all such rights and obligations, Seller, to the maximum extent permitted by law and such Facilities Contracts, shall after the Closing appoint Purchaser to be Seller's representative and agent with respect to such Facilities Contracts, and Seller shall, to the maximum extent permitted by law and such Facilities Contracts, enter into such reasonable arrangements with Purchaser as are necessary to transfer to Purchaser the benefits and obligations of such Facilities Contracts. Seller and Purchaser shall cooperate and shall each use Commercially Reasonable Efforts after the Closing to obtain an assignment of such Facilities Contracts to Purchaser.

3.8 Deliveries by Seller. Subject to the terms and conditions hereof, at the Closing Seller shall deliver, or cause to be delivered, the following to Purchaser:

(a) The Deed, duly executed by Seller and in recordable form, subject only to Permitted Encumbrances and any owner's affidavits or similar documents reasonably required by Title Insurer;

(b) The Bill of Sale, duly executed by Seller;

(c) The Assignment and Assumption Agreement, duly executed by Seller;

(d) Evidence, in form and substance reasonably satisfactory to Purchaser and its respective counsel, of Seller's receipt of (i) Seller's Required Regulatory Approvals, (ii) Seller's Required Consents, and (iii) documentation evidencing the release of all Encumbrances, except for Permitted Encumbrances, including the release of Seller's Mortgage;

(e) A Certificate of Good Standing with respect to Seller, as of a recent date, issued by the Secretary of State of the State of California and of the state where the Facilities are located;

(f) To the extent available, originals of all of the Facilities Contracts to which Seller has Knowledge that it is a party (other than Facilities Contracts referenced in the proviso to Section 2.1(h)), the Transferable Permits issued to Seller and of which it has Knowledge and, if not available, true and correct copies thereof;

(g) A certificate addressed to Purchaser dated the Closing Date executed by a duly authorized officer of Seller to the effect set forth in Section 8.6;

(h) A FIRPTA Affidavit to Purchaser, duly executed by Seller;

(i) Copies, certified by the Secretary or Assistant Secretary of Seller, of corporate resolutions authorizing the execution and delivery of this Agreement, each Ancillary, Agreement to which Seller is a party and the authorization or ratification of all of the other agreements and instruments, in each case, to be executed and delivered by Seller in connection herewith;

(j) A certificate of the Secretary or Assistant Secretary of Seller identifying the name and title and bearing the signatures of the officers of Seller authorized to execute and deliver this Agreement, each Ancillary Agreement to which Seller, is a party and the other agreements and instruments contemplated hereby; and

(k) All such other agreements, documents, instruments and writings required to be delivered by Seller at or prior to the Closing Date pursuant to this Agreement necessary to sell, assign, convey, transfer and deliver all of Seller's rights, title and interests in and to the Assets, to Purchaser, in accordance with this Agreement and, where necessary or desirable, in recordable form.

3.9 Deliveries by Purchaser. Subject to the terms and conditions hereof, at the Closing, Purchaser shall deliver, or cause to be delivered, the following to Seller:

(a) The Purchase Price, by wire transfer of immediately available funds to the account of Seller designated by Seller in writing on or before the Closing Date;

(b) The Assignment and Assumption Agreement, duly executed by Purchaser;

(c) Evidence, in form and substance reasonably satisfactory to Seller and its respective counsel, of Purchaser's receipt of (i) Purchaser's Required Regulatory Approvals, and (ii) Purchaser's Required Consents;

(d) A Certificate of Good Standing with respect to Purchaser, as of a recent date, issued by the ACC and the state in which the Facilities are located;

(e) A certificate dated the Closing Date executed by a duly authorized officer of Purchaser to the effect set forth in Section 9.6;

(f) Copies, certified by the Secretary or Associate Secretary of Purchaser, of resolutions authorizing the execution and delivery of this Agreement, each Ancillary Agreement to which Purchaser is a party and the authorization or ratification of all of the agreements and instruments, in each case, to be executed and delivered by Purchaser in connection herewith;

(g) A certificate of the Secretary or Associate Secretary of Purchaser identifying the name and title and bearing the signatures of the officers of Purchaser authorized to execute and deliver this Agreement, each Ancillary Agreement to which Purchaser is a party and the other agreements contemplated hereby; and

(h) All such other agreements, documents, instruments and writings required to be delivered by Purchaser at or prior to the Closing Date pursuant to this Agreement.

3.10 **Facilities Contracts**. The Parties agree that between the date hereof and the Closing Date, the ownership, lease, maintenance and operation of the Facilities and the Facilities Switchyard will be governed by the Facilities Contracts.

ARTICLE 4
REPRESENTATIONS, WARRANTIES AND DISCLAIMERS OF SELLER

Except as set forth in Seller's Schedule of Exceptions corresponding to the Section of this Agreement to which such disclosure applies, Seller represents, warrants and, where specified, disclaims to Purchaser as follows:

4.1 **Organization and Existence**. Seller is a corporation, duly organized, validly existing and in good standing under the laws of the State of California and has all requisite corporate power and authority to own, lease and operate its properties and to carry on its business as is now being conducted. Seller is duly qualified to do business and is in good standing in the state where the Facilities are located. Seller has heretofore delivered to Purchaser complete and correct copies of its Articles of Incorporation and Bylaws as currently in effect.

4.2 **Execution, Delivery and Enforceability**. Seller has full corporate power to enter into, and carry out its obligations under, this Agreement and the Ancillary Agreements which are executed by Seller and to consummate the transactions contemplated hereby and thereby. The execution, delivery and performance of this Agreement and the Ancillary Agreements which are executed by Seller, and the consummation of the transactions contemplated hereby and thereby, have been duly and validly authorized by all necessary corporate action required on the part of Seller and no other corporate proceedings on the part of Seller are necessary to authorize this Agreement and the Ancillary Agreements to which it is a party or to consummate the transactions contemplated hereby and thereby. Assuming Purchaser's due authorization, execution and delivery of this Agreement and the Ancillary Agreements when executed by Purchaser, this Agreement does and the Ancillary Agreements when executed by Seller will constitute the valid and legally binding obligations of Seller, enforceable against Seller in accordance with its and their terms, except as such enforceability may be limited by bankruptcy, insolvency, reorganization, moratorium or other similar laws of general application relating to or affecting the enforcement of creditors' rights and by general equitable principles.

4.3 **No Violation**. Subject to Seller obtaining Seller's Required Regulatory Approvals and Seller's Required Consents, and except for compliance with the requirements of the HSR Act, neither the execution and delivery of this Agreement or any of the Ancillary

Agreements executed by Seller, nor the compliance with any provision hereof or thereof, nor the consummation of the transactions contemplated hereby or thereby will:

(a) violate, or conflict with, or result in a breach of any provisions of the Articles of Incorporation or Bylaws of Seller;

(b) result in a default (or give rise to any right of termination, cancellation or acceleration) under or conflict with any of the terms, conditions or provisions of any note, bond, mortgage, indenture, license, or agreement or other instrument or obligation to which Seller is a party or by which Seller or any of the Assets may be bound, except for such defaults (or rights of termination or acceleration) as to which requisite waivers or consents have been, or prior to the Closing will have been, obtained or which would not, individually or in the aggregate, create a Material Adverse Effect;

(c) violate any law, rule, regulation, order, writ, injunction, or decree, applicable to Seller or any of its assets, except where such violations, individually or in the aggregate, would not create a Material Adverse Effect and will not affect the validity or enforceability of this Agreement or the Ancillary Agreements or the validity of the transactions contemplated hereby or thereby; or

(d) require consent or approval of, filing with, or notice to any Person which, if not obtained would prevent Seller from performing its obligations hereunder.

4.4 **<u>Compliance with Laws</u>**. Seller has no Knowledge that it is in material violation of any laws, orders, ordinances, rules, regulations or judgment of any Governmental Authority in existence as of execution of this Agreement with respect to the Assets, except for (a) violations or alleged violations the subject matter of which Purchaser or the Operating Agent has Knowledge, (b) violations or alleged violations by the Facilities Owners in common, or by the Operating Agent acting on their behalf, or (c) violations or alleged violations that will not have a Material Adverse Effect.

4.5 **<u>Permits, Licenses, Etc</u>**. Prior to the Closing Date, Seller will hold all permits, registrations, franchises, certificates, licenses and other authorizations, consents and approvals of all Governmental Authorities that Seller requires in order to own any of the Assets (collectively, "**Seller Permits**"), except for such failures to hold such Seller Permits as to which Purchaser or the Operating Agent has Knowledge, are also failures of all of the other Facilities Owners (or all other than the Operating Agent) or would not, individually or in the aggregate, have a Material Adverse Effect.

4.6 **<u>Litigation</u>**. There is no claim, action, proceeding or investigation pending, or to Seller's Knowledge, threatened against or relating to Seller or its Affiliates before any court, arbitrator or Governmental Authority, or any judgment, decree or order of any court, arbitrator or Governmental Authority, which could, individually or in the aggregate, reasonably be expected to result, or has resulted, in (a) the institution of legal proceedings to prohibit or restrain the performance of this Agreement or any of the Ancillary Agreements, or the consummation of the transactions contemplated hereby or thereby, (b) a claim against Purchaser or its Affiliates for damages as a result of Seller entering into this Agreement or any of the Ancillary Agreements, or the consummation by Seller of the transactions contemplated hereby or thereby, (c) a material impairment of Seller's ability to perform its obligations under this Agreement or any of the Ancillary Agreements, or (d) a Material Adverse Effect, except for claims, actions, proceedings or investigations pending against, or judgments, decrees or orders involving all of the other Facilities Owners or the Operating Agent as agent for the Facilities Owners, or as to which Purchaser has Knowledge.

4.7 __Title__. Subject to the right of first refusal contained in the Facilities Co-Tenancy Agreement, Seller has good and marketable title, or valid and effective leasehold rights in the case of leased property, and valid and effective licenses in the case of licensed rights, to the tangible personal property included in the Assets to be sold, conveyed, assigned, transferred and delivered to Purchaser by Seller, free and clear of all liens, charges, claims, pledges, security interests, equities and encumbrances of any nature whatsoever, except for (a) those created by Purchaser, (b) those which will be discharged or released prior to or substantially simultaneously with, the Closing, (c) Permitted Encumbrances, (d) those which do not apply only and exclusively to the interest of Seller but that also apply to interests of the other Facilities Owners in common and/or the Operating Agent, as agent for any of the Facilities Owners, and (e) possible minor matters that do not materially interfere with the intended use of the Assets.

4.8 __Facilities Contracts__. Seller has no Knowledge of any claim, action, proceeding or investigation, pending or threatened, challenging the enforceability against Seller of the Facilities Contracts, except for challenges to the enforceability of such contracts against the Facilities Owners in common, challenges of which Purchaser or the Operating Agent has Knowledge, or challenges which are not likely to result in a Material Adverse Effect.

4.9 __Intellectual Property__. Seller does not own or otherwise have any right to use any patent, trade name, trademark, service mark or other intellectual property that is used in and necessary for the operation of the Facilities or the Facilities Switchyard, other than such as may be included in the Assets or is licensed to the Facilities Owners or the Operating Agent, acting on their behalf.

4.10 __Taxes__. At least sixty (60) Business Days before the Closing, Seller will advise Purchaser in writing of any taxing jurisdictions in which Seller owns assets or conducts business that require a notification to a taxing authority of the transactions contemplated by this Agreement, if the failure to make such notification, or obtain Tax clearances in connection therewith, would either require Purchaser to withhold any portion of the Purchase Price or would subject Purchaser to any liability for any Taxes of Seller.

4.11 __Undisclosed Liabilities__. Except for liabilities and obligations specifically referred to in __Section 2.3__ or __Section 2.4__, the Assets are not, to the Knowledge of Seller, subject to any liability or obligation that has arisen solely as a result of an act or omission by Seller, except for Permitted Encumbrances, acts or omissions of which Purchaser or the Operating Agent has Knowledge, or liabilities and obligations that are not reasonably likely to have a Material Adverse Effect.

4.12 __Brokers__. All negotiations relating to this Agreement and the transactions contemplated hereby have been carried on by Seller and in such a manner as not to give rise to any valid claim against Purchaser (by reason of Seller's actions) for a brokerage commission, finder's fee or other like payment to any Person.

ARTICLE 5
REPRESENTATIONS AND WARRANTIES OF PURCHASER

Except as set forth in Purchaser's Schedule of Exceptions corresponding to the Section of this Agreement to which such disclosure applies Purchaser represents, warrants and, where specified, disclaims to Seller as follows:

5.1 **Organization and Existence**. Purchaser is a corporation, duly organized, validly existing and in good standing under the laws of the State of Arizona and has all requisite corporate power and authority to own, lease and operate its properties and to carry on its business as is now being conducted. Purchaser has heretofore delivered to Seller complete and correct copies of its Articles of Incorporation and Bylaws as currently in effect.

5.2 **Execution, Delivery and Enforceability**. Purchaser has full corporate power to enter into, and carry out its obligations under, this Agreement and the Ancillary Agreements which are executed by Purchaser and to consummate the transactions contemplated hereby and thereby. The execution, delivery and performance of this Agreement and the Ancillary Agreements which are executed by Purchaser, and the consummation of the transactions contemplated hereby and thereby, have been duly and validly authorized by all necessary corporate action required on the part of Purchaser and no other corporate proceedings on the part of Purchaser are necessary to authorize this Agreement and the Ancillary Agreements to which it is a party or to consummate the transactions contemplated hereby and thereby. Assuming Seller's due authorization, execution and delivery of this Agreement and the Ancillary Agreements when executed by Seller, this Agreement does and the Ancillary Agreements when executed by Purchaser, will constitute the valid and legally binding obligations of Purchaser, enforceable against Purchaser in accordance with its and their terms, except as such enforceability may be limited by bankruptcy, insolvency, reorganization, moratorium or other similar laws of general application relating to or affecting the enforcement of creditors' rights and by general equitable principles.

5.3 **No Violation**. Subject to Purchaser obtaining the Purchaser's Required Regulatory Approvals and the Purchaser's Required Consents, and except for compliance with the requirements of the HSR Act, neither the execution and delivery of this Agreement or any of the Ancillary Agreements executed by Purchaser, nor the compliance with any provision hereof or thereof, nor the consummation of the transactions contemplated hereby or thereby will:

(a) violate, or conflict with, or result in a breach of any provisions of the Articles of Incorporation or Bylaws of Purchaser;

(b) result in a default (or give rise to any right of termination, cancellation or acceleration) under or conflict with any of the terms, conditions or provisions of any note, bond, mortgage, indenture, license, or agreement or other instrument or obligation to which Purchaser is a party or by which Purchaser may be bound, except for such defaults (or rights of termination or acceleration) as to which requisite waivers or consents have been, or prior to the Closing will have been, obtained or which would not, individually or in the aggregate, create a Material Adverse Effect;

(c) violate any law, rule, regulation, order, writ, injunction, or decree, applicable to Purchaser or any of its assets, except where such violations, individually or in the aggregate; would not create a Material Adverse Effect and will not affect the validity or enforceability of this Agreement or the Ancillary Agreements or the validity of the transactions contemplated hereby or thereby; or

(d) require consent or approval of, filing with, or notice to any Person which, if not obtained would prevent Purchaser from performing its obligations hereunder.

5.4 **<u>Compliance with Laws</u>**. Except as otherwise disclosed in writing by Purchaser to Seller contemporaneously with the execution of this Agreement, Purchaser has no Knowledge that it is in material violation of any applicable laws, orders, ordinances, rules, regulations or judgment of any Governmental Authority in existence as of the Effective Date with respect to the Assets, except for violations or alleged violations that are reasonably expected not to have a Material Adverse Effect.

5.5 **<u>Litigation</u>**. There is no claim, action, proceeding or investigation pending, or to Purchaser's Knowledge, threatened against or relating to Purchaser or its Affiliates before any court, arbitrator or Governmental Authority, or any judgment, decree or order of any court, arbitrator or Governmental Authority, which could, individually or in the aggregate, reasonably be expected to result, or has resulted, in (a) the institution of legal proceedings to prohibit or restrain the performance of this Agreement or any of the Ancillary Agreements, or the consummation of the transactions contemplated hereby or thereby, (b) a claim against Seller or its Affiliates for damages as a result of Purchaser entering into this Agreement or any of the Ancillary Agreements, or the consummation by Purchaser of the transactions contemplated hereby or thereby, (c) a material impairment of Purchaser's ability to perform its obligations under this Agreement or any of the Ancillary Agreements, or (d) a Material Adverse Effect.

5.6 **<u>Brokers</u>**. All negotiations relating to this Agreement and the transactions contemplated hereby have been carried on by Purchaser and in such a manner as not to give rise to any valid claim against Seller (by reason of Purchaser's actions) for a brokerage commission, finder's fee or other like payment to any Person.

5.7 **<u>Financing</u>**. Purchaser has now, and at the Closing Purchaser will have, liquid capital or committed sources therefor sufficient to permit Purchaser to perform timely its obligations hereunder and under the Ancillary Agreements.

5.8 **<u>Qualified for Permits</u>**. To Purchaser's Knowledge, Purchaser is, or will be prior to the Closing, qualified to obtain any Facilities Permits necessary for the ownership and operation by Purchaser of the Assets as of the Closing in substantially the same manner as the Assets are currently operated.

5.9 **<u>"AS IS" SALE</u>. EXCEPT AS OTHERWISE EXPRESSLY PROVIDED HEREIN, PURCHASER UNDERSTANDS AND AGREES THAT THE ASSETS ARE BEING ACQUIRED "AS IS, WHERE IS" ON THE CLOSING DATE, AND IN THEIR**

CONDITION ON THE CLOSING DATE, AND THAT PURCHASER IS RELYING ON ITS OWN EXAMINATION OF THE ASSETS. WITHOUT LIMITING THE GENERALITY OF THE FOREGOING AND EXCEPT FOR THE REPRESENTATIONS AND WARRANTIES EXPRESSLY SET FORTH IN THIS AGREEMENT, PURCHASER UNDERSTANDS AND AGREES THAT SELLER EXPRESSLY DISCLAIMS ANY REPRESENTATIONS OR WARRANTIES AS TO LIABILITIES, OPERATIONS OF THE ASSETS, TITLE, CONDITION, VALUE OR QUALITY OF THE ASSETS OR THE PROSPECTS (FINANCIAL OR OTHERWISE), RISKS AND OTHER INCIDENTS OF THE ASSETS AND ANY REPRESENTATION OR WARRANTY OF MERCHANTABILITY, USAGE, SUITABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE WITH RESPECT TO THE ASSETS OR ANY PART THEREOF, OR AS TO THE WORKMANSHIP THEREOF, OR THE ABSENCE OF ANY DEFECTS THEREIN, WHETHER LATENT OR PATENT. PURCHASER FURTHER AGREES THAT NO INFORMATION OR MATERIAL PROVIDED BY OR COMMUNICATION MADE BY SELLER OR ANY REPRESENTATIVE OF SELLER WILL CAUSE OR CREATE ANY REPRESENTATION OR WARRANTY DISCLAIMED BY THE FOREGOING EXCEPT AS DISCLOSED IN THIS AGREEMENT OR IN A SCHEDULE ATTACHED HERETO.

ARTICLE 6
COVENANTS OF EACH PARTY

6.1 Efforts to Close.

(a) **Commercially Reasonable Efforts**. Subject to the terms and conditions herein provided, each of the Parties hereto agrees to use its Commercially Reasonable Efforts to consummate and make effective, as soon as reasonably practicable, the transactions contemplated hereby, including the satisfaction of all conditions thereto set forth herein. Such actions shall include, without limitation, exerting their Commercially Reasonable Efforts to (i) obtain the consents, authorizations and approvals of all private parties and any Governmental Authority whose consent is reasonably necessary to effectuate the transactions contemplated hereby, (ii) effect all other necessary registrations and filings, including, without limitation, filings under applicable laws, including the HSR Act and all other necessary filings with the CPUC, ACC, FERC (including applications to transfer the Facilities Switchyard), and any other Governmental Authority, and in the case of Purchaser, negotiate the extension or renewal referenced in Section 8.14 and the amendment referenced in Section 8.15. Each Party will provide the other with copies of all written communications from Governmental Authorities relating to the approval or disapproval of the transactions contemplated by the Agreement and the Ancillary Agreements.

(b) **Expenses**. Whether or not the transactions contemplated hereby are consummated, except as otherwise provided in this Agreement, all costs and expenses incurred in connection with this Agreement and the transactions contemplated hereby shall be paid by the Party incurring such expenses. Notwithstanding the foregoing:

(i) Costs associated with preliminary title reports and title policies shall be borne by Seller up to the costs that would have been incurred had the title policies been standard coverage policies of title insurance, and the remaining costs, if any, including costs for extended coverage and any endorsements shall be borne by Purchaser (except that any survey costs shall be borne one-half by Purchaser and one-half by Seller);

(ii) Documentary transfer fees, if any, will be borne by Seller and recording costs and charges respecting real property will be borne one-half by Purchaser and one-half by Seller; and

(iii) Except as otherwise specifically set forth in Section 6.4, all fees, charges and costs of economists and other experts, if any, jointly retained by Purchaser and Seller in connection with submissions made to any Governmental Authority and advice in connection therewith respecting approval of the transactions will be borne one-half by Purchaser and one-half by Seller.

All such charges and expenses shall be promptly settled between the Parties at the Closing or upon termination or expiration of further proceedings under this Agreement, or with respect to such charges and expenses not determined as of such time, as soon thereafter as is reasonably practicable.

(c) **Environmental Investigations.**

(i) Prior to Closing, Seller and/or Purchaser may, at their own cost and expense, conduct or cause to be conducted their own Phase 1 and Phase 2 environmental site assessments, and any follow up investigation, of the Facilities and the Facilities Switchyard as Seller and/or Purchaser deem necessary. The party conducting such assessments shall provide the other party with (1) a copy of any written reports resulting from such assessments; and (2) timely notice of any Environmental Condition(s) that require public disclosure or reporting to a regulatory authority or Remediation. Purchaser shall cooperate with and allow Seller to conduct such assessments and investigation. The results of such assessments and investigation shall not be binding on the Parties, and shall not be deemed to constitute an agreement by the Parties as to the existence or extent of current Environmental Conditions at the Facilities.

(ii) Following the Closing, Purchaser and Seller shall each appoint a representative to serve as an environmental liaison. Purchaser's environmental liaison shall provide Seller's environmental liaison with access to all information of Purchaser related to Environmental Conditions at the Facilities, consistent with Purchaser's normal record creation and retention policies and subject to a reasonable and appropriate non-disclosure agreement. The liaisons will meet periodically to address questions of Seller and to discuss generally Environmental Conditions at the Facilities that would affect the Retained Environmental Liabilities, including the status of ongoing Remediation programs.

(iii) Without limiting the generality of the foregoing, Purchaser's environmental liaison will provide Seller's environmental liaison with notice of and documentation relating to the initiation of any legal action and any threatened legal action of which Purchaser becomes aware, in each case that could reasonably be expected to affect Retained Environmental Liabilities. Purchaser also will provide Seller's liaison with a reasonable opportunity to review and comment on any new material Remediation initiative and on environmental expenditures in the Facilities' annual budgets that could reasonably be expected to affect Retained Environmental Liabilities. If requested by Seller's liaison, Purchaser will present Seller's views on such environmental expenditures to the Engineering and Operating Committee (as defined in the Facilities Operating Agreement), and will allow Seller to participate in such presentation.

(iv) If Seller's liaison has significant concerns that an environmental matter will adversely affect Retained Environmental Liabilities, and the liaisons cannot satisfactorily address the concerns by themselves, the liaisons shall elevate the concerns to senior officers to be designated by each party prior to the Closing for further good faith discussions.

(v) The rights granted to Seller under this Section 6.1(c) shall not in any way alter or limit any rights retained by Seller under Section 2.1(h). In the event Purchaser transfers all or substantially all of the Assets to another Person and Purchaser is no longer the Operating Agent or a Facilities Owner, Purchaser shall cause such Person to assume Purchaser's obligations to Seller under Sections 6.1(c)(ii) through (v), or make such other arrangements as are reasonably acceptable to Seller.

6.2 Updating. Seller shall promptly notify Purchaser of any changes or additions to any of Seller's Schedules to this Agreement with respect to the Assets or Assumed Liabilities related thereto by the delivery of updates thereof, if any, as of a reasonably current date prior to the Closing, but in any event not later than three (3) Business Days prior thereto. No such updates made pursuant to this Section shall be deemed to cure any inaccuracy of any representation or warranty made in this Agreement as of the date hereof, unless Purchaser specifically agrees thereto in writing, nor shall any such notification be considered to constitute or give rise to a waiver by Purchaser of any condition set forth in this Agreement. Without limiting the generality of the foregoing, Seller shall notify Purchaser promptly of the occurrence of (i) any material casualty, physical damage, destruction or physical loss respecting, or any material adverse change in the physical condition of the Facilities or the Facilities Switchyard, subject to ordinary wear and tear and to routine maintenance, reasonably likely to result in a Material Adverse Effect, and (ii) any other material event likely to impair Seller's ability to perform, if, in the cases of clauses (i) and (ii), the occurrence is one of which Seller has Knowledge and of which the Operating Agent does not have Knowledge.

6.3 Conduct Pending Closing. Prior to consummation of the transactions contemplated hereby or the termination or expiration of this Agreement pursuant to its terms, and except to the extent approved by Purchaser, Seller shall:

(a) Except as required by their terms, or except to the extent agreed to by all Facilities Owners (including Seller and Purchaser), not amend, terminate, renew, or renegotiate any existing Facilities Contract or enter into any new Facilities Contract, except in the ordinary course of business and consistent with practices of the recent past, or default (or take or omit to take any action that with or without the giving of notice or passage of time, would constitute a default) under any of its obligations under any Facilities Contract;

(b) Not: (i) sell, lease, transfer or dispose of, or make any contract for the sale lease, transfer or disposition of, any assets or properties which would be included in the Assets, other than sales in the ordinary course of business which would not, individually or in the aggregate; have a Material Adverse Effect upon the operations or value of the Facilities or the Facilities Switchyard; (ii) incur, assume, guaranty, or otherwise become liable in respect of any indebtedness for money borrowed, in each case which would result in Purchaser assuming such liability hereunder after the Closing; (iii) delay the payment and discharge of any liability which, upon Closing, would be an Assumed Liability, because of the transactions contemplated hereby; (iv) encumber or voluntarily subject to any lien any Asset, except for Permitted Encumbrances or (v) except to the extent approved by the other Facilities Owners, not settle any claims against the Facilities or against Seller relating to the Facilities or the Facilities Contracts; and

(c) Not take any action which would cause any of Seller's representations and warranties set forth in ARTICLE 4 to be materially false as of the Closing;

provided, that nothing in this Section 6.3 shall (i) preclude Seller from paying, prepaying or otherwise satisfying any liability which, if outstanding as of the Closing Date, would be an Assumed Liability or an Excluded Liability, or (ii) preclude Seller from incurring any liabilities or obligations to any third party in connection with obtaining such Party's consent to any transaction contemplated by this Agreement or the Ancillary Agreements; provided that any such liabilities or obligations incurred pursuant to clause (ii) shall be Excluded Liabilities.

(d) Seller agrees to advise Purchaser of any request that Seller intends to file with the CPUC for approval of Capital Expenditures by Seller budgeted for 2012 and of any action taken by the CPUC with respect thereto. If the CPUC denies such request or CPUC approval is not received by November 30, 2011, the Parties will meet within 15 days thereafter to discuss the consequences of the CPUC denial or failure to act, including its potential impact on the 2012 capital budget for the Plant, the respective obligations of the Parties under the Facilities Contracts and the operation of the Plant in 2012; it being understood that there is no obligation of either Party to reach any agreement with respect to any of the matters discussed.

6.4 Consents and Approvals.

(a) Subject to Section 6.1(a), as promptly as practicable after the date of this Agreement, Seller and Purchaser shall each file or cause to be filed with the Federal Trade Commission and the Department of Justice all notifications required to be filed under the HSR Act and the rules and regulations promulgated thereunder with respect to the transactions contemplated hereby. The Parties shall consult with each other as to the appropriate time of filing such notifications and shall agree upon the timing of such filings, respond promptly to any requests for additional information made by either of such agencies, and cause the waiting periods under the HSR Act to terminate or expire at the earliest possible date after the date of filing. Purchaser and Seller shall be equally responsible for the cost of all filing fees under the HSR Act and each Party will bear its own costs for the preparation of any such filing.

(b) Subject to Section 6.1(a), as promptly as practicable after the date of this Agreement, Purchaser shall file with FERC any other applications required under the Federal Power Act for the purchase and sale contemplated hereby, which filing(s) may be made individually by Purchaser or jointly with Seller, as reasonably determined by the Parties.

(c) Subject to Section 6.1(a), Seller shall be responsible for obtaining CPUC approval of the transactions contemplated by this Agreement and the Ancillary Agreements, and Purchaser shall be responsible for obtaining ACC approval of the transactions contemplated by this Agreement and the Ancillary Agreements, in each case including the filing of the necessary applications therefor and diligently prosecuting any resulting proceedings. Each Party shall afford the other Party the opportunity to review such filings. Unless requested by the filing Party, the other Party agrees not to intervene in the regulatory proceedings related to the approval of the transaction.

(d) Subject to Section 6.1(a), Purchaser shall have the primary responsibility for securing the transfer, reissuance or procurement of the Facilities Permits, effective as of the Closing Date. Seller shall use Commercially Reasonable Efforts to cooperate with Purchaser's efforts in this regard and assist in any transfer or reissuance of Facilities Permits held by Seller or the procurement of any other Facilities Permits when so requested by Purchaser.

(e) Within fifteen (15) days after the receipt of any Purchaser's or Seller's Required Regulatory Approval, the Party receiving such approval (the "**Receiving Party**") shall notify the other Party in writing if the approval contains any condition that the Receiving Party determines could reasonably be expected to have a Material Adverse Effect on the Receiving Party or, in the case of Purchaser, on the Assets; provided, however, that if the Receiving Party does not provide such notice to the other Party within the fifteen (15) day period specified in this sentence, the Receiving Party shall be deemed to have accepted such Required Regulatory Approval, including any condition contained therein, and the condition to Closing set forth in Section 8.4 or Section 9.4, as applicable to such Party with respect to such Required Regulatory Approval, shall be deemed satisfied. Within fifteen (15) days after receipt of any notice specified in the previous sentence, Seller and Purchaser shall meet to consider what Commercially Reasonable Efforts the Receiving Party intends to take in order to obtain the Required Regulatory Approval or to eliminate the materially adverse conditions. After the Receiving Party has completed such agreed upon Commercially Reasonable Efforts with respect to the materially adverse condition contained in such Required Regulatory Approval, within fifteen (15) days of such completion or as soon as practicable thereafter, the Receiving Party shall notify the other Party, if the materially adverse condition has been eliminated or remains in effect, and whether the Receiving Party either will accept such materially adverse condition by a waiver of the applicable Closing condition in Section 8.4 or Section 9.4 with respect to such materially adverse condition or deem that the applicable Closing condition in Section 8.4 or Section 9.4 cannot be satisfied due to the materially adverse condition in such Required Regulatory Approval.

(f) From the date hereof through Closing, the Parties shall consult with each other at the senior management executive level prior to any party intervening in any regulatory proceeding of another Party, or commencing legal action or pursuing contractual remedies against any other Party with respect to the Facilities.

6.5 Tax Matters.

(a) All Transfer Taxes incurred in connection with this Agreement and the transactions contemplated hereby shall be borne one-half by Seller and one-half by Purchaser.

Seller will file, to the extent required by applicable law, all necessary Tax Returns and other documentation with respect to all such Transfer Taxes, and Purchaser will be entitled to review such returns in advance and, if required by applicable law, will join in the execution of any such Tax Returns or other documentation. Not less than five (5) Business Days prior to the due date of such Tax Returns, Purchaser shall pay Seller one-half of the amount shown as due on such Tax Returns, as determined in accordance, with this Agreement, and shall, to the extent required by Law, join in the execution of any such Tax Return. Prior to the Closing Date, Purchaser will provide to Seller, to the extent possible, an appropriate exemption certificate in connection with this Agreement and the transactions contemplated hereby, with respect to each applicable taxing authority.

(b) With respect to taxes to be prorated in accordance with Section 3.6 of this Agreement (except for pro-rated Property Taxes required to be paid by Seller), Purchaser shall prepare and timely file all Tax Returns required to be filed after the Closing with respect to the Assets, if any, and shall duly and timely pay all such Taxes shown to be due on such Tax Returns. For Property Tax purposes, any returns or filings with a lien or due date prior to Closing shall be prepared by Seller. Purchaser's preparation of any such Tax Returns shall be subject to Seller's approval, which approval shall not be unreasonably withheld or delayed. Purchaser shall make such Tax Returns available for Seller's review and approval (which approval shall not be unreasonably withheld or delayed) no later than fifteen (15) Business Days prior to the due date for filing such Tax Returns, it being understood that Seller's failure to approve any such Tax Returns shall not limit Purchaser's obligation to timely file such Tax Returns and duly and timely pay all Taxes shown to be due thereon. Not less than five (5) Business Days prior to the due date of any such Tax Return, Seller shall pay to Purchaser the amount shown as due on such Tax Returns as determined in accordance with Section 3.6 of this Agreement and shall, to the extent required by law, join in the execution of any such Tax Returns.

(c) With respect to pro-rated Property Taxes, specifically including but not limited to Property Tax Returns prepared and filed with any Tribal Authority, Seller's preparation of any such Tax Return shall be subject to Purchaser's approval, which approval shall not be unreasonably withheld or delayed. Seller shall make such tax Returns available for Purchaser's review and approval no later than fifteen (15) Business Days prior to the due date for filing such Tax Return, it being understood that Purchaser's failure to approve any such Tax Return shall not limit Seller's obligation to timely file such Tax Returns. In preparing and reviewing said Property Tax Returns, each Party shall cooperate and act in good faith to resolve any disagreement related to such Tax Returns as between the Parties or as between either Party and any Governmental Authority.

(d) Purchaser and Seller shall provide the other Party with such assistance as may reasonably be requested by the other Party in connection with the preparation of any Tax Return, any audit or other examination by any taxing authority, or any judicial or administrative proceedings relating to liability for Taxes, and each will retain and provide the requesting Party with any records or information which may be relevant to such return, audit or examination, proceedings or determination. Any information obtained pursuant to this Section 6.5 or pursuant to any other Section hereof providing for the sharing of information or review of any Tax Return or other schedule relating to Taxes shall be kept confidential by the Parties hereto in accordance with Section 6.8.

(e) In the event that a dispute arises between Seller and Purchaser as to the amount of taxes, the Parties shall attempt in good faith to resolve such dispute, and any amount so agreed upon shall be paid to the appropriate Party. If such dispute is not resolved within thirty (30) days thereafter, the Parties shall submit the dispute to the Independent Accounting Firm for resolution, which resolution shall be final, conclusive and binding on the Parties. Notwithstanding anything in this Agreement to the contrary, the fees and expenses of the Independent Accounting Firm in resolving the dispute shall be borne equally by Seller and Purchaser. Any payment required to be made as a result of the resolution of the dispute by the Independent Accounting Firm shall be made within ten (10) days after such resolution, together with any interest determined by the Independent Accounting Firm to be appropriate.

(f) Seller hereby certifies that all Transfer Tax liabilities of Seller accruing before the Closing Date have been or will be fully satisfied or provided for. In the event Purchaser is assessed any Transfer Tax with respect to the Assets for any period prior to the Closing Date, Purchaser shall notify Seller promptly and shall provide Seller with a validly executed power of attorney authorizing Seller to act in Purchaser's stead with regard to the assessment. Whether Seller determines to contest any such assessment in whole or in part, Seller shall indemnify and hold harmless Purchaser, in connection with any assessment of Tax described in this Section 6.5, whether or not contested hereunder, to the extent such Tax is determined to be due and owing, together with interest and penalties as well as any expenses incurred (including legal fees that may be incurred by Purchaser) in participating in any action related to such assessment. If the laws of the State or the local taxing authority require payment of assessed Taxes as a condition to contesting or further contesting their applicability, Seller shall make such payments together with interest and penalties. Purchaser agrees to cooperate fully in initiating and pursuing any action directed by Seller for recovery of such payments and shall refund any amounts received (including interest and penalties) within three (3) days of receipt by Purchaser. Any action to contest Tax assessments hereunder or to recover Taxes paid hereunder by Seller on behalf of Purchaser shall be under the control of Seller and at Seller's sole cost and expense.

(g) Notwithstanding any other provision hereof, Purchaser covenants and agrees that, after the Closing Date, Purchaser will, to the extent practicable, and at Seller's expense, (i) provide or cause to be provided written notice to Seller sixty (60) days in advance of taking any of the actions specified on a Schedule to be provided by Seller to Purchaser, within one hundred twenty (120) days of the Effective Date, which Schedule shall be reasonably acceptable to Purchaser; listing actions, including discontinuing the operation of the Facilities, or modifications to the Assets which in Seller's reasonable opinion could result in a loss of the exclusion of interest on the Pollution Control Bonds from gross income for federal income tax purposes under Code Section 103, and (ii) take any reasonable actions which it has authority to take that are reasonably requested by Seller in writing for the purpose of maintaining such exclusion (including without limitation, inserting notification requirements, in operating manuals and posting notices within the Facilities). Notwithstanding anything in this Agreement to the contrary, (i) Purchaser will have no liability whatsoever in excess of $250,000 to Seller or any other Person if Purchaser fails to comply with the covenants in the preceding sentence and

(ii) Purchaser shall not be required to take, or refrain from taking, any action inconsistent with Purchaser's rights or obligations under any of the Facilities Contracts. Purchaser further covenants and agrees that, in the event that Purchaser transfers any of the Assets, Purchaser, shall obtain from its transferee a covenant and agreement that is analogous to Purchaser's covenants and agreements in this Section 6.5(g) pursuant to the first sentence of this Section 6.5(g) as well as a covenant and agreement that is analogous to that of this sentence. This covenant shall survive Closing and shall continue in effect so long as such Pollution Control Bonds remain outstanding. Seller agrees to promptly notify Purchaser at such time as no Pollution Control Bonds remain outstanding. Seller will reimburse Purchaser for any expenses incurred by Purchaser, in connection with Purchaser's compliance with this Section 6.5(g). The term **"Pollution Control Bonds"** means the pollution control bonds specified on Schedule 6.5(g) and any refundings thereof, issued or to be issued on behalf of Seller in connection with the Assets.

6.6 Risk of Loss.

(a) Between the date hereof and the Closing Date, all risk of loss or damage to the property included in the Assets shall be borne by Seller.

(b) If, before the Closing Date, all or any portion of the Facilities or the Facilities Switchyard becomes subject to or is threatened with any condemnation or eminent domain proceeding, Seller shall notify Purchaser promptly in writing of such fact. If such taking would create a Material Adverse Effect, then Purchaser may, at its option, (i) receive from Seller an assignment of any claim, settlement or proceeds thereof and proceed with the transactions contemplated by this Agreement, or (ii) terminate this Agreement pursuant to Section 10.1.

(c) If, before the Closing Date all or any portion of the Facilities or the Facilities Switchyard are damaged or destroyed (whether by fire, theft, vandalism or other casualty) in whole or in part, and Seller's share of the fair market value of such damage or destruction or the cost of repair of the Facilities or the Facilities Switchyard that were damaged, lost or destroyed is less than fifteen percent (15%) of the Initial Purchase Price, Seller shall, at its option, either (i) reduce the Purchase Price by the lesser of (x) Seller's share of the fair market value of the Facilities or the Facilities Switchyard damaged or destroyed (such value to be determined as of the date immediately prior to such damage or destruction), or (y) Seller's share of the estimated cost to repair or restore the same (any disagreement with respect thereto being resolved in accordance with Section 11.10), (ii) upon the Closing, transfer the proceeds or the rights to the proceeds of applicable insurance to Purchaser, or (iii) bear Seller's share of the costs of repairing, or restoring such damaged or destroyed portions of the Facilities or the Facilities Switchyard and, at Seller's election, delay the Closing and any right to terminate this Agreement for a reasonable time necessary to accomplish the same. If any part of the Facilities or the Facilities Switchyard is damaged or destroyed (whether by fire, theft, vandalism or other casualty) in whole or in part prior to the Closing and the lesser of Seller's share of the fair market value of the Facilities or the Facilities Switchyard damaged or destroyed or Seller's share of the cost of repair is greater than fifteen percent (15%) of the Initial Purchase Price, then Purchaser may elect either to (x) require Seller upon the Closing to transfer the rights to Seller's share of proceeds (or the right to the proceeds) of applicable insurance to Purchaser and proceed with the transactions contemplated by this Agreement, or (y) terminate this Agreement.

6.7 Cooperation Relating to Insurance. Until the Closing, Seller will not take any action that will decrease the level of insurance coverage for the Facilities and the Facilities Switchyard as in effect on the date hereof, including, without limitation, property damage and liability insurance, unless agreed by the other Facilities Owners. In addition, Seller agrees to use Commercially Reasonable Efforts to assist Purchaser in making any claims against pre-Closing insurance policies of Seller that may provide coverage related to Assumed Liabilities. Purchaser agrees that it will indemnify Seller for its reasonable out-of-pocket expenses incurred in providing such assistance and cooperation. On and after the Closing, Seller authorizes the Operating Agent to take any actions necessary to remove Seller from any Facilities Insurance Policies and, except with respect to insurance rights retained by Seller pursuant to Sections 2.1(m), 2.1(o) or 2.2(h), Seller agrees to waive its rights with respect to such insurance coverage from and after the Closing. If requested by Seller, Purchaser agrees to exercise Commercially Reasonable Efforts to assist Seller, at Seller's cost, in obtaining so-called "tail" coverage in respect of claims brought after the Closing for events occurring prior to the Closing, including, if appropriate, listing Seller as an additional insured or named insured in policies of Purchaser and/or the Facilities Owners. Seller agrees that it will reimburse Purchaser for its reasonable out-of-pocket expenses incurred in providing such assistance to Seller in obtaining tail coverage.

6.8 Confidentiality.

(a) **General.** Each Party (and its officers, employees, counsel, representatives and agents) will, using the same degree of care as that Party takes to preserve and safeguard its own confidential information, but not less than reasonable care, maintain in confidence and not disclose to third Persons, any Confidential Information received from the other Party (or its officers, employees, counsel, representatives and agents) in connection with the transactions contemplated by this Agreement. Each Party may disclose Confidential Information received from the other Party if and to the extent required by law, court order, subpoena or other lawful order of a Governmental Authority with jurisdiction, provided that the other Party is given written notice of such disclosure ten (10) days in advance, or as soon in advance as is reasonably practicable, or with the prior written consent of the other Party. If this Agreement is terminated pursuant to ARTICLE 10, each Party will return promptly, if so requested by the other Party, any Confidential Information provided to it and will use Commercially Reasonable Efforts to return any copies thereof that may have been provided to others in accordance with this Section 6.8. To the extent practicable, the Parties further agree, subject to Section 6.11, to not issue any public announcement, statement, press release or other public disclosure with respect to this Agreement or the transactions contemplated hereby; without the prior written consent of the other Party, which consent will not be unreasonably withheld. To the extent the provisions of this Section 6.8(a) conflict with the Confidentiality Agreement, as between Seller and Purchaser, this Section 6.8(a) shall control.

(b) **Regulatory Agencies.** Subject to Section 6.1(a), upon the other Party's prior written approval (which, except as provided below, will not be unreasonably withheld), either Party may provide Confidential Information to the CPUC, ACC, FERC or any other Governmental Authority with jurisdiction as necessary to obtain Seller's Required Regulatory Approvals or Purchaser's Required Regulatory Approvals or approval under the HSR Act. The disclosing Party will seek confidential treatment for the Confidential Information provided to any

Governmental Authority and the disclosing Party will notify the other Party as far in advance as is practicable of its intention to release to any Governmental Authority any Confidential Information.

6.9 **Reasonable Cooperation**. Each Party agrees to use Commercially Reasonable Efforts to cooperate with the other Party to effect the consummation of the transactions contemplated by this Agreement, and to provide the other Party with such access or information related to the Facilities as may reasonably be requested in connection with such transactions. Without limiting the generality of the forgoing, the Parties shall work with each other prior to the Closing Date to determine if any Facilities Contract which is not currently listed on Schedule 1.1.67 or Schedule 1.1.77, or approval of any Governmental Authority which is not currently listed on Schedule 1.1.67 or Schedule 1.1.77, should be listed on such Schedule.

6.10 **Title to Real Property and Leased Property**. As soon as reasonably possible after the Effective Date, Seller and Purchaser shall work cooperatively to cause Title Insurer to deliver a current preliminary title report on the real property and leased property included in the Assets, accompanied by legible copies of all documents referred to in the exception portion of such report, to Purchaser (the **"Preliminary Title Report"**). Purchaser shall have not more than thirty (30) days from the delivery date of the Preliminary Title Report in which to review and to give Seller and Title Insurer written notice of any title exception which is unacceptable to Purchaser, and, in the event any amendment is issued to the Preliminary Title Report, Purchaser shall have not more than thirty (30) days from the delivery of an amendment to deliver a written objection to any title exception, appearing for the first time in such amendment. If Purchaser is dissatisfied with any exception to title as shown in the Preliminary Title Report, then, Seller shall have until the Closing to eliminate any disapproved exceptions from the Preliminary Title Report, or obtain title insurance endorsements against such exceptions. If Seller cannot remove such exceptions or obtain title insurance endorsements before the Closing, then Purchaser may either cancel this Agreement, or Purchaser may waive such objections and the transaction shall close as scheduled, provided that if Purchaser disapproves any title exception that would otherwise qualify as a Permitted Encumbrance under Section 1.1.60 but for Purchaser's position that such title exception constitutes or will constitute a Material Adverse Effect, then Seller shall have the right to terminate this Agreement on fifteen (15) Business Days' notice given within thirty (30) days following Purchaser's disapproval of such title exception. Notwithstanding any other provision hereof, the following exceptions shall be deemed accepted by Purchaser and need not be removed or endorsed over: (a) Permitted Encumbrances, and (b) exceptions not objected to in writing by Purchaser during the time periods set forth above.

6.11 **Right of First Refusal**. Seller hereby agrees to promptly orally notify Purchaser, confirmed in writing, as to any notices received by Seller pursuant to Section 13 of the Facilities Co-Tenancy Agreement regarding the Facilities Owners' right of first refusal. If one or more of the Facilities Owners exercises their right of first refusal with respect to the Assets under the Facilities Co-Tenancy Agreement, Purchaser shall, subject to the terms and conditions of the Facilities Co-Tenancy Agreement and without limitation of any of the rights of the other the Facilities Owners thereunder, automatically and without further notice to Seller be deemed to have exercised its right of first refusal with respect to the Assets to the maximum extent permitted by the Facilities Co-Tenancy Agreement. In the event one or more of the Facilities Owners exercises such right, the interest in the Assets to be transferred pursuant to this

Agreement and the Initial Purchase Price shall both be reduced to reflect the pro rata interest in the Assets to be purchased by Purchaser pursuant to Section 13.10 of the Facilities Co-Tenancy Agreement or as otherwise agreed to by Seller, Purchaser and the Facilities Owner exercising its right of first refusal, and Seller and Purchaser will enter into an amendment to this Agreement to reflect such reductions and other changes that the Parties deem appropriate.

6.12 **Exclusivity**. During the term of this Agreement, and except as necessary to fulfill its obligations under the Facilities Co-Tenancy Agreement, or an order of the CPUC, Seller will (a) deal exclusively with Purchaser and other Facilities Owners that elect to participate in the purchase of the Assets under this terms of this Agreement (**"Participating Owners"**), and will not offer to sell, solicit offers to sell or negotiate with any third party for the sale of the Assets; and (b) promptly notify Purchaser and Participating Owners of any unsolicited offer, interest or inquiry by a third party concerning a possible purchase of the Assets and will not provide any information with respect to a possible sale of the Assets to any third party.

6.13 **Post Closing – Further Assurances**. At any time or from time to time after the Closing; each Party, will, upon the reasonable request of the other Party, execute and deliver any further instruments or documents, and exercise Commercially Reasonable Efforts to take such further actions as may reasonably be required to fulfill and implement the terms of this Agreement or realize the benefits intended to be afforded hereby. After the Closing, and upon prior reasonable request, each Party shall exercise Commercially Reasonable Efforts to cooperate with the other, at the requesting Party's expense (but including only out-of-pocket expenses to third parties and not the costs incurred by any Party for the wages or other benefits paid to its officers, directors or employees), in furnishing non-privileged records, information, testimony and other assistance in connection with any inquiries, actions, audits, proceedings or disputes involving either of the Parties hereto (other than in connection with disputes between the Parties hereto) and based upon contracts, arrangements or acts of Seller, Purchaser, the other Facilities Owners or the Operating Agent on behalf of one or more of the Facilities Owners which were in effect or occurred on, prior to, or after Closing and which relate to the Assets, including, without limitation, arranging discussions with (and calling as a witness) officers, directors, employees, agents, and representatives of Purchaser or Seller.

6.14 **Post Closing – Information and Records.**

(a) Following the Closing, Purchaser will not dispose of any books, records, documents or information reasonably relating to any Excluded Assets or Excluded Liabilities except in accordance with Purchaser's existing record retention policies. During such period, Purchaser will permit Seller to examine and make copies, at Seller's expense, of such books, records, documents and information for any reasonable purpose, including any litigation now pending or hereafter commenced against Seller, or the preparation of income or other Tax Returns. Seller will provide reasonable notice to Purchaser of its need to access such books, records, documents or other information.

(b) Seller shall not be entitled to examine or copy privileged and/or attorney work product documents or information pursuant to Section 6.14(a). If privileged and/or attorney work product documents or information, including communications between Purchaser and its counsel, are disclosed to Seller in the books, records, documents or other information made available by Purchaser, Seller agrees (1) such disclosure is inadvertent, (2) such disclosure will not constitute a waiver, in whole or in part, of any privilege or work product, (3) such information will constitute Confidential Information, and (4) Seller will promptly return to Purchaser (or will destroy or make inaccessible such Confidential Information to the extent reasonably possible and certify as such to Purchaser) all copies of such books, records, documents or other information in the possession of Seller.

6.15 Post Closing – Landfill and Remediation Costs. Purchaser covenants that: (a) it shall not cause the Landfill to be used or operated at any time after the Closing; and (b) in the event that Purchaser, without Seller's approval, enters into (i) any lease or lease amendment or extension or (ii) any other agreement of any kind with a Person other than a Governmental Authority, in either case altering or purporting to alter in any material respect any obligations of Seller with respect to Remediation of any Environmental Conditions or Hazardous Substances or the removal or Remediation of the Landfill, Purchaser shall hold Seller harmless from any incremental Remediation or removal costs, resulting from such lease, lease amendment or extension or other agreement.

ARTICLE 7
INDEMNIFICATION

7.1 Indemnification by Seller.

(a) **Purchaser Claims**. From and after the Closing, Seller will indemnify, defend and hold harmless Purchaser and its parents and Affiliates, and each of their officers, directors, employees, attorneys, agents and successors and assigns (collectively, the "**Purchaser Group**"), from and against any and all demands, suits, penalties, obligations, damages, claims, losses, liabilities, payments, costs and expenses (including reasonable legal, accounting and other expenses in connection therewith) and including costs and expenses incurred in connection with investigations, and settlement proceedings which arise out of, in connection with, or relate to, the following (collectively, "**Purchaser Claims**"):

(i) any breach or violation of any covenant or agreement of Seller set forth in this Agreement;

(ii) any breach or inaccuracy of the representations or warranties made by Seller contained in this Agreement in ARTICLE 4;

(iii) the Excluded Liabilities; and

(iv) any loss or damages resulting from or arising out of Seller's ownership of the Assets prior to Closing, except for any loss or damage resulting from or arising out of Assumed Liabilities.

(b) **Seller Limitations**. If the Closing occurs, the Purchaser Group will not be entitled to any punitive, incidental, indirect, special or consequential damages resulting from or arising out of any Purchaser Claims, including damages for lost revenues, income, profits or tax benefits, diminution in value of the Facilities, or any other damage or loss resulting from the disruption to or loss of operation of the Assets, except to the extent due on any Third Party Claim.

7.2 Indemnification by Purchaser.

(a) **Seller Claims**. From and after the Closing, Purchaser will indemnify, defend and hold harmless Seller and its parents and Affiliates and each of their officers, directors, employees, attorneys, agents and successors and assigns (collectively, the "**Seller Group**"), from and against any and all demands, suits, penalties, obligations, damages, claims, losses, liabilities, payments, costs and expenses (including reasonable legal, accounting and other expenses in connection therewith) and including costs and expenses incurred in connection with, investigations and settlement proceedings which arise out of or relate to the following (collectively, "**Seller Claims**"):

(i) any breach or violation of any covenant or agreement of Purchaser set forth in this Agreement;

(ii) any breach or inaccuracy of any of the representations or warranties made by Purchaser contained in this Agreement in ARTICLE 5;

(iii) the Assumed Liabilities; and

(iv) any loss or damages resulting from or arising out of Purchaser's ownership or operation of the Assets from and after the Closing, except for any loss or damage resulting from or arising out of Excluded Liabilities.

(b) **Purchaser Limitations**. If the Closing occurs, the Seller Group will not be entitled to any punitive, incidental, indirect, special or consequential damages resulting from or arising out of any Seller Claim, including damages for lost revenues, income, profits or tax benefits, diminution in the value of the Facilities or any other damage or loss resulting from the disruption to or loss of operation of the Assets, except to the extent due on any Third Party Claim.

7.3 Notice of Claim. Subject to the terms of this Agreement and upon a Party's receipt of notice of the assertion of a claim or of the commencement of any suit, action or proceeding made or brought by any Person who is not a Party to this Agreement or an Affiliate, the Party seeking indemnification hereunder (the "**Indemnitee**") will promptly notify the Party against whom indemnification is sought (the "**Indemnitor**") in writing of any damage, claim, loss, liability or expense which the Indemnitee has determined has given or could give rise to a claim under Section 7.1 or Section 7.2. (The written notice is referred to as a "**Notice of Claim.**") A Notice of Claim will specify, in reasonable detail, the facts known to the Indemnitee regarding the claim. Subject to the terms of this Agreement, the failure to provide (or timely provide) a Notice of Claim will not affect the Indemnitee's rights to indemnification; provided, however, the Indemnitor is not obligated to indemnify the Indemnitee for the increased amount of any claim which would otherwise have been payable to the extent that the increase resulted from the failure to deliver timely a Notice of Claim.

7.4 **Defense of Third Party Claims**. The Indemnitor will defend, in good faith and at its expense, any claim or demand set forth in a Notice of Claim relating to a Third Party Claim and the Indemnitee, at its expense, may participate in the defense. The Indemnitee cannot settle or compromise any Third Party Claim so long as the Indemnitor is defending it in good faith. If the Indemnitor elects not to contest a Third Party Claim, the Indemnitee may undertake its defense, and the Indemnitor will be bound by the result obtained by the Indemnitee. The Indemnitor may at any time request the Indemnitee to agree to the abandonment of the contest of the Third Party Claim or to the payment or compromise by the Indemnitor of the asserted claim or demand. If the Indemnitee does not object in writing within fifteen (15) days of the Indemnitor's request, the Indemnitor may proceed with the action stated in the request. If within that fifteen (15) day period the Indemnitee notifies the Indemnitor in writing that it has determined that the contest should be continued, the Indemnitor will be liable under this ARTICLE 7 only for an amount up to the amount which the third party to the contested Third Party Claim had agreed to accept in payment or compromise as of the time the Indemnitor made its request. This Section 7.4 is subject to the rights of any Indemnitee's insurance carrier that is defending the Third Party Claim.

7.5 **Cooperation**. The Party defending the Third Party Claim will (a) consult with the other Party throughout the pendency of the Third Party Claim regarding the investigation, defense, settlement, trial, appeal or other resolution of the Third Party Claim; and (b) afford the other Party the opportunity to be associated in the defense of the Third Party Claim. The Parties will cooperate in the defense of the Third Party Claim. The Indemnitee will make available to the Indemnitor or its representatives all records and other materials reasonably required by them for use in contesting any Third Party Claim (subject to obtaining an agreement to maintain the confidentiality of confidential or proprietary materials in a form reasonably acceptable to Indemnitor and Indemnitee). If requested by the Indemnitor, the Indemnitee will cooperate with the Indemnitor and its counsel in contesting any Third Party Claim that the Indemnitor elects to contest or, if appropriate, in making any counterclaim against the Person asserting the claim or demand, or any cross-complaint against any Person. The Indemnitor will reimburse the Indemnitee for any expenses incurred by Indemnitee in cooperating with or acting at the request of the Indemnitor.

7.6 **Mitigation and Limitation on Claims**. As used in this Agreement, the term "**Indemnifiable Claim**" means any Purchaser Claims or Seller Claims. Notwithstanding anything to the contrary contained herein:

(a) **Reasonable Steps to Mitigate**. The Indemnitee will take all reasonable steps to mitigate all losses, damages and the like relating to an Indemnifiable Claim, including availing itself of any defenses, limitations, rights of contribution, claims against third Persons and other rights at law or equity, and will provide such evidence and documentation of the nature and extent of the Indemnifiable Claim as may be reasonably requested by the Indemnitor. The Indemnitee's reasonable steps include the reasonable expenditure of money to mitigate or otherwise reduce or eliminate any loss or expense for which indemnification would otherwise be due under this ARTICLE 7, and the Indemnitor will reimburse the Indemnitee for the Indemnitee's reasonable expenditures in undertaking the mitigation, together with, interest thereon from the date of payment to the date of repayment at the "prime rate" as published in *The Wall Street Journal*.

(b) **Net of Benefits**. Any Indemnifiable Claim is limited to the amount of actual damages sustained by the Indemnitee by reason of such breach or nonperformance.

(c) **Minimum Claim**. No Party shall have any liability or obligation to indemnify under Section 7.1(a)(ii) or Section 7.2(a)(ii), as the case may be, unless the aggregate amount for which such Party would be liable thereunder, but for this provision, exceeds One Million Dollars ($1,000,000), and recovery shall be limited only to such amounts as exceed One Million Dollars ($1,000,000). For purposes of the foregoing, individual claims of Fifteen Thousand Dollars ($15,000) or less shall not be aggregated for purposes of calculating such deductible threshold amount or for calculating damages in excess of such amount. Nothing in this Section 7.6 is intended to modify or limit a Party's liability or obligation hereunder for other Indemnifiable Claims or to constitute an assumption by Purchaser of any Excluded Liability or an assumption by Seller of any Assumed Liability.

7.7 Exclusivity. Except for intentional fraud, following the Closing, the rights and remedies of Seller, on the one hand, and Purchaser, on the other hand, for money damages under this Article are, solely as between Seller on the one hand and Purchaser on the other hand, exclusive and in lieu of any and all other rights and remedies for money damages which each of Seller on the one hand, and Purchaser on the other hand, may have under this Agreement under applicable Law with respect to any Indemnifiable Claim, whether at common law or in equity.

ARTICLE 8
CONDITIONS PRECEDENT TO OBLIGATIONS OF PURCHASER AT THE CLOSING

The obligations of Purchaser under this Agreement to complete the purchase of the Assets and assume the Assumed Liabilities are subject to the satisfaction or waiver, or deemed satisfaction or waiver, on or prior to the Closing, of each of the following conditions precedent:

8.1 Compliance with Provisions. Seller has performed or complied in all material respects with all covenants, agreements and conditions contained in this Agreement on its part required to be performed or complied with at or prior to the Closing.

8.2 HSR Act. The waiting period under the HSR Act applicable to the consummation of the sale of the Assets contemplated hereby shall have expired or been terminated.

8.3 Injunction. No preliminary or permanent injunction or other order or decree by any federal or state court or Governmental Authority which prevents the consummation of the sale of the Assets contemplated herein shall have been issued and remain in effect (each Party agreeing to cooperate in all efforts to have any such injunction, order or decree lifted) and no Law shall have been enacted by any state or federal government or Governmental Authority, which prohibits the consummation of the sale of the Assets.

8.4 Required Regulatory Approvals. Without limiting the generality of Sections 6.1(a) and 6.4, Purchaser shall have received all of Purchaser's Required Regulatory Approvals and Seller shall have received all of Seller's Required Regulatory Approvals; without limiting the generality of the foregoing, Purchaser shall have obtained a final order no longer subject to appeal from the ACC approving the purchase by Purchaser of its share of the Facilities including financial and economic terms and conditions and the ratemaking treatment of the transaction under this Agreement, all in form and substance reasonably satisfactory to Purchaser, and without significant conditions, modifications of the transaction or qualifications in the order that are not reasonably acceptable to Purchaser.

8.5 **Representations and Warranties**. The representations and warranties of Seller set forth in this Agreement (without giving effect to materiality, Material Adverse Effect, or similar phrases in such representations and warranties) shall be true and correct as of the Closing Date, in each case as though made at and as of the Closing Date, except as would not individually or in the aggregate result in a Material Adverse Effect.

8.6 **Officer's Certificate**. Purchaser shall have received a certificate from Seller, executed by an authorized officer, dated the Closing Date, to the effect that the conditions set forth in Sections 8.1, 8.4 (insofar as it relates to Seller's Required Regulatory Approvals), 8.5 and 8.10 (insofar as it relates to Seller's Required Consents) have been satisfied by Seller.

8.7 **Title Policy Insurance**. Title to Assets comprised of interests in real property and leased property shall have been evidenced by the willingness of a title insurer mutually agreeable to the Parties (the "**Title Insurer**") to issue at regular rates ALTA owner's, or lessee's, as the case may be, extended coverage policies of title insurance (1990 Form B) (the "**Title Policies**"), with the general survey and creditors' rights exceptions removed, in amounts equal to the portion of the Purchase Price allocated to such interests, showing title to such interests in such real property vested in Purchaser in the condition described in Section 6.10, subject only to Permitted Encumbrances, and transfer of such interest to Purchaser. The willingness of Title Insurer to issue the Title Policies shall be evidenced either by the issuance thereof at the Closing or by the title Insurer's delivery of written commitments or binders, dated as of the Closing (but insuring title as of the date title conveyance documents are recorded), to issue such Title Policies within a reasonable time after the Closing Date, subject to actual transfer of the real property in question.

8.8 **Material Adverse Effect**. Subject to Section 6.6, since the Effective Date, no Material Adverse Effect shall have occurred and be continuing with respect to the Facilities and the Facilities Switchyard.

8.9 **Liens**. Any and all liens and encumbrances (other than Permitted Encumbrances) on the Assets, constituting personal property shall have been released and any documents necessary to evidence such release shall have been delivered to Purchaser.

8.10 **Seller's Required Consents**. Without limiting the generality of Sections 6.1(a) and 6.4, all of Seller's Required Consents shall have been obtained.

8.11 **No Termination**. Neither Party has exercised any termination right such Party is entitled to exercise pursuant to Section 10.1.

8.12 **Right of First Refusal and Notice**. The right of first refusal and notice periods set forth in Sections 13.3 and 13.4 of the Facilities Co-Tenancy Agreement shall have expired or all Facilities Owners other than Purchaser shall have either waived or exercised their right of first refusal (and, in the event of an exercise of such right of first refusal, Seller and Purchaser shall have entered into the amendment to this Agreement contemplated by Section 6.11).

8.13 **Termination Agreement**. Concurrently with the Closing, closing shall have occurred under the Termination Agreement.

8.14 **Facilities Lease Amendments**. Amendment No. 2 to the Facilities Lease shall have become effective and Amendment No. 3 to the Facilities Lease shall have been executed by the Navajo Nation and each of the Facilities Owners other than Seller, both in substantially the form provided by Purchaser to Seller on the Effective Date.

8.15 **Fuel Agreement**. Purchaser and BHP shall have executed an amendment or replacement to the Facilities Fuel Agreement extending the period under which coal is to be supplied thereunder until 2041, on terms reasonably acceptable to Purchaser.

ARTICLE 9
CONDITIONS PRECEDENT TO OBLIGATIONS OF SELLER AT THE CLOSING

The obligations of Seller under this Agreement to complete the sale of the Assets and transfer the Assets and Assumed Liabilities to Purchaser are subject to the satisfaction or waiver, or deemed satisfaction or waiver, on or prior to the Closing, of each of the following conditions precedent:

9.1 **Compliance with Provisions**. Purchaser has performed or complied in all material respects with all covenants, agreements and conditions contained in this Agreement on its part required to be performed or complied with at or prior to the Closing.

9.2 **HSR Act**. The waiting period under the HSR Act applicable to the consummation of the sale of the Assets contemplated hereby shall have expired or been terminated.

9.3 **Injunction**. No preliminary or permanent injunction or other order or decree by any federal or state court or Governmental Authority which prevents the consummation of the sale of the Assets contemplated herein shall have been issued and remain in effect (each Party agreeing to use its best efforts to have any such injunction, order or decree lifted) and no Law shall have been enacted by any state or federal government or Governmental Authority in the United States which prohibits the consummation of the sale of the Assets.

9.4 **Approvals**. Without limiting the generality of Sections 6.1(a) and 6.4, Purchaser shall have received all of Purchaser's Required Regulatory Approvals, and Seller shall have received all of Seller's Required Regulatory Approvals; without limiting the generality of the foregoing, Seller will have obtained a final order no longer subject to appeal from the CPUC approving the application for, inter alia, the sale of the Assets by Seller and the ratemaking treatment of the transaction under this Agreement, including Seller's proposed cost recovery mechanism, all in form and substance reasonably satisfactory to Seller, and without significant conditions, modifications of the transaction or qualifications in the order that are not reasonably acceptable to Seller, and Seller shall have obtained written approval of the transaction and the termination of the transmission capacity under the Edison-Arizona Transmission Agreement from the California ISO or written confirmation from the California ISO that such approval is not required.

9.5 **<u>Representations and Warranties</u>**. The representations and warranties of Purchaser set forth in this Agreement (without giving effect to materiality, Material Adverse Effect, or similar phrases in such representations and warranties) shall be true and correct as of the Closing Date, in each case as though made at and as of the Closing Date, except as would not individually or in the aggregate result in a Material Adverse Effect, it being understood and agreed to by the Parties that, with respect to Purchaser's representation in <u>Section 5.4</u> hereof, Purchaser's Knowledge, for purposes of this <u>Section 9.5</u>, will mean Purchaser's Knowledge as of the Closing Date, and Purchaser will be entitled to supplement its written disclosure to Seller through the Closing Date.

9.6 **<u>Officer's Certificate</u>**. Seller shall have received a certificate from Purchaser, executed by an authorized officer, dated the Closing Date, to the effect that the conditions set forth in <u>Sections 9.1</u>, <u>9.4</u> (insofar as it relates to Purchaser's Required Regulatory Approvals), <u>9.5</u> and <u>9.9</u> (insofar as it related to Purchaser's Required Consents) have been satisfied by Purchaser.

9.7 **<u>No Termination</u>**. Neither Party has exercised any termination right such Party is entitled to exercise pursuant to <u>Section 10.1</u>.

9.8 **<u>Right of First Refusal</u>**. The right of first refusal and notice periods set forth in Sections 13.3 and 13.4 of the Facilities Co-Tenancy Agreement shall have expired or all Facilities Owners other than Purchaser shall have either waived or exercised their right of first refusal (and, in the event of an exercise of such right of first refusal, Seller and Purchaser shall have entered into the amendment to this Agreement contemplated by <u>Section 6.11</u>).

9.9 **<u>Purchaser's Required Consents</u>**. Without limiting the generality of <u>Sections 6.1(a)</u> and <u>6.4</u>, all of Purchaser's Required Consents shall have been obtained, subject to <u>Section 3.7</u>, and the Closing shall not result in a material breach by Seller of a material Facilities Contract.

9.10 **<u>Material Adverse Effect</u>**. Subject to <u>Section 6.6</u>, since the Effective Date, no Material Adverse Effect shall have occurred and be continuing with respect to the Facilities and the Facilities Switchyard.

9.11 **<u>Termination Agreement</u>**. Concurrently with the Closing, closing shall have occurred under the Termination Agreement.

ARTICLE 10
TERMINATION

10.1 **<u>Rights To Terminate</u>**. This Agreement, or to the extent specifically permitted herein a portion thereof, may, by written notice given on or prior to the Closing Date, in the manner provided in <u>Section 11.10</u>, be terminated at any time prior to the Closing Date (or such other date as may be set forth below):

(a) by Seller if there has been a misrepresentation with respect to Purchaser's representations and warranties in this Agreement (without giving effect to materiality, Material Adverse Effect, or similar phrases in such representations and warranties) that would result in a Material Adverse Effect, or a material default or breach by Purchaser with respect to the due and timely performance of any of Purchaser's covenants and agreements contained in this Agreement, and such misrepresentation; default or breach is not cured by the earlier of the Closing Date or the date thirty (30) days after receipt by Purchaser, of written notice specifying particularly such misrepresentation, default or breach;

(b) by Purchaser if there has been a misrepresentation with respect to Seller's representations and warranties in this Agreement (without giving effect to materiality, Material Adverse Effect, or similar phrases in such representations and warranties) that would result in a Material Adverse Effect, or a material default or breach by Seller with respect to the due and timely performance of any of Seller's covenants and agreements contained in this Agreement, and such misrepresentation, default or breach is not cured by the earlier of the Closing Date, or the date thirty (30) days after receipt by Seller of written notice specifying particularly such misrepresentation, default or breach;

(c) by Purchaser if Purchaser is not at the time of termination in breach of this Agreement, upon written notice to Seller, (i) if any of Purchaser's Required Regulatory Approvals shall have been denied (and a petition for rehearing or refiling of an application initially denied without prejudice shall also have been denied), or shall have been granted but are not in form and substance reasonably satisfactory to Purchaser (including, adverse conditions relating to Purchaser or the Assets), or (ii) if the CPUC has not approved the transaction by March 31, 2012; provided that Purchaser may only exercise the termination right described in this clause (ii) prior to the time the CPUC approves the transaction;

(d) by Seller if Seller is not at the time of termination in breach of this Agreement, upon written notice to Purchaser, if any of the Seller's Required Regulatory Approvals shall have been denied (and a petition for rehearing or refiling of an application initially denied without prejudice shall also have been denied), or shall have been granted but are not in form and substance reasonably satisfactory to Seller (including adverse conditions relating to Seller or the Assets);

(e) by Purchaser in accordance with Section 6.6;

(f) by mutual agreement of Seller and Purchaser; or

(g) by Seller or Purchaser if the conditions to such Party's Closing have not occurred by December 31, 2012, unless the Party seeking to terminate is then in breach of this Agreement.

10.2 Effect of Termination. If this Agreement is terminated pursuant to Section 10.1, all further obligations and liabilities of the Parties hereunder will terminate, except (i) as set forth in ARTICLE 7 or as otherwise contemplated by this Agreement, (ii) for the obligations set forth in Sections 4.12, 5.6 and 6.8 and ARTICLE 11, and (iii) for the obligations of the Parties set forth in the Confidentiality Agreement. In the event this Agreement is terminated by Purchaser pursuant to Section 10.1(b) or Seller pursuant to Section 10.1(a), the non-breaching party shall be entitled to liquidated damages in an amount equal to two percent (2%) of the Initial Purchase Price. Upon termination, the originals of any items, documents or written materials provided by one Party to the other Party will be returned by the receiving Party to the providing Party, and any Confidential Information retained by the receiving Party will be kept confidential.

10.3 **Specific Performance; Limitation of Damages**. Seller acknowledges that the transactions contemplated by this Agreement are unique and that Purchaser will be irreparably injured should such transactions not be consummated in a timely fashion. Consequently, Purchaser will not have an adequate remedy at law if Seller shall fail to transfer, assign and convey the Assets when required to do so hereunder. In such event, prior to any termination of this Agreement pursuant to Section 10.1, Purchaser shall have the right, in addition to any other remedy available in equity or law, to specific performance of such obligation by Seller, subject to Purchaser's performance of its obligations hereunder. Purchaser acknowledges that the transactions contemplated by this Agreement are unique and that Seller will be irreparably injured should such transactions not be consummated in a timely fashion. Consequently, Seller will not have an adequate remedy at law if Purchaser shall fail to purchase the Assets when required to do so hereunder. In such event, prior to any termination of this Agreement pursuant to Section 10.1, Seller shall have the right, in addition to any other remedy available in equity or law, to specific performance of such obligation by Purchaser, subject to Seller's performance of its obligations hereunder. Except as otherwise provided in Section 7.1(a)(iv), 7.2(a)(iv) and 10.2, neither Party will be entitled to any punitive, incidental, indirect, special or consequential damages, including damages for lost revenues, income or profits, resulting from or arising out of a breach of this Agreement, whether or not the Closing occurs.

ARTICLE 11
MISCELLANEOUS AGREEMENTS AND ACKNOWLEDGMENTS

11.1 **Purchaser as Operating Agent**. Notwithstanding the sale of the Assets and the assignment of the Facilities Contracts by Seller to Purchaser, the actions or inactions of Purchaser, in its capacity as Operating Agent, insofar as they may affect Retained Environmental Liabilities or Excluded Liabilities, shall continue to be subject to the standard of conduct and the limitations on liability set forth in Section 22 of the Facilities Operating Agreement in effect at the time of Closing and the retention by Seller of Retained Environmental Liabilities and of rights under the Facilities Contracts with respect to Excluded Liabilities shall not impose a different standard of conduct on Purchaser, in its capacity as Operating Agent, or change in any manner the limitations of liability of Purchaser, in its capacity as Operating Agent, to Seller under the Facilities Contracts with respect to any actions or inactions of the Operating Agent that may affect Retained Environmental Liabilities or Excluded Liabilities. Nothing contained in this Section 11.1 shall excuse or limit Purchaser's performance of the specific covenants set forth in this Agreement in accordance with their terms.

11.2 **Expenses**. Except as otherwise provided herein, each Party is responsible for its own costs and expenses (including attorneys' and consultants' fees, costs and expenses) incurred in connection with this Agreement and the consummation of the transactions contemplated by this Agreement.

11.3 Entire Document. This Agreement (including the Exhibits and Schedules to this Agreement) the Ancillary Agreements and the Confidentiality Agreement contain the entire agreement between the Parties with respect to the transactions contemplated hereby and supersede all negotiations, representations, warranties, commitments, offers, contracts and writings (except for the Confidentiality Agreement) prior to the execution date of this Agreement, written or oral. No waiver and no modification or amendment of any provision of this Agreement is effective unless made in writing and duly signed by the Parties referring specifically to this Agreement, and then only to the specific purpose, extent and interest so provided.

11.4 Schedules. The Parties agree and acknowledge that the Schedules in this Agreement may be incomplete or subject to revision prior to the Closing, subject to Section 6.2. The Parties will cooperate and work in good faith to complete and update such Schedules in a manner consistent with the requirements of this Agreement. The Schedules delivered pursuant to the terms of this Agreement are an integral part of this Agreement to the same extent as if they were set forth verbatim herein.

11.5 Counterparts. This Agreement may be executed in one or more counterparts, each of which is an original, but all of which together constitute one and the same instrument.

11.6 Severability. If any provision hereof is held invalid or unenforceable by any arbitrator or as a result of future legislative action, this holding or action will be strictly construed and will not affect the validity or effect of any other provision hereof. To the extent permitted by law, the Parties waive, to the maximum extent permissible, any provision of law that renders any provision hereof prohibited or unenforceable in any respect.

11.7 Assignability. This Agreement is binding upon and inures to the benefit of the successors and assigns of the Parties, but is not assignable by any Party without the prior written consent of the other Party.

11.8 Captions. The captions of the various Articles, Sections, Exhibits and Schedules of this Agreement have been inserted only for convenience of reference and do not modify, explain, enlarge or restrict any of the provisions of this Agreement.

11.9 Governing Law. The validity, interpretation and effect of this Agreement are governed by and will be construed in accordance with the laws of the state in which the Facilities are located applicable to contracts made and performed in such state and without regard to conflicts of law doctrines except to the extent that certain matters are preempted by Federal law or are governed by the law of the jurisdiction of organization of the respective Parties.

11.10 Dispute Resolution.

(a) **Intent of the Parties**. Subject to ARTICLE 7 with respect to an Indemnifiable Claim, Section 3.2(e) with respect to Post-Closing Adjustments, Section 3.5 with respect to the Purchase Price allocation, and Section 6.5(e) with respect to disputes regarding Taxes, and except as provided in Section 11.10(b), the sole process available to either Party for resolution of any dispute or claim arising out of or relating to this Agreement or any Ancillary Agreement shall be the dispute resolution procedure set forth in this Section 11.10. If the Parties cannot resolve a dispute under Sections 11.10(c) or (d), then the dispute shall be settled through final and binding arbitration under Section 11.10(e).

(b) **Provisional Relief**. The Parties acknowledge and agree that irreparable damage would occur if certain provisions of this Agreement are not performed in accordance with the terms of this Agreement, that money damages would not be a sufficient remedy for any breach of these provisions of this Agreement, and that the Parties shall be entitled, without the requirement of posting a bond or other security, to seek a preliminary injunction, temporary restraining order, or other provisional relief as a remedy for a breach of this Agreement in any court of competent jurisdiction, notwithstanding the obligation to submit all other disputes (including all claims for monetary damages under this Agreement) to mediation and arbitration pursuant to Sections 11.10(d) or (e). The Parties further acknowledge and agree that the results of the arbitration may be rendered ineffectual without the provisional relief. Such a request for provisional relief does not waive a Party's right to seek other remedies for the breach of the Agreement, notwithstanding any prohibition against claim-splitting or other similar doctrine. The other remedies that may be sought include specific performance and injunctive or other equitable relief, plus any other remedy specified in this Agreement for the breach of the provision, or if the Agreement does not specify a remedy for the breach, all other remedies available at law or equity to the Parties for the breach.

(c) **Management Negotiations**. The Parties will attempt in good faith to resolve any dispute or claim arising out of or relating to this Agreement or an Ancillary Agreement promptly by negotiations between a vice president (or more senior officer) of Seller or his or her designated representative and an executive of similar authority of Purchaser. Either Party may give the other Party written notice of any dispute or claim. Within twenty (20) days after delivery of said notice, the executives will confer by telephone or meet at a mutually acceptable time and place, and thereafter as often as they reasonably deem necessary to exchange information and to attempt to resolve the dispute or claim. If the matter has not been resolved within sixty (60) days of the first meeting, either Party (by notice to the other Party) may submit the controversy for non-binding mediation pursuant to Section 11.10(d).

(d) **Mediation**. Either Party may initiate mediation by providing Notice to the other Party in accordance with Section 11.11 of a written request for mediation, setting forth a description of the dispute and the relief requested. The Parties will cooperate with one another in selecting the mediator (**"Mediator"**) from the panel of neutrals from Judicial Arbitration and Mediation Services, Inc. (**"JAMS"**), its successor, or any other mutually acceptable non-JAMS Mediator, and in scheduling the time and place of the mediation. Such selection and scheduling will be completed within forty-five (45) days after Notice of the request for mediation. Unless otherwise agreed to by the Parties, the mediation will not be scheduled for a date that is greater than one hundred twenty (120) days from the date of Notice of the request for mediation. The Parties covenant that they will participate in the mediation in good faith, and that they will share equally in its costs (other than each Party's individual attorneys' fees and costs related to the Party's participation in the mediation, which fees and costs will be borne by such Party). All offers, promises, conduct and statements, whether oral or written, made in connection with or during the mediation by either of the Parties, their agents, representatives, employees, experts and attorneys, and by the Mediator or any of the Mediator's agents, representatives and employees, will not be subject to discovery and will be confidential, privileged and inadmissible for any purpose, including impeachment, in any arbitration or other proceeding between or involving the Parties, or either of them, provided, evidence that is otherwise admissible or discoverable will not be rendered inadmissible or non-discoverable as a result of its use in the mediation.

(e) __**Arbitration**__. Either Party may initiate final and binding arbitration with respect to the matters first submitted to mediation by providing Notice of a demand for binding arbitration before a single, neutral arbitrator (the "**Arbitrator**") at any time following the unsuccessful conclusion of the mediation provided for above. The Parties will cooperate with one another in selecting the Arbitrator within sixty (60) days after Notice of the demand for arbitration and will further cooperate in scheduling the arbitration to commence no later than one hundred eighty (180) days from the date of Notice of the demand. To be qualified as an Arbitrator, each candidate must be a retired judge of a trial court of any state or federal court, or retired justice of any appellate or supreme court. Unless otherwise agreed to by the Parties, the individual acting as the Mediator will be disqualified from serving as the Arbitrator in the dispute, although the Arbitrator may be another member of the JAMS panel of neutrals or such other panel of neutrals from which the Parties have agreed to select the Mediator. Upon Notice of a Party's demand for final and binding arbitration, such dispute submitted to arbitration, including the determination of the scope or applicability of this Agreement to arbitrate, will be determined by final and binding arbitration before the Arbitrator, in accordance with the laws of the State of New Mexico, without regard to principles of conflicts of laws. Except as provided for herein, the arbitration will be conducted by the Arbitrator in accordance with the rules and procedures for arbitration of complex business disputes for the organization with which the Arbitrator is associated. Notwithstanding the rules and procedures that would otherwise apply to the arbitration, and unless the Parties agree to a different arrangement, the place of the arbitration will be Phoenix, Arizona, if arbitration is initiated by Seller, and Los Angeles, California, if arbitration is initiated by Purchaser.

Also notwithstanding the rules and procedures that would otherwise apply to the arbitration, and unless the Parties agree to a different arrangement, discovery will be limited as follows:

(i) Before discovery commences, the Parties shall exchange an initial disclosure of all documents and percipient witnesses which they intend to rely upon or use at any arbitration proceeding (except for documents and witnesses to be used solely for impeachment);

(ii) The initial disclosure will occur within thirty (30) days after the initial conference with the Arbitrator or at such time as the Arbitrator may order;

(iii) Discovery may commence at any time after the Parties' initial disclosure;

(iv) The Parties will not be permitted to propound any interrogatories or requests for admissions;

(v) Discovery by each Party will be limited to twenty-five (25) document requests (with no subparts), three (3) lay witness depositions, and three (3) expert witness depositions (unless the Arbitrator holds otherwise following a showing by the Party seeking the additional documents or depositions that the documents or depositions are critical for a fair resolution of the dispute or that a Party has improperly withheld documents);

(vi) Each Party is allowed a maximum of three (3) expert witnesses, excluding rebuttal experts;

(vii) Within sixty (60) days after the initial disclosure, or at such other time as the Arbitrator may order, the Parties shall exchange a list of all experts upon which they intend to rely at the arbitration proceeding;

(viii) Within thirty (30) days after the initial expert disclosure, each Party may designate a maximum of two (2) rebuttal experts;

(ix) Unless the Parties agree otherwise, all direct testimony will be in form of affidavits or declarations under penalty of perjury; and

(x) Each Party shall make available for cross examination at the arbitration hearing its witnesses whose direct testimony has been so submitted.

The Arbitrator will have the authority to grant any form of equitable or legal relief a Party might recover in a court action. The Parties acknowledge and agree that irreparable damage would occur if certain provisions of this Agreement are not performed in accordance with the terms of the Agreement, that money damages would not be a sufficient remedy for any breach of these provisions of this Agreement, and that the Parties shall be entitled, without the requirement of posting a bond or other security, to specific performance and injunctive or other equitable relief as a remedy for a breach of this Agreement. Judgment on the award may be entered in any court having jurisdiction. The Arbitrator must, in any award, allocate all of the costs of the binding arbitration (other than each Party's individual attorneys' fees and costs related to the Party's participation in the arbitration, which fees and costs will be borne by such Party), including the fees of the Arbitrator and any expert witnesses, against the Party who did not prevail; provided that if neither Party prevails completely such costs shall be allocated in favor of the Party who substantially prevailed as determined by the Arbitrator. Until such award is made, however, the Parties will share equally in paying the costs of the arbitration.

11.11 __Notices__. All notices, requests, demands and other communications under this Agreement must be in writing and must be delivered in person or sent by certified mail, postage prepaid, or by overnight delivery, and properly addressed as follows:

If to Seller:

Southern California Edison Company
2244 Walnut Grove Avenue
Rosemead, California 91770
Attention: Chief Financial Officer

With a copy to:

Southern California Edison Company
2244 Walnut Grove Avenue
Rosemead, California 91770
Attention: General Counsel

If to Purchaser:

Arizona Public Service Company
400 North Fifth Street, Station 9085
Phoenix, Arizona 85004
Attn: Mark A. Schiavoni, Senior Vice President of Fossil Operations

With a copy to:

Arizona Public Service Company
400 North Fifth Street, Station 8695
Phoenix, Arizona 85004
Attn: Shirley Baum, Associate General Counsel

With a copy to:

Ballard Spahr LLP
1735 Market Street, 51st Floor
Philadelphia, Pennsylvania 19103
Attention: Robert C. Gerlach, Esq.

Any Party may from time to time change its address for the purpose of notices to that Party by a similar notice specifying a new address, but no such change is effective until it is actually received by the Party sought to be charged with its contents.

All notices and other communications required or permitted under this Agreement which are addressed as provided in this Section 11.10 are effective upon delivery, if delivered personally, or by overnight delivery, and, are effective five (5) days following deposit in the United States mail postage prepaid if delivered by mail.

11.12 Time is of the Essence. Time is of the essence of each term of this Agreement Without limiting the generality of the foregoing, all times provided for in this Agreement for the performance of any act will be strictly construed.

11.13 No Third Party Beneficiaries. Except as may be specifically set forth in this Agreement, nothing in this Agreement, whether express or implied, is intended to confer any rights or remedies under or by reason of this Agreement on any Persons other than the Parties and their respective permitted successors and assigns, nor is anything in this Agreement intended to relieve or discharge the obligation or liability of any third Persons to any Party, nor give any third Persons any right of subrogation or action against any Party.

11.14 **No Joint Venture**. Nothing contained in this Agreement creates or is intended to create an association, trust, partnership, or joint venture or impose a trust or partnership duty, obligation, or liability on or with regard to any Party.

11.15 **Construction of Agreement**. Ambiguities or uncertainties in the wording of this Agreement will not be construed for or against any Party, but will be construed in the manner that most accurately reflects the Parties' intent as of the date they executed this Agreement.

11.16 **Effect of Closing Over Known Unsatisfied Conditions or Breached Representations, Warranties or Covenants**. If Seller or Purchaser elects to proceed with the Closing with Knowledge by it of any failure to be satisfied of any condition in its favor or the breach of any representation, warranty or covenant by the other Party, the condition that is unsatisfied or the representation, warranty or covenant which is breached at the Closing Date will be deemed waived by such Party, and such Party will be deemed to fully release and forever discharge the other Party on account of any and all claims, demands or charges, known or unknown, with respect to the same.

11.17 **Conflicts**. In the event of any conflicts or inconsistencies between the terms of this Agreement and the terms of any of the Ancillary Agreements, the terms of this Agreement will govern and prevail.

11.18 **Waiver of Compliance**. To the extent permitted by applicable Law, any failure of any of the Parties to comply with any obligation, covenant, agreement or condition set forth herein may be waived by the Party entitled to the benefit thereof only by a written instrument signed by such Party, but any such waiver shall not operate as a waiver, of, or estoppel with respect to, any prior or subsequent failure to comply therewith. The failure of a Party to this Agreement to assert any of its rights under this Agreement or otherwise shall not constitute a waiver of such rights.

11.19 **Survival.**

(a) The representations and warranties given or made by any Party in ARTICLE 4 or ARTICLE 5 hereof or in any certificate or other writing furnished in connection herewith shall survive the Closing indefinitely.

(b) The covenants and agreements of the Parties contained in this Agreement, including those set forth in ARTICLE 7, shall survive the Closing indefinitely, unless otherwise specified herein.

(c) The obligations of the Parties in Section 6.8 will survive (i) the termination of this Agreement, (ii) the discharge of all other obligations owed by the Parties to each other, (iii) any transfer of title to the Assets and (iv) the Closing of the transactions contemplated in this Agreement.

IN WITNESS WHEREOF, the Parties have executed this Agreement as of the date first above written.

SOUTHERN CALIFORNIA EDISON COMPANY,
a California corporation

By: ______________________
Name: R.W. Krieger
Title: Vice President Power Production

ARIZONA PUBLIC SERVICE COMPANY,
an Arizona corporation

By: ______________________
Name:
Title:

IN WITNESS WHEREOF, the Parties have executed this Agreement as of the date first above written.

SOUTHERN CALIFORNIA EDISON COMPANY,
a California corporation

By: ______________________________
Name:
Title:

ARIZONA PUBLIC SERVICE COMPANY,
an Arizona corporation

By: ______________________________
Name: Donald G. Robinson
Title: President and Chief Operating Officer

Schedules to Purchase and Sale Agreement

Schedule 1.1.50(a)

Seller's Officers, Employees, and Knowledgeable Persons

Russ Krieger – Vice President, Power Production
John Dayton – Manager of Business Planning and Development, Power Production
Steven Pickett – Senior Vice President and General Counsel
Daniel Cobb – Alternate E&O Committee Member

Schedule 1.1.50(b)

Purchaser's Officers, Employees and Authorized Agents

Mark Schiavoni – Senior Vice President Fossil
David Hansen – Vice President Fossil Operations
David Falck – Executive Vice President, General Counsel and Secretary
John Franchini – Fossil Plant Manager Four Corners
Susan Kidd – Director Coal/Co-Owned Generation
Nick Svor – General Manager Generation Engineering
Frank Perkins – Plant Manager Four Corners Units 4, 5
Richard Grimes – Four Corners Environmental Section Leader

Schedule 1.1.50(c)

Operating Agent's Officers, Employees and Authorized Agents

See Schedule 1.1.50(b) which is incorporated herein by reference.

Schedule 1.1.62

PNW Plans

- Pinnacle West Capital Corporation Retirement Plan
- Pinnacle West Capital Corporation Group Life and Medical Plan

Schedule 1.1.67

Purchaser's Required Consents

- None

<u>Schedule 1.1.68</u>

Purchaser's Required Regulatory Approvals

- Arizona Corporation Commission
- Federal Energy Regulatory Commission
- Hart-Scott-Rodino Antitrust Improvements Act of 1976

<u>Schedule 1.1.77</u>

Seller's Required Consents

- Trustee under Seller's Mortgage

Schedule 1.1.78

Seller's Required Regulatory Approvals

- California Public Utilities Commission
- Federal Energy Regulatory Commission
- California Independent System Operator
- Hart-Scott-Rodino Antitrust Improvements Act of 1976

Schedule 2.1(b)

Leased Real Property

- Facilities Lease
- The real property interests described in Exhibits 2 – 9 of the Facilities Lease
- See Schedule 2.1(c) which is incorporated herein by reference

Schedule 2.1(c)

Rights-of-Way/Easements and Water Rights

Item	*Existing § 323 Grants*	*Property or Facility*	*APS File #*	*Grant Date*	*Expiration Date*
1	Plant Site	New Lease (Units 4-5)		07/06/66	07/06/16
2	Ancillary Facilities	Utah Mine Haul Road (Communication Lines and Access Road)	IN-13	07/28/61	07/28/11
		Plant – Coal Lease Area – 69 kV	IN-15	12/15/61	12/15/11
		Pumping Station to Plant Access Road Pipeline	IN-12	04/02/62	04/02/12
		River Pumping Station to Plant – 69 kV	IN-11	04/02/62	04/02/12
		Plant – EPNG Bridge / Access Rd	IN-16	07/03/63	07/03/13
		Pumping Station to Plant Access Road Pipeline Addition	IN-92	04/21/69	04/21/19

Schedule 2.1(h)

Seller Facilities Contracts

1. § 323 Grants.
2. Facilities Lease.
3. Facilities Co-Tenancy Agreement.
4. Facilities Operating Agreement.
5. Restated and Amended Four Corners Fuel Agreement Number 2, dated August 31, 2003, by and among BHP Navajo Coal Company and the Participants, as the same may be amended.
6. Conditional Partial Assignment of Fuel Agreement Number 2, dated September 2, 1966, by and among Utah Construction & Mining Co. and the Participants.
7. Memorandum for Recordation of Original Four Corners Fuel Agreement and of Four Corners Fuel Agreement No. 2 and Imposition of Equitable Servitude and Covenant Running with the Land, dated September 2, 1966, by and among Utah Construction & Mining Co. and the Participants.
8. Facilities Fuel Agreement.
9. Four Corners Project Emission Abatement System Operating Power Agreement, dated October 15, 1982 among the Participants.
10. Four Corners Project Unit Tripping Agreement, dated May 23, 1969 among the Participants.
11. Four Corners Units 4 & 5 Capital Improvements Design and Construction Agreement, dated March 23, 1981 among the Participants.
12. Agreement to Purchase and Sell Undivided Interest in the Reserve Auxiliary Power Source Four Corners Project, dated August 15, 1968 among the Participants.
13. Exchange Agreement dated March 28, 1967 among the Participants with Letter of Clarification dated March 28, 1967, a Supplemental Letter Agreement dated February 9, 1972 and Ruling of Internal Revenue Service with Letter of Transmittal.
14. Four Corners Designated Representative Agreement, dated March 18, 1994, by and among the Participants, John R. Denman and D. Craig Walling.
15. Four Corners Designated Representative Agreement Assignment and Novation, dated October 22, 2002 from D. Craig Walling to David L. Saliba.
16. Four Corners Designated Representative Agreement Assignment and Novation Form, dated July 31, 2009 from John R. Denman to David L. Saliba as the new designated representative and Richard Grimes as the new alternate designated representative.
17. Four Corners Designated Representative Agreement Assignment and Novation Form, dated January 31, 2010, from David L. Saliba to Frank E. Perkins.

18. Principals of Interconnected Operation Four Corners Project dated May 12, 1969, among the Participants as amended by Amendment No. 1 dated April 29, 1974, among the Participants.

19. Water Supply Agreement, dated March 2, 2007 between the Jicarilla Apache Nation, BHP Navajo Coal Company, APS on behalf of itself and with respect to Units 4 and 5 the Four Corners Participants and Public Service Company of New Mexico on behalf of itself and the San Juan Participants.

20. Voluntary Compliance Agreement Air Quality, dated May 18, 2005, by and among the Navajo Nation, Salt River Project Agricultural Improvement and Power District, as operating agent for the Navajo Generating Station ("NGS") and with the express written consent of each participant of NGS and APS, as operating agent for the Four Corners Power Plant and with the express written consent of each Participant.

21. Tax Settlement and Closing Agreement, dated August 13, 2002, by and between the Seller and the Office of the Navajo Nation Uniform Tax Administration Statute.

22. Shiprock-Four Corners Project 345-kV Switchyard Interconnection Agreement, dated October 2, 2002, by and among the Facilities Owners and Public Service Company of Colorado, Tri-State Generation and Transmission Association, Inc., and Western Area Power Administration.

Schedule 3.6(a)(iii)

Operating and Maintenance Expense Pro-Rations

The following costs and expenses incurred for the applicable period during which the Closing occurs shall be pro-rated between the Parties:

1. Seller is responsible for the operation and maintenance expenses as defined in the Facilities Operating Agreement, Section 17, Operating and Maintenance Expenses, incurred prior to the Closing Date, including but not limited to the following:

    a. Outside services and materials and supplies, including all administrative and general loads, for operating and maintaining the plant; and

    b. Payroll including related administrative and general, payroll taxes and benefits expenses.

2. Employee Incentive Plan payroll including related administrative and general, payroll taxes and benefits expenses.

3. Fuel expenses (Coal and Gas).

4. Insurance premiums.

5. Navajo Land Lease.

6. Environmental Operating Permit.

7. Ash Hauling Agreement costs.

8. All related royalties and taxes for Operating and Maintenance expenses and Fuel expenses.

Schedule 6.5(g)

Pollution Control Bonds

$55,540,000 City of Farmington, New Mexico 5.125% Pollution Control Refunding Revenue Bonds (Southern California Edison Company Four Corners Project) 1999 Series A

City of Farmington, New Mexico Pollution Control Refunding Revenue Bonds (Southern California Edison Company Four Corners Project) $103,460,000 2005 Series A (Non-AMT)

City of Farmington, New Mexico Pollution Control Refunding Revenue Bonds (Southern California Edison Company Four Corners Project) $100,000,000 2005 Series B (Non-AMT)

Exhibit A-1

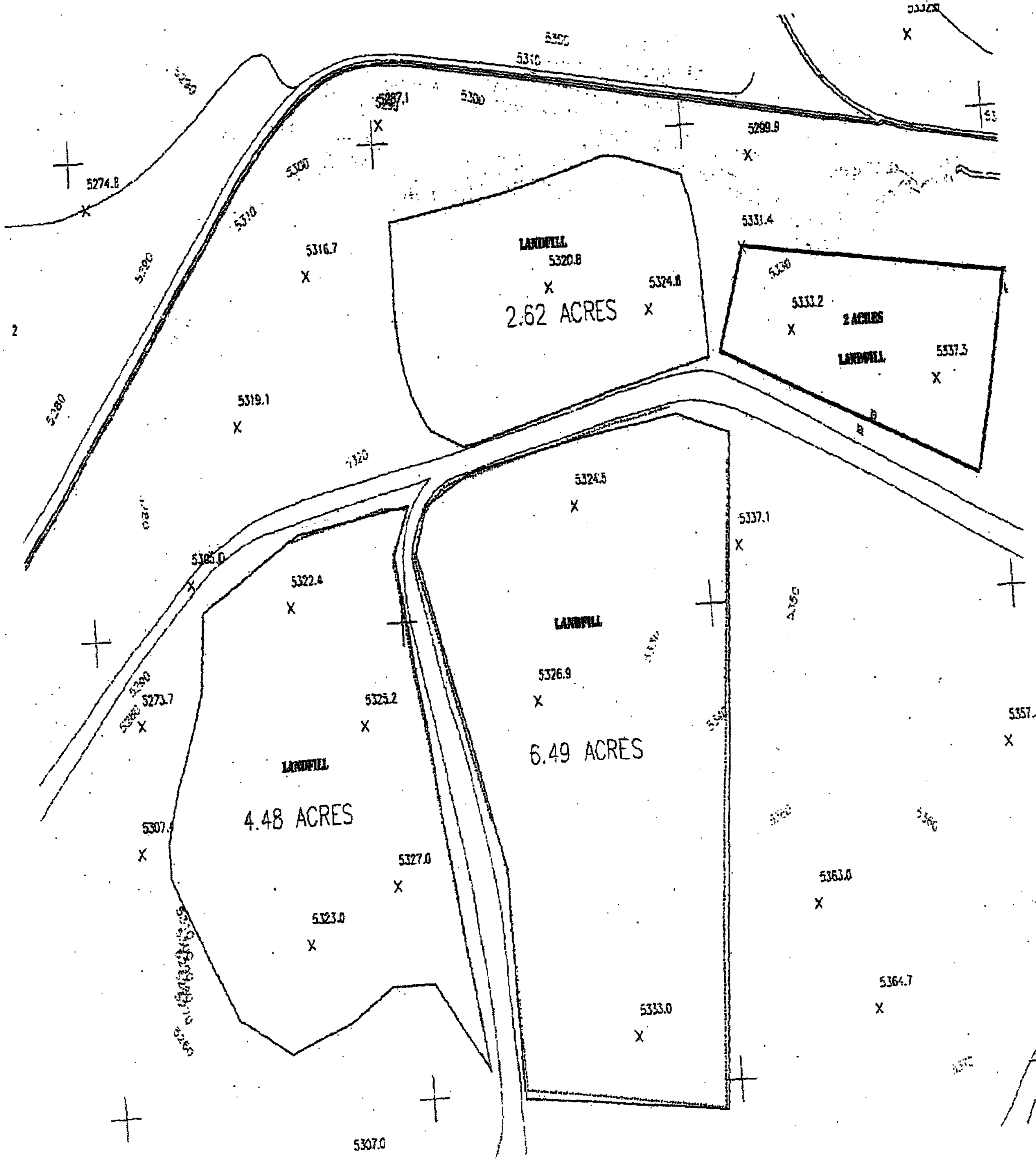
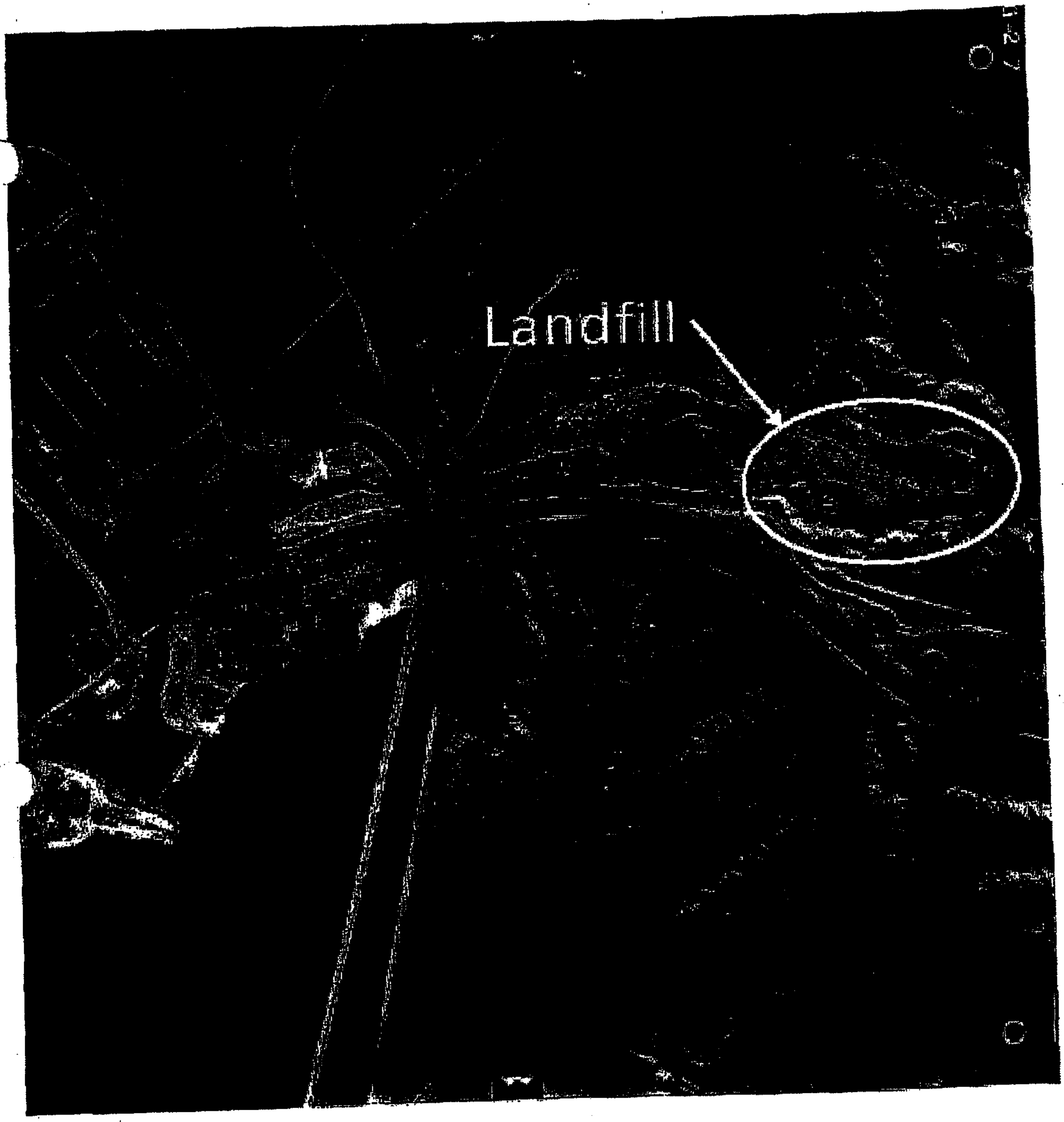


Exhibit A-1



Four Corners Power Plant
Aerial Photo taken on 12/18/1979
EXHIBIT A-2

PROSPECTUS SUPPLEMENT (To Prospectus Dated April 24, 2012)

aps

Arizona Public Service Company

$250,000,000 4.70% Notes due 2044

This is an offering by Arizona Public Service Company of $250,000,000 of its 4.70% Notes due 2044, referred to in this prospectus supplement as the "notes." Interest on the notes is payable on January 15 and July 15 of each year, beginning on July 15, 2014. The notes will mature on January 15, 2044. We may redeem some or all of the notes at any time at the redemption prices described under the caption "Description Of The Notes—Optional Redemption" in this prospectus supplement, plus accrued and unpaid interest to the redemption date. The notes do not have sinking fund provisions. The notes will be issued only in denominations of $2,000 and integral multiples of $1,000 in excess thereof. We do not intend to list the notes on any securities exchange or quotation system.

The notes will be our unsecured senior obligations and will rank equally with all of our other unsecured senior indebtedness from time to time outstanding.

Investing in the notes involves risks. See "Risk Factors" on page S-5 of this prospectus supplement, which refers you to the risks described under "Risk Factors" contained in our Annual Report on Form 10-K for the year ended December 31, 2012.

	Per Note	Total Notes
Initial public offering price(1)	99.600%	$249,000,000
Underwriting discounts and commissions	0.875%	$ 2,187,500
Proceeds, before expenses, to Arizona Public Service Company . .	98.725%	$246,812,500

(1) Plus accrued interest, if any, from January 10, 2014 to the date of delivery, if settlement occurs after that date.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus supplement or the accompanying prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the notes to purchasers in book-entry form only through the facilities of The Depository Trust Company against payment in New York, New York on or about January 10, 2014.

Joint Book-Running Managers

BofA Merrill Lynch **Citigroup** **UBS Investment Bank** **US Bancorp**

Co-Managers

Blaylock Robert Van, LLC **Drexel Hamilton** **The Williams Capital Group, L.P.**

The date of this prospectus supplement is January 7, 2014.

You should rely only on the information contained in or incorporated by reference in this prospectus supplement, the accompanying prospectus and any related free writing prospectus required to be filed with the Securities and Exchange Commission (the "SEC"). Neither we nor the underwriters have authorized anyone to provide you with different information. We are not, and the underwriters are not, making an offer of the notes in any jurisdiction where the offer or sale is not permitted. You should not consider this prospectus supplement and the accompanying prospectus to be an offer to sell, or a solicitation of an offer to buy, the notes if the person making the offer or solicitation is not qualified to do so or if it is unlawful for you to receive the offer or solicitation. You should assume that the information contained in this prospectus supplement and the accompanying prospectus is accurate only as of their respective dates and that the information incorporated by reference is accurate only as of the date such information is filed with the SEC, regardless of the time of delivery of any document or of any sale of the notes. If anyone provides you with different or inconsistent information, you should not rely on it. Our business, financial condition, results of operations and prospects may have changed since the date on any document.

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ABOUT THIS PROSPECTUS SUPPLEMENT

This document is in two parts. The first part is this prospectus supplement, which describes the terms of the offering of the notes and also adds to and updates information contained in the accompanying prospectus and the documents incorporated by reference into this prospectus supplement and the accompanying prospectus. The second part is the accompanying prospectus, which gives more general information, some of which will not apply to the notes. If the description of the offering varies between this prospectus supplement and the accompanying prospectus (or information incorporated by reference into this prospectus supplement or the accompanying prospectus), you should rely on the information in this prospectus supplement. The accompanying prospectus also includes information about Pinnacle West Capital Corporation and its securities, which information does not apply to the notes. We are a wholly owned subsidiary of Pinnacle West Capital Corporation. The notes are solely our obligations and not obligations of Pinnacle West Capital Corporation. Pinnacle West Capital Corporation is not guaranteeing or providing any credit support for the notes. You should read both this prospectus supplement and the accompanying prospectus together with the additional information about us described in the section entitled "Where You Can Find More Information."

This prospectus supplement and the accompanying prospectus are part of a registration statement that we filed jointly with our parent company, Pinnacle West Capital Corporation, with the SEC using a "shelf" registration process as a "well-known seasoned issuer." Under the shelf registration process, we may, from time to time, issue and sell to the public any of our unsecured debt securities described in the accompanying prospectus, including the notes, up to an indeterminate amount, of which this offering is a part. In this prospectus supplement, we provide you with specific information about the terms of the notes and this offering.

PROSPECTUS SUPPLEMENT SUMMARY

This summary highlights information contained elsewhere, or incorporated by reference, in this prospectus supplement and the accompanying prospectus. As a result, it does not contain all of the information that may be important to you. You should carefully read this prospectus supplement and the accompanying prospectus and the documents incorporated by reference into this prospectus supplement and the accompanying prospectus in their entirety before making an investment decision. We describe the documents that we incorporate by reference under the heading "Where You Can Find More Information" in this prospectus supplement, including in particular the information referred to under "Risk Factors" in this prospectus supplement. The following material is qualified in its entirety by reference to the detailed information and financial statements included or incorporated by reference in this prospectus supplement and the accompanying prospectus. References in this prospectus supplement to "we," "our" and "us" refer to Arizona Public Service Company and, unless the context requires otherwise, its subsidiaries.

Arizona Public Service Company

We were incorporated in 1920 under the laws of the State of Arizona and are a wholly owned subsidiary of Pinnacle West Capital Corporation ("Pinnacle West"). We are a vertically-integrated electric utility that provides either retail or wholesale electric service to most of the State of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. We currently have approximately 1.1 million customers. Our principal executive offices are located at 400 North Fifth Street, P.O. Box 53999, Phoenix, Arizona 85072-3999, and our telephone number is 602-250-1000.

The Offering

Issuer	Arizona Public Service Company.
Securities Offered	$250,000,000 of 4.70% Notes due 2044.
Maturity	January 15, 2044.
Interest Rate	4.70% per annum.
Interest Payment Dates	January 15 and July 15 of each year, beginning July 15, 2014 (and including the date of maturity).
Record Date for Interest Payments	The record date for interest payments on the notes will be January 1 for the January 15 interest payment date and July 1 for the July 15 interest payment date.
Use of Proceeds	We intend to use the net proceeds from the sale of the notes (i) to repay commercial paper issued on a short-term, temporary basis, and replenish cash temporarily used to fund our acquisition of Southern California Edison Company's 48% ownership interest in each of Units 4 and 5 of the Four Corners Power Plant for approximately $182 million, which closed on December 30, 2013 (the "Four Corners Acquisition"), (ii) to replenish cash used to re-acquire two series of our tax-exempt indebtedness and (iii) to finance the payment of other costs and expenses related to the Four Corners Acquisition. See "Use Of Proceeds" in this prospectus supplement.

Optional Redemption	All or a portion of the notes may be redeemed at our option at any time or from time to time on at least 30 days' but not more than 60 days' notice, (i) if prior to July 15, 2043 (six months prior to the maturity date of the notes), at a redemption price equal to the greater of (a) 100% of the principal amount of the notes being redeemed on the redemption date and (b) the applicable make-whole price described under "Description Of The Notes—Optional Redemption" in this prospectus supplement, or (ii) if on or after July 15, 2043 (six months prior to the maturity date of the notes), at a redemption price equal to 100% of the principal amount of the notes being redeemed on the redemption date, plus, in any case, accrued and unpaid interest thereon to the redemption date.
Ranking	The notes will be our unsecured senior obligations, will rank equally in right of payment with all of our other unsecured senior indebtedness from time to time outstanding and will be effectively subordinated to any secured debt we may issue or incur in the future. As of September 30, 2013, we had approximately $3.2 billion aggregate principal amount of unsecured senior indebtedness outstanding. In addition, we have operating lease obligations to three separate variable-interest entity lessor trusts related to sale-leaseback transactions for interests in Unit 2 at the Palo Verde Nuclear Generating Station. As of September 30, 2013, these lessor trusts had approximately $57 million of indebtedness outstanding that is secured by the lessor trusts' ownership interests in these assets. The outstanding amount of this indebtedness is reduced as payments are made under the leases.
Covenants	The notes will be subject to the limitation on liens covenant described under "Description Of The Notes—Limitation on Liens" in this prospectus supplement. However, this covenant is subject to a number of important exceptions and qualifications, including an exception permitting secured debt in an amount that does not exceed 10% of Tangible Assets (as defined in that description), which, at September 30, 2013, was approximately $1.3 billion. As of September 30, 2013, we had no outstanding secured debt.
Form of Notes	The notes will be represented by one or more global securities to be deposited with the trustee as custodian for The Depository Trust Company ("DTC") in a minimum denomination of $2,000 and any integral multiple of $1,000 in excess thereof.
Trustee	The Bank of New York Mellon Trust Company, N.A. See "Description Of The Notes—Regarding the Trustee" in this prospectus supplement.

Risk Factors	Your investment in the notes involves risks. You should carefully consider the information referred to in the section entitled "Risk Factors" and the other information contained or incorporated by reference in this prospectus supplement and the accompanying prospectus, including information under the heading "Forward-Looking Statements," before deciding whether to purchase the notes.

Selected Financial Data

We are providing the following selected financial data to assist you in analyzing an investment in the notes. We derived the selected financial data presented below for each of the three years in the period ended December 31, 2012 from our annual financial statements, which have been audited by Deloitte & Touche LLP, an independent registered public accounting firm. The following selected financial data as of September 30, 2013 and for the nine months ended September 30, 2013 and 2012 is unaudited, but, in the judgment of our management, contains all necessary adjustments for a fair presentation of our financial position on that date and the results of operations for that period. The information below should be read in conjunction with, and is qualified in its entirety by, "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the fiscal year ended December 31, 2012 (the "2012 Form 10-K") and in our Quarterly Reports on Form 10-Q for the fiscal quarters ended March 31, 2013, June 30, 2013 and September 30, 2013, as well as in our financial statements, related notes and other financial or statistical information that we include or incorporate by reference in this prospectus supplement and the accompanying prospectus. See "Where You Can Find More Information" below. These selected financial data do not necessarily indicate the results to be expected in the future. See also page S-8 for a description of the historical ratios of our earnings to fixed charges for the years ended December 31, 2012, 2011, 2010, 2009 and 2008 and for the nine months ended September 30, 2013.

(All dollar figures in thousands, except footnotes)	Nine Months Ended September 30,		Year Ended December 31,		
	2013	2012	2012	2011	2010
Electric Operating Revenues	$2,752,427	$2,606,458	$3,293,489	$3,237,241	$3,180,807
Net Income Attributable to Common Shareholder	$ 394,945	$ 368,654	$ 395,497	$ 336,249	$ 335,663

	As of September 30, 2013	As adjusted(1)
Long-term Debt (less current maturities)(2)	$2,657,901	$2,907,901
Palo Verde Sale Leaseback Lessor Notes (less current maturities)	37,414	37,414
Current Maturities of Long-term Debt(3)	566,481	534,981
Total Equity(4)	4,538,421	4,538,421
Total Capitalization	$7,800,217	$8,018,717

(1) As adjusted for the issuance of the notes and the application of the net proceeds therefrom. See "Use Of Proceeds" in this prospectus supplement.

(2) Includes unamortized debt discount of approximately $8.9 million.

(3) Includes current maturities of Palo Verde Sale Leaseback Lessor Notes of approximately $20 million.

(4) Includes Noncontrolling Interests of approximately $146 million.

RISK FACTORS

See the discussions of risk factors contained in the accompanying prospectus and Part I, Item 1A of the 2012 Form 10-K, which are incorporated by reference in this prospectus supplement and the accompanying prospectus, to read about certain risks relating to our business and an investment in the notes.

An investment in the notes involves a significant degree of risk. Before investing in the notes, you should carefully consider the discussion of those risks and the other information included or incorporated by reference in this prospectus supplement and the accompanying prospectus, including the information under the heading "Forward-Looking Statements" below. Although we try to discuss material risks in these risk factors and other information, please be aware that other risks may prove to be important in the future. New risks may emerge at any time and we cannot predict those risks or estimate the extent to which they may affect our business, financial condition, cash flows or operating results.

FORWARD-LOOKING STATEMENTS

The forward-looking statements disclaimer set forth below supersedes any similarly entitled forward-looking statements disclaimer contained in the accompanying prospectus.

This prospectus supplement, the accompanying prospectus and the information incorporated by reference in this prospectus supplement and the accompanying prospectus may contain forward-looking statements within the meaning of the safe harbor of the Private Securities Litigation Reform Act of 1995, and are based on current expectations. These forward-looking statements are often identified by words such as "estimate," "predict," "hope," "may," "believe," "anticipate," "plan," "expect," "require," "intend," "should," "could," "project," "forecast," "assume" and similar words. Forward-looking statements are not guarantees of performance. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by us. These factors include:

- our ability to manage capital expenditures and operations and maintenance costs while maintaining reliability and customer service levels;
- variations in demand for electricity, including those due to weather, the general economy, customer and sales growth (or decline), and the effects of energy conservation measures and distributed generation;
- power plant and transmission system performance and outages;
- volatile fuel and purchased power costs;
- fuel and water supply availability;
- our ability to achieve timely and adequate rate recovery of our costs, including returns on debt and equity capital;
- regulatory and judicial decisions, developments and proceedings;
- new legislation or regulation, including those relating to environmental requirements, nuclear plant operations and potential deregulation of retail electric markets;
- our ability to meet renewable energy and energy efficiency mandates and recover related costs;
- risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainty;
- competition in retail and wholesale power markets;

- the duration and severity of the economic decline in Arizona and current real estate market conditions;
- the cost of debt and equity capital and the ability to access capital markets when required;
- changes to our credit ratings;
- the investment performance of the assets of our nuclear decommissioning trust, pension, and other postretirement benefit plans and the resulting impact on future funding requirements;
- the liquidity of wholesale power markets and the use of derivative contracts in our business;
- potential shortfalls in insurance coverage;
- new accounting requirements or new interpretations of existing requirements;
- generation, transmission and distribution facility and system conditions and operating costs;
- the ability to meet the anticipated future need for additional baseload generation and associated transmission facilities in our region;
- the willingness or ability of our counterparties, power plant participants and power plant land owners to meet contractual or other obligations or extend the rights for continued power plant operations;
- technological developments affecting the electric industry; and
- restrictions on dividends or other provisions in our credit agreements and Arizona Corporation Commission ("ACC") orders.

These and other factors are discussed in the risk factors described in Part I, Item 1A of the 2012 Form 10-K, which you should review carefully before placing any reliance on our financial statements or disclosures. We do not assume any obligation to update any forward-looking statements, even if our internal estimates change, except as may be required by applicable law.

We claim the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995 for any forward-looking statements contained in this prospectus supplement and the accompanying prospectus, including in the information incorporated by reference in this prospectus supplement and the accompanying prospectus.

WHERE YOU CAN FIND MORE INFORMATION

Available Information

We file annual, quarterly and current reports and other information with the SEC under File No. 1-4473. Our SEC filings are available to the public over the Internet at the SEC's website: http://www.sec.gov. You may also read and copy any materials we file with the SEC at the SEC's public reference room, which is located at 100 F Street, N.E., Washington D.C. 20549. You may obtain information on the operation of the public reference room by calling the SEC at 1-800-SEC-0330. Our filings with the SEC are also available on Pinnacle West's website at http://www.pinnaclewest.com. The information on Pinnacle West's website is not part of this prospectus supplement or the accompanying prospectus.

Incorporation by Reference

We are incorporating by reference the information we file with the SEC, which means that we can disclose important information to you by referring you to those documents. The information incorporated by reference is considered to be part of this prospectus supplement and the accompanying prospectus, except for information superseded by information in this prospectus supplement and the accompanying prospectus, and later information that we file with the SEC will automatically update and supersede this information. We incorporate by reference the documents listed below and any future filings we make with the SEC under Section 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934, as amended, excluding, in each case, information deemed furnished and not filed, until all of the notes offered by this prospectus supplement are sold.

- Annual Report on Form 10-K for the fiscal year ended December 31, 2012;
- Quarterly Reports on Form 10-Q for the fiscal quarters ended March 31, 2013, June 30, 2013 and September 30, 2013; and
- Current Reports on Form 8-K filed on March 11, 2013, March 21, 2013, April 9, 2013 (two filings), May 21, 2013, June 17, 2013, September 13, 2013, November 15, 2013, December 23, 2013 and December 30, 2013.

These documents contain important information about us and our finances.

We will provide to each person, including any beneficial owner, to whom this prospectus supplement and the accompanying prospectus is delivered, a copy of any or all of the information that has been incorporated by reference in this prospectus supplement and the accompanying prospectus but not delivered with this prospectus supplement and the accompanying prospectus. You may request a copy of these filings, at no cost, by writing, telephoning or contacting us through our website at the following address:

Arizona Public Service Company
Office of the Secretary
Station 8602
P.O. Box 53999
Phoenix, Arizona 85072-3999
(602) 250-4400
www.pinnaclewest.com

USE OF PROCEEDS

We estimate that the net proceeds from the sale of the notes, after deducting underwriting discounts and commissions but before deducting estimated offering expenses, will be approximately $246.8 million. We intend to use the net proceeds from the sale of the notes (i) to repay commercial paper issued on a short-term, temporary basis, and replenish cash temporarily used to fund the Four Corners Acquisition, (ii) to replenish cash used to re-acquire upon prior mandatory tender dates and subsequently refinance via redemption or cancellation at par our indebtedness related to the $31.50 million principal amount City of Farmington, New Mexico Pollution Control Revenue Bonds (Arizona Public Service Company Four Corners Project), 1994 Series C due 2024, which had a short-term interest rate of 0.26% per annum on January 3, 2014, and the $32.65 million principal amount Coconino County, Arizona Pollution Control Corporation Pollution Control Revenue Bonds (Arizona Public Service Company Navajo Project), 1994 Series A due 2029, which had a short-term interest rate of 0.13% per annum on January 3, 2014, and (iii) to finance the payment of other costs and expenses related to the Four Corners Acquisition. The issuance of commercial paper and use of cash on hand in connection with the Four Corners Acquisition was a temporary funding source to accommodate the timing of the closing of the Four Corners Acquisition; accordingly, the relevant portion of the net proceeds from the sale of the notes is intended to provide the permanent financing for the Four Corners Acquisition. As of January 3, 2014, we had $139.5 million of commercial paper outstanding bearing a weighted average interest rate of 0.23% per annum. Until we use the net proceeds for the above purposes, we may temporarily invest the net proceeds in highly liquid short-term investments such as institutional money market funds, deposit the net proceeds with banks or temporarily utilize the proceeds in our business.

RATIOS OF EARNINGS TO FIXED CHARGES

The following table sets forth the historical ratio of our earnings to fixed charges for each of the indicated periods:

Nine Months Ended September 30,		Year Ended December 31,				
2013	2012	2012	2011	2010	2009	2008
5.12	4.66	3.98	3.21	3.16	2.77	2.78

For the purposes of computing our ratios of earnings to fixed charges, earnings are divided by fixed charges. "Earnings" represent the aggregate of income (loss) from continuing operations before income taxes and fixed charges. "Fixed charges" represent interest expense, the amortization of debt discount and the interest portion of rentals.

DESCRIPTION OF THE NOTES

The notes will be issued as a separate series of debt securities under the indenture dated as of January 15, 1998, between us and The Bank of New York Mellon Trust Company, N.A., successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank), as trustee. The following description of specific terms of the notes supplements the description of the general terms and provisions of the debt securities in the accompanying prospectus under "Description Of APS Unsecured Debt Securities." Because this is a summary, it does not contain all the information that may be important to you.

General

The terms of the notes are set forth below:

- **Title:** 4.70% Notes due 2044.
- **Total principal amount being issued:** $250,000,000.
- **Due date for principal:** January 15, 2044.
- **Interest rate:** 4.70% per annum.
- **Date interest starts accruing:** January 10, 2014.
- **Interest payment dates:** January 15 and July 15 of each year (including the date of maturity). In the event that any interest payment date is not a business day, then payment of interest will be made on the succeeding business day.
- **First interest payment date:** July 15, 2014.
- **Regular record dates for interest payment dates:** January 1 for the January 15 interest payment date and July 1 for the July 15 interest payment date.
- **Computation of interest:** On the basis of a 360-day year of twelve 30-day months.
- **Form of notes:** The notes will be represented by one or more global securities in denominations of $2,000 and any integral multiples of $1,000 in excess thereof. We will deposit each global security with the trustee as custodian for DTC. See "Description Of APS Unsecured Debt Securities—Global Securities" in the accompanying prospectus. We may allow exchange of each global security for registered notes and transfer of each global security to a person other than DTC in additional circumstances that we agree to other than those described under that heading.
- **Sinking fund:** The notes will not be subject to any sinking fund.

The notes will constitute a separate series of our unsecured senior debt securities under the indenture relating to the notes. The notes will rank equally in right of payment with all of our existing and future senior unsecured debt and senior to all of our existing and future subordinated debt and will be effectively subordinated to any secured debt we may issue or incur in the future. As of September 30, 2013, we had no outstanding secured debt. The limitation on liens covenant described under "—Limitation on Liens" below will limit our ability to create liens on our operating property to secure indebtedness. However, this covenant is subject to a number of important exceptions and qualifications, including an exception permitting secured debt in an amount that does not exceed 10% of Tangible Assets (as defined therein), which, at September 30, 2013, was approximately $1.3 billion. The prospectus that accompanies this prospectus supplement further describes our debt securities under "Description Of APS Unsecured Debt Securities."

As of September 30, 2013, we had approximately $3.2 billion of senior unsecured debt outstanding, of which approximately $2.7 billion was outstanding under the indenture relating to the notes.

We must obtain the approval of the ACC before incurring long-term debt. The ACC issued an order on February 6, 2013 allowing us to have $5.1 billion in principal amount of long-term debt outstanding, subject to the satisfaction of certain conditions, including the satisfaction of a minimum common equity test and a debt service coverage test.

Additional Notes

We may from time to time, without notice to, or the consent of, the then existing registered holders of the notes, create and issue additional notes equal in rank and having the same maturity, payment terms, redemption features, and other terms as the notes, except for the issue date of the additional notes, the public offering price of the additional notes, the payment of interest accruing prior to the issue date of the additional notes and (under some circumstances) the first payment of interest following the issue date of the additional notes, but we will not issue such additional notes unless the additional notes are fungible with the previously issued notes for U.S. federal income tax purposes or are issued with a separate CUSIP number. These additional notes may be consolidated and form a single series with the notes.

Optional Redemption

All or a portion of the notes may be redeemed at our option at any time or from time to time. The redemption price for any notes to be redeemed on any redemption date prior to July 15, 2043 (six months prior to the maturity date of the notes) will be equal to the greater of the following amounts:

- 100% of the principal amount of the notes being redeemed on the redemption date; or
- the sum of the present values of the remaining scheduled payments of principal of and interest on the notes being redeemed on that redemption date (not including any portion of any payments of interest accrued to the redemption date) discounted to the redemption date on a semiannual basis at the Adjusted Treasury Rate (as defined below), plus 15 basis points, as determined by a Reference Treasury Dealer (as defined below) appointed by us for such purpose;

plus, in each case, accrued and unpaid interest on the notes being redeemed to the redemption date. The redemption price for any notes to be redeemed on any redemption date on or after July 15, 2043 (six months prior to the maturity date of the notes) will be equal to 100% of the principal amount of the notes being redeemed on the redemption date plus accrued and unpaid interest on the notes being redeemed to the redemption date. Notwithstanding the foregoing, installments of interest on notes that are due and payable on interest payment dates falling on or prior to a redemption date will be payable on the interest payment date to the registered holders as of the close of business on the relevant record date according to the notes and the related indenture. The redemption price will be calculated on the basis of a 360-day year consisting of twelve 30-day months.

If less than all of the notes are to be redeemed, the notes to be redeemed will be selected in accordance with the procedures of DTC. However, the unredeemed portion of the principal amount of any note must be in an authorized denomination.

We will deliver notice of any redemption at least 30 days but not more than 60 days before the redemption date to each registered holder of the notes to be redeemed. However, in the case of any notes being redeemed prior to July 15, 2043 (six months prior to the maturity date of the notes), we will not know the exact redemption price until three business days before the redemption date. Therefore, the related notice of redemption will only describe how the redemption price will be calculated. Unless we default in payment of the redemption price, on and after the redemption date, interest will cease to accrue on the notes or portions thereof called for redemption.

"Adjusted Treasury Rate" means, with respect to any applicable redemption date, the rate per annum equal to the semiannual equivalent yield to maturity of the Comparable Treasury Issue (as defined below), assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price (as defined below) for such redemption date.

"Comparable Treasury Issue" means the U.S. Treasury security selected by a Reference Treasury Dealer appointed by us for such purpose as having a maturity comparable to the remaining term of the notes to be redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of such notes.

"Comparable Treasury Price" means, with respect to any applicable redemption date, (A) if we obtain three or more Reference Treasury Dealer Quotations (as defined below), the average of such Reference Treasury Dealer Quotations for such redemption date, after excluding the highest and lowest of such Reference Treasury Dealer Quotations, (B) if we obtain two such Reference Treasury Dealer Quotations, the average of such quotations, or (C) if only one Reference Treasury Dealer Quotation is received, such quotation.

"Primary Treasury Dealer" means a primary U.S. Government securities dealer in the United States.

"Reference Treasury Dealer" means (A) Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, UBS Securities LLC and a Primary Treasury Dealer selected by U.S. Bancorp Investments, Inc.; provided, however, that if any of the foregoing shall cease to be a Primary Treasury Dealer, we will substitute therefor another Primary Treasury Dealer; and (B) any other Primary Treasury Dealer(s) selected by us.

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any applicable redemption date, the average of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to us by such Reference Treasury Dealer at 5:00 p.m. (New York City time) on the third business day preceding such redemption date.

Defeasance

The provisions described in the accompanying prospectus under the caption "Description Of APS Unsecured Debt Securities—Defeasance and Covenant Defeasance" are applicable to the notes.

Limitation on Liens

So long as any of the notes are outstanding, we will not issue, assume, guarantee or permit to exist any Debt (as defined below) secured by any mortgage, security interest, pledge, or lien (a "Mortgage") of or upon any of our Operating Property (as defined below), whether owned at the date that the notes are issued or subsequently acquired, without effectively securing the notes (together with, if we so determine, any other indebtedness or obligations of us ranking senior to, or equally with, the notes) equally and ratably with such Debt (but only so long as that Debt is so secured). This restriction will not apply to Debt secured by any of the following:

(1) Mortgages on any property existing at the time of acquisition of such property (which Mortgages may also extend to subsequent repairs, alterations and improvements to that property);

(2) Mortgages on property of a corporation existing at the time such corporation is merged into or consolidated with us or at the time of a sale, lease, or other disposition of the properties of such corporation or a division thereof as an entirety or substantially as an entirety to us;

(3) Mortgages on property to secure all or part of the cost of acquiring, constructing, developing, or substantially repairing, altering, or improving such property or to secure indebtedness incurred to provide funds for any such purpose or for reimbursement of funds previously expended for any such purpose, provided such Mortgages are created or assumed contemporaneously with, or within eighteen (18) months after, such acquisition or completion of construction, development, or substantial repair, alteration, or improvement;

(4) Mortgages in favor of the United States of America or any State thereof, or any department, agency, instrumentality or political subdivision of the United States of America or any State thereof, or for the benefit of holders of securities issued by any such entity (or providers of credit enhancement with respect to those securities), to secure any Debt (including our obligations with respect to industrial development, pollution control or similar revenue bonds) incurred for the purpose of financing or refinancing all or any part of the purchase price or the cost of constructing, developing, or substantially repairing, altering, or improving our property;

(5) Mortgages to compensate the trustee as provided in the indenture relating to the notes; or

(6) any extension, renewal or replacement (or successive extensions, renewals, or replacements), in whole or in part, of any Mortgage referred to in the foregoing clauses (1) to (5), but the principal amount of Debt secured by such Mortgages and not otherwise authorized by said clauses (1) to (5) may not exceed the principal amount of Debt, plus any premium or fee payable in connection with any such extension, renewal, or replacement, so secured at the time of such extension, renewal, or replacement.

We may issue, assume, or guarantee or permit to exist Debt that is secured by Mortgages that would otherwise be subject to the restrictions that we describe above in connection with our existing sale and leaseback transactions relating to Unit 2 of the Palo Verde Nuclear Generating Station, including but not limited to Mortgages on the leased interests in Unit 2 of the Palo Verde Nuclear Generating Station and related rights if we reacquire ownership in any of those interests or acquire any of the equity or owner participants' interests in the trusts that hold title to such leased interests, whether or not we also directly assume the Sale Leaseback Obligation Bonds (as defined below), and Mortgages on our interests in the trusts that hold title to such leased interests and related rights in the event that we acquire any of the equity or owner participants' interests in such trusts pursuant to a "special transfer" under the Unit 2 sale and leaseback transactions. In addition, we may issue, assume, or guarantee or permit to exist Debt that is secured by Mortgages that would otherwise be subject to the restrictions that we describe above up to an aggregate principal amount that, together with the principal amount of all of our other Debt secured by such Mortgages, does not at the time exceed ten percent (10%) of Tangible Assets (as defined below).

The following terms have the following meanings:

"Debt" means any of our outstanding debt for money borrowed evidenced by notes, debentures, bonds, or other securities, or guarantees of any thereof.

"Operating Property" means (i) any interest in real property owned by us and (ii) any asset owned by us that is depreciable in accordance with generally accepted accounting principles, excluding in any case any interest of us as lessee under any lease.

"Sale Leaseback Obligation Bonds" means PVNGS II Funding Corp.'s 8.00% Secured Lease Obligation Bonds, Series 1993, due 2015, any other bonds issued in connection with the Unit 2 sale and leaseback transactions and any refinancing or refunding of any of these obligations.

"Tangible Assets" means the amount shown as total assets on our most recent balance sheet, less: (i) intangible assets, including, but without limitation, goodwill, trademarks, trade names, patents, and unamortized debt discount and expense and (ii) appropriate adjustments, if any, on account of minority interests. However, if, subsequent to the date of our most recent balance sheet, we acquire any property, whether by acquisition (including by way of capital lease) from a third party, through merger or consolidation, through construction, development, or substantial repair, alteration or improvement of property, or by any other means, and such property is or becomes subject to any Mortgage securing Debt, we may prepare a pro forma balance sheet to include the value of such property in any calculation of Tangible Assets hereunder. Subject to the foregoing, Tangible Assets will be determined in accordance with generally accepted accounting principles and practices applicable to the type of business in which we are engaged and that are approved by the independent accountants regularly retained by us, and may be determined as of a date not more than 60 days prior to the happening of the event for which such determination is being made.

Regarding the Trustee

The Bank of New York Mellon Trust Company, N.A., successor to JPMorgan Chase Bank, N.A., is the trustee under the indenture relating to the notes. It or its affiliate, The Bank of New York Mellon, is also the trustee under certain indentures relating to the sale and leaseback transactions that we entered into in 1986 with respect to a portion of our interest in Unit 2 of the Palo Verde Nuclear Generating Station and certain related common facilities as well as under various other indentures covering securities issued or that may be issued by us or our affiliates or on our or their behalf and also acts as auction agent for certain of that debt. We and our affiliates maintain normal commercial and banking relationships with The Bank of New York Mellon Trust Company, N.A. and/or its affiliates. In the future, The Bank of New York Mellon Trust Company, N.A. and/or its affiliates may provide banking, investment and other services to us and our affiliates.

CERTAIN MATERIAL UNITED STATES FEDERAL INCOME TAX CONSEQUENCES

The following is a summary of certain material U.S. federal income tax consequences of the purchase, ownership and disposition of the notes. Except where noted, this summary deals only with notes held as capital assets by beneficial owners of the notes who purchase notes in this offering at their issue price, which is the first price at which a substantial amount of the notes is sold to investors, excluding sales to the underwriters or to similar persons acting in the capacity of placement agents or wholesalers. This summary is based upon the provisions of the Internal Revenue Code of 1986, as amended (the "Code"), the Treasury Regulations promulgated thereunder and judicial and administrative rulings and decisions now in effect, all of which are subject to change or differing interpretations, possibly with retroactive effect. This summary does not purport to address all aspects of U.S. federal income taxation that may affect particular investors in light of their individual circumstances, or certain types of investors subject to special treatment under the U.S. federal income tax laws, such as persons that mark to market their securities, financial institutions, regulated investment companies, real estate investment trusts, corporations subject to the accumulated earnings tax, holders subject to the alternative minimum tax, individual retirement and other tax-deferred accounts, tax-exempt organizations, brokers, dealers in securities and commodities, certain former U.S. citizens or long-term residents, life insurance companies, persons that hold notes as part of a hedge against currency or interest rate risks or that hold notes as part of a position in a constructive sale, straddle, conversion transaction or other integrated transaction for U.S. federal income tax purposes, controlled foreign corporations, passive foreign investment companies, persons that acquire their notes in connection with employment or other performance of personal services, partnerships or other pass-through entities and investors in such entities, subsequent purchasers of the notes and U.S. holders (as defined below) whose "functional currency" is not the U.S. dollar. This summary does not address any aspect of state, local or foreign taxation or any U.S. federal tax other than the income tax.

For purposes of this summary, a "U.S. holder" is a beneficial owner of a note that is, for U.S. federal income tax purposes:

- an individual citizen or resident of the United States;
- a corporation, or other entity treated as a corporation for U.S. federal income tax purposes, created or organized in or under the laws of the United States, any state or the District of Columbia;
- an estate, the income of which is subject to U.S. federal income taxation regardless of its source; or
- a trust, if (a) a court within the United States is able to exercise primary jurisdiction over administration of the trust and one or more U.S. persons have authority to control all substantial decisions of the trust or (b) it has a valid election in effect to be treated as a U.S. person.

For purposes of this summary, a "non-U.S. holder" is a beneficial owner of a note that is not a U.S. holder or a partnership (including an entity or arrangement treated as a partnership for U.S. federal income tax purposes).

If a partnership (including an entity or arrangement treated as a partnership for U.S. federal income tax purposes) is a beneficial owner of notes, the tax treatment of a partner will generally depend upon the status of the partner and the activities of the partnership. Partnerships that hold notes (and partners in such partnerships) should consult their tax advisors.

We have not requested, and do not intend to request, a ruling from the U.S. Internal Revenue Service (the "IRS") with respect to any of the U.S. federal income tax consequences described below.

There can be no assurance that the IRS will not disagree with or challenge any of the conclusions set forth herein.

If you are considering investing in the notes, you should consult your own tax advisor with respect to your particular tax consequences of the purchase, ownership and disposition of the notes, including the consequences under the laws of any state, local or non-U.S. jurisdiction.

U.S. Holders

Payments of Interest

If the notes are issued at a discount from their stated redemption price at maturity, it is expected that any such discount will be less than the statutorily defined *de minimis* amount. Accordingly, subject to the discussion under "—Optional Redemption" below, interest on a note will generally be taxable to a U.S. holder as ordinary interest income at the time it accrues or is received in accordance with the holder's regular method of accounting for U.S. federal income tax purposes.

Optional Redemption

All or a portion of the notes may be redeemed at our option at any time or from time to time on at least 30 days' but not more than 60 days' notice, (i) if prior to July 15, 2043 (six months prior to the maturity date of the notes), at a redemption price equal to the greater of (a) 100% of the principal amount of the notes being redeemed on the redemption date and (b) the applicable make-whole price described under "Description Of The Notes—Optional Redemption" in this prospectus supplement, or (ii) if on or after July 15, 2043 (six months prior to the maturity date of the notes), at a redemption price equal to 100% of the principal amount of the notes being redeemed on the redemption date, plus, in any case, accrued and unpaid interest thereon to the redemption date.

Sale, Exchange or Other Taxable Disposition of a Note

Upon the sale, exchange, redemption or other taxable disposition of a note, a U.S. holder will recognize taxable gain or loss equal to the difference between the amount realized on the sale, exchange, redemption or other taxable disposition and the holder's adjusted tax basis in the note. For these purposes, the amount realized does not include any amount attributable to accrued interest. Amounts attributable to accrued interest are treated as interest as described under "—Payments of Interest" above. A U.S. holder's adjusted tax basis in a note will generally be such holder's cost for the note. Gain or loss realized on the sale, exchange, redemption or other taxable disposition of a note will generally be capital gain or loss and will be long-term capital gain or loss if at the time of the sale, exchange, redemption or other taxable disposition the note has been held by the holder for more than one year. The deductibility of capital losses is subject to limitations under the Code.

Medicare Tax on Unearned Income

Certain U.S. holders who are individuals, estates or trusts will be subject to a 3.8% tax on all or a portion of their "net investment income", which may include all or a portion of their interest on the notes and net gains upon a disposition of the notes. U.S. holders that are individuals, estates or trusts should consult their tax advisors regarding the applicability of the Medicare tax to any of their income or gains in respect of the notes.

Information Reporting and Backup Withholding

Information returns will be filed with the IRS in connection with payments on the notes and the proceeds from a sale or other disposition of the notes, unless the U.S. holder is an exempt recipient such as a corporation. A U.S. holder will be subject to U.S. backup withholding, currently at a rate of

28%, on these payments if the U.S. holder fails to provide its taxpayer identification number to the paying agent and comply with certain certification procedures or otherwise establish an exemption from backup withholding. Backup withholding is not an additional tax. The amount of any backup withholding from a payment to a U.S. holder will be allowed as a credit against the U.S. holder's U.S. federal income tax liability and may entitle the U.S. holder to a refund, provided that the required information is timely furnished to the IRS.

Non-U.S. Holders

Payments of Interest

Subject to the discussion below concerning backup withholding and FATCA withholding, payments of interest on a note received or accrued by a non-U.S. holder generally will not be subject to U.S. federal income or withholding tax, as long as the non-U.S. holder:

- does not conduct a trade or business in the United States with respect to which the interest is effectively connected;
- does not actually, indirectly or constructively own 10% or more of the total combined voting power of all classes of our stock entitled to vote, within the meaning of Section 871(h)(3) of the Code;
- is not a "controlled foreign corporation" with respect to which we are a "related person" within the meaning of Section 881(c)(3)(C) of the Code;
- is not a bank whose receipt of the interest is described in Section 881(c)(3)(A) of the Code; and
- satisfies the certification requirements described below.

The certification requirements will be satisfied if either (a) the beneficial owner of the note timely certifies, under penalties of perjury, to us or to the person who otherwise would be required to withhold U.S. tax that such owner is a non-U.S. holder and provides its name and address or (b) a custodian, broker, nominee or other intermediary acting as an agent for the beneficial owner (such as a securities clearing organization, bank or other financial institution that holds customers' securities in the ordinary course of its trade or business) that holds the note in such capacity timely certifies, under penalties of perjury, to us or to the person who otherwise would be required to withhold U.S. tax that such statement has been received from the beneficial owner of the note by such intermediary, or by any other financial institution between such intermediary and the beneficial owner, and furnishes to us or to the person who otherwise would be required to withhold U.S. tax a copy thereof. In general, the foregoing certification may be provided on a properly completed IRS Form W-8BEN or W-8IMY, as applicable.

A non-U.S. holder that is not exempt from tax under the foregoing rules generally will be subject to U.S. federal income tax withholding on payments of interest at a rate of 30% unless:

- the interest is effectively connected with a U.S. trade or business conducted by such holder (and, if an applicable income tax treaty so provides, is attributable to a permanent establishment maintained in the United States by the non-U.S. holder), in which case the non-U.S. holder will be subject to U.S. federal income tax on a net income basis at the rate applicable to U.S. holders generally; or
- an applicable income tax treaty provides for a lower rate of, or exemption from, withholding tax.

A non-U.S. holder that is treated as a corporation for U.S. federal income tax purposes and has effectively connected interest income (as described in the first bullet point above) may also, under certain circumstances, be subject to an additional "branch profits tax," which is generally imposed on a foreign corporation on the deemed repatriation from the United States of effectively connected earnings and profits, at a 30% rate, unless the rate is reduced or eliminated by an applicable income tax treaty.

To claim the benefit of an income tax treaty or to claim exemption from withholding because income is effectively connected with a U.S. trade or business, the non-U.S. holder must timely provide the appropriate, properly executed IRS forms. Certification to claim income is effectively connected with a U.S. trade or business is generally made on IRS Form W-8ECI. Certification to claim the benefit of an income tax treaty is generally made on IRS Form W-8BEN. These forms may be required to be periodically updated.

Sale, Exchange or Other Taxable Disposition of a Note

A non-U.S. holder generally will not be subject to U.S. federal income tax on any gain realized on the sale, exchange, redemption or other taxable disposition of a note unless (a) such gain is effectively connected with the conduct by the non-U.S. holder of a U.S. trade or business (and, if an applicable income tax treaty so provides, is attributable to a permanent establishment maintained in the United States by the non-U.S. holder) or (b) in the case of a non-U.S. holder who is an individual, the holder is present in the United States for 183 days or more during the taxable year in which such gain is realized and certain other conditions exist.

Except to the extent that an applicable income tax treaty otherwise provides, generally a non-U.S. holder that is described in clause (a) above will be taxed in the same manner as a U.S. holder with respect to gain that is effectively connected with the non-U.S. holder's conduct of a U.S. trade or business and such a non-U.S. holder that is treated as a corporation for U.S. federal income tax purposes may also, under certain circumstances, be subject to the branch profits tax as described above. Except to the extent that an applicable income tax treaty otherwise provides, an individual non-U.S. holder who is described in clause (b) above will be subject to a flat 30% tax on gain derived from the sale or other disposition, which may be offset by certain U.S. source capital losses.

Information Reporting and Backup Withholding

Payments of interest to a non-U.S. holder generally will be reported to the IRS and to the non-U.S. holder. Copies of applicable IRS information returns may be made available under the provisions of a specific tax treaty or agreement to the tax authorities of the country in which the non-U.S. holder resides. Non-U.S. holders are generally exempt from backup withholding, currently at a rate of 28%, and additional information reporting on payments of principal, premium (if any), or interest, provided that the non-U.S. holder (a) certifies its nonresident status on the appropriate IRS form (or a suitable substitute form) and certain other conditions are met or (b) otherwise establishes an exemption. Backup withholding is not an additional tax. Any backup withholding generally will be allowed as a credit or refund against the non-U.S. holder's U.S. federal income tax liability, provided that the required information is timely furnished to the IRS.

FATCA

Legislation known as the "Foreign Account Tax Compliance Act" or "FATCA," when applicable, and recent guidance issued by the IRS regarding the implementation of FATCA, generally will impose a U.S. federal withholding tax of 30% on interest on a debt obligation paid on or after July 1, 2014, and the gross proceeds from the disposition of a debt obligation paid on or after January 1, 2017, to non-U.S. financial institutions and other non-U.S. entities that fail to comply with certain certification and information reporting requirements. However, under such recent guidance from the IRS, the obligation to withhold under FATCA will not apply to a debt obligation issued before July 1, 2014 unless the debt obligation is significantly modified and deemed reissued for U.S. federal income tax purposes on or after July 1, 2014. Accordingly, withholding under FATCA will not apply to payments on the notes, or the gross proceeds from the disposition of the notes, unless the notes are so significantly modified and deemed reissued on or after July 1, 2014. Prospective purchasers of the notes should consult their own tax advisors regarding the effect, if any, of the FATCA rules for them based on their particular circumstances.

UNDERWRITING

Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, UBS Securities LLC and U.S. Bancorp Investments, Inc. are acting as the representatives of the underwriters and as joint book-running managers. Under the terms and subject to the conditions of an underwriting agreement dated the date of this prospectus supplement, which will be filed as an exhibit to a current report on Form 8-K and incorporated by reference in this prospectus supplement and the accompanying prospectus, each of the underwriters named below has severally agreed to purchase from us, and we have agreed to sell to them, severally, the principal amount of notes shown opposite its respective name below:

Underwriters	Principal Amount of Notes
Citigroup Global Markets Inc.	$ 56,250,000
Merrill Lynch, Pierce, Fenner & Smith Incorporated	56,250,000
UBS Securities LLC	56,250,000
U.S. Bancorp Investments, Inc.	56,250,000
Blaylock Robert Van, LLC	8,334,000
Drexel Hamilton, LLC	8,333,000
The Williams Capital Group, L.P.	8,333,000
Total	$250,000,000

The underwriting agreement provides that the obligations of the underwriters to purchase the notes included in this offering are several and not joint and are subject to approval of legal matters by counsel and to other conditions. The underwriters are obligated to purchase all of the notes if they purchase any of the notes.

The underwriters propose to offer the notes directly to the public at the public offering price presented on the cover page of this prospectus supplement and may offer the notes to selected dealers, which may include the underwriters, at the public offering price less a selling concession not in excess of 0.50% of the principal amount of the notes. The underwriters may allow, and dealers may reallow, a concession not to exceed 0.35% of the principal amount of the notes on sales to other dealers. After the initial offering of the notes to the public, the underwriters may change the public offering price and other selling terms.

The following table summarizes the underwriting discounts and commissions to be paid to the underwriters by us (expressed as a percentage of the principal amount of the notes). The underwriting discount is the difference between the offering price and the amount the underwriters pay to purchase the notes from us.

	Paid by Arizona Public Service Company
Per Note	0.875%

The notes are a new issue of securities with no established trading market. We do not intend to apply for the notes to be listed on any securities exchange or to be quoted on any quotation system. One or more of the underwriters intend to make a secondary market for the notes. However, they are not obligated to do so and may discontinue making a secondary market at any time without notice. No assurance can be given as to how liquid the trading market for the notes will be.

In order to facilitate this offering of the notes, the underwriters may engage in transactions that stabilize, maintain or otherwise affect the price of the notes. These transactions may include over-allotment, syndicate covering transactions and stabilizing transactions. Over-allotment involves syndicate sales of notes in excess of the principal amount of notes to be purchased by the underwriters in this offering, which creates a syndicate short position. Syndicate covering transactions involve purchases of notes in the open market after the distribution has been completed in order to cover syndicate short positions. Stabilizing transactions consist of certain bids or purchases of the notes made for the purpose of preventing or retarding a decline in the market price of the notes while this offering is in progress.

The underwriters also may impose a penalty bid. Penalty bids permit the underwriters to reclaim a selling concession from a syndicate member when the representatives of the underwriters, in covering syndicate short positions or making stabilizing purchases, repurchase notes originally sold by that syndicate member.

Any of these activities may have the effect of preventing or retarding a decline in the market price of the notes. They may also cause the price of the notes to be higher than the price that otherwise would exist in the open market in the absence of these transactions. The underwriters may conduct these transactions in the over-the-counter market or otherwise. If the underwriters commence any of these transactions, they may discontinue them at any time.

We estimate that the total expenses of the offering payable by us, excluding underwriting discounts and commissions, will be approximately $504,150.

Certain of the underwriters and/or their affiliates have performed investment banking, commercial banking and/or advisory services for us and/or our affiliates from time to time for which they have received customary fees and expenses. Affiliates of certain of the underwriters are lenders to us and/or our affiliates under our credit facilities. The underwriters and/or their affiliates may, from time to time, engage in transactions with and perform services for us and our affiliates in the ordinary course of their business.

In addition, in the ordinary course of their business activities, the underwriters and their affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers. Such investments and securities activities may involve securities and/or instruments of ours or our affiliates. Certain of the underwriters or their affiliates that have a lending relationship with us routinely hedge their credit exposure to us consistent with their customary risk management policies. Typically, such underwriters and their affiliates would hedge such exposure by entering into transactions which consist of either the purchase of credit default swaps or the creation of short positions in our securities, including potentially the notes offered hereby. Any such credit default swaps or short positions could adversely affect future trading prices of the notes offered hereby. The underwriters and their affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or financial instruments and may hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

We have agreed to indemnify the underwriters against certain liabilities relating to the offering, including liabilities under the Securities Act of 1933, as amended, and to contribute to payments that the underwriters may be required to make for these liabilities.

EXPERTS

The consolidated financial statements of Arizona Public Service Company, and the related consolidated financial statement schedule, incorporated in this prospectus supplement and the accompanying prospectus by reference from Arizona Public Service Company's Annual Report on Form 10-K for the year ended December 31, 2012, and the effectiveness of Arizona Public Service Company's internal control over financial reporting, have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report, incorporated herein by reference, which report (i) expresses an unqualified opinion on the financial statements and financial statement schedule and includes an explanatory paragraph referring to the adoption of amended guidance on the presentation of comprehensive income and (ii) expresses an unqualified opinion on the effectiveness of internal control over financial reporting. Such consolidated financial statements and consolidated financial statement schedule have been so incorporated in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

LEGAL OPINIONS

Certain legal matters with respect to the offering of the notes described in this prospectus supplement will be passed upon for us by David P. Falck, our Executive Vice President, General Counsel & Secretary, and for the underwriters by Pillsbury Winthrop Shaw Pittman LLP, New York, New York. Mr. Falck is regularly employed by us, participates in various Pinnacle West employee benefit plans under which he may receive shares of common stock and currently beneficially owns less than one percent of the outstanding shares of common stock of Pinnacle West. In giving his opinion, Mr. Falck may rely as to all matters of New York law upon the opinion of Pillsbury Winthrop Shaw Pittman LLP.

Prospectus

PINNACLE WEST CAPITAL CORPORATION

Unsecured Debt Securities

Preferred Stock

Common Stock

ARIZONA PUBLIC SERVICE COMPANY

Unsecured Debt Securities

We may offer and sell these securities from time to time in one or more offerings. This prospectus provides you with a general description of the securities we may offer.

Each time we sell these securities, we will provide a supplement to this prospectus that contains specific information about the offering and the terms of the securities, including the plan of distribution for the securities. You should carefully read this prospectus and any supplement, as well as the documents incorporated by reference in this prospectus, before you invest in any of these securities.

See "Risk Factors" beginning on page 2 of this prospectus where we describe certain factors you should consider in making an investment decision.

Our principal executive offices are located at 400 North Fifth Street, P.O. Box 53999, Phoenix, Arizona 85072-3999. Our telephone number is (602) 250-1000.

Pinnacle West's common stock is listed on the New York Stock Exchange under the symbol "PNW." Unless otherwise indicated in a supplement to this prospectus, the other securities offered hereby will not be listed on a national securities exchange.

NEITHER THE SECURITIES AND EXCHANGE COMMISSION NOR ANY STATE SECURITIES COMMISSION HAS APPROVED OR DISAPPROVED OF THESE SECURITIES OR PASSED UPON THE ADEQUACY OR ACCURACY OF THIS PROSPECTUS. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

We may offer and sell these securities directly to purchasers, through agents, dealers, or underwriters as designated from time to time, or through a combination of these methods. If any agents, dealers or underwriters are involved in the sale of any securities, the relevant prospectus supplement will set forth any applicable commissions or discounts.

The date of this prospectus is April 24, 2012

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RISK FACTORS

We include a discussion of risk factors relating to our business and an investment in our securities in our Annual Reports on Form 10-K and Quarterly Reports on Form 10-Q filed from time to time by us with the Securities and Exchange Commission (the "SEC"). These reports are incorporated by reference in this prospectus. See "Where You Can Find More Information." We describe an additional risk of investment in our securities below. We may also describe additional risks related to our securities in a prospectus supplement from time to time. Before purchasing our securities, you should carefully consider the risk factors we describe in those reports, in this prospectus and in any prospectus supplement. Although we try to discuss key risks in the risk factor descriptions, please be aware that other risks may prove to be important in the future. New risks may emerge at any time and we cannot predict these risks or estimate the extent to which they may affect our business, financial condition, cash flows or operating results.

In addition to the general risks that we describe in our SEC reports, you should consider the following additional risk before investing in our securities.

Risk Factor Relating to Unsecured Debt Securities

You may be unable to sell your unsecured debt securities if a trading market for the unsecured debt securities does not develop.

An established trading market for the unsecured debt securities does not exist and may not develop. Unless the applicable prospectus supplement specifies otherwise, we do not intend to apply for listing of the unsecured debt securities on any securities exchange or for quotation on any automated dealer quotation system. The liquidity of any market for the unsecured debt securities will depend on the number of holders of the securities, the interest of securities dealers in making a market in the unsecured debt securities, and other factors. If an active trading market does not develop, the market price and liquidity of the unsecured debt securities may be adversely affected. If the unsecured debt securities are traded, they may trade at a discount from their initial offering price depending upon prevailing interest rates, the market for similar securities, general economic conditions, our performance and business prospects, and certain other factors.

ABOUT THIS PROSPECTUS

This prospectus is part of a shelf registration statement that we filed with the SEC. By using a shelf registration statement, we may sell, from time to time, in one or more offerings, any combination of the securities described in this prospectus. In this prospectus we may refer to the unsecured debt securities, preferred stock and common stock that may be offered by Pinnacle West Capital Corporation ("Pinnacle West") and the unsecured debt securities that may be offered by Arizona Public Service Company ("APS") collectively as the "securities."

This prospectus provides you with a general description of the securities we may offer. Each time we offer securities, we will provide you with a prospectus supplement and, if applicable, a pricing supplement. The prospectus supplement and any applicable pricing supplement will describe the specific terms of the securities being offered. The prospectus supplement and any applicable pricing supplement may also add to, update or change the information in this prospectus. If there is any inconsistency between the information in this prospectus and in any supplement, you should rely on the information in the supplement. In addition, the registration statement we filed with the SEC includes exhibits that provide more details about the securities.

You should rely only on the information contained or incorporated by reference in this prospectus, any prospectus supplement and any pricing supplement. See "Where You Can Find More Information."

We are not making an offer to sell these securities in any jurisdiction where the offer or sale is not permitted.

You should assume that the information appearing in this prospectus and any supplement to this prospectus is accurate only as of the dates on their covers and that information incorporated by reference is accurate only as of the date of the report that is incorporated, unless, in either case, the information is given as of another specific date. Our business, financial condition, results of operations, and prospects may have changed since those dates.

FORWARD-LOOKING STATEMENTS

This prospectus, any accompanying prospectus supplement, and the information contained or incorporated by reference in this prospectus may contain forward-looking statements based on current expectations, and we assume no obligation to update these statements, even if our internal estimates change, except as required by applicable law. These forward-looking statements are often identified by words such as "estimate," "predict," "may," "believe," "plan," "expect," "require," "intend," "assume" and similar words. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by us. In addition to the Risk Factors described above, these factors include, but are not limited to:

- our ability to achieve timely and adequate rate recovery of our costs, including returns on debt and equity capital;
- our ability to manage capital expenditures and other costs while maintaining reliability and customer service levels;
- variations in demand for electricity, including those due to weather, the general economy, customer and sales growth (or decline), and the effects of energy conservation measures and distributed generation;
- power plant and transmission system performance and outages;
- volatile fuel and purchased power costs;
- fuel and water supply availability;
- regulatory and judicial decisions, developments and proceedings;
- new legislation or regulation, including those relating to environmental requirements and nuclear plant operations;
- our ability to meet renewable energy and energy efficiency mandates and recover related costs;
- risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainty;
- competition in retail and wholesale power markets;
- the duration and severity of the economic decline in Arizona and current real estate market conditions;
- the cost of debt and equity capital and the ability to access capital markets when required;
- changes to our credit ratings;
- the investment performance of the assets of our nuclear decommissioning trust, pension, and other postretirement benefit plans and the resulting impact on future funding requirements;
- the liquidity of wholesale power markets and the use of derivative contracts in our business;

- potential shortfalls in insurance coverage;
- new accounting requirements or new interpretations of existing requirements;
- generation, transmission and distribution facility and system conditions and operating costs;
- the ability to meet the anticipated future need for additional baseload generation and associated transmission facilities in our region;
- the willingness or ability of our counterparties, power plant participants and power plant land owners to meet contractual or other obligations or extend the rights for continued power plant operations;
- technological developments affecting the electric industry; and
- restrictions on dividends or other provisions in our credit agreements and Arizona Corporation Commission ("ACC") orders.

We generally update these factors in each of our Annual Reports on Form 10-K and Quarterly Reports on Form 10-Q filed with the SEC. We claim the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995 for any forward-looking statements contained or incorporated by reference in this prospectus or any prospectus supplement.

WHERE YOU CAN FIND MORE INFORMATION

Available Information

We file annual, quarterly, and current reports and other information with the SEC. Our SEC filings are available to the public over the Internet at the SEC's website: http://www.sec.gov. You may also read and copy any materials we file with the SEC at the SEC's public reference room, at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the public reference room by calling the SEC at 1-800-SEC-0330. Our filings with the SEC are also available on Pinnacle West's website at http://www.pinnaclewest.com. The other information on Pinnacle West's website is not part of this prospectus, any prospectus supplement or any pricing supplement.

Incorporation by Reference

The SEC allows us to incorporate by reference the information we file with them, which means that we can disclose important information to you by referring you to those documents. The information incorporated by reference is considered to be part of this prospectus, except for information superseded by information in this prospectus, and later information that we file with the SEC will automatically update and supersede this information. We incorporate by reference the documents listed below and any future filings we make with the SEC under Section 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), (SEC file No. 1-8962 for Pinnacle West and No. 1-4473 for APS) prior to the termination of this offering, excluding, in each case, information deemed furnished and not filed.

Pinnacle West Capital Corporation:

- Pinnacle West Capital Corporation's Annual Report on Form 10-K for the fiscal year ended December 31, 2011;
- Pinnacle West Capital Corporation's Current Reports on Form 8-K filed January 9, 2012, January 12, 2012, February 3, 2012 and April 18, 2012; and

- The description of Pinnacle West's common stock included in its registration statement on Form 8-B, File No. 1-8962, as filed on July 25, 1985, and any amendment or report that we have filed (or will file after the date of this prospectus and prior to the termination of this offering) for the purpose of updating such description, including Pinnacle West's Current Report on Form 8-K filed with the SEC on June 28, 2011.

Arizona Public Service Company:

- Arizona Public Service Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2011; and
- Arizona Public Service Company's Current Reports on Form 8-K filed January 9, 2012, January 12, 2012, February 3, 2012 and April 18, 2012.

These documents contain important information about us and our financials. We will provide to each person, including any beneficial owner, to whom a prospectus is delivered, a copy of any or all of the information that has been incorporated by reference in this prospectus but not delivered with this prospectus. You may request a copy of these filings, at no cost, by writing, telephoning or contacting us through our website at the following:

Pinnacle West Capital Corporation Office of the Secretary Station 8602 P.O. Box 53999 Phoenix, Arizona 85072-3999 (602) 250-4400	Arizona Public Service Company Office of the Secretary Station 8602 P.O. Box 53999 Phoenix, Arizona 85072-3999 (602) 250-4400

Or online at www.pinnaclewest.com.

THE COMPANIES

Pinnacle West was incorporated in 1985 under the laws of the State of Arizona and owns all of the outstanding equity securities of APS, its major subsidiary. APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to most of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona.

The principal executive offices of Pinnacle West and APS are located at 400 North Fifth Street, PO Box 53999, Phoenix, Arizona 85072-3999, and the telephone number is 602-250-1000.

USE OF PROCEEDS

Pinnacle West intends to use the proceeds from the sale of these securities for general corporate purposes, which may include the repayment of indebtedness, capital expenditures, the funding of working capital, acquisitions, stock repurchases and/or capital infusions into one or more of its subsidiaries for any of those purposes. APS intends to use the proceeds from the sale of these securities to finance its construction, resource acquisition and maintenance programs, to redeem or retire outstanding securities, to fund working capital and/or to repay or refund other outstanding long-term or short-term debt. Any specific use of proceeds from the sale of securities will be set forth in the prospectus supplement relating to each offering of these securities.

GENERAL DESCRIPTION OF THE SECURITIES

Pinnacle West, directly or through agents, dealers or underwriters that it designates, may offer and sell, from time to time, an indeterminate amount of:

- its unsecured debt securities, in one or more series, which may be senior unsecured debt securities or subordinated unsecured debt securities, in each case consisting of notes or other unsecured evidences of indebtedness;
- shares of its preferred stock;
- shares of its common stock; or
- any combination of these securities.

APS, directly or through agents, dealers or underwriters that it designates, may offer and sell, from time to time, an indeterminate amount of its senior unsecured debt securities, in one or more series, consisting of notes or other unsecured evidences of indebtedness.

Pinnacle West and APS may offer and sell these securities either individually or as units consisting of one or more of these securities, each on terms to be determined at the time of sale. Pinnacle West may issue unsecured debt securities and/or shares of preferred stock that are exchangeable for and/or convertible into common stock or any of the other securities that it may sell under this prospectus. When particular securities are offered, a supplement to this prospectus will be delivered with this prospectus, which will describe the terms of the offering and sale of the offered securities.

DESCRIPTION OF PINNACLE WEST UNSECURED DEBT SECURITIES

General

The following description highlights the general terms of the unsecured debt securities that Pinnacle West may offer. In this description, we will refer to the unsecured debt securities as "debt securities." When we use the terms "we," "us," "our," and like terms in this description, we are referring to Pinnacle West. When we offer debt securities in the future, the prospectus supplement will explain the particular terms of those securities and the extent to which any of these general provisions will not apply.

We can issue an unlimited amount of debt securities under the indentures listed below. We can issue debt securities from time to time and in one or more series as determined by us. In addition, we can issue debt securities of any series with terms different from the terms of debt securities of any other series and the terms of particular debt securities within any series may differ from each other, all without the consent of the holders of previously issued series of debt securities. If specified in a prospectus supplement relating to an offering of debt securities, from time to time, without notice to, or the consent of, the existing holders of any series of debt securities then outstanding, we may create and issue additional debt securities equal in rank and having the same maturity, payment terms, redemption features, and other terms as the debt securities of such series, except for the issue date of the additional debt securities, the public offering price of the additional debt securities, the payment of interest accruing prior to the issue date of the additional debt securities and (under some circumstances) the first payment of interest following the issue date of the additional debt securities. The additional debt securities may be consolidated and form a single series with previously issued debt securities of the affected series.

The debt securities will be our direct, unsecured obligations. The debt securities may be issued in one or more series under:

- an Indenture, dated as of December 1, 2000, as amended from time to time, between The Bank of New York Mellon Trust Company, N.A., successor to The Bank of New York Mellon, as trustee, and us, in the case of senior debt securities; or
- an Indenture, dated as of December 1, 2000, as amended from time to time, between The Bank of New York Mellon Trust Company, N.A., successor to The Bank of New York Mellon, as trustee, and us, in the case of subordinated debt securities.

Because we are structured as a holding company, all existing and future indebtedness and other liabilities of our subsidiaries will be effectively senior in right of payment to our debt securities, whether senior debt securities or subordinated debt securities. Neither of the above Indentures limits our ability or the ability of our subsidiaries to incur additional indebtedness in the future. The assets and cash flows of our subsidiaries will be available, in the first instance, to service their own debt and other obligations and our ability to have the benefit of their assets and cash flows, particularly in the case of any insolvency or financial distress affecting our subsidiaries, would arise only through our equity ownership interests in our subsidiaries and only after their creditors had been satisfied.

We have summarized the material provisions of the Indentures below. We have filed the senior and subordinated Indentures as exhibits to the registration statement. You should read the Indentures in their entirety, including the definitions, together with this prospectus and the prospectus supplement before you make any investment decision in our debt securities. Although separate Indentures are used for subordinated debt securities and senior debt securities, references to the "Indenture" and the description of the "Indenture" in this section apply to both Indentures, unless otherwise noted.

You should refer to the prospectus supplement used in connection with the offering of any debt securities for information about a series of debt securities, including:

- title of the debt securities;
- the aggregate principal amount of the debt securities or the series of which they are a part;
- the date on which the debt securities mature;
- the interest rate;
- when the interest on the debt securities accrues and is payable;
- the record dates for the payment of interest;
- places where principal, premium, or interest will be payable;
- periods within which, prices at which, and terms upon which we can redeem debt securities at our option;
- any obligation on our part to redeem or purchase debt securities pursuant to a sinking fund or at the option of the holder;
- denominations and multiples at which debt securities will be issued if other than $1,000;
- any index or formula from which the amount of principal or any premium or interest may be determined;
- any allowance for alternative currencies and determination of value;
- whether the debt securities are defeasible under the terms of the Indenture;
- whether we are issuing the debt securities as global securities;

- any additional or different events of default and any change in the right of the trustee or the holders to declare the principal amount due and payable if there is any default;
- any addition to or change in the covenants in the Indenture; and
- any other terms.

We may sell the debt securities at a substantial discount below their principal amount. The prospectus supplement may describe special federal income tax considerations that apply to debt securities sold at an original issue discount or to debt securities that are denominated in a currency other than United States dollars.

Unless the applicable prospectus supplement specifies otherwise, we do not intend to list the debt securities on any securities exchange.

Other than the protections described in this prospectus and in the prospectus supplement, holders of debt securities would not be protected by the covenants in the Indenture from a highly-leveraged transaction.

Subordination

The Indenture relating to the subordinated debt securities states that, unless otherwise provided in a supplemental indenture or a board resolution or officers' certificate establishing a series of debt securities, the debt securities will be subordinate to all senior debt. This is true whether the senior debt is outstanding as of the date of the Indenture or is incurred afterwards. The balance of the information under this heading assumes that a supplemental indenture or a board resolution results in a series of debt securities being subordinated obligations.

The Indenture states that we cannot make payments of principal, premium, or interest on the subordinated debt if:

- the principal, premium or interest on senior debt is not paid when due and the applicable grace period for the default has ended and the default has not been cured or waived; or
- the maturity of any senior debt has been accelerated because of a default.

The Indenture provides that we must pay all senior debt in full before the holders of the subordinated debt securities may receive or retain any payment if we make any payment to our creditors or our assets are distributed to our creditors, with certain exceptions, upon any of the following:

- dissolution;
- winding up;
- liquidation;
- reorganization, whether voluntary or involuntary;
- bankruptcy;
- insolvency;
- receivership; or
- any other proceedings.

The Indenture provides that when all amounts owing on the senior debt are paid in full, the holders of the subordinated debt securities will be subrogated to the rights of the holders of senior debt to receive payments or distributions applicable to senior debt.

The Indenture defines senior debt as the principal, premium, interest and any other payment due under any of the following, whether outstanding at the date of the Indenture or thereafter incurred, created or assumed:

- all of our debt evidenced by notes, debentures, bonds, or other securities we sell for money;
- all debt of others of the kinds described in the preceding bullet point that we assume or guarantee in any manner; and
- all renewals, extensions, or refundings of debt of the kinds described in either of the two preceding bullet points.

However, the preceding will not be considered senior debt if the document creating the debt or the assumption or guarantee of the debt states that it is not superior to or that it is on equal footing with the subordinated debt securities.

The Indenture does not limit the aggregate amount of senior debt that we may issue.

Form, Exchange, and Transfer

Each series of debt securities will be issuable only in fully registered form and without coupons. In addition, unless otherwise specified in a prospectus supplement, the debt securities will be issued in denominations of $1,000 and multiples of $1,000. We, the trustee, and any of our agents may treat the registered holder of a debt security as the absolute owner for the purpose of making payments, giving notices, and for all other purposes.

The holders of debt securities may exchange them for any other debt securities of the same series, in authorized denominations and equal principal amount. However, this type of exchange will be subject to the terms of the Indenture and any limitations that apply to global securities.

A holder may transfer debt securities by presenting the endorsed security at the office of a security registrar or transfer agent we designate. The holder will not be charged for any exchange or registration of transfer, but we may require payment to cover any tax or other governmental charge in connection with the transaction. We have appointed the trustee under each Indenture as security registrar. A prospectus supplement will name any transfer agent we designate for any debt securities if different from the security registrar. We may designate additional transfer agents or rescind the designation of any transfer agent or approve a change in the office through which any transfer agent acts at any time, except that we will maintain a transfer agent in each place of payment for debt securities.

If the debt securities of any series and/or specified tenor are to be redeemed, we will not be required to do any of the following:

- issue, register the transfer of, or exchange any debt securities of that series and/or tenor beginning 15 days before the day of mailing of a notice of redemption of any such debt security that may be selected for redemption and ending at the close of business on the day of the mailing; or
- register the transfer of or exchange any debt security selected for redemption, except for the unredeemed portion of a debt security that is being redeemed in part.

Payment and Paying Agents

Unless otherwise indicated in the applicable prospectus supplement, we will pay interest on a debt security on any interest payment date to the person in whose name the debt security is registered on the regular record date for such interest payment date.

Unless otherwise indicated in the applicable prospectus supplement, the principal, premium, and interest on the debt securities of a particular series will be payable at the office of the paying agents that we may designate. However, we may pay any interest by check mailed to the address, as it appears in the security register, of the person entitled to that interest. Also, unless otherwise indicated in the applicable prospectus supplement, the corporate trust office of the trustee in The City of New York will be our sole paying agent for payments with respect to debt securities of each series. Any other paying agent that we initially designate for the debt securities of a particular series will be named in the applicable prospectus supplement. We may at any time designate additional paying agents or rescind the designation of any paying agent or approve a change in the office through which any paying agent acts, except that we will maintain a paying agent in each place of payment for the debt securities of a particular series.

All money that we pay to a paying agent for the payment of the principal, premium, or interest on any debt security that remains unclaimed at the end of two years after the principal, premium, or interest has become due and payable will be repaid to us, and the holder of the debt security may look only to us for payment.

Consolidation, Merger, and Sale of Assets

Unless otherwise indicated in the applicable prospectus supplement, we may not:

- consolidate with or merge into any other entity;
- convey, transfer, or lease our properties and assets substantially as an entirety to any entity; or
- permit any entity to consolidate with or merge into us or convey, transfer, or lease its properties and assets substantially as an entirety to us,

unless the following conditions are met:

- the successor entity is a corporation, partnership, unincorporated organization or trust organized and validly existing under the laws of any domestic jurisdiction and assumes our obligations on the debt securities and under the Indenture;
- immediately after giving effect to the transaction, no event of default, and no event which, after notice or lapse of time or both, would become an event of default, shall have occurred and be continuing; and
- other conditions are met.

Upon any such merger, consolidation, or transfer or lease of properties, the successor person will be substituted for us under the Indenture, and, thereafter, except in the case of a lease, we will be relieved of all obligations and covenants under the Indenture and the debt securities.

Events of Default

Each of the following will be an event of default under the Indenture with respect to debt securities of any series:

- our failure to pay principal of or any premium on any debt security of that series when due;
- our failure to pay any interest on any debt securities of that series when due, and the continuance of that failure for 30 days;
- our failure to deposit any sinking fund payment, when due, in respect of any debt securities of that series;

- our failure to perform any of our other covenants in the Indenture relating to that series and the continuance of that failure for 90 days after written notice has been given by the trustee or the holders of at least 25% in principal amount of the outstanding debt securities of that series;
- bankruptcy, insolvency, or reorganization events involving us; and
- any other event of default for that series described in the applicable prospectus supplement.

If an event of default occurs and is continuing, other than an event of default relating to bankruptcy, insolvency, or reorganization, either the trustee or the holders of at least 25% in aggregate principal amount of the outstanding debt securities of the affected series may declare the principal amount of the debt securities of that series to be due and payable immediately. In the case of any debt security that is an original issue discount security, the trustee or the holders of at least 25% in aggregate principal amount of the outstanding debt securities of that series may declare the portion of the principal amount of the debt security specified in the terms of such debt security to be immediately due and payable upon an event of default.

If an event of default involving bankruptcy, insolvency, or reorganization occurs, the principal amount of all the debt securities of the affected series will automatically, and without any action by the trustee or any holder, become immediately due and payable. After any acceleration, but before a judgment or decree based on acceleration, the holders of a majority in aggregate principal amount of the outstanding debt securities of that series may rescind and annul the acceleration if all events of default, other than the non-payment of accelerated principal, have been cured or waived as provided in the Indenture.

The trustee will be under no obligation to exercise any of its rights or powers under the Indenture at the request or direction of any of the holders, unless the holders have offered the trustee reasonable indemnity. The holders of a majority in principal amount of the outstanding debt securities of any series will have the right to direct the time, method, and place of conducting any proceeding for any remedy available to the trustee, or exercising any trust or power conferred on the trustee, with respect to the debt securities of that series, provided that:

- such direction shall not be in conflict with law or the Indenture;
- the trustee may take any other action not inconsistent with such direction; and
- subject to the provisions of the Indenture, the trustee may decline to follow such direction if it determines in good faith that the proceedings so directed would involve the trustee in personal liability.

No holder of a debt security of any series will have any right to institute any proceeding under the Indenture, or for the appointment of a receiver or a trustee, or for any other remedy under the Indenture, unless:

- the holder has previously given the trustee written notice of a continuing event of default with respect to the debt securities of that series;
- the holders of at least 25% in aggregate principal amount of the outstanding debt securities of that series have made written request, and the holder or holders have offered reasonable indemnity, to the trustee to institute the proceeding as trustee; and
- the trustee has failed to institute the proceeding, and has not received from the holders of a majority in aggregate principal amount of the outstanding debt securities of that series a direction inconsistent with the request within 60 days after the notice, request, and offer of indemnity.

The limitations provided above do not apply to a suit instituted by a holder of a debt security for the enforcement of payment of the principal, premium, or interest on the debt security on or after the applicable due date.

We are required to furnish to the trustee annually a certificate of various officers stating whether or not we are in default in the performance or observance of any of the terms, provisions, and conditions of the Indenture and, if so, specifying all known defaults.

Modification and Waiver

In limited cases, we and the trustee may make modifications and amendments to the Indenture without the consent of the holders of any series of debt securities, including to cure any ambiguity, to correct or supplement any provision in the Indenture that is defective or inconsistent with any other provision, or to make other provisions with respect to matters or questions arising under the Indenture, but such action shall not adversely affect the interests of the holders of the debt securities of any series in any material respect. We and the trustee may also make modifications and amendments to the Indenture with the consent of the holders of not less than 66⅔% in aggregate principal amount of the outstanding debt securities of each series affected by the modification or amendment. However, without the consent of the holder of each outstanding debt security affected, no modification or amendment may:

- change the stated maturity of principal of or interest on any debt security;
- reduce the principal amount of any debt security or the rate of interest thereon or any premium payable on redemption thereof;
- reduce the amount of principal of an original issue discount security or any other debt security payable upon acceleration of the maturity of the security;
- change the stated maturity of the principal of, or any installment of principal of or interest on, any debt security;
- change the place or currency of payment of principal of, or any premium or interest on, any debt security;
- impair the right to institute suit for the enforcement of any payment on or with respect to any debt security; or
- reduce the percentage in principal amount of outstanding debt securities of any series, the consent of whose holders is required for modification or amendment of the Indenture or is necessary for waiver of compliance with certain provisions of the Indenture or of certain defaults, or modify the provisions of the Indenture relating to modification and waiver.

In general, compliance with certain restrictive provisions of the Indenture may be waived by the holders of not less than 66⅔% in aggregate principal amount of the outstanding debt securities of any series. The holders of a majority in aggregate principal amount of the outstanding debt securities of any series may waive any past default under the Indenture, except:

- a default in the payment of principal, premium, or interest; and
- a default under covenants and provisions of the Indenture which cannot be amended without the consent of the holder of each outstanding debt security of the affected series.

In determining whether the holders of the requisite principal amount of the outstanding debt securities have given or taken any direction, notice, consent, waiver, or other action under the Indenture as of any date:

- the principal amount of an outstanding original issue discount security will be the amount of the principal that would be due and payable upon acceleration of the maturity on that date,
- if the principal amount payable at the stated maturity of a debt security is not determinable, the principal amount of the outstanding debt security will be an amount determined in the manner prescribed for the debt security; and
- the principal amount of an outstanding debt security denominated in one or more foreign currencies will be the U.S. dollar equivalent of the principal amount of the debt security or, in the case of a debt security described in the previous bullet points above, the amount described in those bullet points.

If debt securities have been fully defeased or if we have deposited money with the trustee to redeem debt securities, they will not be considered outstanding.

Except in limited circumstances, we will be entitled to set any day as a record date for the purpose of determining the holders of outstanding debt securities of any series entitled to give or take any direction, notice, consent, waiver, or other action under the Indenture. In limited circumstances, the trustee will be entitled to set a record date for action by holders. If a record date is set for any action to be taken by holders of a particular series, the action may be taken only by persons who are holders of outstanding debt securities of that series on the record date. To be effective, the action must be taken by holders of the requisite principal amount of the debt securities within a specified period following the record date. For any particular record date, this period will be 180 days or any other shorter period that we may specify. The period may be shortened or lengthened, but not beyond 180 days.

Defeasance and Covenant Defeasance

We may elect to have the provisions of the Indenture relating to defeasance and discharge of indebtedness, or defeasance of restrictive covenants in the Indenture, applied to the debt securities of any series, or to any specified part of a series. The prospectus supplement used in connection with the offering of any debt securities will state whether we have made these elections for that series.

Defeasance and Discharge

We will be discharged from all of our obligations with respect to the debt securities of a series if we deposit with the trustee money in an amount sufficient to pay the principal, premium, and interest on the debt securities of that series when due in accordance with the terms of the Indenture and the debt securities. We can also deposit securities that will provide the necessary monies. However, we will not be discharged from the obligations to exchange or register the transfer of debt securities, to replace stolen, lost, or mutilated debt securities, to maintain paying agencies, and to hold monies for payment in trust. The defeasance or discharge may occur only if we satisfy certain requirements, including that we deliver to the trustee an opinion of counsel stating that we have received from, or there has been published by, the United States Internal Revenue Service a ruling, or there has been a change in tax law, in either case to the effect that holders of such debt securities:

- will not recognize gain or loss for federal income tax purposes as a result of the deposit, defeasance, and discharge; and
- will be subject to federal income tax on the same amount, in the same manner, and at the same times as would have been the case if the deposit, defeasance, and discharge were not to occur.

Defeasance of Covenants

We may elect to omit compliance with restrictive covenants in the Indenture and any additional covenants that may be described in the applicable prospectus supplement for a series of debt securities. This election will preclude some actions from being considered defaults under the Indenture for the applicable series. In order to exercise this option, we will be required to deposit, in trust for the benefit of the holders of debt securities, funds in an amount sufficient to pay the principal, premium and interest on the debt securities of the applicable series. We may also deposit securities that will provide the necessary monies. We will also be required to satisfy certain requirements, including that we deliver to the trustee an opinion of counsel to the effect that holders of the debt securities will not recognize gain or loss for federal income tax purposes as a result of such deposit and defeasance of certain obligations and will be subject to federal income tax on the same amount, in the same manner and at the same times as would have been the case if the deposit and defeasance were not to occur. If we exercise this option with respect to any debt securities and the debt securities are declared due and payable because of the occurrence of any event of default, the amount of funds deposited in trust would be sufficient to pay amounts due on the debt securities at the time of their respective stated maturities but may not be sufficient to pay amounts due on the debt securities on any acceleration resulting from an event of default. In that case, we would remain liable for the additional payments.

Governing Law

The law of the State of New York will govern the Indenture and the debt securities.

Global Securities

Some or all of the debt securities of any series may be represented, in whole or in part, by one or more global securities, which will have an aggregate principal amount equal to that of the debt securities they represent. We will register each global security in the name of a depositary or nominee identified in a prospectus supplement and deposit the global security with the depositary or nominee. Each global security will bear a legend regarding the restrictions on exchanges and registration of transfer referred to below and other matters specified in a supplemental indenture to the Indenture.

No global security may be exchanged for debt securities registered, and no transfer of a global security may be registered, in the name of any person other than the depositary for the global security or any nominee of the depositary, unless:

- the depositary has notified us that it is unwilling or unable to continue as depositary for the global security or has ceased to be a clearing agency registered under the Exchange Act;
- an event of default has occurred and is continuing with respect to the debt securities represented by the global security; or
- any other circumstances exist that may be described in the applicable supplemental indenture and prospectus supplement.

We will register all securities issued in exchange for a global security or any portion of a global security in the names specified by the depositary.

As long as the depositary or its nominee is the registered holder of a global security, the depositary or nominee will be considered the sole owner and holder of the global security and the debt securities that it represents. Except in the limited circumstances referred to above, owners of beneficial interests in a global security will not:

- be entitled to have the global security or debt securities registered in their names;

- receive or be entitled to receive physical delivery of certificated debt securities in exchange for a global security; and
- be considered to be the owners or holders of the global security or any debt securities for any purpose under the Indenture.

We will make all payments of principal, premium, and interest on a global security to the depositary or its nominee. The laws of some jurisdictions require that purchasers of securities take physical delivery of securities in definitive form. These laws make it difficult to transfer beneficial interests in a global security.

Ownership of beneficial interests in a global security will be limited to institutions that have accounts with the depositary or its nominee, referred to as "Participants," and to persons that may hold beneficial interests through Participants. In connection with the issuance of any global security, the depositary will credit, on its book-entry registration and transfer system, the respective principal amounts of debt securities represented by the global security to the accounts of its Participants. Ownership of beneficial interests in a global security will only be shown on records maintained by the depositary or the Participant. Likewise, the transfer of ownership interests will be effected only through the same records. Payments, transfers, exchanges, and other matters relating to beneficial interests in a global security may be subject to various policies and procedures adopted by the depositary from time to time. Neither we, the trustee, nor any of our agents will have responsibility or liability for any aspect of the depositary's or any Participant's records relating to, or for payments made on account of, beneficial interests in a global security, or for maintaining, supervising, or reviewing any records relating to the beneficial interests.

Regarding the Trustee

The Bank of New York Mellon Trust Company, N.A., successor to The Bank of New York Mellon, is the trustee under our Indentures relating to the senior debt securities and the subordinated debt securities. It or its affiliate, The Bank of New York Mellon, is also trustee under various indentures covering securities issued by APS or on APS's behalf or on which APS is the ultimate obligor and also acts as auction agent for certain of that debt. We and our affiliates maintain normal commercial and banking relationships with The Bank of New York Mellon Trust Company, N.A., and its affiliates. In the future The Bank of New York Mellon Trust Company, N.A. and its affiliates, including The Bank of New York Mellon, may provide banking, investment and other services to us and our affiliates.

DESCRIPTION OF PINNACLE WEST PREFERRED STOCK

Pinnacle West may issue, from time to time, shares of one or more series of its preferred stock. When we use the terms "we," "us," "our," and like terms in this description, we are referring to Pinnacle West. The following description sets forth certain general terms and provisions of the preferred stock to which any prospectus supplement may relate. The particular terms of any series of preferred stock and the extent, if any, to which these general provisions may apply to the series of preferred stock offered will be described in the prospectus supplement relating to that preferred stock.

The following summary of provisions of the preferred stock does not purport to be complete and is subject to, and is qualified in its entirety by reference to, the provisions of our articles of incorporation, bylaws, and the amendment to our articles relating to a specific series of the preferred stock (the "statement of preferred stock designations"), which will be in the form filed as an exhibit to, or incorporated by reference in, the registration statement of which this prospectus is a part. Before investing in any series of our preferred stock, you should read our articles and bylaws.

General

Under our articles of incorporation, we have the authority to issue up to 10,000,000 shares of preferred stock. As of April 24, 2012, no shares of preferred stock were outstanding. Our Board of Directors is authorized to issue shares of preferred stock in one or more series and to fix for each series voting powers and those preferences and relative, participating, optional or other special rights and those qualifications, limitations or restrictions as are permitted by the Arizona Business Corporation Act (the "ABCA"). For a description of provisions in our articles and bylaws or under Arizona law that could delay, defer or prevent a change in control, see "Description of Pinnacle West Common Stock—Certain Anti-takeover Effects."

Our Board of Directors is authorized to determine the terms for each series of preferred stock, and the prospectus supplement will describe the terms of any series of preferred stock being offered, including:

- the designation of the shares and the number of shares that constitute the series;
- the dividend rate (or the method of calculation thereof), if any, on the shares of the series and the priority as to payment of dividends with respect to other classes or series of our capital stock;
- the dividend periods (or the method of calculation thereof);
- the voting rights of the shares;
- the liquidation preference and the priority as to payment of the liquidation preference with respect to other classes or series of our capital stock and any other rights of the shares of the series upon our liquidation or winding up;
- whether and on what terms the shares of the series will be subject to redemption or repurchase at our option or at the option of the holders thereof;
- whether and on what terms the shares of the series will be convertible into or exchangeable for other securities;
- whether the shares of the series of preferred stock will be listed on a securities exchange;
- any special United States federal income tax considerations applicable to the series; and
- the other rights and privileges and any qualifications, limitations or restrictions of the rights or privileges of the series.

Dividends

Holders of shares of preferred stock will be entitled to receive, when and as declared by our Board of Directors out of our funds legally available therefor, a cash dividend payable at the dates and at the rates, if any, per share as set forth in the applicable prospectus supplement.

Convertibility

No series of preferred stock will be convertible into, or exchangeable for, other securities or property except as set forth in the applicable prospectus supplement.

Redemption and Sinking Fund

No series of preferred stock will be redeemable or receive the benefit of a sinking fund except as set forth in the applicable prospectus supplement.

Liquidation Rights

Unless otherwise set forth in the applicable prospectus supplement, in the event of our liquidation, dissolution or winding up, the holders of shares of each series of preferred stock are entitled to receive distributions out of our assets available for distribution to shareholders, before any distribution of assets is made to holders of (i) any other shares of preferred stock ranking junior to that series of preferred stock as to rights upon liquidation and (ii) shares of common stock. The amount of liquidating distributions received by holders of preferred stock will generally equal the liquidation preference specified in the applicable prospectus supplement for that series of preferred stock, plus any dividends accrued and accumulated but unpaid to the date of final distribution. The holders of each series of preferred stock will not be entitled to receive the liquidating distribution of, plus such dividends on, those shares until the liquidation preference of any shares of our capital stock ranking senior to that series of the preferred stock as to the rights upon liquidation shall have been paid or set aside for payment in full.

If upon our liquidation, dissolution or winding up, the amounts payable with respect to the preferred stock, and any other preferred stock ranking as to any distribution on a parity with the preferred stock are not paid in full, then the holders of the preferred stock and the other parity preferred stock will share ratably in any distribution of assets in proportion to the full respective preferential amount to which they are entitled. Unless otherwise specified in a prospectus supplement for a series of preferred stock, after payment of the full amount of the liquidating distribution to which they are entitled, the holders of shares of preferred stock will not be entitled to any further participation in any distribution of our assets. Neither a consolidation or merger of us with another corporation nor a sale of securities shall be considered a liquidation, dissolution or winding up of us.

Voting Rights

The holders of each series of preferred stock we may issue will have no voting rights, except as required by law and as described below or in the applicable prospectus supplement. Our Board of Directors may, upon issuance of a series of preferred stock, grant voting rights to the holders of that series, including rights to elect additional board members if we fail to pay dividends in a timely fashion.

Arizona law provides for certain voting rights for holders of a class of stock, even if the stock does not have other voting rights. Thus, the holders of all shares of a class would be entitled to vote on any amendment to our articles of incorporation that would:

- increase or decrease the aggregate number of authorized shares of the class;
- effect an exchange or reclassification of all or part of the shares of the class into shares of another class;
- effect an exchange or reclassification, or create the right of exchange of all or part of the shares of another class into shares of the class;
- change the designations, rights, obligations, preferences, or limitations of all or part of the shares of the class;
- change the shares of all or part of the class into a different number of shares of the same class;
- create a new class of shares having rights or preferences with respect to distributions or to dissolution that are prior, superior or substantially equal to the shares of the class;
- increase rights, preferences or number of authorized shares of any class that, after giving effect to the amendment, have rights or preferences with respect to distributions or to dissolution that are prior, superior or substantially equal to the shares of the class;
- limit or deny an existing preemptive right of all or part of the class; and

- cancel or otherwise affect rights to distributions or dividends that have accumulated but have not yet been declared on all or part of the shares of the class.

If the proposed amendment would affect a series of the class, but not the entire class, in one or more of the ways described in the bullets above, then the shares of the affected series will have the right to vote on the amendment as a separate voting group. However, if a proposed amendment that would entitle two or more series of the class to vote as separate voting groups would affect those series in the same or a substantially similar way, the shares of all the series so affected must vote together as a single voting group on the proposed amendment.

Unless the articles of incorporation, Arizona law or the Board of Directors would require a greater vote or unless the articles or Arizona law would require a different quorum, if an amendment to the articles would allow the preferred stock or one or more series of the preferred stock to vote as voting groups, the vote required by each voting group would be:

- a majority of the votes entitled to be cast by the voting group, if the amendment would create dissenters' rights for that voting group; and
- in any other case, if a quorum is present in person or by proxy consisting of a majority of the votes entitled to be cast on the matter by the voting group, the votes cast by the voting group in favor of the amendment must exceed the votes cast against the amendment by the voting group.

Arizona law may also require that the preferred stock be entitled to vote on certain other extraordinary transactions.

Miscellaneous

The holders of our preferred stock will have no preemptive rights. All shares of preferred stock being offered by the applicable prospectus supplement will be fully paid and not liable to further calls or assessment by us. If we should redeem or otherwise reacquire shares of our preferred stock, then these shares will resume the status of authorized and unissued shares of preferred stock undesignated as to series, and will be available for subsequent issuance. There are no restrictions on repurchase or redemption of the preferred stock while there is any arrearage on sinking fund installments except as may be set forth in an applicable prospectus supplement. Payment of dividends on any series of preferred stock may be restricted by loan agreements, indentures and other transactions entered into by us. Any material contractual restrictions on dividend payments that exist at the time of the offer of any preferred stock will be described or incorporated by reference in the applicable prospectus supplement.

When we offer to sell a series of preferred stock, we will describe the specific terms of the series in the applicable prospectus supplement. If any particular terms of a series of preferred stock described in a prospectus supplement differ from any of the terms described in this prospectus, then the terms described in the applicable prospectus supplement will be deemed to supersede the terms described in this prospectus.

No Other Rights

The shares of a series of preferred stock will not have any preferences, voting powers or relative, participating, optional or other special rights except as set forth above or in the applicable prospectus supplement, our articles of incorporation or the applicable statement of preferred stock designations or as otherwise required by law.

Transfer Agent and Registrar

The transfer agent and registrar for each series of preferred stock will be designated in the applicable prospectus supplement.

DESCRIPTION OF PINNACLE WEST COMMON STOCK

Pinnacle West may issue, from time to time, shares of its common stock, the general terms and provisions of which are summarized below. When we use the terms "we," "us," "our," and like terms in this description, we are referring to Pinnacle West. This summary does not purport to be complete and is subject to, and is qualified in its entirety by express reference to, the provisions of our articles of incorporation, our bylaws and the applicable prospectus supplement.

Authorized Shares

Under our articles of incorporation, we have the authority to issue 150,000,000 shares of common stock. Our Board of Directors has significant discretion to determine the timing, circumstances and purposes for which the authorized shares of common stock available for issuance under our articles of incorporation may be issued, including in the context of acquisitions or other strategic transactions.

Dividends

Subject to any preferential rights of any series of preferred stock, holders of shares of common stock will be entitled to receive dividends on the stock out of assets legally available for distribution when, as and if declared by our Board of Directors. The payment of dividends on the common stock will be a business decision to be made by our Board of Directors from time to time based upon results of our operations and our financial condition and any other factors that our Board of Directors considers relevant. Payment of dividends on the common stock may be restricted by loan agreements, indentures and other transactions entered into by us from time to time. Any material contractual restrictions on dividend payments that exist at the time of the offer of any common stock will be described in the applicable prospectus supplement. In addition, our principal income consists of dividends paid to us by our subsidiaries, primarily APS. APS's ability to pay dividends could be limited or restricted from time to time by loan agreements, indentures and other transactions or by law or regulatory authorities.

Voting Rights

Holders of common stock are entitled to one vote per share on all matters voted on generally by the shareholders. Arizona law provides for cumulative voting for the election of directors. As a result, any shareholder may cumulate his or her votes by casting them all for any one director nominee or by distributing them among two or more nominees. This may make it easier for minority shareholders to elect a director.

Liquidation Rights

Subject to any preferential rights of any series of preferred stock, holders of shares of common stock are entitled to share ratably in our assets legally available for distribution to our shareholders in the event of our liquidation, dissolution or winding up.

Absence of Other Rights or Assessments

Holders of common stock have no preferential, preemptive, conversion or exchange rights. When issued in accordance with our articles of incorporation and law, shares of our common stock being offered by the applicable prospectus supplement will be fully paid and not liable to further calls or assessment by us.

Transfer Agent and Registrar

Computershare Shareowner Services LLC is the transfer agent and registrar for the common stock.

Preferred Stock

Our Board of Directors has the authority, without any further action by our shareholders, to issue from time to time up to 10,000,000 shares of preferred stock, in one or more series, and to fix the designations, preferences, rights, qualifications, limitations and restrictions thereof, including voting rights, dividend rights, dividend rates, conversion rights, terms of redemption, redemption prices, liquidation preferences and the number of shares constituting any series. The issuance of preferred stock with voting rights could have an adverse effect on the voting power of holders of common stock by increasing the number of outstanding shares having voting rights. In addition, if our Board of Directors authorizes preferred stock with conversion rights, the number of shares of common stock outstanding could potentially be increased up to the authorized amount. The issuance of preferred stock could decrease the amount of earnings and assets available for distribution to holders of common stock. Any such issuance could also have the effect of delaying, deterring or preventing a change in control of us. See also "Description of Pinnacle West Preferred Stock" above.

Certain Anti-takeover Effects

General. Certain provisions of our articles of incorporation, our bylaws, and Arizona law may have an anti-takeover effect and may delay or prevent a tender offer or other acquisition transaction that a shareholder might consider to be in his or her best interest. The summary of the provisions of our articles, bylaws and Arizona law set forth below does not purport to be complete and is qualified in its entirety by reference to our articles, bylaws and Arizona law.

Business Combinations. Arizona law and our bylaws restrict a wide range of transactions (collectively, "business combinations") between us or, in certain cases, one of our subsidiaries, and an interested shareholder. An "interested shareholder" is:

- any person who beneficially owns, directly or indirectly, 10% or more of our outstanding voting power, or
- any of our affiliates or associates who at any time within the prior three years was such a beneficial owner.

The statute defines "business combinations" to include, with certain exceptions:

- mergers, consolidations and share exchanges with an interested shareholder;
- any sale, lease, exchange, mortgage, pledge, transfer or other disposition of assets to an interested shareholder, representing 10% or more of (i) the aggregate market value of all of our consolidated assets as of the end of the most recent fiscal quarter, (ii) the aggregate market value of all our outstanding shares, or (iii) our consolidated revenues or net income for the four most recent fiscal quarters;
- the issuance or transfer of shares of stock having an aggregate market value of 5% or more of the aggregate market value of all of our outstanding shares to an interested shareholder;
- the adoption of a plan or proposal for our liquidation or dissolution or reincorporation in another state or jurisdiction pursuant to an agreement or arrangement with an interested shareholder;
- corporate actions, such as stock splits and stock dividends, and other transactions, in each case resulting in an increase in the proportionate share of the outstanding shares of any series or class of stock of us or any of our subsidiaries owned by an interested shareholder; and
- the receipt by an interested shareholder of the benefit (other than proportionately as a shareholder) of any loans, advances, guarantees, pledges or other financial assistance or any tax credits or other tax advantages provided by or through us or any of our subsidiaries.

Arizona law and our bylaws provide that, subject to certain exceptions, we may not engage in a business combination with an interested shareholder or authorize one of our subsidiaries to do so, for a period of three years after the date on which the interested shareholder first acquired the shares that qualify such person as an interested shareholder (the "share acquisition date"), unless either the business combination or the interested shareholder's acquisition of shares on the share acquisition date is approved by a committee of our Board of Directors (comprised solely of disinterested directors or other disinterested persons) prior to the interested shareholder's share acquisition date.

In addition, after such three-year period, Arizona law and our bylaws prohibit us from engaging in any business combination with an interested shareholder, subject to certain exceptions, unless:

- the business combination or acquisition of shares by the interested shareholder on the share acquisition date was approved by our Board of Directors prior to the share acquisition date;
- the business combination is approved by holders of a majority of our outstanding shares (excluding shares beneficially owned by the interested shareholder) at a meeting called after such three-year period; or
- the business combination satisfies specified price and other requirements.

Anti-Greenmail Provisions. Arizona law and our bylaws prohibit us from purchasing any shares of our voting stock from any beneficial owner (or group of beneficial owners acting together) of more than 5% of the voting power of our outstanding shares at a price per share in excess of the average closing sale price during the 30 trading days preceding the purchase or if the person or persons have commenced a tender offer or announced an intention to seek control of us, during the 30 trading days prior to the commencement of the tender offer or the making of the announcement, if the 5% beneficial owner has beneficially owned the shares to be purchased for a period of less than three years, unless:

- holders of a majority of our voting power (excluding shares held by the 5% beneficial owner or by any of our officers and directors) approve the purchase; or
- we make the repurchase offer available to all holders of the class or series of securities to be purchased and to all holders of other securities convertible into that class or series.

Control Share Acquisition Statute. Under Arizona law, a control share acquisition is an acquisition, subject to certain exceptions, by a beneficial owner that would result in the owner having a new range of voting power within any of the following ranges: (i) at least 20% but less than 33⅓%; (ii) at least 33⅓% but less than or equal to 50%; or (iii) more than 50%. Through a provision in our bylaws, we have opted out of the Arizona statutory provisions regulating control share acquisitions. As a result, potential acquirors are not subject to the limitations imposed by that statute.

Special Meetings of Shareholders. Our bylaws provide that, except as required by law, special meetings of shareholders may be called by a majority of our Board of Directors, the Chairman of the Board, the President, or shareholders who hold in the aggregate at least 25% of the voting power of the outstanding capital stock of Pinnacle West ("Requesting Shareholders"). Requesting Shareholders must meet certain qualifications and must submit a written request to our Corporate Secretary, containing the information required by our bylaws. A request for a special meeting made by Requesting Shareholders may be rejected if: (1) a meeting of shareholders that included an identical or substantially similar item of business, as determined in good faith by our Board of Directors, was held not more than 90 days before our Corporate Secretary received the request; (2) our Board of Directors has called or calls for a meeting of shareholders to be held within 90 days after our Corporate Secretary receives the request and our Board of Directors determines in good faith that the business to be conducted at such meeting includes similar business to that stated in the request; or (3) the request relates to an item of business that is not a proper subject for shareholder action under, or involves a violation of, applicable law.

Election and Removal of Directors. Each member of our Board of Directors is elected annually to hold office until the next annual meeting of the shareholders or until his or her earlier death, resignation or removal or until his or her successor is duly elected and qualified.

Our bylaws provide that any director or the entire Board of Directors may be removed by vote of the shareholders with or without cause, but only at a special meeting called for that purpose, if the votes cast in favor of such removal exceed the votes cast against such removal. However, if less than the entire Board of Directors is to be removed, no one director may be removed if the votes cast against the director's removal would be sufficient to elect the director if then cumulatively voted at an election of directors.

Our bylaws provide that a director in an uncontested election who receives a greater number of votes cast "withheld" for his or her election than "for" such election must tender his or her resignation to the Corporate Governance Committee of our Board of Directors for consideration. The Corporate Governance Committee will evaluate the director's tendered resignation, taking into account the best interest of Pinnacle West and its shareholders and will recommend to our Board of Directors whether to accept or reject the resignation. Any director tendering a resignation pursuant to this provision of our bylaws will not participate in any committee or Board of Director consideration of his or her resignation.

Shareholder Proposals and Director Nominations. A shareholder can submit shareholder proposals and nominate candidates for election to our Board of Directors in connection with our annual meeting if he or she follows the advance notice and other relevant provisions set forth in our bylaws. With respect to director nominations at an annual meeting, shareholders must submit written notice to our Corporate Secretary at least 180 days prior to the date of the meeting. With respect to shareholder proposals to bring other business before the annual meeting, shareholders must submit a written notice to our Corporate Secretary not fewer than 90 nor more than 120 days prior to the first anniversary of the date of our previous year's annual meeting of shareholders. However, if we have changed the date of the annual meeting by more than 30 days from the anniversary date of the previous year's annual meeting, the written notice must be submitted no earlier than 120 days before the annual meeting and not later than 90 days before the annual meeting or ten days after the day we make public the date of the annual meeting.

A shareholder must also comply with all applicable laws in proposing business to be conducted and in nominating directors. The notice provisions of the bylaws do not affect rights of shareholders to request inclusion of proposals in our proxy statement pursuant to Rule 14a-8 of the Exchange Act.

Amendment to Articles of Incorporation and Bylaws. Both the Board of Directors and the shareholders must approve amendments to an Arizona corporation's articles of incorporation, except that the Board of Directors may adopt specified ministerial amendments without shareholder approval. Unless the articles of incorporation, Arizona law or the Board of Directors would require a greater vote or unless the articles of incorporation or Arizona law would require a different quorum, the vote required by each voting group allowed or required to vote on the amendment would be:

- a majority of the votes entitled to be cast by the voting group, if the amendment would create dissenters' rights for that voting group; and
- in any other case, if a quorum is present in person or by proxy consisting of a majority of the votes entitled to be cast on the matter by the voting group, the votes cast by the voting group in favor of the amendment must exceed the votes cast against the amendment by the voting group.

The Board of Directors may amend or repeal the corporation's bylaws unless either: (i) the articles or applicable law reserves this power exclusively to shareholders in whole or in part or (ii) the shareholders in amending or repealing a particular bylaw provide expressly that the Board may not amend or repeal that bylaw. An Arizona corporation's shareholders may amend or repeal the corporation's bylaws even though they may also be amended or repealed by the Board of Directors. Our bylaws may not be amended or repealed without the vote of a majority of the Board of Directors then in office or the affirmative vote of a majority of votes cast on the matter at a meeting of shareholders.

DESCRIPTION OF APS UNSECURED DEBT SECURITIES

General

The following description highlights the general terms of the unsecured debt securities that APS may offer. In this description, we will refer to the unsecured debt securities as "debt securities." When we use the terms "we," "us," "our," and like terms in this description, we are referring to APS. When we offer debt securities in the future, the prospectus supplement will explain the particular terms of those securities and the extent to which any of these general provisions will not apply.

We can issue an unlimited amount of debt securities under the indenture listed below. We can issue debt securities from time to time and in one or more series as determined by us. In addition, we can issue debt securities of any series with terms different from the terms of debt securities of any other series and the terms of particular debt securities within any series may differ from each other, all without the consent of the holders of previously issued series of debt securities. If specified in a prospectus supplement relating to an offering of debt securities, from time to time, without notice to, or the consent of, the existing holders of any series of debt securities then outstanding, we may create and issue additional debt securities equal in rank and having the same maturity, payment terms, redemption features, and other terms as the debt securities of such series, except for the issue date of the additional debt securities, the public offering price of the additional debt securities, the payment of interest accruing prior to the issue date of the additional debt securities and (under some circumstances) the first payment of interest following the issue date of the additional debt securities. The additional debt securities may be consolidated and form a single series with previously issued debt securities of the affected series.

The debt securities will be our direct, unsecured obligations. The debt securities may be issued in one or more series under an Indenture, dated as of January 15, 1998, as amended from time to time, between The Bank of New York Mellon Trust Company, N.A., successor to JPMorgan Chase Bank, N.A., and us.

We have summarized the material provisions of the Indenture below. We have filed the Indenture as an exhibit to the registration statement. You should read the Indenture in its entirety, including the definitions, together with this prospectus and the prospectus supplement before you make any investment decision in our debt securities.

You should refer to the prospectus supplement used in connection with the offering of any debt securities for information about a series of debt securities, including:

- title of the debt securities;
- the aggregate principal amount of the debt securities or the series of which they are a part;
- the date on which the debt securities mature;
- the interest rate;
- when the interest on the debt securities accrues and is payable;

- the record dates for the payment of interest;
- places where principal, premium, or interest will be payable;
- periods within which, prices at which, and terms upon which we can redeem debt securities at our option;
- any obligation on our part to redeem or purchase debt securities pursuant to a sinking fund or at the option of the holder;
- denominations and multiples at which debt securities will be issued if other than $1,000;
- any index or formula from which the amount of principal or any premium or interest may be determined;
- any allowance for alternative currencies and determination of value;
- whether the debt securities are defeasible under the terms of the Indenture;
- whether we are issuing the debt securities as global securities;
- any additional or different events of default and any change in the right of the trustee or the holders to declare the principal amount due and payable if there is any default;
- any addition to or change in the covenants in the Indenture; and
- any other terms.

We may sell the debt securities at a substantial discount below their principal amount. The prospectus supplement may describe special federal income tax considerations that apply to debt securities sold at an original issue discount or to debt securities that are denominated in a currency other than United States dollars.

We must obtain the approval of the ACC before incurring long-term debt. An existing ACC order allows us to have approximately $4.2 billion in principal amount of long-term debt outstanding at any one time, subject to the satisfaction of certain conditions, including the satisfaction of a minimum common equity test and a debt service coverage test.

Unless the applicable prospectus supplement specifies otherwise, we do not intend to list the debt securities on any securities exchange.

Other than the protections described in this prospectus and in the related prospectus supplement, holders of debt securities would not be protected by the covenants in the Indenture from a highly-leveraged transaction.

Form, Exchange, and Transfer

Each series of debt securities will be issuable only in fully registered form and without coupons. In addition, unless otherwise specified in a prospectus supplement, the debt securities will be issued in denominations of $1,000 and multiples of $1,000. We, the trustee, and any of our agents may treat the registered holder of a debt security as the absolute owner for the purpose of making payments, giving notices, and for all other purposes.

The holders of debt securities may exchange them for any other debt securities of the same series, in authorized denominations and equal principal amount. However, this type of exchange will be subject to the terms of the Indenture and any limitations that apply to global securities.

A holder may transfer debt securities by presenting the endorsed security at the office of a security registrar or transfer agent we designate. The holder will not be charged for any exchange or registration of transfer, but we may require payment to cover any tax or other governmental charge in connection with the transaction. We have appointed the trustee under the Indenture as security registrar. A prospectus supplement will name any transfer agent we designate for any debt securities if different from the security registrar. We may designate additional transfer agents or rescind the designation of any transfer agent or approve a change in the office through which any transfer agent acts at any time, except that we will maintain a transfer agent in each place of payment for debt securities.

If the debt securities of any series and/or specified tenor are to be redeemed, we will not be required to do any of the following:

- issue, register the transfer of, or exchange any debt securities of that series and/or tenor beginning 15 days before the day of mailing of a notice of redemption of any such debt security that may be selected for redemption and ending at the close of business on the day of the mailing; or
- register the transfer of or exchange any debt security selected for redemption, except for the unredeemed portion of a debt security that is being redeemed in part.

Payment and Paying Agents

Unless otherwise indicated in the applicable prospectus supplement, we will pay interest on a debt security on any interest payment date to the person in whose name the debt security is registered on the regular record date for such interest payment date.

Unless otherwise indicated in the applicable prospectus supplement, the principal, premium, and interest on the debt securities of a particular series will be payable at the office of the paying agents that we may designate. However, we may pay any interest by check mailed to the address, as it appears in the security register, of the person entitled to that interest. Also, unless otherwise indicated in the applicable prospectus supplement, the corporate trust office of the trustee in The City of New York will be our sole paying agent for payments with respect to debt securities of each series. Any other paying agent that we initially designate for the debt securities of a particular series will be named in the applicable prospectus supplement. We may at any time designate additional paying agents or rescind the designation of any paying agent or approve a change in the office through which any paying agent acts, except that we will maintain a paying agent in each place of payment for the debt securities of a particular series.

All money that we pay to a paying agent for the payment of the principal, premium, or interest on any debt security that remains unclaimed at the end of two years after the principal, premium, or interest has become due and payable will be repaid to us, and the holder of the debt security may look only to us for payment.

Consolidation, Merger, and Sale of Assets

Unless otherwise indicated in the applicable prospectus supplement, we may not:

- consolidate with or merge into any other entity;
- convey, transfer, or lease our properties and assets substantially as an entirety to any entity; or
- permit any entity to consolidate with or merge into us or convey, transfer, or lease its properties and assets substantially as an entirety to us,

unless the following conditions are met:

- the successor entity is a corporation, partnership, unincorporated organization or trust organized and validly existing under the laws of any domestic jurisdiction and assumes our obligations on the debt securities and under the Indenture;

- immediately after giving effect to the transaction, no event of default, and no event which, after notice or lapse of time or both, would become an event of default, shall have occurred and be continuing; and
- other conditions are met.

Upon any such merger, consolidation, or transfer or lease of properties, the successor person will be substituted for us under the Indenture, and, thereafter, except in the case of a lease, we will be relieved of all obligations and covenants under the Indenture and the debt securities.

Events of Default

Each of the following will be an event of default under the Indenture with respect to debt securities of any series:

- our failure to pay principal of or any premium on any debt security of that series when due;
- our failure to pay any interest on any debt securities of that series when due, and the continuance of that failure for 30 days;
- our failure to deposit any sinking fund payment, when due, in respect of any debt securities of that series;
- our failure to perform any of our other covenants in the Indenture relating to that series and the continuance of that failure for 90 days after written notice has been given by the trustee or the holders of at least 25% in principal amount of the outstanding debt securities of that series;
- bankruptcy, insolvency, or reorganization events involving us; and
- any other event of default for that series described in the applicable prospectus supplement.

If an event of default occurs and is continuing, other than an event of default relating to bankruptcy, insolvency, or reorganization, either the trustee or the holders of at least 25% in aggregate principal amount of the outstanding debt securities of the affected series may declare the principal amount of the debt securities of that series to be due and payable immediately. In the case of any debt security that is an original issue discount security, the trustee or the holders of at least 25% in aggregate principal amount of the outstanding debt securities of that series may declare the portion of the principal amount of the debt security specified in the terms of such debt security to be immediately due and payable upon an event of default.

If an event of default involving bankruptcy, insolvency, or reorganization occurs, the principal amount of all the debt securities of the affected series will automatically, and without any action by the trustee or any holder, become immediately due and payable. After any acceleration, but before a judgment or decree based on acceleration, the holders of a majority in aggregate principal amount of the outstanding debt securities of that series may rescind and annul the acceleration if all events of default, other than the non-payment of accelerated principal, have been cured or waived as provided in the Indenture.

The trustee will be under no obligation to exercise any of its rights or powers under the Indenture at the request or direction of any of the holders, unless the holders have offered the trustee reasonable indemnity. The holders of a majority in principal amount of the outstanding debt securities of any series will have the right to direct the time, method, and place of conducting any proceeding for any remedy available to the trustee, or exercising any trust or power conferred on the trustee, with respect to the debt securities of that series, provided that:

- such direction shall not be in conflict with law or the Indenture;
- the trustee may take any other action not inconsistent with such direction; and

- subject to the provisions of the Indenture, the trustee may decline to follow such direction if it determines in good faith that the proceedings so directed would involve the trustee in personal liability.

No holder of a debt security of any series will have any right to institute any proceeding under the Indenture, or for the appointment of a receiver or a trustee, or for any other remedy under the Indenture, unless:

- the holder has previously given the trustee written notice of a continuing event of default with respect to the debt securities of that series;
- the holders of at least 25% in aggregate principal amount of the outstanding debt securities of that series have made written request, and the holder or holders have offered reasonable indemnity, to the trustee to institute the proceeding as trustee; and
- the trustee has failed to institute the proceeding, and has not received from the holders of a majority in aggregate principal amount of the outstanding debt securities of that series a direction inconsistent with the request within 60 days after the notice, request, and offer of indemnity.

The limitations provided above do not apply to a suit instituted by a holder of a debt security for the enforcement of payment of the principal, premium, or interest on the debt security on or after the applicable due date.

We are required to furnish to the trustee annually a certificate of various officers stating whether or not we are in default in the performance or observance of any of the terms, provisions, and conditions of the Indenture and, if so, specifying all known defaults.

Modification and Waiver

In limited cases, we and the trustee may make modifications and amendments to the Indenture without the consent of the holders of any series of debt securities, including to cure any ambiguity, to correct or supplement any provision in the Indenture that is defective or inconsistent with any other provision, or to make other provisions with respect to matters or questions arising under the Indenture, but such action shall not adversely affect the interests of the holders of the debt securities of any series in any material respect. We and the trustee may also make modifications and amendments to the Indenture with the consent of the holders of not less than 66⅔% in aggregate principal amount of the outstanding debt securities of each series affected by the modification or amendment. However, without the consent of the holder of each outstanding debt security affected, no modification or amendment may:

- change the stated maturity of principal of or interest on any debt security;
- reduce the principal amount of any debt security or the rate of interest thereon or any premium payable on redemption thereof;
- reduce the amount of principal of an original issue discount security or any other debt security payable upon acceleration of the maturity of the security;
- change the place or currency of payment of principal of, or any premium or interest on, any debt security;
- impair the right to institute suit for the enforcement of any payment on or with respect to any debt security; or
- reduce the percentage in principal amount of outstanding debt securities of any series, the consent of whose holders is required for modification or amendment of the Indenture or is

necessary for waiver of compliance with certain provisions of the Indenture or of certain defaults, or modify the provisions of the Indenture relating to modification and waiver.

In general, compliance with certain restrictive provisions of the Indenture may be waived by the holders of not less than 66⅔% in aggregate principal amount of the outstanding debt securities of any series. The holders of a majority in aggregate principal amount of the outstanding debt securities of any series may waive any past default under the Indenture, except:

- a default in the payment of principal, premium, or interest; and
- a default under covenants and provisions of the Indenture which cannot be amended without the consent of the holder of each outstanding debt security of the affected series.

In determining whether the holders of the requisite principal amount of the outstanding debt securities have given or taken any direction, notice, consent, waiver, or other action under the Indenture as of any date:

- the principal amount of an outstanding original issue discount security will be the amount of the principal that would be due and payable upon acceleration of the maturity on that date;
- if the principal amount payable at the stated maturity of a debt security is not determinable, the principal amount of the outstanding debt security will be an amount determined in the manner prescribed for the debt security; and
- the principal amount of an outstanding debt security denominated in one or more foreign currencies will be the U.S. dollar equivalent of the principal amount of the debt security or, in the case of a debt security described in the previous bullet points above, the amount described in those bullet points.

If debt securities have been fully defeased or if we have deposited money with the trustee to redeem debt securities, they will not be considered outstanding.

Except in limited circumstances, we will be entitled to set any day as a record date for the purpose of determining the holders of outstanding debt securities of any series entitled to give or take any direction, notice, consent, waiver, or other action under the Indenture. In limited circumstances, the trustee will be entitled to set a record date for action by holders. If a record date is set for any action to be taken by holders of a particular series, the action may be taken only by persons who are holders of outstanding debt securities of that series on the record date. To be effective, the action must be taken by holders of the requisite principal amount of the debt securities within a specified period following the record date. For any particular record date, this period will be 180 days or any other shorter period that we may specify. The period may be shortened or lengthened, but not beyond 180 days.

Defeasance and Covenant Defeasance

We may elect to have the provisions of the Indenture relating to defeasance and discharge of indebtedness, or defeasance of restrictive covenants in the Indenture, applied to the debt securities of any series, or to any specified part of a series. The prospectus supplement used in connection with the offering of any debt securities will state whether we have made these elections for that series.

Defeasance and Discharge. We will be discharged from all of our obligations with respect to the debt securities of a series if we deposit with the trustee money in an amount sufficient to pay the principal, premium, and interest on the debt securities of that series when due in accordance with the terms of the Indenture and the debt securities. We can also deposit securities that will provide the necessary monies. However, we will not be discharged from the obligations to exchange or register the transfer of debt securities, to replace stolen, lost, or mutilated debt securities, to maintain paying agencies, and to hold monies for payment in trust. The defeasance or discharge may occur only if we satisfy certain requirements, including that we deliver to the trustee an opinion of counsel stating that we have received from, or there has been published by, the United States Internal Revenue Service a ruling, or there has been a change in tax law, in either case to the effect that holders of such debt securities:

- will not recognize gain or loss for federal income tax purposes as a result of the deposit, defeasance, and discharge; and
- will be subject to federal income tax on the same amount, in the same manner, and at the same times as would have been the case if the deposit, defeasance, and discharge were not to occur.

Defeasance of Covenants. We may elect to omit compliance with restrictive covenants in the Indenture and any additional covenants that may be described in the applicable prospectus supplement for a series of debt securities. This election will preclude some actions from being considered defaults under the Indenture for the applicable series. In order to exercise this option, we will be required to deposit, in trust for the benefit of the holders of debt securities, funds in an amount sufficient to pay the principal, premium and interest on the debt securities of the applicable series. We may also deposit securities that will provide the necessary monies. We will also be required to satisfy certain requirements, including that we deliver to the trustee an opinion of counsel to the effect that holders of the debt securities will not recognize gain or loss for federal income tax purposes as a result of such deposit and defeasance of certain obligations and will be subject to federal income tax on the same amount, in the same manner and at the same times as would have been the case if the deposit and defeasance were not to occur. If we exercise this option with respect to any debt securities and the debt securities are declared due and payable because of the occurrence of any event of default, the amount of funds deposited in trust would be sufficient to pay amounts due on the debt securities at the time of their respective stated maturities but may not be sufficient to pay amounts due on the debt securities on any acceleration resulting from an event of default. In that case, we would remain liable for the additional payments.

Governing Law

The law of the State of New York will govern the Indenture and the debt securities.

Global Securities

Some or all of the debt securities of any series may be represented, in whole or in part, by one or more global securities, which will have an aggregate principal amount equal to that of the debt securities they represent. We will register each global security in the name of a depositary or nominee identified in a prospectus supplement and deposit the global security with the depositary or nominee. Each global security will bear a legend regarding the restrictions on exchanges and registration of transfer referred to below and other matters specified in a supplemental indenture to the Indenture.

No global security may be exchanged for debt securities registered, and no transfer of a global security may be registered, in the name of any person other than the depositary for the global security or any nominee of the depositary, unless:

- the depositary has notified us that it is unwilling or unable to continue as depositary for the global security or has ceased to be a clearing agency registered under the Exchange Act;
- an event of default has occurred and is continuing with respect to the debt securities represented by the global security; or
- any other circumstances exist that may be described in the applicable supplemental indenture and prospectus supplement.

We will register all securities issued in exchange for a global security or any portion of a global security in the names specified by the depositary.

As long as the depositary or its nominee is the registered holder of a global security, the depositary or nominee will be considered the sole owner and holder of the global security and the debt securities that it represents. Except in the limited circumstances referred to above, owners of beneficial interests in a global security will not:

- be entitled to have the global security or debt securities registered in their names;
- receive or be entitled to receive physical delivery of certificated debt securities in exchange for a global security; and
- be considered to be the owners or holders of the global security or any debt securities for any purpose under the Indenture.

We will make all payments of principal, premium, and interest on a global security to the depositary or its nominee. The laws of some jurisdictions require that purchasers of securities take physical delivery of securities in definitive form. These laws make it difficult to transfer beneficial interests in a global security.

Ownership of beneficial interests in a global security will be limited to institutions that have accounts with the depositary or its nominee, referred to as Participants, and to persons that may hold beneficial interests through Participants. In connection with the issuance of any global security, the depositary will credit, on its book-entry registration and transfer system, the respective principal amounts of debt securities represented by the global security to the accounts of its Participants. Ownership of beneficial interests in a global security will only be shown on records maintained by the depositary or the Participant. Likewise, the transfer of ownership interests will be effected only through the same records. Payments, transfers, exchanges, and other matters relating to beneficial interests in a global security may be subject to various policies and procedures adopted by the depositary from time to time. Neither we, the trustee, nor any of our agents will have responsibility or liability for any aspect of the depositary's or any Participant's records relating to, or for payments made on account of, beneficial interests in a global security, or for maintaining, supervising, or reviewing any records relating to the beneficial interests.

Regarding the Trustee

The Bank of New York Mellon Trust Company, N.A., successor to JPMorgan Chase Bank, N.A., is the trustee under the Indenture relating to the senior debt securities. The Bank of New York Mellon Trust Company, N.A. or its affiliate, The Bank of New York Mellon, is also the trustee under certain indentures relating to the sale and leaseback transactions that we entered into in 1986 with respect to a portion of our interest in Unit 2 of the Palo Verde Nuclear Generating Station and certain related common facilities and under various other indentures covering securities issued by us, our affiliates or on our or their behalf and also acts as auction agent for certain of that debt. We and our affiliates maintain normal commercial and banking relationships with The Bank of New York Mellon Trust Company, N.A. and its affiliates. In the future, The Bank of New York Mellon Trust Company, N.A. and its affiliates may provide banking, investment and other services to us and our affiliates.

EXPERTS

The consolidated financial statements of Pinnacle West Capital Corporation and the related financial statement schedules, incorporated in this prospectus by reference from Pinnacle West Capital Corporation's Annual Report on Form 10-K, and the effectiveness of Pinnacle West Capital Corporation's internal control over financial reporting have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report, which is incorporated herein by reference. Such consolidated financial statements and financial statement schedules have been so incorporated in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

The consolidated financial statements of Arizona Public Service Company and the related financial statement schedule, incorporated in this prospectus by reference from Arizona Public Service Company's Annual Report on Form 10-K, and the effectiveness of Arizona Public Service Company's internal control over financial reporting have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report, which is incorporated herein by reference. Such consolidated financial statements and financial statement schedule have been so incorporated in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

LEGAL OPINIONS

The validity of the offered securities will be passed upon for Pinnacle West and APS by David P. Falck, Executive Vice President, General Counsel and Secretary of Pinnacle West and APS. Mr. Falck is regularly employed by Pinnacle West and APS, participates in various Pinnacle West employee benefit plans under which he may receive shares of common stock and currently beneficially owns less than one percent of the outstanding shares of common stock of Pinnacle West. We currently anticipate that Pillsbury Winthrop Shaw Pittman LLP, 1540 Broadway, New York, New York 10036, will pass on certain legal matters with respect to the offered securities for any underwriters. David P. Falck may rely as to all matters of New York law upon the opinion of Pillsbury Winthrop Shaw Pittman LLP.

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTY-SIXTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
FOUR CORNERS RATE RIDER
DOCKET NO. E-01345A-11-0224
APRIL 8, 2014

Staff 36.8: Refer to the Company's Workpaper EAB-2, Page 2. Please provide the source and support for the 24.5833 year life for the STM plant.

Response: APS estimated the remaining life for the Four Corners plant is June 30, 2038, which is 24.5 years from January 1, 2014. The 24.5833 was derived using an extra month. This depreciable life is consistent with what was approved in the 2010 Test Year Rate Case proposed by APS Witness Ron White. Attached as APS15306 is an excerpt from his testimony supporting this depreciable life and attached as APS15307 is Section 6.1 of the Settlement, approving the depreciation and amortization rates.

Witness: Beth Blankenship

EXHIBIT
S-7
ADMITTED

RUCO'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN FOUR CORNERS RATE RIDER DOCKET NO. E-01345A-11-0224 JANUARY 14, 2014

RUCO 1.1: In Pinnacle West/APS recent 8-K filing, it is noted that APS has agreed to assume the 7% shortfall obligation of El Paso Company's failure to sign the 2016 Coal Supply Agreement. Please explain the circumstances. Please explain what is happening with the asset (i.e. will El Paso retain its 7% ownership), why APS agreed to pick up the shortfall and whether APS seeks to include the expense in the pending Rate Rider application. If so; please explain why APS' ratepayers should have to pay the expense. Is the additional coal from the El Paso contract necessary for the provision of service to APS' ratepayers – please explain.

Response: APS does not seek to include any costs associated with this 7% in the pending Rate Rider application, nor are there any existing costs to include. APS agreed to accept El Paso's 7% coal supply obligation if, by 2016, the 7% interest in Four Corners 4 and 5 has not been conveyed to the Navajo Nation. The Navajo Nation has expressed an interest in acquiring El Paso's share of the plant, and would assume the El Paso coal supply obligation, instead of APS, if and when it acquires that interest.

Witness: Jeff Guldner

EXHIBIT
S-8
ADMITTED

RUCO'S SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
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DOCKET NO. E-01345A-11-0224
MAY 23, 2014

RUCO 2.8: What is the anticipated asset utilization of the APS's owned units at Four Corners for the first 10 years and over 20 years?

Response: The Four Corners average capacity factors are:

10 year – 73.6%

20 year – 76.9%

Witness: Jeff Guldner

EXHIBIT
S-9
ADMITTED

RUCO'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN FOUR CORNERS RATE RIDER DOCKET NO. E-01345A-11-0224 JANUARY 14, 2014

RUCO 1.2: Admit that this expense was not forecasted in APS' original Four Corner's application.

Response: See APS's response to RUCO 1.1. APS was unaware that El Paso would not sign a renewed 2016 Coal Supply Agreement at the time of APS's Original Four Corners Application. APS may never incur any expense associated with the El Paso shortfall obligation under the 2016 Coal Supply Agreement, and has not included any amount associated with that shortfall in the current application.

Witness: Jeff Guldner

EXHIBIT
S-10
ADMITTED

RUCO'S SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
FOUR CORNERS RATE RIDER
DOCKET NO. E-01345A-11-0224
MAY 23, 2014

RUCO 2.6: Has APS identified potential risks from further EPA rulings that may impact the economics of Four Corners?

Response: Yes. The potential risks from further EPA rulings were identified in APS's 2014 Integrated Resource Plan ("IRP") - Chapter 3 & Section E of Response to Rules – Rule E.1(D), Rule E.2(D), Rule E.3(D), Rule E.1(E), Rule E.2(E), Rule E.3(E). This filing is available on APS's website at www.aps.com/resources.

Witness: Jeff Guldner

RUCO'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN FOUR CORNERS RATE RIDER DOCKET NO. E-01345A-11-0224 MAY 23, 2014

RUCO 2.7: Has APS attempted to quantify these EPA related risks to Four Corners?

Response: Uncertainty pertaining to regional haze regulations (BART) – APS has assumed and included the installation costs of SCR controls in the analyses.

Uncertainty pertaining to National Ambient Air Quality Standard (NAAQS) – Because the proposed ozone NAAQS were withdrawn by EPA and the agency has yet to establish new NAAQS for ozone, it is difficult to estimate the impact, if any, of new standards on the Four Corners evaluation.

Uncertainties pertaining to RCRA regulations – Proposed regulations include two different scenarios – Subtitle C (hazardous) and Subtitle D (non-hazardous). For the Four Corners evaluation and all other studies, APS has assumed EPA will choose to regulate CCR under Subtitle D and has included cost estimates in the analyses. The Subtitle C option was not evaluated because APS does not believe CCRs to be hazardous waste, but APS estimates the CCR costs would be 20% higher than Subtitle C.

Uncertainty pertaining to Greenhouse gas (GHG) - New source performance standards (NSPS) regulations – APS has included in its analysis the potential for carbon pricing in the form of three carbon price forecasts, see response to Staff 35.31 and 35.35

Uncertainty pertaining to Effluent limitation guidelines (ELG) – Any revisions to the ELG would impact the discharge limits at Four Corners which may be faced with increased capital and O&M expenses to achieve and maintain compliance. This risk was not evaluated because the EPA is not expected to have a final rule until late 2015 and it is uncertain what, if any, impact will come from such regulation.

Witness: Jeff Guldner

EXHIBIT

S-12

ADMITTED

SIERRA CLUB FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
FOUR CORNERS RATE RIDER
DOCKET NO. E-01345A-11-0224
FEBRUARY 7, 2014

Sierra Club 1.13: Reference the December 30, 3013 testimony of Jeffrey Guldner in this docket, page 9: "And, despite generally lower natural gas prices, the SCE interest in FC 4-5 is forecast to provide long-term value to APS customers."

a. Provide all analyses and documentation relied on by APS that supports this statement.

b. What is the levelized natural gas price that APS assumed when it concluded that the SCE interest in FC 4-5 is forecast to provide long-term value to APS customers?

Response:

a. APS objects to this question as vague, ambiguous and unduly burdensome. Notwithstanding this objection, APS responds as follows. The acquisition of SCE's share of Units 4-5 results in a revenue requirement that is $426 million less than the alternative of replacing Four Corners with a comparable natural gas resource. This analysis assumes carbon costs beginning in 2021. If a carbon market does not materialize as assumed, the revenue requirement would be as high as $633 million less than a comparable natural gas alternative. Attached, in Excel as APS15273, is the requested information. Also, see the APS Four Corners Rate Rider Technical Conference Materials filed February 18, 2014 in Docket E-1345A-11-0224.

b. Please see APS's response to Sierra Club question 1.22. The levelized natural gas price from 2014 to 2029 is $5.38/MMBTU.

Witness: Jeff Guldner

EXHIBIT
ALL-STATE LEGAL®
S-13
ADMITTED

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTY-SIXTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
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APRIL 8, 2014

Staff 36.42: Refer to the Company's Workpaper EAB-5, Page 10. Please explain the Company's rationale for first including 4.5% inflation within the formula for the base amount ($36,051,545) and then growing this amount by inflation the same inflation rate to future years.

Response: Generally Accepted Accounting Principles (GAAP) requires that asset retirement obligations be recognized at fair value. The obligation equals the present value of the expected cost of remediation (decommissioning), which is calculated by inflating the costs (cash flow) to the date when the cash is expected to be expended and discounting to reflect obligation to current value. We are using a 4.5% inflation of the costs through end of plant life (June 30, 2038) when Units 4-5 and Common are expected to commence site decommissioning. Thus, we are merely compounding rather than double-counting as perhaps implied in the question.

Witness: Beth Blankenship

EXHIBIT
S-14
ADMITTED

ARIZONA CORPORATION COMMISSION
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DOCKET NO. E-01345A-11-0224
APRIL 8, 2014

Staff 36.40: Refer to the Company's Workpaper EAB-5, Page 10. Please provide the source and support for the decommissioning amounts ($30,625,354 and $4,433,732) included on this schedule.

Response: The sources for the decommissioning amounts are based on the 2009 Four Corners Decommissioning Study prepared by Shaw Group Power, provided in discovery in the 2010 Test Year Rate Case in Docket E-01345A-11-0224, and the 2012 Ash Closure Study prepared by URS. Attached as APS15320 is a calculation for the "Decommissioning Study 2013 dollars" reflected in Workpaper EAB-5, Page 10, column b lines 2 and 3. APS15320 also includes the cost summaries from the 2009 Shaw Decommissioning Study and the 2012 URS Ash Pond Study.

Witness: Beth Blankenship

EXHIBIT
S-15
ADMITTED

ARIZONA CORPORATION COMMISSION
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DOCKET NO. E-01345A-11-0224
MAY 14, 2014

Staff 39.3: In Docket No. E-01345A-10-0474, APS briefly discusses the "acquisition adjustment" in this case, or the difference between book value and the market price paid. Staff's understanding of the general rule in Arizona is that the Commission does not permit recovery of an acquisition adjustment arising from a sale of assets barring extraordinary circumstances. In addition, the Commission has found that "if a party believes that an acquisition adjustment is necessary to bring about an efficiency-enhancing transaction, it should come to the Commission and establish at the very least: (1) the transaction will not likely occur but for an acquisition adjustment; (2) that operational efficiencies will likely result from the transaction; and (3) in a subsequent rate case, that operational efficiencies resulted from the transaction."[1] Please explain how this transaction meets this standard, specifically the following:

a. Please explain what extraordinary circumstances exist that would justify the Commission's recognition of an acquisition adjustment in this case.

b. Please explain how this transaction would not likely have occurred without the acquisition adjustment.

c. Please describe any operational efficiencies that are likely to result from this transaction. Please describe in detail the "clear, quantifiable, and substantial net benefits to ratepayers that have resulted from the acquisition that would not have been realized had the transaction not occurred."

[1] *See In the Matter of the Joint Application of Black Mountain Gas Company and SemStream Arizona Propane, L.L.C. for Approval of the Transfer of the Black Mountain Page Division and Related Assets to SemStream Arizona Propane, L.L.C.*, 2007 WL 4127237 (Ariz.C.C.).

Response: APS is unaware of any ACC decision applying the above criteria for including what FERC accounting characterizes as an acquisition adjustment in the case of a specific asset acquisition as contrasted to the acquisition of an entire system as was the case in *Black Mountain*. A better analogy would be if water Company (A) has future water needs and has an option to purchase an existing well from Company (B) or drill a new well to serve A's customers. After evaluation, it is clear that purchasing the existing well is more advantageous than any other available option to the customers of Company A. Since the well has been serving Company B, it has depreciated its book value over several years of ownership and the book value is now below the fair market value of the well. Company A purchases the well at a fair value which is above the remaining book value of Company B, allowing the purchase to move forward and Company B to break

Witness: Jeff Guldner

even on the sale after all liabilities are taken into account. The difference between fair value paid by A and book value is called an acquisition adjustment per FERC. This is a significantly different circumstance than if A were to purchase all of the utility assets of B and continue to provide service to Company B customers with the same assets. In fact, APS is unaware of any ACC decision involving the acquisition of a new asset that did not recognize the full acquisition cost. That being said, the Company will attempt to respond to Staff's specific inquiries.

a. Decision No. 73130 (April 24, 2012) established the Four Corners acquisition from SCE as an extraordinary circumstance that warranted both an exemption from the "self-build" moratorium imposed by the Commission in Decision No. 67744 (April 5, 2005) and the "best practices" for resource acquisition later codified in the Commission's Resource Planning Rules. *See* A.A.C. R14-2-705(B) (5).

   The acquisition was also extraordinary in the level of customer benefit (over $400 million on a net present value basis), the ability to preserve APS's customers' existing benefits from the Company's pre-existing share of Four Corners 4 and 5, and the significant environmental benefit (specifically cited in Decision No. 73130 at pages 8-11) from closure of Units 1-3 by the end of 2013. None of these benefits could or would have happened absent this transaction.

b. The transaction could never have occurred absent the agreement by APS to pay a sufficient amount to compensate SCE for its exit of the facility prior to mid-2016. SCE would not have agreed to a selling price that placed it in a worse economic position than not selling, and even if SCE would have agreed to a contract that was financially irresponsible, the sale would never have received necessary CPUC approval.

   And neither APS nor any other rational utility would agree to pay nearly $300 million for a plant and then write off five sixths of that investment less than a year later. The significant operational benefits from additional ownership of Four Corners 4 and 5 justifying APS' acquisition would all accrue to APS customers, leaving APS shareholders with nothing to show for management's good faith efforts to benefit customers but a staggering write off.

c. See APS responses to Sierra Club 1.13, Sierra Club 2.1, Sierra Club 2.4, Staff 35.31, and Staff 35.35. Also see the Four Corners Technical Conference materials provided in Docket No. E-01345A-11-0224 on February 18, 2013.

Witness: Jeff Guldner

ARIZONA CORPORATION COMMISSION
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Staff 39.4: In Docket No. E-01345A-10-0474, APS refers to the difference between book value and the purchase price as an "acquisition adjustment". In Docket No. E-01345A-11-0224, APS's witnesses do not refer to the difference between book value and the market price paid as an "acquisition adjustment."

a. Does APS consider the difference between the book value and the purchase price to be an "acquisition adjustment?"

b. If the answer to subpart (a) is "no," please explain what the difference between book value and purchase price is and why APS referred to it as an "acquisition adjustment" in Docket No. 10-0474.

c. If the difference is an acquisition adjustment, why wasn't it called an "acquisition adjustment" in the testimony in this Docket (11-0224)?

Response:

a. Not in the traditionally understood sense. This adjustment is based on fundamentally different circumstances than the traditional acquisition adjustment requested in Black Mountain and similar cases. FERC rules require this amount to be recorded as an "acquisition adjustment," which is what APS describes on page 9 of Elizabeth Blankenship's testimony as the accounting fair value of the acquisition. Also see Staff 39.8.

b. See above.

c. Docket No. E-01345A-11-0224 was a rate case, and the provision of the Settlement in that rate case addressed only the process for incorporating the Four Corners transaction in rates as a continuation of that proceeding rather than in a subsequent rate case. This accounting designation had and has no ratemaking significance in the context of an acquisition of a discreet asset never previously used to serve APS customers and thus no party to above Docket, including Staff, referenced the term "acquisition adjustment."

Also, attached as APS15321 and APS15328 are two data requests from Docket E-01354A-10-0474 that discuss the acquisition adjustment in detail. As can be seen by both responses, the forecast of the acquisition adjustment that was provided in that proceeding and ultimately used by the Commission when approving the transaction is consistent with the treatment requested in this

Witness: Jeff Guldner

proceeding and clearly contemplated by the Settlement in Docket No. E-01345A-11-0224.

EXHIBIT
S-16
ADMITTED

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTY-SIXTH SET OF DATA REQUESTS TO
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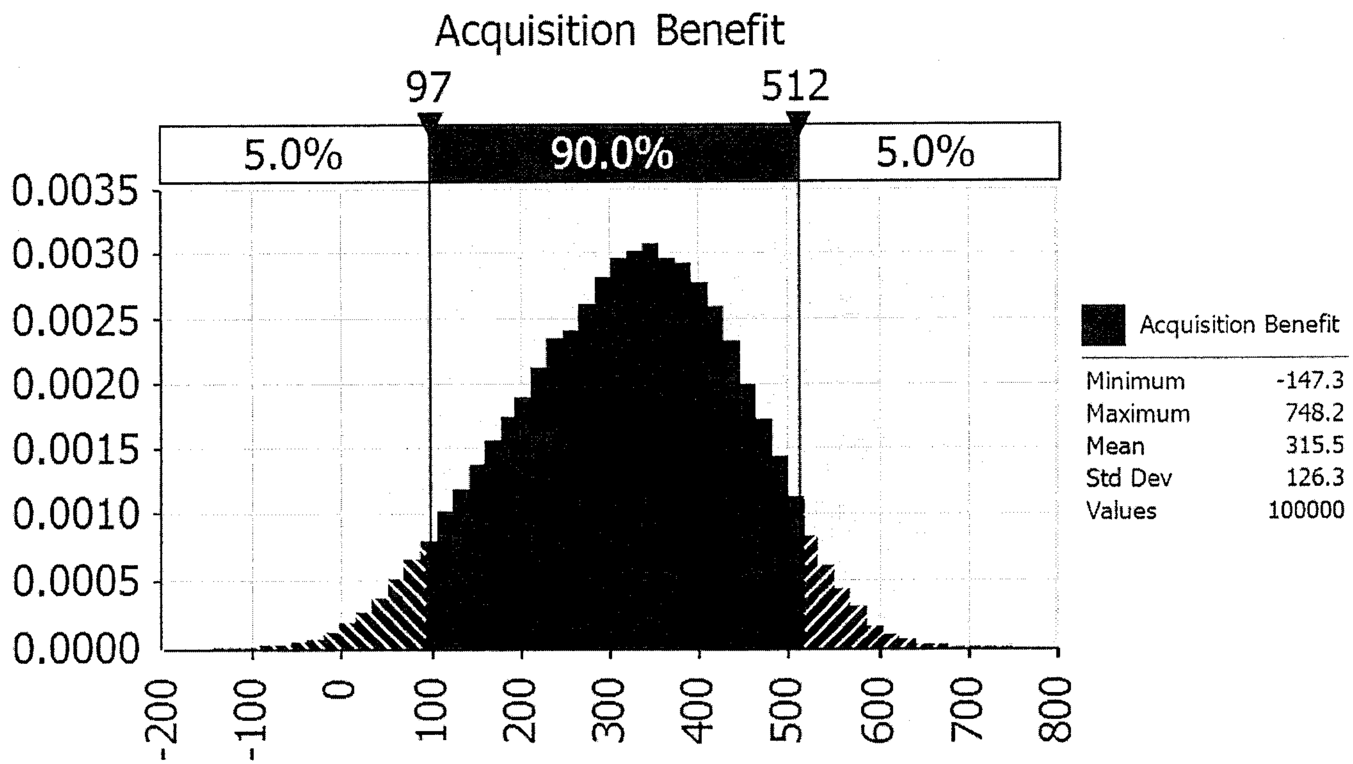
DOCKET NO. E-01345A-11-0224
APRIL 8, 2014

Staff 36.22: Refer to the Company's Workpaper EAB-4, Page 2. Please provide the source and support for the 5.25% rate used as the marginal cost of debt.

Response: In Workpaper EAB-4, page 2 the Company used the 5.25% rate based on the anticipated forecasted interest rate of the Company's next bond financing. APS issued debt at a 4.7% yield on January 7, 2014 to fund the purchase of SCE's share of Units 4 and 5 of Four Corners. APS is currently deferring costs at 4.7%. When APS updates the deferral calculation in Rebuttal Testimony the 4.7% debt rate will be used.

Witness: Beth Blankenship

Acquisition Benefit (NPV $M)



Acquisition Benefit (NPV $M)

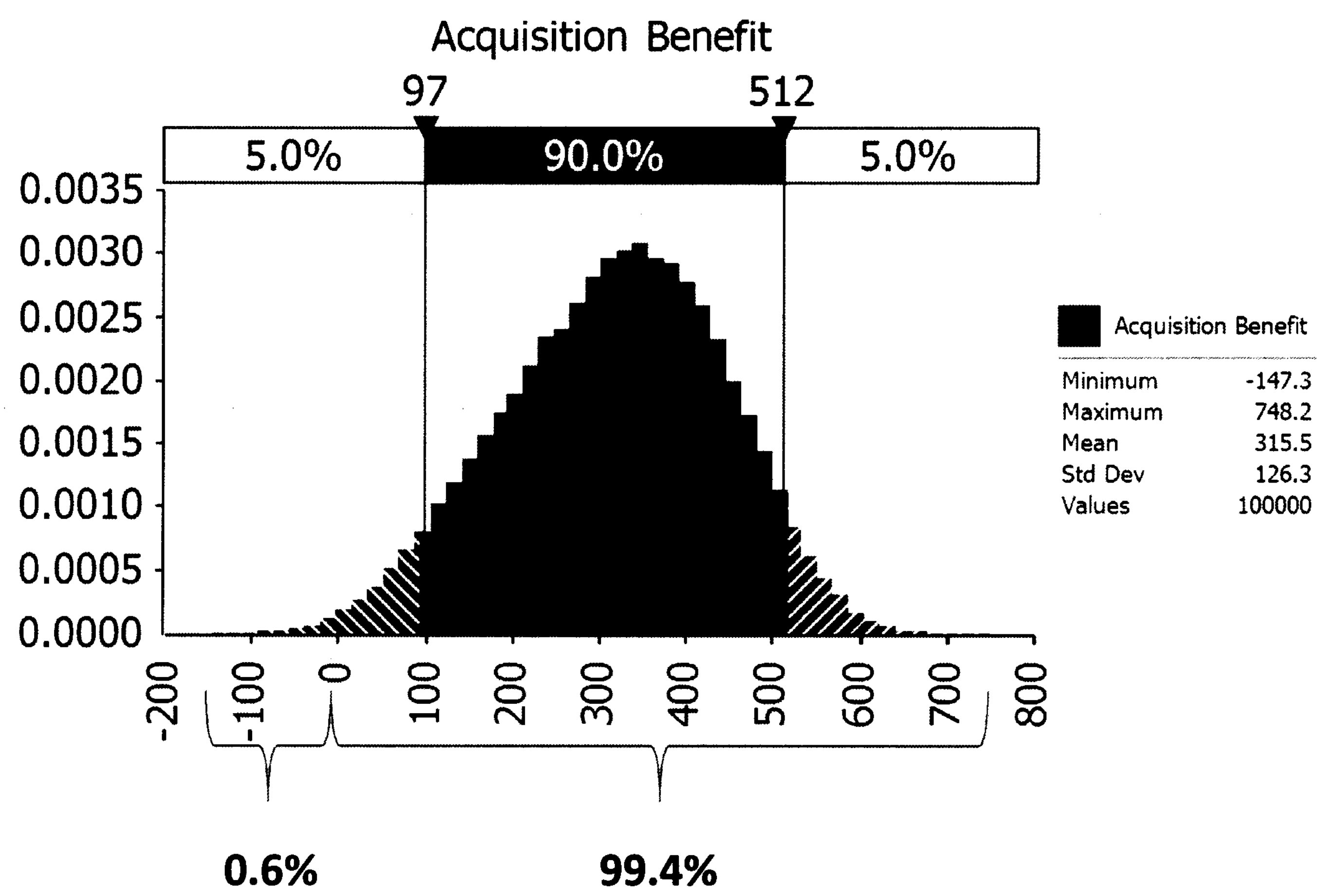


EXHIBIT
S-20
ADMITTED

Summary Of APS, RUCO, STAFF Rate of Return Positions to Include FVROR

APS Position

		Settlement	Four Corners	Four Corners Plus Settlement
1	Original Cost Rate Base	$ 5,662,998	$ 225,934	$ 5,888,932
2	Required Rate of Return (WACC)	8.33%	8.33%	8.33%
3	Required Operating Income (Line 1 x Line 2)	$ 471,728	$ 18,820	$ 490,548
4	Fair Value Rate Base	$ 8,167,126	$ 225,934	$ 8,393,060
5	Incremental Fair Value Rate Base Over OCRB (Line 4 - Line 1)	$ 2,504,128	$ -	$ 2,504,128
6	Fair Value Increment per Settlement	1.00%	1.00%	1.00%
7	Fair Value Increment x Incremental FVRB (Line 5 x Line 6)	$ 25,041	$ -	$ 25,041
8	OCRB + FVRB Required Operating Income (Line 3 + Line 7)	$ 496,769	$ 18,820	$ 515,589
9	Fair Value Rate of Return (Line 8 / Line 4)	6.09%	8.33%	6.14%

RUCO Position

		Settlement	Four Corners	Four Corners Plus Settlement
1	Original Cost Rate Base	$ 5,662,998	$ 225,934	$ 5,888,932
2	Required Rate of Return (WACC / Debt / Combined)	8.33%	4.725%	8.19%
3	Required Operating Income (Line 1 x Line 2)	$ 471,728	$ 10,675	$ 482,403
4	Fair Value Rate Base	$ 8,167,126	$ 225,934	$ 8,393,060
5	Incremental Fair Value Rate Base Over OCRB (Line 4 - Line 1)	$ 2,504,128	$ -	$ 2,504,128
6	Fair Value Increment per Settlement	1.00%	1.00%	1.00%
7	Fair Value Increment x Incremental FVRB (Line 5 x Line 6)	$ 25,041	$ -	$ 25,041
8	OCRB + FVRB Required Operating Income (Line 3 + Line 7)	$ 496,769	$ 10,675	$ 507,444
9	Fair Value Rate of Return (Line 8 / Line 4)	6.09%	4.725%	6.05%

Staff Position

		Settlement	Four Corners	Four Corners Plus Settlement
1	Original Cost Rate Base	$ 5,662,998	$ 225,934	$ 5,888,932
2	Required Rate of Return (WACC / FVROR / Combined)	8.33%	6.09%	8.24%
3	Required Operating Income (Line 1 x Line 2)	$ 471,728	$ 13,759	$ 485,487
4	Fair Value Rate Base	$ 8,167,126	$ 225,934	$ 8,393,060
5	Incremental Fair Value Rate Base Over OCRB (Line 4 - Line 1)	$ 2,504,128	$ -	$ 2,504,128
6	Fair Value Increment per Settlement	1.00%	1.00%	1.00%
7	Fair Value Increment x Incremental FVRB (Line 5 x Line 6)	$ 25,041	$ -	$ 25,041
8	OCRB + FVRB Required Operating Income (Line 3 + Line 7)	$ 496,769	$ 13,759	$ 510,528
9	Fair Value Rate of Return (Line 8 / Line 4)	6.09%	6.09%	6.09%

Analysis Of WACC Related To Four Corners related to $250 M @ 4.725%New Debt Financing

	Amount	%	Cost Rate	Weighted Average
Long-Term Debt	$ 182,000,000	80.55%	4.725%	3.81%
Common Equity	43,934,000	19.45%	10.00%	1.94%
TOTAL	$ 225,934,000	100.00%		5.75%

REDACTED

EXHIBIT
SC-1
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
BOB STUMP, Chairman
GARY PIERCE
BRENDA BURNS
ROBERT L. BURNS
SUSAN BITTER SMITH

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01345A-11-0224

REDACTED DIRECT TESTIMONY OF EZRA D. HAUSMAN, PH.D.

On Behalf of the Sierra Club

June 19, 2014

REDACTED

Table of Contents

REDACTED

I. Introduction

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

A. My name is Ezra D. Hausman, Ph.D. I am an independent consultant doing business as Ezra Hausman Consulting, operating from offices at 77 Kaposia Street, Auburndale, Massachusetts 02466.

Q. ARE YOU PROVIDING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am sponsoring the following exhibits:

Exhibit No.	Content	Contains APS Designated Confidential Information
EDH-1	Resume of Ezra D. Hausman, PH.D.	No
EDH-2	Direct testimony of Mr. Patrick Dinkel on behalf of Arizona Public Service Corp., ACC Docket No. E-01345A-10-0474, Dated November 22, 2010.	No
EDH-3	APS response to Sierra Club Data Request 2.1	Yes
EDH-4	APS response to Sierra Club Data Request 2.4	Yes
EDH-5	APS response to Staff Data Request 35.35	Yes
EDH-6	"Greenhouse Gas Legislative Review and CO_2 Price Outlook", prepared by Charles River Associates on behalf of Arizona Public Service Corp, and attached as Appendix A to APS's 2012 Integrated Resource Plan. Dated November 4, 2011.	No

REDACTED

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I hold a BA in Psychology from Wesleyan University, an MS in Environmental Engineering from Tufts University, an SM in Applied Physics from Harvard University, and a PhD in Atmospheric Chemistry from Harvard University. I have been involved in analysis of both regulated and restructured electricity markets for more than 15 years. I have provided a detailed resume as Exhibit EDH-1.

From 2005 until early 2014, I was employed at Synapse Energy Economics, Inc., a research and consulting company located in Cambridge, Massachusetts, where I served most recently as Vice President and Chief Operating Officer. At Synapse, and continuing as an independent consultant, I served as an analyst and expert in several areas related to my expertise and experience in energy economics. Specific areas include:

- State and regional energy, capacity, and transmission planning, including both utility resource planning and long-term (multi-decadal) climate-constrained resource planning
- Electricity and generating capacity market design and analysis
- Electric system dispatch modeling
- Economic analysis of environmental and other regulations, including greenhouse gas regulation, in electricity markets
- Economic analysis, price forecasting, and asset valuation in electricity markets

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- Quantification of the economic and environmental benefits of displaced emissions and market price impacts associated with energy efficiency and renewable energy
- Regulation and mitigation of greenhouse gas emissions from the supply and demand sides of the U.S. electricity sector

I have testified or appeared before public utility commissions and/or legislative committees in Nevada, Maryland, Kansas, Louisiana, Missouri, Mississippi, Vermont, Washington State, and Massachusetts, as well as at the federal level. I have provided expert representation for stakeholders at the PJM ISO and at the FERC. While most of my testimony and analytical work has centered on issues in electricity market economics, I have also brought my expertise as a scientist to bear on cases involving greenhouse gas mitigation in the electric sector.

Prior to joining Synapse, I was employed from 1998 through 2004 as a Senior Associate at Tabors Caramanis and Associates (TCA) of Cambridge, Massachusetts. In 2004, TCA was acquired by Charles River Associates (CRA), where I remained until I joined Synapse in 2005. At TCA/CRA, I performed a wide range of electricity market and economic analyses and price forecast modeling studies. These included asset valuation studies, market transition cost/benefit studies, market power analyses, and litigation support. I have extensive personal experience with market simulation, production cost modeling, and resource planning methodologies and software.

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Q. HAVE YOU EVER PARTICIPATED IN ANY RESOURCE PLANNING PROCESSES CONCERNING ARIZONA PUBLIC SERVICE COMPANY (APS)?

A. Yes. In 2010, I participated in the stakeholder process supporting the company's then-current resource planning process, on behalf of the Sierra Club. I gave a presentation on June 18, 2010, on the monetization of externalities in the resource planning process.

Q. HAVE YOU EVER TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION?

A. No.

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

A. The purpose of my testimony is to bring to light certain aspects of APS' recent acquisition of a large additional ownership share of Four Corners Units 4 and 5 from Southern California Edison (SCE). I would like to bring to the Commission's attention the fact that while APS's NPV analyses in this case purports to show benefits to ratepayers from the acquisition relative to other resource options, this analysis was based on limited and biased information, and does not adequately support the company's conclusions.

APS originally filed for permission to pursue the Four Corners acquisition in 2010. Despite numerous changes in the underlying economic drivers forming

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the basis of APS's economic analysis since the original filing, the resulting "benefit" to ratepayers on an NPV basis is remarkably similar: a $426 Million NPV benefit claimed today, compared to a $488 Million NPV benefit claimed in 2010. However, based on my review of the company's data as provided in its filing and in response to data requests, I conclude that numerous decisions and assumptions were made that had the effect, intentional or not, of making the acquisition plan appear to be more favorable to ratepayers than it actually is. I show that many of these decisions individually, if reversed, would have the effect of reversing the result of the analysis, and revealing that the Four Corners acquisition is not in fact in the interest of ratepayers. Taken together, these questionable assumptions mask what is likely a very poor deal for ratepayers.

Q. WHAT PARTICULAR ASPECTS OF APS'S ANALYSIS DO YOU ADDRESS IN YOUR TESTIMONY?

A. I address the following aspects of APS' analysis and underlying assumptions:

- **Fuel price forecasts.** The revisions made to APS's fuel price forecasts for the updated analysis would, were no other changes made to the underlying assumptions, make enough of a difference in the forward-looking economics of the plant as to make it uneconomic. This is because the expected future price for natural gas has decreased significantly in the intervening years, while the company's expectation for the cost of coal has increased. However, I find that the company has implausibly

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minimized the effect of these fuel price outlook changes by reverting to its previous, higher gas price forecast just a few years in the future.

- **Carbon dioxide emission costs.** I find that APS misapplied its own consultant's recommendations on the projection of CO_2 emission costs, and departed dramatically from the company's own forecasts as applied in the 2010 filing, without any explanation for its actions. As a result, APS used unrealistically low price forecasts for both its "Base Case" and "High Case" trajectories. My analysis shows that this anomalous treatment of emissions costs accounts for the entire claimed savings associated with the Four Corners acquisition in the current docket, and possibly much more.

- **Capital expenditures.** I find that the unexplained changes in the stream of projected capital costs for Four Corners between APS's 2010 filing and the current docket are anomalous and counterintuitive, and are starkly inconsistent with the changes in anticipated capital costs for other resources—and as a result tend to bias the analysis strongly in favor of the acquisition.

- **Other operational assumptions.** I find that APS continues to make optimistic assumptions regarding the future performance of Four Corners, projecting that the plant will run at a very high capacity factor through 2039. The company has apparently not considered the implications for ratepayers in the likely event that this assumption turns out to be incorrect.

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Q. WHAT IS YOUR RECOMMENDATION FOR THE COMMISSION?

I recommend that at this time the Commission reject APS's request for an increase to rate base of $183.3 million, reflecting costs associated with the purchase of SCE's share of Four Corners Units 4 and 5.[1] The Commission should further condition any future approval of rate base adjustments reflecting the Four Corners acquisition on APS re-filing its petition with a revised analysis that is more detailed, and that provides a full explanation and justification for the numerous changes in the company's assumptions and projections since its 2010 filing.

Q. ARE YOU SUGGESTING THAT THE COMMISSION RECONSIDER ITS DECISION NOS. 73130 (DOCKET NO. E-01345A-10-0474) OR 73183 (DOCKET NO. E-01345A-11-0224)?

No. In Decision No. 73130, the Commission authorized APS "if it so chooses" (p.43 at 3) to pursue the acquisition of SCE's interest in the units, and to defer the costs of this acquisition for later recovery through rates. The Commission did *not* deem the acquisition to be prudent, nor did it offer APS a blank check for either the purchase of Units 4 and 5 or for any additional costs:

[1] Direct Testimony of Elizabeth Blankenship, 9 at 23.

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> 8. This Decision should not be construed to limit this Commission's authority to review the acquisition of Four Corners Units 4 and 5, or the unrecovered costs or additional costs incurred in connection with the closure of Four Corners Units 1-3 at the appropriate time, and to make disallowances thereof due to imprudence, errors or inappropriate application of the requirements of this Decision. (Decision 73130, p.42 at 19)

Order No. 73183 simply kept the relevant Docket open until December 31, 2013 so that APS could file the current request for rate treatment, but did not in any way guarantee approval of that request.

Allowing costs associated with the purchase of SCE's ownership share of Four Corners 4 and 5 into rate base exposes APS's ratepayers to new and expanded risks and costs. The purpose of my testimony is to bring these risks and costs to light, and to detail certain questionable assumptions and other shortcomings in the company's NPV analysis. In light of these shortcomings, APS has not made an adequate case that the acquisition is prudent, or that the requested rate base increase is justified. I recommend that the Commission hold APS accountable for its decision to move forward with this acquisition despite significant changes in market conditions. In my opinion, the company's petition in this docket cannot reasonably be approved based on the analysis and evidence presented.

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II. Background

Q. PLEASE PROVIDE BACKGROUND INFORMATION ON THE FOUR CORNERS PLANT, AND ON APS'S DECISION TO ACQUIRE SCE'S SHARE OF FOUR CORNERS UNITS 4 AND 5.

A. The Four Corners Generating Station is a 5-unit, coal-fired power plant located within the Navajo Reservation in Northwestern New Mexico. Units 1, 2, and 3, which had a combined capacity of 560 MW, began operation in the early 1960s and were wholly owned by APS.[2] These units have now ceased operation.

Units 4 and 5, which have a combined capacity of 1,540 MW, came online in 1969-70. Prior to December 2013, APS owned 15% of these units; 48% was owned by Southern California Edison (SCE), a subsidiary of Edison International that serves customers in much of southern California, and the remaining shares are variously owned by Public Service Company of New Mexico (13%), Salt River Project (10%), El Paso Electric (7%), and Tucson Electric Power Company (7%).[3]

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[2] Direct testimony of Mark A. Schiavoni on behalf of APS in Docket No. E-01345A-10-0474, pp. 2-3.
[3] *Id.*, p.3.

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In 2010, SCE announced that it would not participate in any further "life-extending" investments in the plant,[4] pursuant to California Public Utilities Commission (CPUC) rules intended to limit investments in electric infrastructure with high levels of greenhouse gas emissions such as baseload coal-fired electric power plants. Because Four Corners Units 4 and 5 will require significant environmental upgrades to meet EPA emissions standards by 2016,[5] this rule meant that SCE would have to divest its 48% share of the units. According to the 2010 testimony of APS witness Mark Schiavoni, had SCE been unable to find a buyer for this share, the units would likely have to be retired.[6]

From APS's perspective, this situation presented an opportunity to shut down the older, less efficient units 1-3, avoiding environmental upgrade costs on those units, and to more than make up for the lost generating capacity by assuming a greater share of the larger, less aged Units 4 and 5.

APS's analysis presented in Docket E-01345A-10-0474 demonstrated convincingly that retaining and investing further in Units 1-3 would be a poor choice for the company and its ratepayers, and those units have since been retired. APS witness Patrick Dinkel further argued that acquiring SCE's

[4] *Id.,* pp.5-6.
[5] *Id.,* p.4-5.
[6] *Id.*, p.6

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share of Units 4 and 5 at the agreed upon purchase price, and assuming the increased cost of the required environmental upgrades on those units, was in ratepayers' interest. Specifically, Mr. Dinkel's NPV analysis concluded that there would be an expected NPV benefit to the acquisition of $488 Million, relative to the alternative of replacing APS's share of the energy and capacity from Four Corners with new natural gas-fired combined cycle (CC) generating units.[7] However, because APS was under a "self-build moratorium" (ACC Decision No. 67744) the company had to seek specific authorization to purchase SCE's share of Units 4 and 5, independent of any request for ratemaking treatment of the acquisition and other associated costs. The Commission authorized the company to pursue the acquisition of SCE's interest in the units, and further ordered that "Arizona Public Service Company is authorized to defer for possible later recovery through rates, all non-fuel costs...of owning, operating, and maintaining" the acquired interest.[8]

Sierra Club intervened in Docket No. E-01345A-10-0474 and retained the services of Mr. David Schlissel to review and provide expert testimony on APS's filing. Among other issues, Mr. Schlissel highlighted the risk that the

[7] Testimony of Patrick Dinkel, ACC Docket No. E-01345A-10-0474 (Exhibit EDH-2). See figure on "APS Customer Benefits", p.10.
[8] Decision No. 73130, p.43.

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Four Corners plant will not operate in the future as long and/or at as high a capacity factor as the company projects:

> Although APS repeatedly emphasizes the risks posed by natural gas price volatility, 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. In particular, without any supporting evidence, the Company 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 sixty. (Direct testimony of David Schlissel in Docket No. E-01345A-10-0474, 3 at 17)

APS has continued to ignore these and other risks in the current filing, despite their very significant potential implications for ratepayers.

Q. HAVE ANY CIRCUMSTANCES CHANGED SINCE THE COMMISSION CONSIDERED THE FOUR CORNERS ACQUISITION IN THE 2010 DOCKET?

Yes. Since the company's initial filing, a number of important economic factors have changed that affect the economics of the transaction. These include:

- A reduction in the purchase price, due to a delay in the closing date of the transaction between SCE and APS;

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- An increase in the expected cost of coal, pursuant to the sale of the coal mine to the Navajo nation and a renegotiation of the coal purchase agreement;
- A reduction in the expected cost of natural gas going forward;
- A change in the company's expectations with respect to the cost of carbon emissions going forward;
- A change in the company's projection of capital requirements for the maintenance of Four Corners Units 4 and 5;
- The duration of the period for which costs and benefits were calculated was reduced from 30 to 25 years.

Many of these changes individually have an impact comparable to or larger than APS's estimated NPV benefit of the Four Corners acquisition relative to the closest alternative plan. However, other than the reduction in the purchase price, the company has provided few or no details about the rationale for these changes. Even more remarkable, the combined impact of all of these very significant changes is almost no net change in the company's assessment of the long term NPV benefit of the transaction for consumers. The projected benefits changed from an estimated $488 Million over 30 years, as projected in 2010, to an estimated $426 Million over 25 years as projected in the current filing.

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Q. HAVE THERE BEEN CHANGES ELSEWHERE IN THE ELECTRIC POWER INDUSTRY THAT HAVE BEARING ON THIS CASE?

Yes. The coal industry across the country continues to face mounting challenges. Throughout the United States, utilities are reconsidering the economics of coal plant ownership in light of both fuel price dynamics and impending and likely environmental regulations, and in many cases they are divesting or shutting their coal assets—much as SCE elected to sell its share of Four Corners. While SCE's decision to exit Four Corners may have been primarily motivated by California law, another owner, El Paso Electric, has decided to divest itself of its 7% share of the very same Four Corners units at issue here without any such regulatory requirement. In addition, BHP Billiton, a huge multi-national mining company, decided to dispose of its ownership in the Navajo mine that provides coal to Four Corners.

As another example of failing industry confidence in the economics of coal plants, a recent proceeding before the Montana Public Service Commission suggested that the Colstrip coal plant in Montana was a net liability. In an application related to the purchase of hydroelectric assets from PPL Montana, a merchant generator and part-owner of Colstrip, NorthWestern Energy witness Brian B. Bird attested that "Northwestern bid $400 Million for all

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[Colstrip and hydro assets] of PPLM...and $740 Million for the Hydros..."[9] This valuation suggests that NorthWestern set a *negative* $340 Million value on PPLM's coal assets in the proposed bid. Mr. Bird explained that this negative valuation was due, in part, "...to recent Environmental Protection Agency ("EPA") actions and uncertainty around the viability of coal-fired assets in the future" including the risks associated with future remediation costs.[10]

There are numerous other examples of coal units that have been recently slated for retirement or conversion to natural gas. Of course, every unit, every market, and every utility is unique. However, if APS is asking this Commission to approve rate recovery for a decision that goes so strongly against the industry trend, the company bears the burden to justify and explain its decision in detail, and to demonstrate that it has done rigorous and unbiased analysis in support of that decision. I do not believe that this standard has been met in the current filing.

[9] Direct testimony of Brian B. Bird on behalf of Northwestern Energy, Montana Public Service Commission Docket No. D2013.12.85, p. BBB-7.
[10] Id., p. BBB-8.

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III. Changes in Economic Outlook after 2010 Filing

Q. WHEN AND AT WHAT PRICE DID APS ORIGINALLY PLAN TO ACQUIRE SCE'S SHARE OF FOUR CORNERS UNITS 4 AND 5?

A. The initial petition specified a closing date of October 1, 2012, for a cash price of $294 Million.[11] This price was to decrease by $7.5 Million for each month that the closing was delayed. [12]

Q. WHEN AND AT WHAT PRICE DID THIS TRANSACTION ACTUALLY TAKE PLACE?

A. The transaction actually closed on December 30, 2013.[13] Because of the delay in the closing date, the final purchase price was approximately $181.5 Million.[14]

Q. OTHER THAN THE CONTRACTUAL DECREASE IN THE PURCHASE PRICE, HOW HAD MARKET CONDITIONS CHANGED IN THE INTERVENING TIME?

A. One important change in the expected market conditions was an increase in the price of coal for the Four Corners plant. Another was a decrease in the

[11] APS *Application* in Docket No. E-01345A-10-0474, 22 at 10.
[12] Id., Footnote 108 on p. 22.
[13] APS *Application* in Docket No. E-01345A-11-0224, 1 at 22.
[14] APS did not readily provide the final purchase prices; I derived the value provided here by reducing the $294 million price by $7.5 million for 15 months. According to the testimony of Elizabeth Blankenship in Docket No. E-01345A-11-0224, Attachment EAB-10, the "Total Rate Base" impact of the acquisition is $183,271,000.

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expected price of natural gas. Together, these reduce the long-term benefit of the transaction to APS's ratepayers.

APS also reduced its expected values for the future cost of carbon emissions between 2010 and the current filing, which would tend to increase the expected benefits of the acquisition for ratepayers. Finally, APS appears to have revised its projection of capital costs for maintaining the plant.

Change in Expected Coal and Gas Prices

Q. HAVE YOU REVIEWED THE FUEL PRICE FORECASTS USED BY APS IN DOCKET NO. E-01345A-10-0474 (2010) AND IN THE CURRENT DOCKET?

A. Yes. Gas and coal price forecasts used for the current filing were provided in response to Sierra Club Data Request 2.1 (Exhibit EDH-3); Gas and coal price forecasts used by APS in Docket No. E-01345A-10-0474 were provided in response to Sierra Club Data Request 2.4 (Exhibit EDH-4). In both cases the coal price forecasts were marked as confidential.

Q. HOW DID APS'S COAL PRICE FORECAST CHANGE BETWEEN THE COMPANY'S ORIGINAL APPLICATION AND THE ACTUAL DATE OF THE ACQUISITION?

A. CONFIDENTIAL Figure 1 compares the coal price forecast assumed by APS when the company originally analyzed the Four Corners acquisition in 2010, as used by APS witness Patrick Dinkel in his NPV analysis, with that

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assumed by the company in its most recent filing. On a levelized basis,[15] the price increased by about [redacted] from [redacted] between these two forecasts.

[redacted]

CONFIDENTIAL Figure 1. Coal price forecasts used by APS witness Patrick Dinkel in 2010 vs. those underlying APS's analysis in 2014.

Q. HOW DID APS'S GAS PRICE FORECAST CHANGE BETWEEN THE COMPANY'S ORIGINAL APPLICATION AND THE ACTUAL DATE OF THE ACQUISITION?

A. Figure 2 compares the gas price forecast assumed by APS when the company originally analyzed the Four Corners acquisition in 2010, as used by APS

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[15] Levelized on a nominal basis over the period 2015-2029, with a discount rate of 7.2%

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witness Patrick Dinkel in his NPV analysis, with that assumed by the company in its most recent filing. On a levelized basis,[16] each price trajectory decreased by 14.3% between the two sets of forecasts. The levelized prices are shown in CONFIDENTIAL Table 1.

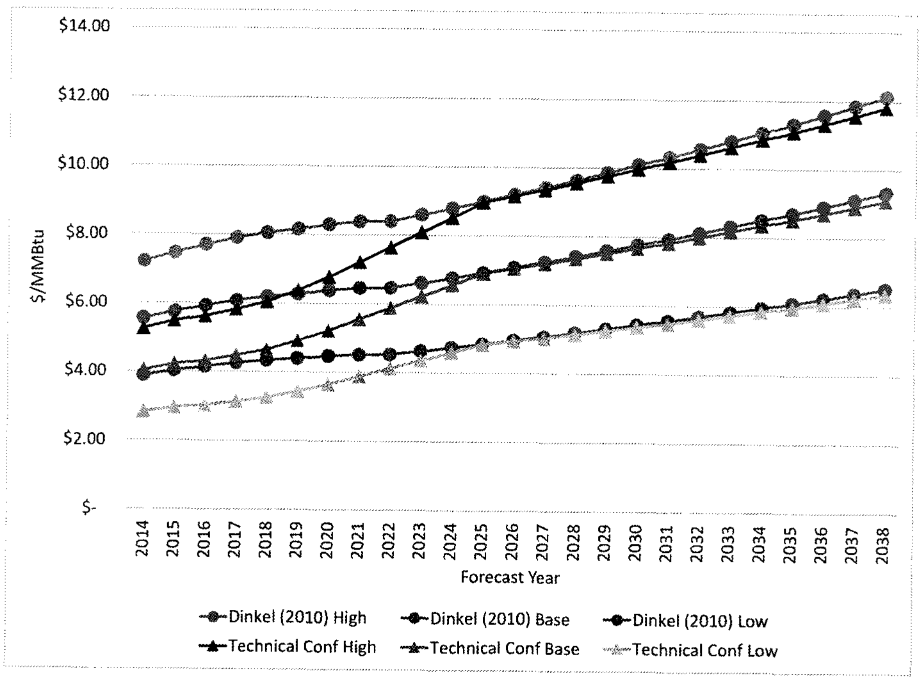

Figure 2. Gas price forecasts used by APS witness Patrick Dinkel in 2010 vs. those underlying APS's 2014 analysis.

[16] Levelized on a nominal basis over the period 2015-2029, with a discount rate of 7.2%

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CONFIDENTIAL Table 1. Comparison of APS's fuel price forecasts levelized over the period 2015-2029 at a discount rate of 7.2%

	Dinkel (2010)	Technical Conference (2014)	% Change
Gas			
Low	$ (4.52)	$ (3.87)	*-14.3%*
Base	$ (6.46)	$ (5.53)	*-14.3%*
High	$ (8.39)	$ (7.19)	*-14.3%*
Coal			
Base	[redacted]	[redacted]	[redacted]

Q. WHAT IS THE IMPACT OF THESE CHANGES IN APS' FUEL PRICE FORECASTS BETWEEN 2010 AND THE CURRENT FILING?

A. The result of these changes is a significant reduction in the economic benefits to ratepayers. In fact, I conclude that had APS used the company's later, updated fuel price projections at the time of the initial filing, all else being unchanged, the company would have found that the alternative plan of retiring Four Corners entirely and replacing it with new gas plants was the preferable option from an NPV perspective.

Q. ON WHAT DO YOU BASE THIS CONCLUSION?

A. In 2010, Mr. Dinkel concluded that in his "base case" analysis there would be an NPV savings of $488 Million from the company's preferred plan (acquiring SCE's share of Four Corners) relative to the company's alternative. I investigated the question: how much of this projected benefit would have

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been eliminated had Mr. Dinkel had the updated, 2014 fuel price forecasts available to him?

Of course, I do not have access to the company's dispatch model, which would be required to capture all of the dynamics of redispatch under different economic conditions. However, as a first cut, I investigated instead how much *larger* the projected benefits would be in the current filing if the fuel costs under the current dispatch were adjusted using the fuel price forecasts used by Mr. Dinkel in 2010, but without redispatching the system.

As summarized in Table 2, I estimate that the change in the fuel price outlook would lead to an NPV change of almost $500 Million. This suggests that the effect of the change in forecasted fuel prices was more than enough to negate the entire benefit claimed by APS either in 2010 or in the present proceeding, had not APS made numerous other changes to different assumptions that counteract this change.

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CONFIDENTIAL Table 2: Impact of Change in Fuel Price Forecast on NPV Benefit

	As Filed ($Million)	Adjusted Fuel Cost ($Million)
Alternative 1		
Four Corners 4,5	[redacted]	[redacted]
Other	[redacted]	[redacted]
Alternative 1 Total	[redacted]	[redacted]
Alternative 2		
Four Corners 4,5	[redacted]	[redacted]
Other	[redacted]	[redacted]
Alternative 2 Total	[redacted]	[redacted]
Fuel Cost Difference	[redacted]	[redacted]
Implied impact on NPV Associated with Change in Fuel Price Outlook:		***($498)***

Q. DO YOU BELIEVE THAT THE COMPANY'S REVISIONS TO ITS FUEL PRICE FORECASTS WERE REASONABLE?

A. Only partly. I expect that the company's coal price outlook is accurate, at least for the duration of the current contract, as it is based on the renegotiated contract with the Navajo Nation for coal from the Navajo mine. However, I find the gas price forecasts, shown in Figure 2, to be more dubious. APS has incorporated the fact that natural gas is much less costly and more abundant today than had been expected prior to 2010, and in the early years of the company's forecast this is reflected in a reduction in the forecasted prices by about 25% relative to the 2010 forecast. However, this difference diminishes rapidly, until in 2025 there is no difference between the two forecasts – and very little difference thereafter (Figure 3). This is hard to reconcile with the general industry expectation of the long-term impact of new gas extraction

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techniques, and it is hard to imagine (nor has the company explained) what the underlying rationale might be.

[redacted]

Figure 3. Percent change in projected gas price from 2010 forecast to forecast used in the present Docket, by year.

Q. WHAT IS YOUR OVERALL CONCLUSION REGARDING APS'S REVISIONS TO ITS FUEL PRICE FORECASTS, AS APPLIED TO THIS DOCKET?

A. My conclusion in this area is that the combination of two changes in fuel price outlook, that is, higher-cost coal and lower-cost gas relative to that anticipated in 2010, substantially reduces the value of the Four Corners acquisition for APS ratepayers. In itself, this change may well have been enough to eliminate any such benefit, even using APS's anomalous revised forecasts which (as noted above) revert to the outdated 2010 forecasts after

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only a few years. Had the forecasts not exhibited this anomalous reversion, the effect would have been much greater—and would have substantially reduced, or more likely eliminated, the projected benefit of the acquisition for ratepayers.

Change in APS's Treatment of Future CO_2 Emissions Costs

Q. WHAT IS THE SIGNIFICANCE OF APS'S PROJECTIONS OF CO_2 EMISSIONS COSTS AS IT APPLIES TO THE FOUR CORNERS ACQUISITION, AND TO THIS DOCKET?

A. CO_2 costs are a fundamental driver of the economics of resource options in the electric sector, and APS has acknowledged this fact and has included these costs in all of the analyses considered here. However, the company has lacked clarity and detail in justifying its cost projections, and has made significant and impactful changes in its approach with no explanation that I have been able to discover. It is true that these costs are shrouded in regulatory uncertainty as to their magnitude, form, and jurisdictional source. This is all the more reason APS and other utilities and resource planners should shine the full light of day on their approach, so that their assumptions and conclusions can be fully understood and evaluated.

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Q. HAVE YOU REVIEWED THE CARBON EMISSIONS PRICE FORECASTS USED BY APS IN DOCKET NO. E-01345A-10-0474 (2010) AND IN THE CURRENT DOCKET?

A. Yes. Assumed carbon emissions prices for the current filing were provided in response to Commission Staff Data Request 35.35 (Exhibit EDH-5), and for the 2010 docket in response to Sierra Club Data Request 2.4(b) (Exhibit EDH-4).

Q. HAS APS PROVIDED A SOURCE FOR ITS CARBON EMISSIONS COST PROJECTIONS?

A. The company has provided very little explanation for its emissions price forecasts, particularly in the present docket. However, APS did provide a study performed for the company by Charles River Associates as Appendix A to its 2012 Integrated Resource Plan.[17] This study, which I have attached as Exhibit EDH-6, recommends for the base case "...using $12 (2011$) per metric tonne $CO_{2\,Eq}$ beginning in 2018-2020 and rising at 5% above inflation." (2012 IRP Appendix A, p. A-11) For the high case, CRA argues that "it makes sense to evaluate a higher carbon price trajectory, for example $20 (2011$) per metric tonne of $CO_{2\,Eq.}$ beginning in 2018-2020 and rising at 5% above inflation." They go on to note that they "do not believe that this is the

[17] Charles River Associates, Arizona Public Service Greenhouse Gas Legislative Review and CO_2 Price Outlook." (Exhibit EDH-6) Dated November 4, 2011.

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highest carbon price trajectory that is politically feasible, but it represents an upper bound to reflect probable policy over the next decade."

The price trajectories provided by APS in response to Sierra Club data requests, along with my interpretation of those recommended by CRA, are shown in Figure 4.

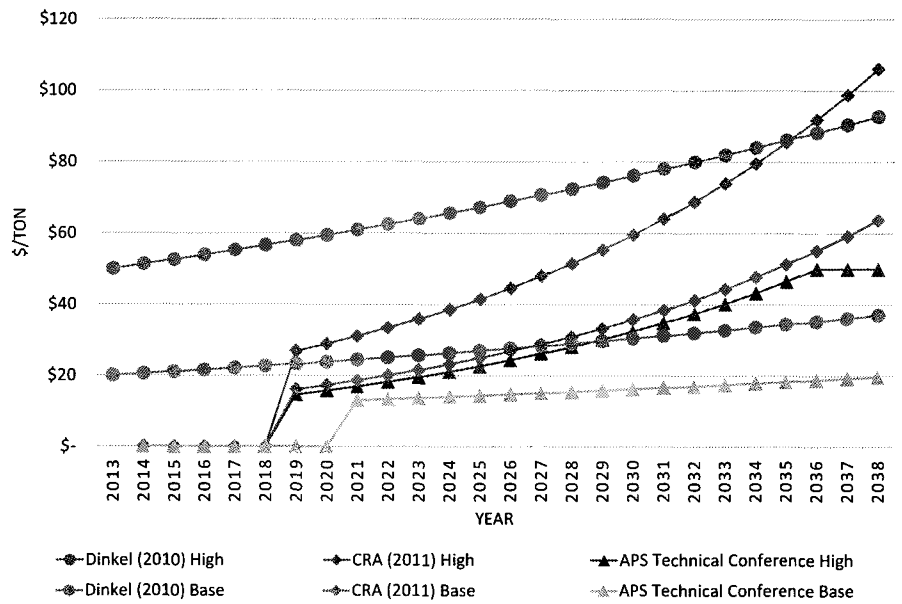

Figure 4. Comparison of all base and high case CO_2 emissions price trajectories used by APS and recommended by CRA, 2011-2014 (nominal dollars).

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Q. HOW DO THE CO_2 PRICE FORECASTS USED IN THE CURRENT DOCKET COMPARE TO THOSE RECOMMENDED BY CRA IN 2011?

A. APS diverged quite dramatically from the recommendations of its consultant. First, it appears that APS made a simple unit conversion error – by taking CRA's prices, which are denominated in dollars per metric tonne, and applying them as if they were dollars per short ton. This in itself renders the effective prices about 10% below what CRA intended.

Second, APS appears to have taken CRA's "Base Case", improperly applied as dollars per short ton, and used it as a "High Case." APS's "Base Case" is substantially lower, and the company has provided no explanation for this case. APS has not considered CRA's recommended "High Case" in the current docket.

Q. HOW DO THE CO_2 PRICE FORECASTS USED IN THE CURRENT DOCKET COMPARE TO THOSE USED BY THE COMPANY IN SUPPORT OF ITS 2010 FILING?

A. As seen in Figure 4, the forecasts used in the current case are far below those used by APS witness Patrick Dinkel in the 2010 docket. It appears that the company's current "High Case" is similar to Mr. Dinkel's "Base Case," but Mr. Dinkel's "High Case" has been dropped from consideration.

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Q. HOW DO THE CARBON PRICE FORECASTS USED BY APS IN THE CURRENT PROCEEDING COMPARE TO THOSE RECOMMENDED BY CRA, AND TO OTHER CO_2 EMISSIONS PRICES USED BY THE COMPANY, ON A LEVELIZED BASIS?

A. Levelized prices are a useful single-number metric because they allow for apples-to-apples comparison amongst different trajectories that start in different years and grow at different rates. For the current case, I determined equivalent levelized prices for each trajectory by first applying the "NPV" function in Excel with a 7.2% discount rate to each trajectory over the period 2019-2038. I then used the "PMT" function in Excel to find an equivalent stream of constant annual payments from ~~2012~~ 2019-2038 that would yield the same NPV – or the equivalent levelized price over this time period. Table 3 compares the levelized prices for each of the trajectories shown in Figure 4.

Table 3. Comparison of APS' CO_2 price trajectories on a levelized basis

Source	Levelized CO_2 Price 2019-2038
Base Case	
Current Docket	**$12.73**
Dinkel (2010)	$28.01
CRA 2011	$29.60
High Case	
Current Docket	**$26.58**
Dinkel (2010) High	$70.02
CRA 2011 High	$49.34

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As seen in Table 3, the "Base Case" price used by APS in its technical conference presentation, and used to support the current application, is well below the other price trajectories shown on a levelized basis. It is less than half of either the Base Case price used by Mr. Dinkel in 2010, or the Base Case price recommended by APS's consultant CRA. In fact, even APS's technical conference "High Case" price is below either the CRA or the Dinkel "Base Case" prices, on a levelized basis.

Q. BASED ON THE FOREGOING, DO YOU BELIEVE THAT THE COMPANY'S REVISIONS TO ITS CARBON EMISSIONS PRICE FORECASTS WERE REASONABLE?

A. No. I conclude that the company erred in choosing both base and high case trajectories that are too low, and that ignore the guidance of its own consultants in this area. The company's emissions prices used to support its "fair value" petition for Four Corners are below both the 2012 and 2014 IRP trajectories; it is hard to reconcile this observation with any realistic or credible change in APS's market outlook during this period.

Q. WHAT IS THE IMPACT OF THIS APPROACH ON THE COMPANY'S ANALYSIS?

A. The impact is quite significant. In response to Sierra Club data request No. 2.4(a) (Exhibit EDH-4), APS provided its projected total CO_2 emissions costs under each of the scenarios considered and presented at the February 2014

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Technical Conference. The CO_2 emissions costs alone have an NPV of $1.75 Billion (2010-2039) for the Four Corners acquisition plan, and $1.19 Billion for the alternative plan—an additional NPV cost of $560 Million for the acquisition case relative to the alternative. This suggests that if the Base Case emissions prices were twice as high (which would still be lower than either the CRA Base Case or the Dinkel Base Case emissions prices) there would have been an *additional* $560 Million NPV penalty for the acquisition case—well exceeding the $426 Million net benefit to ratepayers claimed by the company.

As with the fuel costs, my quantitative estimate of the impact assumes no change in dispatch – but again as with fuel costs, it strongly suggests that the impact is important, and that were the company more thorough and forthcoming in its analysis, it would be presenting a very different picture of the relative benefits of the acquisition.

Q. WHAT IS YOUR OVERALL CONCLUSION REGARDING APS'S REVISIONS TO ITS CO_2 EMISSIONS COST FORECASTS, AS APPLIED TO THIS DOCKET?

A. I conclude that a very significant and unexplained change was made in the company's stated carbon emissions price outlook – a change that is inconsistent not only with the company's earlier practice, but with its consultant's recommendations. This change has enough of an impact on the

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company's NPV analysis to reverse the result – that is, without this change the company would find that the alternative plan, relying on new natural gas plants, would be less costly on an NPV basis than the Four Corners acquisition.

The Commission should require a much more complete, detailed, and rigorous explanation of the company's change in its carbon price forecast prior to ruling on the current petition; further, the company should be required to re-run its analysis using the CO_2 emissions prices recommended by its consultant CRA. If ratepayer benefits cannot be shown using realistic and fully justified CO_2 emissions prices, the petition should be denied.

<u>Change in Projected Capital Expenditures for Units 4 and 5</u>

Q. HAVE YOU REVIEWED APS'S PROJECTED CAPITAL EXPENDITURES ON ITS GENERATING UNITS, INCLUDING FOUR CORNERS, AS APPLIED IN DOCKET E-01345A-10-0474 AND IN THE CURRENT DOCKET?

A. Yes. APS provided projected annual capital expenditures as applied for the current filing in response to Sierra Club Data Request 2.4(a), and for the 2010 docket in response to Sierra Club Data Request 2.4(d), both of which are included in Exhibit EDH-4. The capital costs were provided for the following categories: APS's share of Four Corners 4 and 5, Future CCs/CTs,

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and "Other Existing."[18] The company has alleged that much of this information is confidential.

Q. HOW DID APS'S PROJECTIONS OF CAPITAL EXPENDITURES CHANGE BETWEEN ITS FILING IN 2010 AND THE CURRENT DOCKET?

A. There were quite a number of changes, and they are difficult to reconcile given the limited information or explanation the company has provided. CONFIDENTIAL Table 4 summarizes the changes in projected capital expenditures by resource category, on an NPV basis,[19] between the 2010 filing and the current docket. Values are shown for both the "Base Case," which represents the acquisition of SCE's share of Four Corners, and the "Gas Alternative," in which Four Corners is shut down in 2016 and APS's resource needs are met by building new gas plants.[20]

In the "Gas Alternative" case, the company's projection of capital costs for APS's share of Four Corners until shutdown increased by [redacted] relative to its

[18] The current data also break out Four Corners Units 1-3, but these expenditures are small and disappear entirely by 2016. For purposes of the discussion here these are included in "Other Existing."
[19] The values in CONFIDENTIAL Table 4 represent Net Present Value for the years 2014-2039, using a discount rate of 7.2%. The underlying data are deemed confidential by the company.
[20] The cases shown were defined and analyzed by APS, and were included in the filing and discovery materials provided by the company. I do not know the details of the two alternative resource plans, nor can I be completely confident that the alternatives considered in the two cases were identical.

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2010 projection. Conversely, the projected capital expenditures associated with the same plant in the Base Case *decreased* by almost [redacted]. This combination of a projected Four Corners capital cost decrease in the Base Case and a projected increase in the Gas Alternative case accounts for $185 Million of the NPV difference between the cases – about 43% of the entire claimed benefit for the Base Case over the alternative.

The decrease in the projected capital cost relative to the 2010 filing has another perplexing aspect: Between 2010 and 2014, the company's expectation for capital costs for all of its existing resources—except Four Corners Units 4 and 5 – *increased* by [redacted]. If the company had expected the capital expenditures associated with Four Corners to increase by [redacted] along with the rest of the fleet, the NPV benefit of the Base Case would be reduced by $473 Million – more than eliminating the entire claimed benefit. The company should be required to explain why it believes Four Corners costs will remain low while other resources in its portfolio have become more expensive to maintain.

The source of the reduction in NPV capital costs for the Four Corners units is also intriguing. CONFIDENTIAL Figure 5 shows the annual capital expenditures as projected by APS in support of each filing. The undiscounted sum of the capital expenditures projected in 2014, shown in the final set of rows in CONFIDENTIAL Table 4, is actually about [redacted] greater

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than the undiscounted sum of those projected in 2010; however, by projecting a delay in these expenditures of several years, APS has realized a decrease in the calculated NPV through the mechanics of discounting.

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CONFIDENTIAL Table 4: Changes in projected capital expenditures from APS's filing in Docket No. E-01345A-10-0474 to the current case, by resource category and case. Values are in $Million NPV for the years 2014-2039, using a discount rate of 7.2%

		Base Case	Gas Alternative
Four Corners 4-5	2010	[redacted]	[redacted]
	2014	[redacted]	[redacted]
	Change ($M)	[redacted]	[redacted]
	Change (%)	[redacted]	[redacted]
Other Existing	2010	[redacted]	[redacted]
	2014	[redacted]	[redacted]
	Change ($M)	[redacted]	[redacted]
	Change (%)	[redacted]	[redacted]
Future CCs/CTs	2010	[redacted]	[redacted]
	2014	[redacted]	[redacted]
	Change ($M)	[redacted]	[redacted]
	Change (%)	[redacted]	[redacted]
Four Corners 4-5 (Un-discounted)	2010	[redacted]	[redacted]
	2014	[redacted]	[redacted]
	Change ($M)	[redacted]	[redacted]
	Change (%)	[redacted]	[redacted]

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[redacted]

CONFIDENTIAL Figure 5. Annual capital expenditures for the Four Corners plant as projected by APS in 2010 (blue) and the current docket (Orange)

Q. WHAT IS YOUR OVERALL CONCLUSION REGARDING APS'S TREATMENT OF FUTURE CAPITAL COSTS IN THIS CASE?

A. I find that there were numerous anomalous and unexplained changes to the capital cost projections between the 2010 filing and the current docket, all of which tend to favor the acquisition of Four Corners over the gas alternative. The aggregate impact of these changes, on an NPV basis, exceeds the NPV benefit the company has shown for its preferred plan.

The Commission should require a much more complete explanation of the company's changes in its capital cost projections prior to ruling on the

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current petition; if these changes are not fully justified, the petition should be denied.

Other Assumptions and Considerations

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING APS'S ASSUMPTIONS AND ECONOMIC ANALYSIS IN THIS CASE?

A. Yes. In particular, I would like to reiterate a concern raised by Sierra Club witness David Schlissel in Docket No. E-01345A-10-0474 before this Commission. Specifically, I note that APS's analysis is still fully dependent on the assumption that the Four Corners units will continue to operate, and to operate at a high capacity factor, through 2039, when the units will be 70 years old.

Q. DO YOU HAVE REASON TO BELIEVE THAT THE UNITS WILL CEASE OPERATING, OR WILL OPERATE AT A LOWER LEVEL, PRIOR TO 2039?

A. I do not know how the units will operate into their seventh decade of service, and neither does APS. It is certainly reasonable to assume that, like all capital equipment, they will require increasing infusions of capital as they age if they are to continue running at such a high level—but APS has actually assumed that capital costs will be close to constant in nominal dollars, meaning that they would decrease precipitously in real terms. (CONFIDENTIAL Figure 5). In fact, as the units age and if these costs

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increase, APS and the other co-owners may well decide to retire one or both units early, or to allow them to run at a much lower level, rather than to continue investing in aging infrastructure. Thus I believe it is an extremely optimistic assumption that they will continue to run at high capacity factors throughout this period.

Further, the risks and costs associated with burning fossils fuels and continuing to emit large quantities of greenhouse gases into the atmosphere are becoming clearer seemingly every day. As I write this testimony, the Intergovernmental Panel on Climate Change is completing its fifth Assessment Report on global climate change,[21] and the results are alarming. The draft report leaves no doubt that climate change is occurring, and that human activity—specifically the continued release of greenhouse gases into the atmosphere—is the major cause.

On May 6 of this year, the Obama Administration released the Third US National Climate Assessment.[22] Among the conclusions of that report are that climate change is already causing costly and disruptive impacts in the United States and elsewhere on air quality, infrastructure, water supply,

[21] http://www.ipcc.ch/report/ar5/index.shtml

[22] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: Highlights of Climate Change Impacts in the United States: The Third National Climate Assessment. U.S. Global Change Research Program, 148 pp.

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agriculture, the way of life of indigenous people, ecosystems, marine life, and human health. These impacts are only expected to become more severe and costly in the years and decades to come.

Finally, on June 2, 2014 the US EPA released its plans for regulating carbon emissions from existing power plants, calling for a reduction of 30% from 2005 levels by 2030. While the implementation details and the impact of this rule are still being worked out, one thing is clear: there are going to be large and increasing costs associated with continuing to run resources, such as Four Corners Units 4 and 5, that emit large amounts of CO_2 into the atmosphere.

While APS has made its first steps towards incorporating risk of climate legislation and emissions costs into account by including a modest cost for CO_2 emissions, the company should recognize that if the United States is to seriously address this critical risk to our economy and the climate of the planet, it will likely become uneconomic to run coal plants at a high level, or perhaps at all, in the coming decades. Prior to asking this Commission to approve ratepayer funding for acquiring additional coal-burning infrastructure today, the company should at least identify what the implications would be for their analysis if the plant were unable or uneconomic to operate and to continue producing greenhouse gas emissions at some point prior to the end of its projected lifetime.

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Q. WHAT WOULD BE THE IMPACT ON THE COMPANY'S ANALYSIS IF IT RAN A SENSITIVITY CASE WITH AN EARLIER SHUTDOWN DATE?

A. It is difficult to know what the financial impact would be without producing a full resource plan assuming an earlier shutdown date—something that would be straightforward for APS to do but unduly burdensome for an outside expert without full access to APS's planning models. As presented by APS, and with all of the input assumption issues described herein, the Four Corners option overtakes the gas alternative option on an NPV basis by around 2022.

Of course, this should not be taken to imply that the Four Corners Acquisition plan is preferable as long as operations continue through that period, even given all of the questionable assumptions described above. In the event Four Corners were to curtail operations or shut down early, APS would still have to find or build alternative resources, such as those identified in the gas alternative case, much earlier than anticipated in the Base Case plan.

Q. HAS APS PERFORMED SUCH AN ANALYSIS?

A. Not that I am aware of. Indeed, Sierra Club asked for any such analysis in Sierra Club interrogatory 3.1, and was informed that "In conjunction with the

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acquisition of SCE's share of Four Corners 4 and 5, APS did not evaluate having an earlier shutdown of Four Corners 4 and 5."[23]

Q. ARE THERE ANY OTHER RISKS THAT THE COMPANY HAS FAILED TO CONSIDER IN ITS NPV ANALYSIS PRESENTED TO THIS COMMISSION?

A. Yes. For example, there is a significant risk that other environmental remediation costs, such as the cost of installing SCRs to comply with the Regional Haze Rule, will be significantly higher than the company has estimated. While I am not a pollution control engineer and I cannot speak to the specific issues related to the Four Corners units, my understanding is that each such installation is highly site-specific, and that it is not uncommon for installation costs to far exceed initial estimates. APS should address this risk in its analysis, making a good-faith estimate of the upper bound on the cost of such an installation, and analyze and report the impacts of such a case on the economics of the resources. A good way to ensure a realistic, good-faith upper bound estimate is for the company to stipulate that it will not seek to recover costs in excess of that amount from ratepayers.

Similarly, there is a risk that the ultimate decommissioning and remediation costs will be higher than the company estimates. This is particularly germane

[23] APS response to Sierra Club data request 3.1.

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as the company is taking on a much larger share of this risk through the acquisition of SCE's share of the Four Corners units. Similar to the environmental retrofit risk, I recommend that the company be directed to analyze and report the impact of such a scenario on project economics, again basing the analysis on a cost higher than which it will guarantee not to seek recovery from ratepayers.

Of course, I do not know precisely what these costs will be any better than the company does, but given the dubious, possibly biased, and poorly-documented nature of other assumptions underlying the company's NPV analysis, it is certainly possible that APS has underestimated and/or understated the risks of higher costs. Even if the Commission is prepared to award APS its requested rate increase based on the analysis presented by the company, the company should not be given a blank check to cover future costs that should have been anticipated and given full consideration in this docket.

IV. Overall Recommendations and Conclusions

Q. WHAT ARE YOUR RECOMMENDATIONS FOR THE COMMISSION IN THIS CASE?

A. First, I recommend that the Commission deny APS's petition at this time, and direct the company to re-file its request with a revised analysis that is more

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detailed, and that provides a full explanation and justification for the numerous changes in the company's assumptions and projections since the 2010 filing. It may be that the sum total of these many changes do indeed cancel out, and that the surprising similarity between the currently-projected $426 Million Net Present Value benefit and the $488 Million NPV benefit projected in 2010 is merely a coincidence. However, there are far too many anomalous and unexplained features of the company's numbers to accept this conclusion without far more explanation.

In particular, I recommend that the Commission ask for fully detailed explanations of the following:

- **Gas price forecasts.** Why is it that the company's gas price forecasts revert to almost the same values as the 2010 forecasts between 2018 and 2024? Has APS fully incorporated the changed natural gas market fundamentals in this assumption?
- **Greenhouse gas emissions costs.** Can the company explain how it derived its revised greenhouse gas emissions costs, why it elected to use the "Base Case" recommended by its consultant as "High Case", and how its "Base Case" was derived? Assuming APS did rely at least in part on CRA's recommendations, the company should also correct its error in units identified above, if my interpretation is correct.
- **Capital expenditures.** Can the company explain why it changed its projected stream of capital expenditures for Four Corners since the 2010 filing as described above, why the expected capital expenditures decreased in the Base Case while increasing dramatically in the Alternative Case, and why the projected expenditures for Four Corners remained almost constant (in nominal dollars) while they increased markedly for all other resources?

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- **Long-term unit operations.** Has the company considered a case where the plant does *not* operate at a high capacity factor through the end of 2039? If so, what are the implications of such an early shut-down (or curtailed operations) for the economics of the acquisition? If not, does the company intend to hold ratepayers harmless if this assumption turns out to be unrealistically optimistic for the readily foreseeable reasons unidentified here?
- **Other costs.** Has APS considered a case in which other costs, such as environmental retrofit, remediation, and decommissioning costs, are higher than the company has projected in its base case analysis?

Without much more detailed explanation and justification of the company's assumptions and analytical decisions in each of these areas, I do not believe that the Commission can reasonably accept APS's NPV analysis as valid or robust, nor can it approve the company's request in this docket.

Second, I recommend that the Commission put APS on notice that there is no guarantee of recovery of future capital investments in the Four Corners plant. The Commission waived the self-build moratorium in Order No. 73130—but it did not relieve the company of the burden of making and justifying prudent decisions. Had APS performed its revised analysis with the CO_2 price trajectories recommended by its own consultant, or made numerous other reasonable changes to its underlying assumptions described here, it would have found no or even negative benefit from the Four Corners acquisition on an NPV basis; if it turns out that other assumptions were also unrealistically biased in favor of the acquisition, the company should be held accountable. Such assumptions could include the future operations and longevity of the

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plant; the extent and cost of required environmental upgrades, and decommissioning and remediation costs.

Similarly, while the company has not at this time requested ratemaking treatment for the acquisition of El Paso Electric's 7% share of Four Corners Units 4 and 5, I recommend that the Commission put the company on notice that a fully updated analysis will be required before ratepayers are shouldered with this additional risk and cost. Continued investment in Four Corners on behalf of APS's ratepayers risks becoming a game of throwing good money after bad, as each "investment" becomes a sunk cost that justifies the next. It was APS's analysis and decisions that started this process, however, and the company, not its ratepayers, should bear the risk of any imprudence or sub-par analysis in the process.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit EDH-1

Resume of Ezra D. Hausman, PH.D.

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ezra@ezrahausman.com

SUMMARY

I am an independent consultant in energy and environmental economics.

I have worked for over 15 years as an electricity market expert with a focus on market design and market restructuring, environmental regulation in electricity markets, and pricing of energy, capacity, transmission, losses and other electricity-related services. I have performed market analysis, offered expert testimony, led workshops and working groups, made presentations and participated on panels, and provided other support to clients in a number of areas, including:

- Economic analysis, price forcasting, and asset valuation in electricity markets, including dispatch model analysis and review of modeling studies
- Electricity and generating capacity market design
- Integrated Resource Planning and portfolio analysis
- Economic analysis of environmental and other regulations, including cap-and-trade regulation of CO_2, in electricity markets
- Quantification of the economic and environmental benefits of displaced emmissions associated with energy efficiency and renewable energy initiatives
- Mitigation of greenhouse gas emissions from the supply and demand sides of the U.S. electric sector.

I have prepared reports and offered other expert services on these and other related topics for clients including federal and state agencies; offices of consumer advocate; legislative bodies; cities and towns; non-governmental organizations; foundations; industry associations; and resource developers.

I previously served as Vice President and Chief Operating Officer of Synapse Energy Economics, Inc. of Cambridge, Massachusetts. In addition to my consulting portfolio, this management role entailed responsibility for day-to-day operations of the company including overseeing finance, HR, communications & marketing, quality assurance, client service, and professional development of staff. I had overall responsibility for ensuring that project managers and project teams had the tools, information, and training they needed to successfully serve our client's needs and produce high-quality deliverables on time and on budget. I was also a resource available to any of our clients to address any issues of customer service, quality, or any other issues that may arise.

I hold a Ph.D. in atmospheric science from Harvard University, an S.M. in applied physics from Harvard University, an M.S. in water resource engineering from Tufts University, and a B.A.degree in psychology from Wesleyan University.

PROFESSIONAL EXPERIENCE

Ezra Hausman Consulting, Newton, MA. President, March 2014 – Present.
I provide research, analytical, and regulatory and litigation support services based upon my 15+ years experience in the electric power industry.

Synapse Energy Economics Inc., Cambridge, MA.
Chief Operating Officer, March 2011 – February 2014;
Vice President, July 2009 – February 2014;
Senior Associate, 2005-2009.
Conducted research, wrote reports, and presented expert testimony pertaining to consumer, environmental, and public policy implications of electricity industry regulation. Focus of work included:

- Economic analysis of electricity industry regulation and restructuring
- Efficient pricing of generating and transmission capacity
- Long-term electric power system planning and market design
- Price forecasting and asset valuation
- Impact of air quality and environmental regulations on electricity markets and pricing
- Energy efficiency and renewable energy programs and policies, including avoided emissions analysis
- Market power and market concentration analysis in electricity markets
- Consumer and environmental protection
- Regulation and mitigation of greenhouse gas emissions.

Charles River Associates (CRA), Cambridge, MA. Senior Associate, 2004-2005
CRA acquired Tabors Caramanis & Associates in October, 2004.

Tabors Caramanis & Associates, Cambridge, MA. Senior Associate, 1998-2004
Modeling and analysis of electricity markets, generation and transmission systems. Projects included:

- Several market transition cost-benefit studies for development of Locational Marginal Price (LMP) based markets in US electricity markets
- Long-term market forecasting studies for valuation of generation and transmission assets,
- Valuation of financial instruments relating to transmission system congestion and losses
- Modeling and analysis of hydrologically and electrically interconnected hydropower system operations
- Natural gas market analysis and price forecasting studies
- Co-developed an innovative approach to hedging financial risk associated with transmission system losses of electricity

- Designed, developed and ran training seminars using a computer-based electricity market simulation game, to help familiarize market participants and students in the operation of LMP-based electricity markets.
- Developed and implemented analytical tools for assessment of market concentration in interconnected electricity markets, based on the "delivered price test" for assessing market accessibility in such a network
- Performed regional market power and market power mitigation studies
- Performed transmission feasibility studies for proposed new generation and transmission projects in various locations in the US
- Provided analytical support for expert testimony in a variety of regulatory and litigation proceedings, including breach of contract, bankruptcy, and antitrust cases, among others.

Global Risk Prediction Network, Inc., Greenland, NH. Vice President, 1997-1998
Developed private sector applications of climate forecast science in partnership with researchers at Columbia University. Specific projects included a statistical assessment of grain yield predictability in several crop regions around the world based on global climate indicators (Principal Investigator); a statistical assessment of road salt demand predictability in the United States based on global climate indicators (Principal Investigator); a preliminary design of a climate and climate forecast information website tailored to the interests of the business community; and the development of client base.

Hub Data, Inc., Cambridge, MA. Financial Software Consultant, 1986-1987, 1993-1997
Responsible for design, implementation and support of analytic and communications modules for bond portfolio management software; and developed software tools such as dynamic data compression technique to facilitate product delivery, Windows interface for securities data products.

Abt Associates, Inc., Cambridge, MA. Environmental Policy Analyst, 1990-1991
Quantitative risk analysis to support federal environmental policy-making. Specific areas of research included risk assessment for federal regulations concerning sewage sludge disposal and pesticide use; statistical alternatives to Most-Exposed-Individual risk assessment paradigm; and research on non-point sources of water pollution.

Massachusetts Water Resources Authority, Charlestown, MA. Analyst, 1988-1990
Applied and evaluated demand forecasting techniques for the Eastern Massachusetts service area. Assessed applicability of various techniques to the system and to regional planning needs; and assessed yield/reliability relationship for the eastern Massachusetts water supply system, based on Monte-Carlo analysis of historical hydrology.

Somerville High School, Somerville, MA. Math Teacher, 1986-1987
Courses included trigonometry, computer programming, and basic math courses.

EDUCATION

Ph.D., Earth and Planetary Sciences. Harvard University, Cambridge, MA, 1997

S.M., Applied Physics. Harvard University, Cambridge, MA, 1993

M.S., Civil Engineering. Tufts University, Medford, MA, 1990

B.A., Wesleyan University, Psychology. Middletown, CT, 1985

FELLOWSHIPS, AWARDS AND AFFILIATIONS

President, Burr Elementary School Parent Teacher Organization, 2005-2007

UCAR Visiting Scientist Postdoctoral Fellowship, 1997

Postdoctoral Research Fellowship, Harvard University, 1997

Certificate of Distinction in Teaching, Harvard University, 1997

Graduate Research Fellowship, Harvard University, 1991-1997

Invited Participant, UCAR Global Change Institute, 1993

House Tutor, Leverett House, Harvard University, 1991-1993

Graduate Research Fellowship, Massachusetts Water Resources Authority, 1989-1990

Teaching Fellowships:

> **Harvard University:** *Principles of Measurement and Modeling in Atmospheric Chemistry; Hydrology; Introduction to Environmental Science and Public Policy; The Atmosphere.*
>
> **Wesleyan University:** *Introduction to Computer Programming; Psychological Statistics; Playwriting and Production.*

Professional affiliations

> *Member, American Association for the Advancement of Science*
>
> *Member, American Economic Association*

EXPERT TESTIMONY AND SERVICES

United States District Court for the Eastern District of Missouri (Civil Action No. 4:11-CV-00077) – Ongoing
Expert witness on behalf of the United States Department of Justice on clean air act enforcement case.

Arizona Corporation Commission (Docket No. E-01345A-11-0224) – Ongoing
Expert witness on behalf of the Sierra Club regarding Arizona Public Service petition for rate treatment for acquisition of an additional ownership share of the Four Corners generating units.

Missouri Public Service Comission (Docket No. ET-2014-0085) – 2013
Testimony on behalf of the Missouri Solar Energy Industries Association regarding Union Electric (d/b/a Ameren Missouri) motion to suspend payment of solar rebates.

Missouri Public Service Comission (Docket No. ET-2014-0059 and ET-2014-0071) – 2013
Testimony on behalf of the Missouri Solar Energy Industries Association regarding Kansas City Power and Light Company's motions to suspend payment of solar rebates.

Puget Sound Energy (PSE) – 2012-2013
Expert participant in PSE's 2013 IRP stakeholder process on behalf of the Sierra Club.

Washington Utilities and Transportation Commission (Docket Nos. UE-111048 and UG-111049) – 2011
Testimony on behalf of the Sierra Club regarding the cost of operating the Colstrip power plant and other power procurement issues.

Kansas Corporation Commission (Docket No. 11-KCPE-581-PRE) - 2011
Presented written and live testimony on behalf of the Sierra Club regarding Kansas City Power and Light request for predetermination of ratemaking principles.

Vermont Department of Public Service - 2011
Provided scenario analysis of the costs and benefits of various electric energy resource scenarios in support of the state Comprehensive Energy Plan.

Massachusetts Department of Energy Resources – 2009-2011
Served as expert analyst and modeling coordinator for analysis related to implementation of the Massachusetts Global Warming Solutions Act.

Iowa Office of Consumer Advocate – 2010-Present
Assisted Consumer Advocate in evaluating a proposed power purchase agreement for the output of the Duane Arnold nuclear power station.

Missouri Public Service Commission (Docket No. EW-2010-0187) – 2010
Expert participant on behalf of the Sierra Club in stakeholder process to develop a "demand side investment mechanism" in Missouri.

Louisiana Public Service Commission (Docket No. R-28271 Subdocket B) – 2009-2010
Expert participant on behalf of the Sierra Club in Renewable Portfolio Standard Task Force considering RPS for Louisiana.

Joint Fiscal Committee of the Vermont Legislature – 2008-2010
Serving as lead expert advising the Legislature on economic issues related to the possible recertification of the Vermont Yankee nuclear power plant.

Town of Littleton, NH – 2006-2010
Serving as expert witness on the value of the Moore hydroelectric facility.

Nevada Public Service Commission (Docket No. 08-05014) – August 2008
Presented prefiled and live testimony on behalf of Nevadans for Clean Affordable Reliable Energy regarding the proposed Ely Energy Center and resource planning practices in Nevada.

Mississippi Public Service Commission (Docket No. 2008-AD-158) – August 2008
Presented written and live testimony on behalf of the Sierra Club regarding the resource plans filed by Entergy Mississippi and Mississippi Power Company.

Kansas House of Representatives - Committee on Energy and Utilities – February 2008
Presented testimony on behalf of the Climate and Energy Project of the Land Institute of Kansas on a proposed bill regarding permitting of power plants. Focus was on the risks and costs associated with new coal plants and on their contribute to global climate change.

Vermont Public Service Board (Docket No. 7250) – 2006-2008
Prepared report and testimony in support of the application of Deerfield Wind, LLC. For a Certificate of Public Good for a proposed wind power facility.

Iowa Utilities Board (Docket No. GCU-07-1) – October, 2007 – January 2008
Presented wrtten and live testimony on behalf of the Iowa Office of Consumer Advocate regarding the science of global climate change and the contribution of new coal plants to atmospheric CO_2.

Nevada Public Service Commission (Docket No. 07-06049) – October 2007
Presented prefiled direct testimony on behalf of Nevadans for Clean Affordable Reliable Energy regarding treatment of carbon emissions costs and coal plant capital costs in utility resource planning.

Massachusetts General Court, Joint Committee on Economic Development and Emerging Technologies – July 2007
Presented written and live testimony on climate change science and the potential benefits of a revenue-neutral carbon tax in Massachusetts.

Town of Rockingham, VT – 2006-2007
Served as expert witness on the value of the Bellows Falls hydroelectric facility.

South Dakota Public Utilities Commission (Case No EL05-22) – June 2006
Minnesota Public Utilities Commission (Docket TR-05-1275) – December 2006
Submitted prefiled and live testimony on the contribution of the proposed Big Stone II coal-fired generator to atmospheric CO_2, global climate change and the environment of South Dakota and Minnesota, respectively.

Arkansas Public Service Commission (Docket No. 06-070-U) – October 2006
Submitted prefiled direct testimony on inclusion of new wind and gas-fired generation resources in utility rate base.

Federal Energy Regulatory Commission (Docket Nos. ER055-1410-000 and EL05-148-000) – May-Sept 2006

- Participant in settlement hearings on proposed capacity market structure (the Reliability Pricing Model, or RPM) on behalf of State Consumer Advocates in Pennsylvania, Ohio and the District of Columbia

- Invited participant on technical conference panel on PJM's proposed Variable Resource Requirement (VRR) curve
- Filed Pre- and post-conference comments and affidavits with FERC
- Participated in numerous training and design conferences at PJM on RPM implementation.

Illinois Pollution Control Board (Docket No. R2006-025) – June-Aug 2006
Prefile and live testimony presented on behalf of the Illinois EPA regarding the costs and benefits of proposed mercury emissions rule for Illinois power plants.

Long Island Sound LNG Task Force – January 2006
Presentation of study on the need for and alternatives to the proposed Broadwater LNG storage and regasification facility in Long Island Sound.

Iowa Utilities Board (Docket No. SPU-05-15) – November 2005
Whether Interstate Power and Light's should be permitted to sell the Duane Arnold Energy Center nuclear facility to FPLE Duane Arnold, Inc., a subsidiary of Florida Power and Light.

PUBLICATIONS AND REPORTS

Luckow, P., E. Stanton, B. Biewald, J. Fisher, F. Ackerman, E. Hausman, *2013 Carbon Dioxide Price Forecast,* Synapse Energy Economics, November 2013.

Stanton, E., T. Comings, K. Takahashi, P. Knight, T. Vitolo, E. Hausman, *Economic Impacts of the NRDC Carbon Standard: Background Report prepared for the Natural Resources Defense Council,* Synapse Energy Economics for NRDC, June 2013

Comings T., P. Knight, E. Hausman, *Midwest Generation's Illinois Coal Plants: Too Expensive to Compete? (Report Update)* Synapse Energy Economics for Sierra Club, April 2013

Stanton E., F. Ackerman, T. Comings, P. Knight, T. Vitolo, E. Hausman, *Will LNG Exports Benefit the United States Economy?* Synapse Energy Economics for Sierra Club, January 2013

Chang M., D. White, E. Hausman, *Risks to Ratepayers: An Examination of the Proposed William States Lee III Nuclear Generation Station, and the Implications of "Early Cost Recovery" Legislation*, Synapse Energy Economics for Consumers Against Rate Hikes, December 2012

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Hausman E.D., T. Comings, K. Takahashi, R. Wilson, and W. Steinhurst, *Electricity Scenario Analysis for the Vermont Comprehensive Energy Plan 2011.* Synapse Energy Economics for Vermont Department of Public Service, September 2011.

Wittenstein M., E.D. Hausman, *Incenting the Old, Preventing the New: Flaws in Capacity Market Design, and Recommendations for Improvement.* Synapse Energy Economics for American Public Power Association, June 2011.

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Peterson P., E. Huasman, R. Fagan, and V. Sabodash, *Report to the Ohio Office of Consumer Counsel, on the value of continued participation in RTOs. Filed under Ohio PUC Case No. 09-90-EL-COI,* May 2009.

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Hausman E.D., R. Fagan, D. White, K. Takahashi and A. Napoleon, *LMP Electricity Markets: Market Operations, Market Power and Value for Consumers.* Synapse Energy Economics for the American Public Power Association's Electricity Market Reform Initiative (EMRI) symposium, "Assessing Restructured Electricity Markets" in Washington, DC, February 2007.

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Rudkevich A., E.D. Hausman, R.D. Tabors, J. Bagnal and C Kopel, *Loss Hedging Rights: A Final Piece in the LMP Puzzle.* Hawaii International Conference on System Sciences, Hawaii, January, 2005 (accepted).

Hausman E.D. and R.D. Tabors, *The Role of Demand Underscheduling in the California Energy Crisis.* Hawaii International Conference on System Sciences, Hawaii, January 2004.

Hausman E.D. and M.B. McElroy, *The reorganization of the global carbon cycle at the last glacial termination.* Global Biogeochemical Cycles, *13*(2), 371-381, 1999.

Norton F.L., E.D. Hausman and M.B. McElroy, *Hydrospheric transports, the oxygen isotope record, and tropical sea surface temperatures during the last glacial maximum.* Paleoceanography, *12,* 15-22, 1997.

Hausman E.D. and M.B. McElroy, *Variations in the oceanic carbon cycle over glacial transitions: a time-dependent box model simulation.* Presented at the spring meeting of the American Geophysical Union, San Francisco, 1996.

PRESENTATIONS AND WORKSHOPS

ELCON 2011 Fall Workshop: "Do RTOs Need a Capacity Market?" October 2011.

Harvard Electricity Policy Group: Presentation on state action to ensure reliability in the face of capacity market failure. February 2011.

NASUCA 2010 Annual Conference: "Addressing Climate Change while Protecting Consumers." November 2010.

NASUCA Consumer Protection Committee: Briefing on the Synapse report entitled, "Productive and Unproductive Costs of CO_2 Cap-and-Trade." September 2009.

NARUC 2009 Summer Meeting: Invited speaker on topic: "Productive and Unproductive Costs of CO2 Cap-and-Trade." July, 2009.

NASUCA 2008 Mid-Year Meeting: Invited speaker on the topic, "Protecting Consumers in a Warming World, Part II: Deregulated Markets." June 2008.

Center for Climate Strategies: Facilitator and expert analyst on state-level policy options for mitigating greenhouse gas emissions. Serve as facilitator/expert for the Electricity Supply (ES) and Residential, Commercial and Industrial (RCI) Policy Working Groups in the states of Colorado and South Carolina. 2007-2008.

NASUCA 2007 Mid-Year Meeting: Invited speaker on the topic, "Protecting Consumers in a Warming World" June 2007.

ASHRAE Workshop on estimating greenhouse gas emissions from buildings in the design phase: Participant expert on estimating displaced emissions associated with energy efficiency in building design. Also hired by ASHRAE to document and produce a report on the workshop. April, 2007.

Assessing Restructured Electricity Markets An American Public Power Association Symposium: Invited speaker on the history and effectiveness of Locational Marginal Pricing (LMP) in northeastern United States electricity markets, February, 2007.

ASPO-USA 2006 National Conference: Invited speaker and panelist on the future role of LNG in the U.S. natural gas market, October, 2006.

Market Design Working Group: Participant in FERC-sponsored settlement process for designing capacity market structure for PJM on behalf of coalition of state utility consumer advocates, July-August 2006.

NASUCA 2006 Mid-Year Meeting: Invited speaker on the topic, "How Can Consumer Advocates Deal with Soaring Energy Prices?" June 2006.

Soundwaters Forum, Stamford, CT: Participated in a debate on the need for proposed Broadwater LNG terminal in Long Island Sound, June 2006.

Energy Modeling Forum: Participant in coordinated academic exercise focused on modeling US and world natural gas markets, December 2004.

Massachusetts Institute of Technology (MIT): Guest lecturer in Technology and Policy Program on electricity market structure, the LMP pricing system and risk hedging with FTRs. 2002-2005.

LMP: The Ultimate Hands-On Seminar. Two-day seminar held at various sites to explore concepts of LMP pricing and congestion risk hedging, including lecture and market simulation exercises. Custom seminars held for FERC staff, ERCOT staff, and various industry groups. 2003-2004.

Learning to Live with Locational Marginal Pricing: Fundamentals and Hands-On Simulation. Day-long seminar including on-line mock electricity market and congestion rights auction, December 2002.

LMP in California. Series of seminars on the introduction of LMP in the California electricity market, including on-line market simulation exercise. 2002.

Resume updated June 2014

Exhibit EDH-2

Direct testimony of Mr. Patrick Dinkel on behalf of Arizona Public Service Corp., ACC Docket No. E-01345A-10-0474, Dated November 22, 2010.

DIRECT TESTIMONY OF PATRICK DINKEL

On Behalf of Arizona Public Service Company

Docket No. E-01345A-10-________

November 22, 2010

Table of Contents

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

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"). In that capacity, I am responsible for power marketing and trading, the integrated resource planning function, long-term generation acquisition, and the Company's Renewable Energy Program.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science degree from Marymount College and a Master of Business Administration from Northern Arizona University. I joined APS in 1986. Prior to being named Vice President of Power Marketing and Resource Planning and Acquisition, I was General Manager of Strategic Planning and Resource Acquisition, where I was also responsible for overseeing APS's long-term power procurement and renewable energy programs. Before that, I was Director of Resource Acquisitions and Renewable Energy, and have also been responsible for Corporate Planning and Business Unit Analysis and Reporting. During my career at APS, I have held various positions within APS and Pinnacle West Capital Corporation, primarily within the renewable energy, financial, and budgeting areas.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION ("COMMISSION")?

A. Yes. I testified in support of APS's requests to acquire the Sundance Assets (Docket No. E-01345A-04-0407), and, later, to include those assets in rate base (Docket No. E-01345A-05-0816). I also testified in support of APS's request for authorization to acquire the Yuma Assets (Docket No. E-01345A-06-0464), in support of the Commission's grant of a Certificate of Environmental Compatibility for Abengoa Solar (Docket No. L-00000GG-08-0407-00139 and L-00000GG-08-0408-00140), and in the recent APS rate case (Docket No. E-01345A-08-0172).

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

A. My testimony supports APS's application for authorization and other support needed to purchase Southern California Edison's ("SCE") existing ownership interest in Four Corners Power Plant ("Four Corners") Units 4 and 5 and retire Units 1-3 of that plant. Specifically, I will describe how that transaction benefits APS customers and makes good business sense from a resource planning perspective.

II. THE PROPOSED TRANSACTION BENEFITS CUSTOMERS.

Q. YOU NOTED ABOVE THAT APS'S PROPOSAL TO ACQUIRE SCE'S SHARE OF FOUR CORNERS AND RETIRE UNITS 1-3 BENEFITS CUSTOMERS. PLEASE ELABORATE.

A. Simply put, the proposed transaction is the best value for APS customers compared to every reasonable resource alternative. Let me explain. The energy APS receives from its current ownership interest in the Four Corners generating station Units 4 and 5 represents 6% of APS's energy resources. If no one acquires SCE's ownership interest in Four Corners, there is a risk that the co-owners of Units 4 and 5 will choose to retire those units. A shutdown of Units 4 and 5 results in APS losing 231 MW of a reliable and economic baseload resource now serving APS customers.

Four Corners Units 1-3 provide APS customers with 560 MW, or 4200 GWH, of baseload energy. Although Units 1-3 currently comply with all environmental regulations, they will require significant environmentally-driven capital investment over the next five years if they are to remain in service. The first expected tranche, $235 million for mercury emission controls, could come as early as 2014; the second, a potential $351 million to comply with the EPA's proposed Best Available Retrofit Technology ("BART") visibility requirements, is due as early as 2016. Units 1-3 are cost-effective for APS customers now, but that may no longer be true if a total of $586 million must be spent in five short years to keep them online. Other costs may also be required for those units to comply with future greenhouse gas regulations. In other words, there is a risk that all of Four Corners could close by 2016.

If all five units are retired, APS will lose 791 MW of low-cost base load generation that currently provides 19% of APS total generation needs. Navajo Generating Station, in which APS, SRP, and TEP each own a share, faces many of the same issues. If it closes, APS would lose yet another 315 MW of baseload capacity, posing the risk that APS could lose 1,106 MW – that is 26% of its energy – in just a few years.

Q. WHAT ALTERNATIVE RESOURCES ARE AVAILABLE TO REPLACE LOST FOUR CORNERS GENERATION?

A. Coal is a baseload resource and a fundamental component of APS's energy mix. A baseload resource is one that is designed to run 24 hours a day, seven days a week, to meet the Company's lowest around-the-clock demand. Continually called on, such a resource must be both reliable and cost-effective, or else customers will pay more for their energy. Potential replacement alternatives for any lost Four Corners generation include coal and nuclear (large, conventional "baseload" resources), geothermal and biomass/biogas (small, renewable baseload resources), and natural gas (an "intermediate" resource that is reliable although it has greater fuel cost volatility compared to others and is most cost-effective when serving peak load). Solar and wind generation, while increasingly important components of APS's energy mix, are intermittent resources that a utility cannot control and that cannot adequately substitute for one that is required night and day, 365 days each year.

Q. MORE SPECIFICALLY, ASSUMING THAT PLANT PARTICIPANTS OPT TO CLOSE UNITS 4 AND 5 IN 2016, HOW WOULD APS REPLACE THE RESULTING 231 MW CAPACITY LOSS?

A. Few of the alternative resources discussed in my prior answer are realistically available to fill the energy void left APS if Four Corners Units 4 and 5 were to shut down in 2016. Arizona does not have sufficient geothermal resources to provide such capacity, and the geothermal that is available in Southern California has many potential buyers competing for this limited resource. Any geothermal plant that might be constructed would be too small (e.g., 50 MW) to address the void left by the retirement of the coal plants. Arizona also has highly limited amounts of biogas and biomass available, and APS will continue to seek those resources irrespective of the outcome of this application. Nuclear energy takes at least ten years to develop, and requires a large upfront capital investment. Putting aside that capital outlay, a new nuclear resource would certainly not be available until several years past the 2016 need date. While energy efficiency will fill a portion of these requirements, APS is already committed to aggressively pursuing its cost effective energy efficiency programs. In any case, energy efficiency cannot be a complete solution – a point well-demonstrated in Graph 4 on page 11 of my Testimony, which compares what APS's energy mix will look like if the Company's Application is approved to what it will be if it is not.

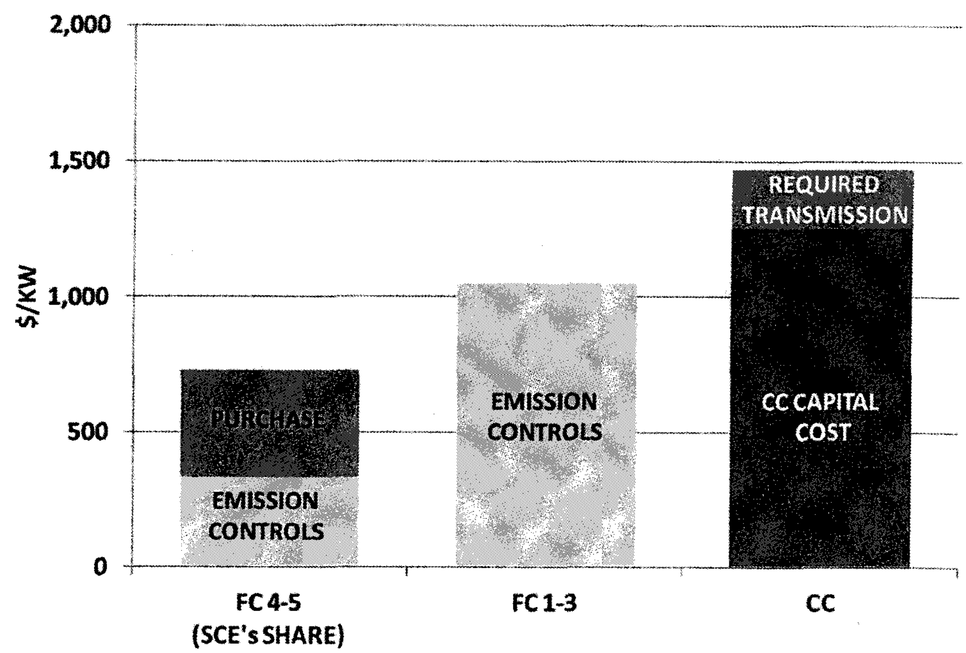
This leaves APS with three potential options: (1) continue to operate Units 1-3 (which still leaves APS 231 MW short in 2016 if Units 4 and 5 shutdown, possibly rising to 546 MW if Navajo Generating Station retires); (2) replace any power lost from Four Corners with combined-cycle gas generation; or (3) retire

Units 1-3 and acquire SCE's interest in Units 4-5. Analysis of these options clearly shows that it is most beneficial to APS customers to retire Units 1-3 early and replace their output with the purchase of SCE's interest in Units 4 and 5.

Q. OF THE OPTIONS YOU DESCRIBE, WHY IS THE TRANSACTION PROPOSED IN THE COMPANY'S APPLICATION THE MOST BENEFICIAL TO CUSTOMERS?

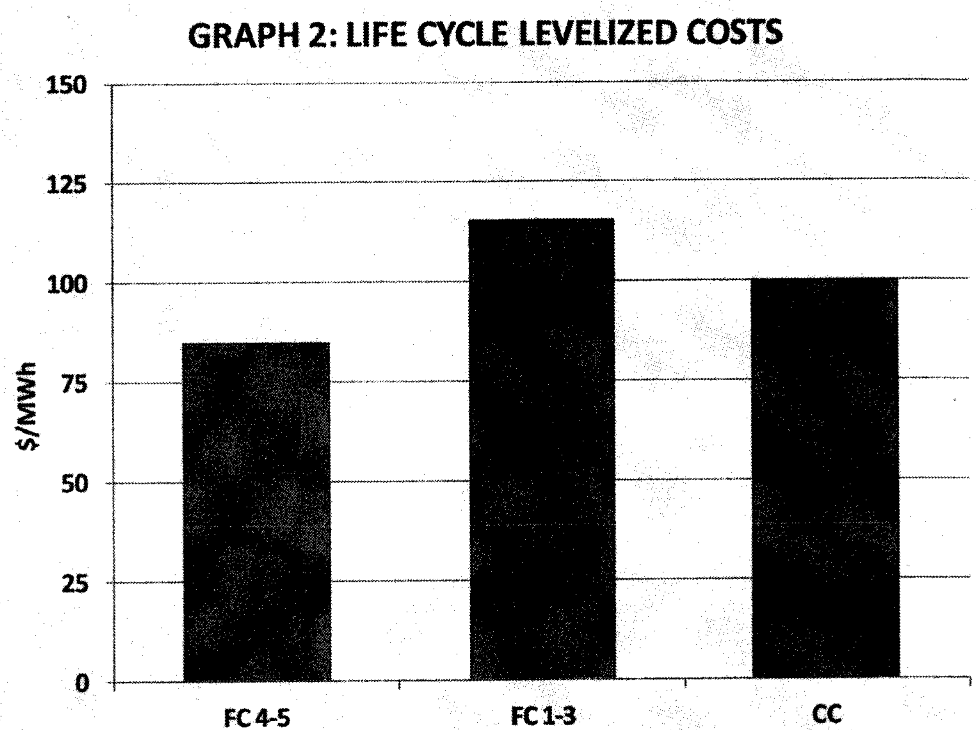
A. There are several reasons. First, from a cost perspective, customers will pay less under the proposed transaction than under either of the alternatives. This point is well demonstrated in the following two graphs, as well as through traditional revenue requirements analysis.

GRAPH 1: CAPITAL COST COMPARISON



Graph 1 compares, on a dollar per kilowatt basis, the initial capital dollars that APS would pay for various generation resources. For the Four Corners-related alternatives, the noted value includes the cost of installing all required environmental controls, a $294 million cash acquisition price, and the assumption of certain decommissioning and mine reclamation liabilities for SCE's additional

739 MW.[1] The graph shows that consummating the proposed transaction and installing potential environmental upgrades at Units 4 and 5 is the lowest cost alternative in terms of up-front cost.



Graph 2 compares, on a dollar per megawatt hour basis, the total cost of the generation resource, fully integrated into the electrical system, levelized over the full life cycle of the plant. For the Four Corners-related alternatives, the noted values include the cost of the environmental upgrades and an assumed internalized carbon price of $20/ton, beginning in 2013. The current carbon price is $0/ton; however, we believe the cost of carbon should be considered as an environmental factor in the resource decision-making process. This graph shows that the proposed transaction is the lowest cost for customers over the project life, compared to the alternatives.

[1] *See* Testimony of Mark Schiavoni at 6-7 for a description of the Purchase and Sale Agreement between APS and SCE.

Finally the cost of the alternatives can be communicated in terms of the net present value of customer revenue requirements. In comparing these three alternatives, the acquisition of SCE's share of Units 4-5 results in a revenue requirement that is $500 million less than the alternative of replacing the retired Four Corners energy with natural gas generation. The proposed transaction also results in a revenue requirement that is $1 billion less than the alternative of investing in and continuing to run Units 1-3 over the same timeframe.

It is clear that none of the alternative resource scenarios brings the same cost benefit to APS customers as that proposed here. Consider the potential for keeping Units 1-3 in service, for example. In that case, as Graph 1 illustrates, APS customers will pay 44% more in capital costs to install the emission controls likely needed on Units 1-3 to keep those units in service than they will under the proposed transaction, an analysis that includes the cost of making the necessary environmental upgrades on Units 4 and 5. Moreover, this option simply preserves a resource that is already serving APS customers and does nothing to replace the other 231 MW of cost-effective generation that APS would forego if Units 4 and 5 retire in 2016, or protect against the potential loss of another 315 MW at Navajo Generating Station not long thereafter. APS customers would incur that much more in replacement power costs if the Company pursued this option.

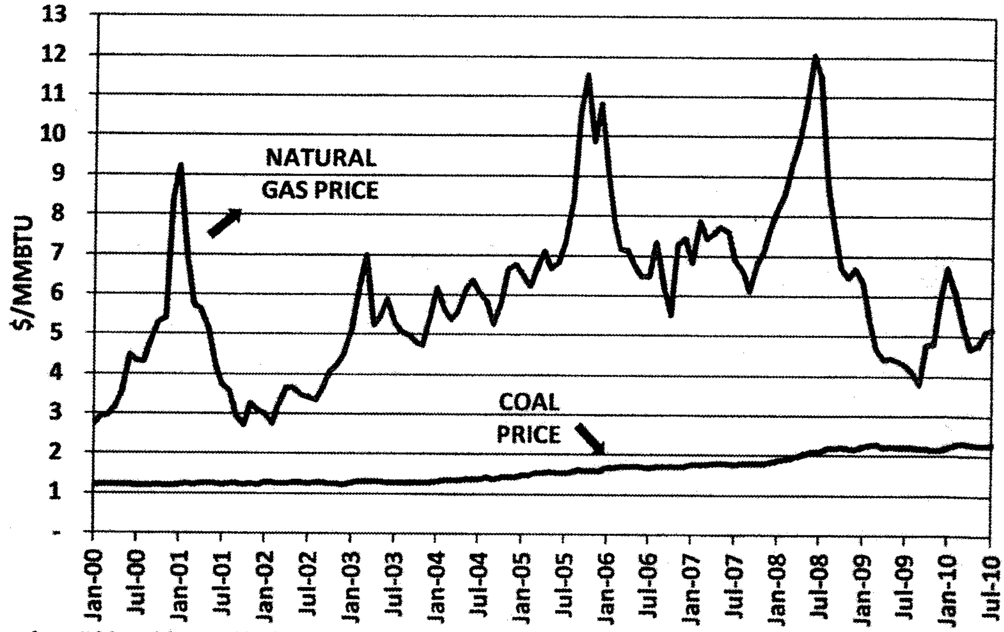
Retiring Units 4 and 5 in favor of Units 1-3 also makes little sense from an operational perspective, given that Units 1-3 are smaller and less efficient, and lack the same economies of scale benefits of Units 4 and 5. By way of example, the cost of installing SCRs on Units 1-3 is approximately $627 per kW, while the cost of installing the same equipment on Units 4-5 is roughly $325 per kW – a significant difference.

Q. YOU NOTED THAT NATURAL GAS WAS A SECOND ALTERNATIVE TO THE PROPOSED TRANSACTION. PLEASE DISCUSS THAT OPTION.

A. Natural gas generation is a reliable economic resource which effectively meets the marginal resource needs of a utility. It has been the "measuring stick" that APS has used in recent years when evaluating all resource alternatives – conventional or renewable. However, the drawbacks of using natural gas to replace 231 MW or more of existing Four Corners capacity are significant. First, the gas option is much more expensive than the approach proposed in the Company's Application. Apart from the capital costs associated with additional combined cycle generation, a new gas resource would require APS both to build new transmission infrastructure, and to maintain the current schedule of now-planned transmission lines. As Graph 1 on page 5 of my Testimony shows, the cost of building new combined-cycle and transmission infrastructure is double the cost of purchasing SCE's share of Units 4 and 5 and installing the required environmental controls on those units, on a dollar per kilowatt basis. Moreover, as Graph 2 depicts, APS customers will pay almost 20% more per megawatt hour over the life cycle of a new gas plant than they will if APS acquires SCE's interest in Units 4 and 5.

In addition, unlike Four Corners' fuel costs, made dependable by virtue of a negotiated long-term fuel agreement with the supplier, gas prices are highly volatile, as well-evidenced by the following graph:

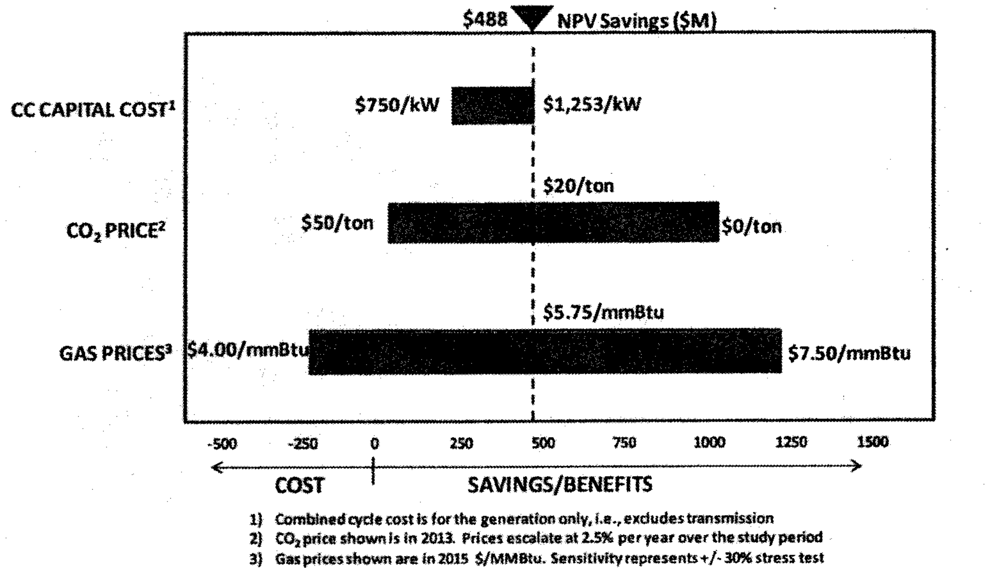
GRAPH 3: HISTORICAL U.S. FOSSIL FUEL PRICES



Source: U.S. Energy Information Administration; October 2010 Monthly Energy Review; Table 9.10. Cost of Fossil-Fuel Receipts at Electric Generating Plants

APS has conducted sensitivity analyses that demonstrate that the economic advantage of acquiring SCE's interest in Four Corners persists over a wide range of factors. In order to break even with the life cycle cost of the proposed transaction, natural gas prices would have to be 20% lower than the current long-term forecast. Or, the price assigned to carbon would have to rise above $50 per ton. Alternatively, replacement combined-cycle gas costs would have to be half of current cost estimates to build that resource. The following illustrates these sensitivities:

APS CUSTOMER BENEFITS DUE TO SCE TRANSACTION

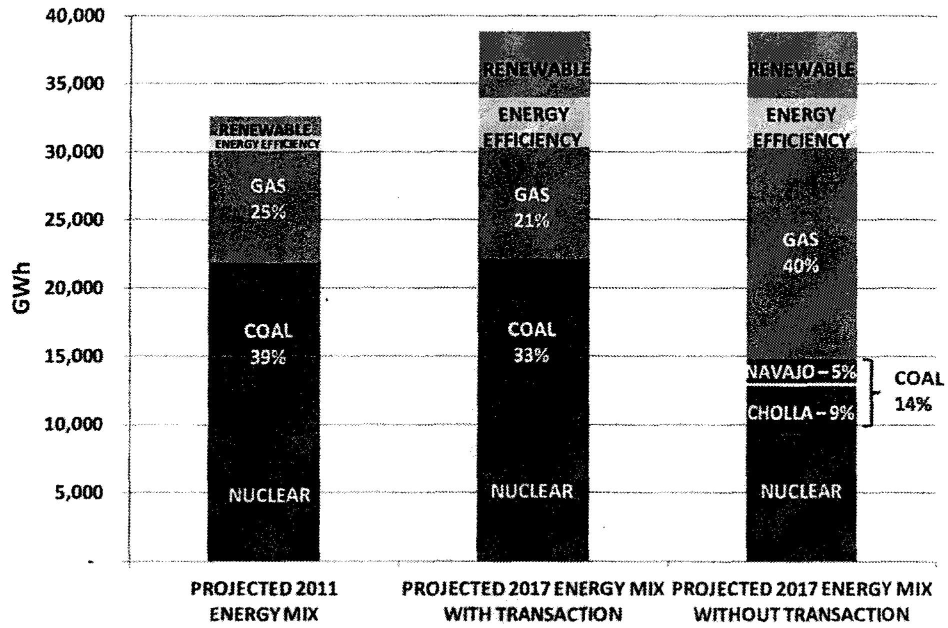


Gas is a reliable resource that has an important place in a utility's resource portfolio, but if APS's resource mix becomes too dependent on natural gas, our customers will be highly exposed to potential fuel cost increases and volatility. APS's resource choices, like those of all power generators, each have a variety of trade-offs. This is why having a diverse energy mix, which reduces reliance on any single power source, mitigates risk and makes good business sense.

Q. HOW WOULD REPLACING APS'S SHARE OF ITS EXISTING FOUR CORNERS COAL CAPACITY WITH NATURAL GAS IMPACT THE COMPANY'S RESOURCE PORTFOLIO?

A. As Graph 4 shows, if APS replaces 791 MW of its existing coal capacity with natural gas generation, the Company's resource diversity decreases and customer reliance on natural gas generation increases by 90%, with natural gas making up 40% of the Company's generation. Having 40% of the Company's generation dependent upon potentially volatile natural gas markets would put APS and its customers at a significantly higher level of risk.

GRAPH 4: TRANSACTION MAINTAINS DIVERSE ENERGY MIX FOR APS



Q. ARE THERE ANY OTHER REASONS WHY THE NATURAL GAS ALTERNATIVE IS A LESS PREFERABLE ONE?

A. Yes. There is also a practical risk to replacing the Four Corners output with natural gas. Additional gas generation and the associated transmission must be sited, permitted and constructed in a very short time frame if it is to be serving APS customers by 2016. As with any construction project, there is always the risk that projects will be delayed and the resources will not be available to customers when needed. Moreover, to execute this contingency, APS's currently planned and certificated Morgan to Sun Valley transmission line (commonly known as "TS-5 to TS-9") would need to be energized by 2016 – a feat which may prove difficult given the unresolved right-of-way issues for that project. The tight time clock not only makes the Four Corners alternative more appealing, but demonstrates the practical need for having this application processed quickly.

Q. DOES APS HAVE A NEED FOR THE CAPACITY IT WILL ACQUIRE AS A RESULT OF THIS TRANSACTION?

A. Yes, it does. APS's Loads and Resource table ("L&R"), attached to my Testimony as Attachment PD-1, shows that APS will require another 545 MW of resources to meet its 2017 load requirements even if this transaction moves forward. That calculation also assumes the addition of over 1400 MW of renewable resources and energy efficiency programs. If the proposed transaction fails, APS's need for new resources could increase to over 1,500 MWs in 2017. Output from Navajo Generating Station may also be lost to similar vulnerabilities, giving need for yet another 315 MW of replacement power. Were both Four Corners and Navajo Generating Station to shut down entirely, APS's existing base load resources would be limited to Cholla Power Plant (providing a total of 647 MW) and Palo Verde Nuclear Generating Station (providing 1,146 MW) – a total of 1,793 MW to serve a 2020 minimum system demand of 2,530 MW. Such a scenario would dramatically increase APS's reliance on natural gas and our customers' exposure to gas price volatility.

Given that potential, the long-term need for maintaining sufficient, reliable base load resources is clear. The proposed transaction essentially preserves a well-balanced energy supply portfolio for APS, with a slight net increase of 179 MW – a small difference that is unavoidable under the circumstances. That additional 179 MW provides protection against volatile natural gas prices as well as the potential loss of the Navajo Generating Station capacity. APS also expects to further defer the need for new base load generation if the transaction is approved.

Q. DID APS CONSIDER PROCURING RESOURCES FROM THE COMPETITIVE WHOLESALE MARKET AS AN ALTERNATIVE TO THE PROPOSED TRANSACTION?

Yes. APS has looked at what exists in the competitive wholesale market, but none of its offerings reasonably compare to the transaction with SCE. As discussed above, gas-fired generation – the most practical alternative to Four Corners in these circumstances – would further expose APS customers to uncertain gas prices and require that new transmission be built for any gas-fired power to reach the Company's primary load center in the Metropolitan Phoenix area. Any potential plant acquisition price is especially uncertain given the fact that the need would not be until 2017. Although APS might also procure new coal, any such resource would have significant development risk, a cost well above that of the Four Corners acquisition price, and could not be built in time to meet the Company's need.

Q. IS THE APPROACH OUTLINED IN APS'S APPLICATION CONSISTENT WITH ITS LONG-TERM RESOURCE PLAN?

A. Yes. APS's L&R table indicates that, even after acquiring SCE's share of Four Corners Units 4 and 5 and retiring Units 1–3, APS will still need over 500 MWs of resources in the 2017 timeframe. This L&R table also includes APS's commitment to exceed compliance with the Renewable Energy Standard, and meet the Commission's ambitious and recently adopted Energy Efficiency Standard. The Resource Plan currently on file with the Commission also stresses the value of maintaining a diverse energy supply portfolio – one that balances coal, gas, and nuclear generation to complement the ever-growing role of renewable resources and energy efficiency in meeting its customers' energy needs. Acquiring the SCE interest in Units 4 and 5, combined with the early retirement of Units 1-3, is thus fully consistent with the Company's resource plans.

Q. THE APPLICATION REQUESTS THAT THE COMMISSION RULE ON THIS MATTER EXPEDITIOUSLY. WHY IS THAT IMPORTANT?

A. If the Commission rejects the Company's requests, Four Corners Units 4 and 5, and possibly Units 1-3, risk closing no later than 2016. APS must start working to implement a contingency plan, accelerating the acquisition and construction of new generation and transmission infrastructure and/or installing emission control devices on Units 1-3. Without a timely order from this Commission, time may run out to construct or buy new replacement generation.

III. CONCLUSION

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

A. The proposal outlined in the Company's Application simply makes good sense for APS and our customers. It has the lowest relative capital cost, greatest cost certainty, and allows APS to maintain a reliable and cost-effective source of base load generation – all while improving the plant's environmental impact and stabilizing the local economies, as APS witness Mark Schiavoni describes. It also has the lowest customer rate impact, as APS witness Jeff Guldner explains. Although, there will be significant capital cost requirements in the short term, the approach outlined in this application provides nearly a $500 million net present value benefit to APS customers. This opportunity is fully consistent with APS's obligation to provide cost effective, reliable, and environmentally conscious service to our customers and the communities we serve. It is one worth seizing.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit EDH-3

APS response to Sierra Club Data Request 2.1

This exhibit is confidential and is provided under separate cover.

Exhibit EDH-4

APS response to Sierra Club Data Request 2.4

This exhibit is confidential and is provided under separate cover.

Exhibit EDH-5

APS response to Staff Data Request 35.35

This exhibit is confidential and is provided under separate cover.

Exhibit EDH-6

"Greenhouse Gas Legislative Review and CO2 Price Outlook", prepared by Charles River Associates on behalf of Arizona Public Service Corp, and attached as Appendix A to APS's 2012 Integrated Resource Plan. Dated November 4, 2011.

CRA Charles River Associates

Arizona Public Service

Greenhouse Gas Legislative Review and CO_2 Price Outlook

Prepared By:

Barclay Gibbs

Charles River Associates

1201 F Street NW

Suite 700

Washington, DC 20004

November 4, 2011

Barclay Gibbs consults to electric utilities, power project investors, and large industrial users of electricity. Using CRA's proprietary North American Electricity & Environment Model (NEEM), Mr. Gibbs has evaluated the impact of various Federal and state policies on generation technology expansion plans, electricity prices, and generation asset value. He has evaluated the reliability implications of proposed federal air pollution regulations and forecasted SO2 and NOx prices under those regulations, forecasted prices for Renewable Energy Credits (RECs), assessed the costs and benefits of expanding transmission to access remote windpower, evaluated the producer and consumer impacts of proposed export tariff changes in a North American electricity market, and forecasted the fuel cost pass-through from a utility to a large industrial user of electricity. Recently, he has worked on a market power evaluation of various proposed allocation schemes under EPA's proposed Clean Air Transport Rule (CATR). He also assessed the impacts of short-term coal market constraints on allowance prices under EPA's final Cross-State Air Pollution Rule (CSAPR). Prior to joining CRA International, Mr. Gibbs was a managing consultant in the Technology Strategy and Management Group at Navigant Consulting where he consulted on energy efficiency policy and bioenergy. Mr. Gibbs holds an M.S. in Technology & Policy from Massachusetts Institute of Technology, an M.A. in Applied Economics from Johns Hopkins University, an M.S. in Environmental Systems Engineering from Clemson University, and a B.S. in Chemical Engineering from Bucknell University.

Introduction

Arizona Public Service (APS) is embarking on its 2012 Integrated Resource Planning (IRP) process. In early August 2011, APS engaged Charles River Associates (CRA) to provide a review of recent Greenhouse Gas (GHG) policy developments and the current outlook for Federal CO_2 pricing. This policy paper reviews the major recent developments in GHG policy, discusses some of the more significant and recent legislative proposals to curb U.S. GHG emissions, and provides recommendations for CO_2 prices in the current APS IRP.

Exhibit 1 summarizes some of the major historical elements of GHG policy development over the last 20 years, with particular emphasis on the more recent years. During the years 2007-2010, many federal legislative proposals addressing climate change surfaced. Since the summer of 2010, there has been almost no attention on federal climate change legislation. The policy debate in Washington has shifted more to EPA actions such as the Cross-State Air Pollution Rule (CSAPR), Air Toxics (formerly Utility MACT), once-through cooling regulations (316b), coal ash regulation, and EPA's own regulation of GHGs.

Exhibit 1. GHG Policy Timeline

Event	Description	Year	Comment
UN Framework Convention on Climate Change (UNFCCC), Rio de Janeiro	Nations agree to voluntary reduction of emissions, with "common but differentiated responsibilities"	1992	This "Earth Summit" is often cited as the beginning of global climate policy negotiation
Kyoto Protocol negotiated	First Internationally Binding Treaty; 160 Countries; 37 Developed Nations agree to cut emissions 5% below 1990 levels by 2012	1997	The Kyoto Protocol was never submitted to the US Senate for ratification
McCain (R-AZ) -Lieberman (D-CT) Climate Stewardship Act proposed in US Senate	First major U.S. Climate Bill	2003	Defeated in the Senate 55-43
European Emissions Trading System (ETS) begins	Europe establishes a cap-and-trade system for CO_2, aimed at Kyoto compliance	2005	Controversies over profits based on allocation scheme
California's AB32 Policy signed into Law	Emissions reduction goals are roughly in-line with Kyoto	2006	Cap-and-trade start date was recently delayed until 2013
Bingaman (D-NM) – Specter (R-PA) propose the Low Carbon Economy Act of 2007	Cap-and-trade climate bill with a relatively low safety valve (called a Technology Accelerator Payment, TAP) of \$12/tonne of $CO_{2\ Eq.}$	2007	Bill never made it out of the Senate Environment and Public Works committee
Lieberman (I-CT) –Warner (R-VA) Climate Security Act	Highly prominent climate bill makes it to main Senate floor but dies in a procedural vote	Oct 2007-June 2008	June 2008 marks the end of significant climate change debate during the Bush Administration

Exhibit 1. GHG Policy Timeline (cont.)

RGGI Cap-and-Trade program begins	10 Northeast states begin cap-and-trade policy that reduces emissions by 10% by 2018	Fall 2008	Allowances have typically traded at the minimum reservation price in recent years. *Gov. Chris Christie has recently announced withdrawal of NJ.*
Waxman (D-CA) -Markey (D-MA) American Clean Energy and Security Act (ACES) is passed by the House		June 2009	Reflects optimism for US Climate legislation in the early days of the Obama administration
A bill competing with Waxman-Markey is introduced	Kerry (D-MA) – Boxer (D-CA)	Fall 2009	
Conference of Parties 15 (COP15), Copenhagen Accord	High-profile, regular meeting of the Conference of the Parties to the UNFCCC	Dec. 2009	Non-binding agreement on emissions targets. A significant outcome was $100B/yr pledged from rich countries to poor countries. Generally viewed as achieving less progress than anticipated.
Negotiations on a grand compromise involving Senators Kerry (D-MA), Lieberman (I-CT), and Graham (R-SC) break down	Graham withdraws from negotiations, citing immigration politics	April 2010	Symptomatic of intensifying partisanship in Washington, particularly around regulation
Kerry (D-MA) – Lieberman (I-CT) American Power Act is proposed	The two senators move forward without Senator Graham	May 2010	Nothing substantial happened with this proposal
Waxman (D-CA) -Markey (D-MA) American Clean Energy and Security Act (ACES) dies in the Senate	Originally passed by the House in June 2009, the Waxman-Markey bill dies in the Senate	June 2010	Climate change legislation takes a back seat to other priorities on Capitol Hill.
The US House of Representatives becomes Republican-controlled and the Democratic majority in the Senate is weakened	Anti-regulation sentiment by incoming Republicans diminishes chances for comprehensive U.S. Climate policy, particularly under current economic conditions	Nov. 2010	
EPA prepares to regulate GHGs as part of NSPS		Scheduled 2011	

Summary of Recent Greenhouse Gas Policy Developments

Recent Federal Legislative Proposals

Bingaman-Specter (S.1766, Low Carbon Economy Act of 2007)

The Bingaman-Specter bill was introduced by Senators Jeff Bingaman (D-NM) and Arlen Specter (R-PA) in July 2007. The bill was more modest in its emissions reduction goals than many of the other major climate proposals. Its goals were to reduce economy-wide GHG emissions to 2006 levels by 2020 and to 1990 levels by 2030. In addition, the bill contained a cost-containment provision called the Technology Accelerator Payment (TAP) which was essentially a safety valve price of \$12/tonne $CO_{2\,Eq.}$ starting in 2012, rising at 5% above inflation.[1] The TAP would have been paid into a fund that would have been used to hasten low-carbon technology development.

The Low Carbon Economy Act of 2007 never made it out of the Senate Environment and Public Works Committee.

Lieberman-Warner (S.2191, America's Climate Security Act)

The Lieberman-Warner bill was a high-profile piece of legislation introduced by Senators Joseph Lieberman (I-CT) and John Warner (R-VA) during October 2007. It was later amended by the Boxer amendment (D-CA). The cap-and-trade policy would have covered more than 75% of U.S. GHG emissions, including the six major GHGs (CO_2, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, and perfluorocarbons) emitted from the electric, industrial, and transportation sectors. The proposal would have capped U.S. emissions at 2005 levels in 2012 before cutting them by 15% by 2020 and 70% by 2050.

After much publicized debate while the bill resided within the Senate Environment and Public Works Committee (EPW), the bill was killed in the Senate during June 2008. It was defeated by a procedural vote (cloture) without undergoing any significant debate on the Senate floor.

Waxman-Markey (HR.2454, American Clean Energy and Security Act of 2009) and Kerry-Lieberman (American Power Act)

The Waxman-Markey bill originally proposed during the Spring of 2009 by House Representatives Henry Waxman (D-CA) and Edward Markey (D-MA). The bill included a combined energy efficiency and renewable energy standard, reaching 20% by 2020. The economy-wide GHG emissions reductions would have been 3% by 2012 (relative to

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[1] $CO_{2\,Eq.}$ indicates *carbon dioxide equivalents.* This measure incorporates the differing global warming potentials (GWPs) of the various GHGs (CO_2 has a GWP of 1.0). A tonne is a metric ton, which is about 10% larger than a short ton.

2005 levels), 20% by 2020, 42% by 2030, and 83% by 2050. Heavy industry would not have been covered by the cap until 2014. The bill covered the same GHGs as Lieberman-Warner, with the addition of nitrogen trifluoride. The bill passed the House during June 2009.

In 2010, after the International Copenhagen Summit (COP15), the Kerry (D-MA)-Lieberman (I-CT)-Graham (R-SC) compromise negotiations received a lot of attention, as an alternative to Waxman-Markey in the Senate. The possibility for compromise was sought by this trio of Republican, Democratic, and Independent Senators representing northern as well as southern constituents. Compromise was being crafted around promotion of offshore oil drilling and delaying the implementation of GHG constraints on heavy industry. After Senator Graham pulled out of the negotiations (due to issues pertaining to immigration reform and the BP Gulf oil spill), Senators Kerry and Lieberman introduced the bill, the American Power Act, without Senator Graham. The American Power Act's GHG coverage and proposed emissions reductions were similar to those in Waxman-Markey. Public estimates of their allowance prices were similar also. The bill included a price floor of \$12/tonne $CO_{2\ Eq.}$, increasing at 3% over inflation and a price ceiling of \$25/tonne of $CO_{2\ Eq.}$, increasing at 5% over inflation. Because of the mechanism used for cost containment, the price ceiling could be broken under scenarios such as zero supply of international offsets.

The American Power Act included provisions to encourage the use of natural gas in the transportation fleet, to delay the implementation of GHG policy on heavy industry until 2016 (the rest of the economy would have been required to begin emissions reductions in 2013), to support offshore oil and gas development, and to support nuclear power development.

Little more happened in the Senate with regard to these two legislative proposals during the summer of 2010 as climate change took a backseat to other issues in the public discourse. Since the mid-term elections in the fall of 2010, there have been no major legislative proposals for addressing climate change.

Some State and Regional Level Developments

California's AB32

California's AB32 policy was signed into law by Governor Schwarzenegger in 2006. AB32 requires California to reduce its GHG emissions to 1990 levels by 2020 and 80% below 1990 levels by 2050. The 2020 cap represents an approximate 15% cut below 2012 emissions. The intended implementation schedule would have covered electricity (including imports[2]) and large industrial facilities in 2012, followed by distributors of fuels and natural gas by 2015.

[2] The coverage of emissions from out-of-state generators that produce electricity for export to (and consumption in) California is expected to be difficult as a practical matter.

AB32 has been delayed a year and will begin in 2013. California carbon allowances have been trading in the $15-$22/tonne for 2013-2014 compliance. The market is thinly traded and is expected to remain so at least until the California Air Resources Board (CARB) approves the final market rules in late October 2011. The allowance pricing in California is indicative of the specific policy design of AB32 and is not necessarily an indicator of the impact of future Federal policy.

AB32 incorporates a variety of flexibility mechanisms such as allowance trading, banking, 3-year compliance periods, and the use of offsets.

Regional Greenhouse Gas Initiative (RGGI)

The Regional Greenhouse Gas Initiative (RGGI) is a regional GHG trading program covering the northeast states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont). Governor Chris Christie (R-NJ) has recently announced the withdrawal of NJ from the program (NJ will cease to be part of RGGI in January 2012). RGGI is scheduled to reduce CO_2 emissions from power plants by 10% by 2018 relative to the 2009-2014 stabilization level. The stabilization level is 188 million tons, which is about 4% higher than the 2000-2005 actual emissions levels.

In recent years, the RGGI prices have been at or near the minimum reserve price of $1.89 per short ton. With reduced load (in part due to the recession), dispatch economics that are more favorable to natural gas than expected, and banking provisions, allowance prices in RGGI have been at or near the price floor. By 2018, the RGGI cap is supposed to be cut by 10% (to about 169 million tons). Current emissions are well under this level, implying that the RGGI policy will not be binding without revisions to the policy design and/or caps. A stakeholder process for reviewing the current RGGI policy has recently begun.

With respect to RGGI allowance trading during 2010, the average daily volume of RGGI futures trading ranged from zero to 1.3 million. Average daily trading in 2010 was 0.21 million allowances, in comparison to 2.7 million during the prior year. The total volume of trading for all of 2010 was 52 million allowances, in comparison to the 143 million allowances that were auctioned or allocated in 2010.[3]

Exchange traded volumes have contracted greatly over the last 12 months (to September 30, 2011) on the NYMEX and the CCFE (Chicago Climate Futures Exchange). The CCFE will close at the end of the calendar year 2011, with existing contracts and related trading rolling over to an over-the-counter (OTC) platform on the Intercontinental Exchange (ICE).

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[3] "Annual Report on the Market for RGGI CO2 Allowances: 2010," Potomac Economics, April 2011.

International Climate Negotiation Outcomes[4]

Copenhagen Accord at COP15

Going into the Conference of the Parties 15 (COP15) to the UNFCCC held in Copenhagen in December 2009, expectations for progress in the international efforts to address climate change were high. The Copenhagen meeting was a capstone to a process that had begun with the Bali Action Plan two years before. A political accord was struck at COP15. The accord calls for emissions reductions from all the major economies – this includes large developing countries such as China for the first time. However, it remains unclear how a binding agreement will be reached.

The conference in Copenhagen was characterized by discord. There were public divisions and arguments. Notably, at the close of the conference multiple countries were trying to block the Accord because they were outside of the room while it was being negotiated. These countries included Venezuela, Sudan, Nicaragua, and Bolivia. In addition, throughout the conference, there were frequent disagreements on approach between the U.S. and China.

Notably, the Accord included the pledge by developed countries to provide $100B per year of transition assistance by 2020 to developing countries. The Copenhagen Accord did include broad agreement on emissions verification procedures.

Cancun Climate Change Conference at COP16

Going into the November/December 2010 Cancun Conference of the Parties 16 (COP16) to the UNFCCC, expectations were low (relative to sentiments prior to COP15). At the conclusion of COP16, there was still no clear path to binding commitments for emissions limitations among the participating countries. However, further progress was made with respect to finance and transparency.

COP16 was less acrimonious than COP15 and the negotiations produced small successes breathing some life back into the UN process.

Summary of Recent Legislative Developments

Since the Waxman-Markey and Kerry-Lieberman bills failed during the summer of 2010, the discussion of federal GHG legislation in Washington has largely faded. This stands in contrast to relatively consistent and vigorous debate over the prior several years. Climate change policy was overshadowed by the national Health Care debate. The Republican victory in the House and the narrowing of the Democratic majority in the Senate has suppressed the legislative debate about GHG legislation. With continued sluggish growth in the U.S. economy and high unemployment, action on climate change appears lower on the national agenda than it was just a few years ago. Considerable anti-

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[4] This section is based on summaries written by the Pew Center on Global Climate Change.

regulation sentiment has also developed as part of a broader discussion about the role of government in the U.S. economy. It is against this backdrop that a massive and complex GHG bill would have to advance – a difficult political proposition at this time.

It seems highly improbable that federal GHG legislation could pass before the next federal election. With this mind and with the assumption that it would take at least one year to pass complex GHG legislation after the election, the earliest feasible date for passage is early 2014. Most GHG legislation has a 3-year implementation period, thus the earliest feasible date for implementation would be early 2017.

Recent EPA Actions on GHG Regulation / Implications for Utilities

EPA has entered into a settlement agreement with environmental organizations and several States to issue rules that will address GHG emissions from electric generating units and refineries. For gas-, oil-, and coal-fired electric generators, EPA committed to proposing regulations by July 2011 and finalizing them by May 2012. The July deadline was extended and EPA recently announced that they would not meet the extended deadline of September 30, 2011. EPA will likely negotiate a new deadline with the other parties to the settlement agreement.

When proposed and finalized, the regulations will take the form of New Source Performance Standards (NSPS) for new and modified generators and State emissions guidelines for existing generators. The NSPS will apply to new and modified generators if their construction begins after EPA proposes the NSPS. The states are given significant discretion under the Clean Air Act with respect to the timelines and stringency of applying EPA's guidelines to existing facilities.

CO_2 Price Trajectories from Recent Public Analyses

CRA reviewed the public analyses of recent GHG legislation by the U.S. Environmental Protection Agency (EPA), U.S. Energy Information Administration (EIA), and the Massachusetts Institute of Technology (MIT). The reviewed legislation includes the Lieberman-Warner, Waxman-Markey, and Kerry-Lieberman bills. Results for EPA are reported for both its ADAGE and IGEM models.[5]

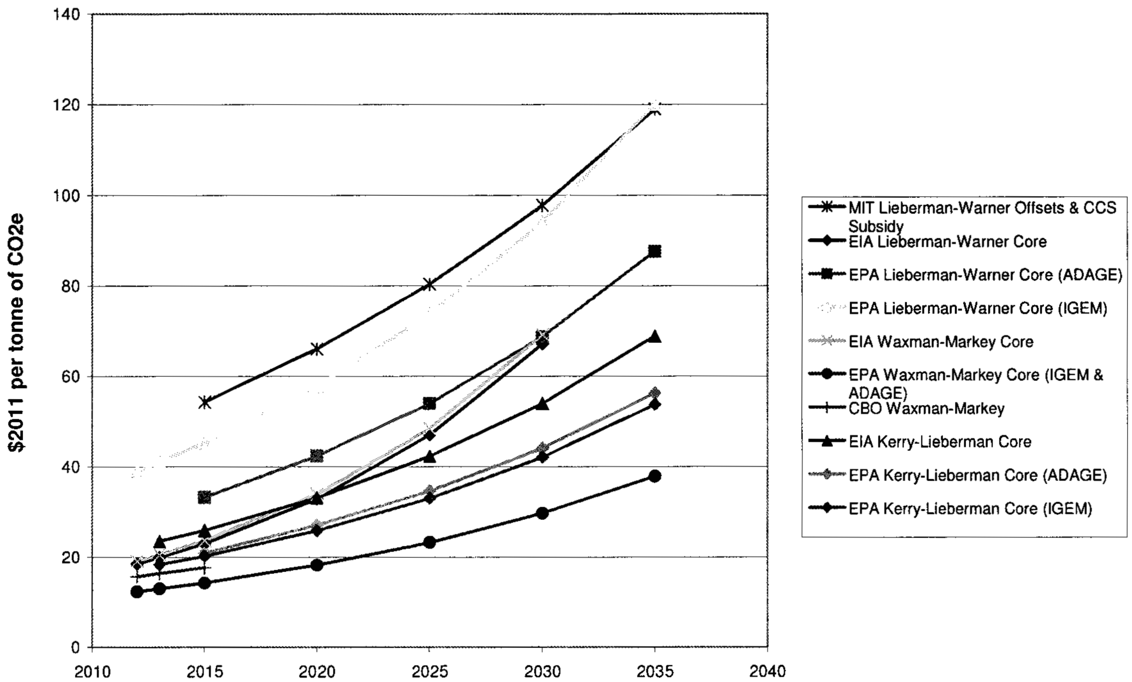
MIT did not evaluate all the bills, so we have only included MIT's Lieberman-Warner analysis. However, MIT did evaluate several GHG trajectories that were approximations

[5] The EPA models are the Applied Dynamic Analysis of the Global Economy (ADAGE) and Intertemporal General Equilibrium Model (IGEM).

of other bills[6] – from this analysis, we observe that MIT's projected allowance prices tend to be higher than those for EIA or EPA.

Exhibit 2 summarizes the "core" cases for the most recent legislation. We have put all of these trajectories into the same units (2011$ per tonne of $CO_{2\,Eq.}$).

Exhibit 2. CO2 Prices for Recent Proposals and Public Analyses



We note that with the exception of the MIT analysis and the EPA Lieberman-Warner (IGEM) analysis, the allowance prices tend to start in the range of \$12 - \$33 per tonne of $CO_{2\,Eq.}$. The two noted exceptions have higher allowance starting prices. Each price path exhibits the standard feature for a cap-and-trade policy that includes banking, namely the price rises at the model's discount rate (this price path prevents arbitrage across time).

We also note that these studies have a variety of sensitivity analyses associated with them (not shown) – key sensitivity variables include restriction on technology availability (e.g., carbon capture), energy efficiency deployment, and the availability of international and domestic offsets. We note that the availability of international offsets has a particularly large impact on the allowance price. For example, the EPA's analysis of Waxman-Markey has a starting allowance price that is 89% higher with zero availability of international offsets.

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[6] Paltsev, et al, *Assessment of U.S. Cap-and-Trade Proposals*, MIT Joint Program on the Science and Policy of Global Change, Report No. 146.

Recommended CO_2 Allowance Price Projection

The future of global and U.S. GHG policy is uncertain. It is not known if federal legislation will ever pass, or if it does, when it will be implemented. The stringency of the caps and the resulting allowance prices are also not known. The co-evolution of climate science, macroeconomic conditions, and electoral politics will ultimately determine the U.S. GHG policy.

Based on our review of the most recent legislative proposals and the CA AB32 policy, we recommend the CO_2 price ranges below for the duration of APS's 15-year planning horizon. As was shown in Exhibit 2, most of the starting prices associated with public analyses of the most recent bills are clustered in the range of \$12 - \$33 per tonne of CO_2. However, this report has discussed the factors that lead us to recommend somewhat lower starting allowance prices. These mitigating factors include slowing of progress in international negotiations and the current U.S. political and macroeconomic conditions. These conditions suggest that future bills might be less strict/aggressive. We also suggested that early 2017 is the earliest feasible date for the implementation of federally legislated GHG policy – we feel it is prudent to expect implementation a year or more beyond 2017. Our recommendations are as follows:

Base Case. For the IRP's base case, we recommend using \$12 (2011\$) per metric tonne of $CO_{2\ Eq.}$ beginning in 2018-2020 and rising at 5% above inflation. This trajectory is highly plausible and represents a reasonable base case for planning.

Note that under cap-and-trade, CO_2 prices are typically projected to rise at the discount rate applicable to the business operations impacted by the CO_2 market. For example, if CO_2-emitters looked forward 3 years into the futures market and saw that the CO_2 price was higher than the discount rate would suggest, they would further cut emissions now and bank them to reduce compliance costs 3 years from now. The result, in aggregate, would be to push up current allowance prices and depress future prices. Given this type of calculation by market actors occurring over 40+ years, the price rise will tend to equilibrate at the discount rate. CRA assumes a 5% real discount rate applies to the cap-and-trade market, which is in line with other studies which typically are in the 4-7% range. A real discount rate reflects the rate over and above the general economy-wide inflation rate. In actual practice, changes in technology, fuel prices, energy demand, caps, and other parameters will yield actual prices for CO_2 that will vary over time.

Low Case. Given the current macroeconomic and political climate, we also believe it makes sense to consider a plausible scenario in which federal climate legislation is not enacted in the U.S. for decades.

High Case. We also believe it makes sense to evaluate a higher carbon price trajectory, for example \$20 (2011\$) per metric tonne of $CO_{2\ Eq.}$ beginning in 2018-2020 and rising at 5% above inflation. We do not believe this is the highest carbon price trajectory that is politically feasible, but it represents a reasonable upper bound to reflect probable policy over the next decade.

We also suggest to APS that it would be reasonable – depending on the horizon of the analysis - to assume a limit on the allowance price above which it could not rise any further (most relevant for the $20 high case). It seems likely that there is a price above which political support for a GHG policy (assuming one could pass) would deteriorate.

We also note that under GHG policy, natural gas prices will likely rise (relative to a business-as-usual forecast) in the short- to medium-term as the electric sector consumes more gas. In the long-term (after APS's 15-year planning horizon), the natural gas prices (exclusive of the CO_2 price) will likely fall (relative to a business-as-usual forecast) as advanced, low-carbon technologies enter the market in large-scale (e.g., carbon capture, new nuclear, etc.). With respect to the demand for electricity, a CO_2 price also will generally dampen the demand for power below a "business-as-usual" load forecast.

CO_2 Allocations to Utilities

The allocation of GHG allowances under a cap-and-trade program is one of the most contentious parts of climate change policy. The allocations represent the division and transfer of wealth. The government has the choice of 100% allowance auction, 100% free allocation, and all options in between. Moreover, the government can select the distribution of the free allocations, that is, the recipients of the transferred wealth. Because the possibilities for allocation design are limitless, potential recipients are put into the position of advocating for the most beneficial allocation. Allocation schemes are by nature contentious and arbitrary.[7]

Generally, the allocation scheme does not affect the compliance choices of energy producers and consumers. Exceptions to this generalization include: (1) the uses of auction revenue can alter decision-making (e.g., to reduce other taxes on capital and labor), (2) free allocations to cost-of-service utilities can lower electricity rates and therefore reduce the role of demand reduction in GHG compliance, and (3) the potential for market power (e.g., if all allowances were freely given to one party, market power would distort the production decisions).

The allocation that a particular generating unit would receive under a federal CO_2 policy in a particular year would be based on: (1) the cap itself, that is, the fractional reduction in emissions represented by the cap (e.g., if the cap were zero, then all units would receive zero allocation), (2) the fraction of total allocations distributed to the electric sector versus other sectors (and versus auctioned), and (3) the allocation among units within the electric sector, typically based on historic emissions. As the cap is tightened, the dollar value of each allowance increases.

[7] In the non-carbon context, EPA's recently finalized Cross-State Air Pollution Rule (CSAPR) allocated units with SO_2 and NOx allowances primarily based on heat input. The final rule marked a significant departure from the proposed Clean Air Transport Rule (CATR) which allocated allowances based on historical emissions. The final CSAPR allocation benefits cleaner units at the expense of more heavily polluting units. This has been a contentious aspect of the CSAPR final rule.

The electric sector typically represents 35-40% of U.S. GHG emissions. The Lieberman-Warner proposal distributed 20% of total allowances to power plant owners and about 10% to load serving entities (LSEs) in 2012. Thus, the power sector was to receive allocations for roughly 80% of its emissions-based share ([10% + 20%] / 37.5%). By 2031, the power plant owners would have received none of the total allowances.

Under Kerry-Lieberman, about 74% of the allocations were to be freely distributed in 2013. By 2035, no allowances would have been freely allocated under Kerry-Lieberman. Of the freely allocated allowances, the Kerry-Lieberman bill would have freely allocated 51% of the allowances to the electric sector in 2013-2015 (before heavy industry is placed under the cap), 35% in 2016-2026, before tapering off to zero by 2030. Prior to 2027, the electric sector would have received slightly less than its emissions-based share.

As discussed above, the allocation of allowances is complex, arbitrary, and difficult to predict. One reasonable scenario would be to assume that the electric sector would receive 80-90% of the allowances that it needed during the first year of GHG policy implementation, and then reducing that quantity of allowances (tonnes) linearly to zero over the subsequent 20-year period. The value of these allowances ($) for the APS portfolio in any year would be equal to the number of allocated tonnes times the allowance price.

While the allocation of allowances to APS under any climate-change policy would be an important component in estimating the ultimate impact to APS electric rates, decisions related to future APS generation resources will be based on applicable CO_2 prices (along with demand growth, fuel prices, etc.). This is because allowances can be bought or sold at the prevailing market price. As such, any allowances provided to APS would not change the most economic resource expansion policy to pursue, notwithstanding impacts on demand growth.

Perspectives on Clean Energy Standards (CES)

Clean Energy Standards (CES) are similar to Renewable Portfolio Standards (RPS) except that natural gas-fired generation and nuclear power would be included in the mandated requirement. Typically, only a portion of the gas-fired generation would count toward the CES requirement.

The CES policy is a mandate for low-carbon power. The CES would result in a price for clean energy credits that power producers would consider in their generation decisions. For example, the CES credit price might encourage a generator to dispatch gas before coal, thereby creating a credit for CES compliance or sale. In contrast, a cap-and-trade policy or a carbon tax provides an economic disincentive to generate CO_2. While the two approaches are fundamentally different, a CES could conceivably be designed to roughly result in the same future generation mix as a cap-and-trade policy or a carbon tax. To achieve this comparability, one of the key choices in the CES policy design would be the treatment of gas-fired generation. If the objective of the policy is to reduce CO_2

emissions, a carbon tax (or cap-and-trade) would typically be a more direct and efficient means of doing so. In general, the CES would be a less direct method of reducing CO_2 emissions.

EXHIBIT
SC-2
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
BOB STUMP, Chairman
GARY PIERCE
BRENDA BURNS
ROBERT L. BURNS
SUSAN BITTER SMITH

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01345A-11-0224

SURREBUTTAL TESTIMONY OF EZRA D. HAUSMAN, PH.D.

On Behalf of the Sierra Club

July 21, 2014

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

A. My name is Ezra D. Hausman, Ph.D. I am an independent consultant doing business as Ezra Hausman Consulting, operating from offices at 77 Kaposia Street, Auburndale, Massachusetts 02466.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS DOCKET?

A. Yes. I filed direct testimony on behalf of intervener Sierra Club.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. I am addressing certain statements made by APS Witness James C. Wilde in his rebuttal testimony in this Docket. Overall, I demonstrate that Mr. Wilde provides little to no foundation for his criticisms of my direct testimony, and that APS continues to obfuscate and withhold critical details of its NPV analysis of the Four Corners acquisition. APS is asking ratepayers to shoulder a great deal of cost and risk for its acquisition; the company bears the burden of transparently demonstrating that its actions are prudent and in ratepayers' interest. I do not believe that the Commission can reasonably grant the company's petition based on the opaque and limited analysis the company has presented.

Q. IN MR. WILDE'S REBUTTAL TESTIMONY, HE CLAIMS THAT APS'S GAS PRICE FORECASTS AS APPLIED IN THIS DOCKET ARE REASONABLE, OR EVEN CONSERVATIVE. DO YOU AGREE?

A. I have no basis on which to agree or disagree, as the company has not provided sufficient detail for me, the Commission, or anyone else to evaluate its approach in this area.

In my direct testimony, I described numerous reasons why the changes in APS's gas price forecasts, relative to those used in Docket No. E-01345A-10-0474, seemed illogical. Mr. Wilde has not addressed these points; he has provided a vague description of how the company's gas price forecasts were developed, saying that they "are *based on* the New York Mercantile Exchange ("NYMEX") forward market gas prices on September 30, 2013" (2 at 12, emphasis added) and that they are then escalated at a fixed rate after 2025. Mr. Wilde does not explain how he uses the NYMEX data, nor does he provide example calculations or anything else that could provide clarity as to the company's approach.

It must be noted that NYMEX forward market data beyond a very short time horizon hold little value, because they are based on at most a very small number of trades, and often on no trades at all. Further, I have not seen any NYMEX data that extend as far as Mr. Wilde suggests. If the company did indeed base its forecasts on this source, it should be more forthcoming in its approach and in explaining why such an approach would be valid.

Q. SIERRA CLUB DATA REQUEST 4.1 REQUESTED THE SEPTEMBER 30, 2013 NYMEX FORWARD NATURAL GAS PRICES REFERENCED BY MR. WILDE, ALONG WITH WORKPAPERS SHOWING THE COMPANY'S CALCULATIONS. DID THE COMPANY RESPOND TO THIS REQUEST?

A. Yes. However, the company's response failed to add clarity. APS's written response referred to "NYMEX" data in quotes, implying perhaps that the company uses this name but hedging on the actual source. The worksheet containing the data identifies an entity called "DataMart" as its source. I am unfamiliar with this entity, nor could I find any information about it through an internet search. The data provided do not look like raw NYMEX data, nor do they include important information, such as trade volume or open interest, that would support assessment of the reliability of the numbers.

Sierra Club's intention in making Data Request 4.1 was to provide me with an opportunity to review the nature and quality of the underlying data used by the company in developing its natural gas price forecast, so that I could further investigate the anomalous forecast characteristics identified in my direct testimony. The response provided by the company has not been illuminating or helpful in this regard.

Q. HAVE YOU REVIEWED NYMEX NATURAL GAS FORWARD PRICE DATA AS OF SEPTEMBER 30, 2013?

A. Yes, I purchased the historic Henry Hub futures prices as of the month of September 2013 from CME DataMine.[1] (CME owns NYMEX, and provides a data archiving service for NYMEX and other data.) Again, I cannot compare these directly to APS's price data because the company has not provided sufficient detail for a full understanding of how its prices were derived. However, I note that the volume of trades recorded for September 30 drops precipitously in the near future: Specifically, there are approximately 150,000 trades for the duration of 2013; 75,000 for all of 2014, 1,360 for 2015, 66 for 2016, about 25 for each of 2017 and 2018, and none at all thereafter. The data for all of September show a similar pattern. This absence of trading activity renders the data meaningless as long-term predictors of market prices.

[1] Historic futures data are available for purchase or subscription through CME Group's DataMine service (http://www.cmegroup.com/market-data/datamine-historical-data/)

Q. HAS MR. WILDE RECONCILED THE COMPANY'S REPRESENTATION OF CARBON EMISSIONS PRICES WITH RECENTLY ANNOUNCED REGULATIONS FROM THE US ENVIRONMENTAL PROTECTION AGENCY?

A. No. To the contrary, Mr. Wilde uses the fact that EPA has announced stringent limitations on greenhouse gas emissions from existing power plants to argue that this issue could be reasonably ignored. Specifically, he states that:

> It is noteworthy that the Clean Power Plan does not propose a carbon market as one of its building blocks for reducing carbon intensity. In light of this, it appears that using any carbon price in the Four Corners analysis may yield a conservatively low estimate of the value of the Transaction. (4 at 22-26)

Q. DO YOU AGREE THAT USING ANY CARBON PRICE FOR THIS ANALYSIS IS "CONSERVATIVE"?

A. I do not. EPA did not mandate a specific carbon market because it does not have authority to do so; however, it is widely accepted in the industry and among economists that requiring limitations on CO_2 emissions from existing plants is tantamount to imposing a cost on emissions, because it creates a scarcity for a good (the right to emit CO_2) that was previously available in unlimited quantities for free. This reality has been recognized throughout the industry and is manifest in the fact that numerous coal-fired plants are likely to curtail operations or shut down altogether in order to comply. To claim as

(4 at 10-13, emphasis added) Again the words "based on" suggest that the company did some interpretive analysis to come up with its numbers.

Q. SIERRA CLUB DATA REQUEST 4.2 REQUESTED THE SEPTEMBER 24, 2013 CO_2 EMISSIONS ALLOWANCE TRADING PRICE DATA REFERENCED BY MR. WILDE, ALONG WITH WORKPAPERS SHOWING THE COMPANY'S CALCULATIONS. DID THE COMPANY RESPOND TO THIS REQUEST?

A. Yes. The company's response is as follows:

> The projected CO2 emission costs are based on the September 24, 2013 NYSE Intercontinental (ICE) California Carbon Allowance Vintage 2016 Futures trade of $11.6/metric ton, escalated at 2.5% per year until 2021, (which is when APS assumed this cost would impact Four Corners). That 2021 cost of $13/metric ton continues to escalate at 2.5% per year through the end of the study period. Also see APS's response to Sierra Club 2.1. (APS response to Sierra Club data request 4.2. The referenced response to Sierra Club 2.1 contains the company's annual emissions price projections without explanation.)

In other words, the company's entire CO_2 emissions price trajectory is based upon extrapolation of a single California carbon allowance trade for 2016, extrapolated throughout the analysis period at something close to the anticipated rate of inflation. In my judgment, this is at best a very tenuous relationship between the company's forecasts and actual trading data, and does not lend credibility to the company's numbers.

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Mr. Wilde does that the existence of regulations to curtail emissions means they have no value simply defies logic.

Q. AS NOTED ABOVE, MR. WILDE CITED STAFF WITNESS JAMES LETZELTER'S OPINION ON GAS PRICES AS EVIDENCE THAT THE COMPANY'S PRICES ARE "REASONABLE". DID MR. LETZELTER ALSO ADDRESS THE COMPANY'S CO_2 PRICE FORECASTS?

A. Yes. Directly following his discussion of gas price forecasts, Mr. Letzelter compares the company's CO_2 emissions prices to those provided by the U.S. Energy Information Administration (EIA).

Q. WHAT DID MR. LETZELTER CONCLUDE REGARDING THE COMPANY'S CO_2 PRICE FORECASTS AND THEIR IMPACT ON THE NPV ANALYSIS?

A. Mr. Letzelter's conclusions are as follows:

> Based on this comparison to the EIA's projections, Liberty considers the APS numbers to be insufficiently conservative (*ie.,* too low for analysis purposes). The result is to underestimate the negative impacts to the Four Corners acquisition option. This, in turn, leads to the conclusion that more conservative (higher) CO_2 projections by APS could materially reduce the expected benefit of the acquisition. (Exhibit JCL-1, p.10)

Q. MR. WILDE CLAIMS THAT USING CRA'S EMISSIONS PRICE FORECAST WOULD NOT "SIGNIFICANTLY" CHANGE THE VALUE OF THE FOUR CORNERS ACQUISITION. DO YOU AGREE?

A. No. I demonstrated in my direct testimony that I believe this difference would overwhelm the entire claimed NPV benefit of the acquisition, and I provided a detailed explanation for why I believe this to be the case. Mr. Wilde simply makes an unsupported claim that there would not be a significant impact, and then goes on to describe the results of an entirely different analysis as if it had bearing on the question asked. It does not.

If the company wishes to provide a straightforward analysis of the impact of using a different CO_2 price forecast, it has the means to do so: simply re-run the analysis using the alternative emissions price forecast, and present the detailed results to the Commission. Merely claiming a result is no substitute for actually doing the analysis and providing the unobscured result.

Q. ON PAGE 6 OF HIS REBUTTAL TESTIMONY, MR. WILDE CHARACTRIZES YOUR CLAIM THAT PROJECTED CAPITAL EXPENDITURES ON THE FOUR CORNERS UNITS HAVE DECLINED SINCE THE COMPANY'S EARLIER FILING. DOES HE CHARACTERIZE YOUR TESTIMONY ACCURATELY?

A. No. I made clear in my testimony, and showed in Table 4, that the *undiscounted* projection of capital expenditures has increased, as Mr. Wilde notes. What the company has done in its NPV analysis, however, is to move these projected costs later in time, so that the NPV impact of the expenditures is dramatically reduced. I noted that this is inconsistent with the treatment of expenditures on other plants in the APS system, and that this raised a red flag in my review of the company's analysis. Once again, Mr. Wilde does not actually address the question raised in my testimony, this time by mischaracterizing it entirely.

Q. ON PAGES 37-39 OF YOUR DIRECT TESTIMONY, YOU DISCUSS THE RISKS THAT THE FOUR CORNERS UNITS WILL NOT REMAIN ON-LINE THROUGHOUT THEIR PROJECTED LIFETIME, OR WILL NOT RUN AT AS HIGH A CAPACITY FACTOR AS IT HAS IN THE PAST. DID MR. WILDE ADDRESS THESE POINTS?

A. Mr. Wilde claimed that I offer (or Sierra Club offers) "no evidence that, properly maintained, Units 4 and 5 could not continue to operate at current levels for the assumed life of the plants." That is true. However, I do describe in detail why I believe that early shutdown or curtailed operations represents a significant *risk* associated with the Four Corners acquisition, and that the company has never provided the Commission with any analysis of how this might impact the claimed benefits for ratepayers.

It is commonplace to note in just about every financial statement that "past performance is no guarantee of future performance", and that is certainly the case here. The company is expanding its dependence on aging, greenhouse gas-intensive infrastructure, and asks the Commission to ignore obvious associated risks. My suggestion was simply that the nature of these risks be put out in the open for full consideration, but Mr. Wilde ignores this point on the basis of Sierra Club's inability to predict the unpredictable – i.e., the operational performance of the units decades into the future.

Q. WHAT ARE YOUR CONCLUSIONS IN THIS SURREBUTTAL TESTIMONY?

A. In my direct testimony, I concluded (among other points) that "Without much more detailed explanation and justification of the company's assumptions and analytical decisions in each of these areas, I do not believe that the commission can reasonably accept APS's NPV analysis as valid or robust, nor can it approve the company's request in this docket." (44 at 18) I find that Mr. Wilde's rebuttal testimony has only perpetuated a pattern of unsupported claims and obfuscations. He purports to rebut the observations made and conclusions reached in my direct testimony, but in each instance he provides only vague and sometimes misleading descriptions, and sometimes direct mischaracterizations.

APS asks the Commission to saddle ratepayers with costs and risks for an acquisition that counters the general industry trend, extending and expanding its reliance on the most greenhouse gas intensive form of generation at a time when science, economics, and national policy point in a very different direction. In doing so, the company assumes a high burden of proof that its investment on behalf of ratepayers is prudent. I do not believe that this standard has been met, so I recommend that the company's petition be denied.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

EXHIBIT
Wal-Mart
ADMITTED

TESTIMONY OF CHARLES A. MIESSNER

On Behalf of Arizona Public Service Company

Docket No. E01345A-11-______

June 1, 2011

A. Yes. APS is proposing Experimental Rate Rider Schedule AG-1, which provides alternative generation service for extra-large general service customers with average monthly demands of 10 MW or more and are served under Rate Schedules E-34 and E-35. The experimental program will be available for three years from the initial date and limited to 200 MW of generation procured under this offering.

The Company is also proposing Rate Rider Schedule IRR which provides interruptible service for extra-large general service customers. This rate concept was previously filed under a separate matter pending under Docket No. E-01345A-10-0250, but is being included in the instant proceeding with the concurrence of potentially interested parties.

Q. PLEASE DESCRIBE RATE RIDER SCHEDULE AG-1.

A. Under this service, the customer can obtain an alternative source of generation to serve their full power requirements. The power must be delivered to one or more of the Company's points of delivery for wholesale power, as designated in a power supply agreement, and must serve at least 90%, but no more than 110%, of the customer's average hourly load. The Company will purchase and manage this generation on behalf of the customer for a management fee of $0.00060 per kWh. The customer will be responsible for any collateral costs associated with the alternative generation.

The Company will also provide scheduling and, if necessary, load following services for the power. APS will continue to supply transmission, delivery and revenue cycle services to the customer under the provisions of the customer's current retail rate schedule, Rate Schedule E-34 or E-35. The customer will also be subject to all of the adjustments in the retail rate schedule, except for Adjustment Schedule PSA-1. Furthermore, the billed amounts under the retail rate and applicable adjustments will be based on the total billed kWh, kW, or billed dollar amount, including the cost of the alternative generation.

Q. WHAT IS LOAD FOLLOWING SERVICE?

A. Load following service is the hourly matching of generation supply to the customer's load. The customer's alternative generation could be structured to supply this service – to ramp up and down hourly to match the load. On the other hand, the customer may purchase an amount of energy that is constant (flat) across many or all hours of the day, month, quarter, or year. In this case, APS would provide load following service to supply the extra energy needed when the alternative generation is less than the customer's load and to credit the surplus energy when generation exceeds load. The hourly sales will be transacted at an hourly market proxy price plus $4.00 to $10.00 per MWh depending on the amount of power that is required. The hourly credits will be based on the hourly market price less $4.00 to $10.00 per MWh.

Q. WHAT HAPPENS IF THE ALTERNATIVE GENERATOR DEFAULTS OR THE CUSTOMER WANTS TO RETURN TO THE STANDARD APS GENERATION SERVICES?

A. The customer must contract for service under this schedule for at least one year, but no more than three years. If the customer wishes to return to the standard APS generation service before the contract term, due to a default or other reason, they will be assessed a returning customer charge, which will be based on the costs to serve the returning customer versus the unbundled generation charge and related adjustments in their retail rate schedule, not to be less than zero. If the alternative generation supplier defaults, the customer will have 60 days to find an alternate supplier or be considered a "returning customer". Default provisions will be specified in the power supply agreement. The proposed Rate Rider Schedule AG-1 is provided as Attachment CAM-7.

Q. PLEASE DESCRIBE RATE RIDER SCHEDULE IRR.

This rate offers interruptible service to extra-large general service customers that can interrupt at least 500 kW of load when requested by the Company. Under this service, the customer can choose between two curtailment options, two notification options, and a one-year or five-year agreement. The Customer receives capacity and energy payments for the interruptible load based on these options. The customer may also incur a penalty for failing to curtail when requested. The proposed Rate Rider Schedule IRR is provided as Attachment CAM-15.

VIII. CLASSIFIED RATES

Q. PLEASE DESCRIBE THE COMPANY'S CLASSIFIED RATES.

A. The classified rates apply to specific types of customers, or specific end uses or customer circumstances. This class includes: rates for street lighting, outdoor area lighting, and water pumping; time-of-use rates for schools and religious houses of worship; a station use rate for merchant generators; and a variety of rates for renewable and on-site generation.

Q. WHAT DOES APS PROPOSE FOR CLASSIFIED RATES?

A. APS proposes to:

- Modify outdoor lighting Rate Schedules E-47 and E-58;
- Increase the demand charge for water pumping Rate Schedule E-221 to better reflect cost of service;
- Increase the demand charge and change the time-of-use hours for Rate Schedule E-221 8T to be consistent with other time-of-use rates;
- Eliminate the time-of-week option for Rate Schedule E-221;
- Cancel Rate Schedule E-40 for agricultural wind machines;

AVAILABILITY

This experimental rate rider schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate rider schedule is available for all Standard Offer customers who have an aggregated Peak load of 10 MW or more each month throughout the year, as measured at the customer's meter(s). All provisions of customer's current applicable rate schedule(s) will apply in addition to this Schedule AG-1, except as noted herein. This experimental rate schedule shall be available for three years after approval by the Arizona Corporation Commission. Total program participation shall be limited to 200 MW of peak load, on a first come first served basis.

DEFINITION

Generation Service Provider: A third party from which the customer contracts to provide power for their load.

DESCRIPTION OF SERVICES

The Generation Service Provider shall provide the customer firm power sufficient to meet their full requirements (total load), as agreed to by the customer and the Company.

The customer shall obtain a Generation Service Provider and notify the Company. The Company will subsequently contract with the Generation Service Provider on behalf of the customer for the specified power and manage the contract for the customer.

The Company shall provide transmission delivery and network services to the customer in accordance with normal retail electric service.

The Customer will be responsible for paying the cost of the energy from the Generation Service Provider for the Generation Service specified in the contract.

Other than the unbundled generation component, all kWh and kW charges in Customer's current applicable parent rate schedule and any other applicable adjustment schedules will be applied to the Energy or Demand, as applicable. Eligibility for placement on a rate schedule will be determined by Customer's Demand, in accordance with the Customer's parent Rate Schedule.

DELIVERY OF POWER TO APS' SYSTEM

Power provided from the Generation Service Provider must be firm power (Western System Power Pool Schedule C or equivalent) and must be contracted in advance and delivered to the Company at APS network delivery points that are not limited by APS' capability to deliver contracted quantities. If the Generation Services do not cover hourly loads in any given hour, the Company will supply for each hour, and the customer will pay for, necessary generation at the hourly pricing proxy plus $4/MWh for up to 10% of the hourly deficit and an additional hourly charge of $6/MWh for hourly supply deficit over 10%. If the Generation Services supplies more power than needed in any given hour, the Company will credit the customer for the excess power for each hour at the hourly pricing proxy minus $4/MWh for up to 10% of the excess and an additional deduction of $6/MWh for the hourly excess over 10%.

DETERMINATION OF HOURLY PRICING PROXY

Hourly pricing proxy shall be the published Dow Jones Electricity Palo Verde Hourly Index for the power delivery date. Hourly prices are expressed in $ per MWh.

RESERVE CAPACITY CHARGE

Customer will pay company a monthly reserve capacity charge equal to 15% of customer's monthly peak load.

POWER SUPPLY ADJUSTER AND HEDGE COST TRUE-UP

When taking this service, the customer will be subject to a true up mechanism (either plus or minus) to account for the unpaid or overpaid Power Supply Adjuster balance and hedge cost associated with the Customers Standard Offer Service.

DEFAULT OF THE THIRD PARTY GENERATION PROVIDER

In the event that the Generation Service Provider is unable to meet its contractual obligations, the customer must notify the Company, and enter into another power contract within 60 days. Prior to execution of a new power contract, the Company shall proved generation service to the Customer, which will be charged at the hourly pricing proxy for generation service.

If the customer is unable to secure a new generation contract in that sixty day period, they will be deemed a returning customer, subject to conditions below.

RETURN TO COMPANY'S BUNDLED GENERATION SERVICE

If the Customer returns to the Company's bundled Generation Service, the Customer will be charged a Returning Customer Charge. The charge will be identified in the Electric Service Agreement between the Customer and the Company and will be in addition to the Standard Offer service charges. The Returning Customer Charge will be based on the cost differential between the applicable Standard Offer rate generation component and the cost of the resources required to serve the returning customer(s). The costs associated with serving customers that are required to enter into Returning Customer Charge agreements will be kept separate from the retail power supply costs subject to recovery through the Power Supply Adjustment. The types of costs that will be used to develop the Returning Customer Charge are incremental Power Supply, Transmission, Ancillary Services and Metering. These costs will be amortized over an appropriate period to allow their timely recovery. In no event, however, will the Returning Customer Charge be in place less than one year, or last longer than 36 months and in no case shall be less than zero for any individual customer.

When taking this service, the Customer will be subject to a true up mechanism (either plus or minus) to account for the unpaid or overpaid Power Supply Adjuster balance and related hedge cost associated with the Customers Standard Offer Service.

RATES

Service under this rate schedule shall be billed according to Customer's current applicable parent rate schedule, except as follows:

1. The adjustment schedules PSA, ERA-1 and EIS will not apply to the Customer's bill while said Customer is on Rate Schedule AG-1.
2. In addition, the Customer agrees to pay a Management fee of $0.00060 per kWh.
3. Other than the unbundled Generation component, all kWh and kW charges in Customer's current applicable parent rate schedule and any other applicable adjustment schedules will be applied to the Energy or Demand, as applicable.

CONTRACT TERM AND REQUIREMENTS

The term of the Customer's contract with the Generation Service Provider shall be for not less than one year, and shall not exceed three years.

The Customer will enter a contract with the Company, stating the pertinent details of the transaction with the Generation Service Provider, including but not limited to the scheduling of power, location of delivery and other terms related APS' management of the generation resource.

CREDIT REQUIREMENTS

Customer must provide all collateral and margining requirements defined in the Generation Service contract to the Company. Failure to do so will be considered a default by the Customer and result in a return to bundled services under the terms stated in the return to Company's bundled service above. In addition, Company will be paid by the Customer for any losses associated with terminating the contract with the Generation Service Provider.

All Generation Service Providers must have at least an investment grade credit rating and demonstrate creditworthiness acceptable to Company.

ADJUSTMENTS

All adjustments of the Customers parent Rate Schedule will apply to the Customers bill, including the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE, Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

EXHIBIT
Walmart
2
ADMITTED

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.

NO. DOCKET NO. E-01345A-11-0224

DIRECT TESTIMONY OF STEVE W. CHRISS

ON FOUR CORNERS ADJUSTMENT SCHEDULE

WAL-MART STORES, INC. AND SAM'S WEST, INC.

June 18, 2014

TABLE OF CONTENTS

<u>Exhibits</u>
Exhibit SWC-1

Introduction

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

A. My name is Steve W. Chriss. My business address is 2001 SE 10th St., Bentonville, AR 72716-0550. I am employed by Wal-Mart Stores, Inc. as Senior Manager, Energy Regulatory Analysis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A. I am testifying on behalf of Wal-Mart Stores, Inc. and Sam's West, Inc. ("Walmart").

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. In 2001, I completed a Master of Science in Agricultural Economics at Louisiana State University. From 2001 to 2003, I was an Analyst and later a Senior Analyst at the Houston office of Econ One Research, Inc., a Los Angeles-based consulting firm. My duties included research and analysis on domestic and international energy and regulatory issues. From 2003 to 2007, I was an Economist and later a Senior Utility Analyst at the Public Utility Commission of Oregon in Salem, Oregon. My duties included appearing as a witness for PUC Staff in electric, natural gas, and telecommunications dockets. I joined the energy department at Walmart in July 2007 as Manager, State Rate Proceedings, and was promoted to my current position in June 2011. My Witness Qualifications Statement is included herein as Exhibit SWC-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE ARIZONA CORPORATION COMMISSION ("THE COMMISSION") IN THIS DOCKET?

A. Yes. I submitted Direct Testimony (Non-Rate Design) on November 18, 2011, Rate Design Testimony on December 2, 2011, and Testimony in Support of the Settlement on January 18, 2012.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE OTHER STATE REGULATORY COMMISSIONS?

A. Yes. I have submitted testimony in over 90 proceedings before 33 other utility regulatory commissions and before the Missouri House Committee on Utilities, the Missouri Senate Veterans' Affairs, Emerging Issues, Pensions, and Urban Affairs Committee, and the Kansas House Standing Committee on Utilities and Telecommunications. My testimony has addressed topics including, but not limited to, cost of service and rate design, ratemaking policy, qualifying facility rates, telecommunications deregulation, resource certification, energy efficiency/demand side management, fuel cost adjustment mechanisms, decoupling, and the collection of cash earnings on construction work in progress.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am sponsoring Exhibit SWC-1, consisting of twelve pages.

Q. PLEASE BRIEFLY DESCRIBE WALMART'S OPERATIONS IN ARIZONA.

A. Walmart operates 121 retail units and employs 32,438 associates in Arizona. In fiscal year ending 2014, Walmart purchased $789 million worth of goods and services from Arizona-based suppliers, supporting 24,245 supplier jobs.[1]

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[1] http://corporate.walmart.com/our-story/locations/united-states#/united-states/arizona

Q. PLEASE BRIEFLY DESCRIBE WALMART'S OPERATIONS WITHIN APS'S SERVICE TERRITORY.

A. Walmart has approximately 49 stores and distribution centers serviced by Arizona Public Service ("APS" or "the Company"), primarily on Schedules E-32L and E-32M. Approximately 40 of those facilities also take service on Experimental Rate Rider Schedule AG-1, Alternative Generation General Service ("AG-1").

Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address concerns regarding APS's proposed Adjustment Schedule FCA, Four Corners Adjustment ("FCA"). Specifically, I respond to the testimonies of Elizabeth A. Blankenship and Jeffrey B. Guldner.

Summary of Recommendations

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. My recommendations to the Commission are as follows:

1) The Commission should reject APS's proposal to apply the FCA to the non-generation, or "APS" portions of AG-1 customer bills.

2) The Commission should modify the Company's proposed FCA tariff language as follows:

"RATE

The FCA charge will be applied to the customer's monthly billed amount, excluding all other adjustments, sales tax, regulatory assessment and franchise fees. The resulting charged amount shall not be less than zero. In addition, the charge shall not apply to:

- Any portion of the monthly billed amount for a customer that takes service under Rate Rider Schedule AG-1."

The fact that an issue is not addressed herein or in related filings should not be construed as an endorsement of any filed position. Additionally, for issues not addressed in this testimony, Walmart specifically reserves the right to address these issues in rebuttal if they are brought up by other parties.

Background

Q. WHAT IS SCHEDULE AG-1 AND HOW DID IT COME INTO EXISTENCE?

A. AG-1 is a buy through rate for large commercial and industrial customers which allows customers to purchase generation service from a third-party Generation Service Provider. APS had proposed AG-1 in its direct testimony in the first phase of this proceeding, and it was adopted with modifications as part of the Settlement Agreement. The Commission approved AG-1 as proposed by the Settlement Agreement in Decision No. 73183. *See* Decision No. 73183, Exhibit A, page 18 and Attachment J.

Q. WHAT ARE THE RATE PROVISIONS INCLUDED IN AG-1?

A. AG-1 includes the following rate provisions:

1) The generation charges will not apply;
2) Adjustment Schedule PSA-1 will not apply, except that the Historical Component will apply for the first twelve months of service under this rate rider schedule;
3) Adjustment Schedule EIS will not apply;
4) The applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the

electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder shall be applied to the customer's bill;

5) A management fee of $0.0006/kWh to the customer's metered kWh;
6) A reserve capacity charge applied to 15 percent of the customer's billed kW;
7) An initial charge for fuel hedging costs;
8) Returning Customer charge, where applicable; and
9) Generation Service Provider Default charge, where applicable. *See* Decision No. 73183, Attachment J, page 4.

Q. WHAT ARE THE TERMS OF THE HEDGING PROVISION IN AG-1?

A. Per the AG-1 tariff, the customer will pay the hedge cost associated with the customer's Standard Generation Service at the time that the customer switches to AG-1. The cost to the customer is determined by the Company as its applicable pro rata hedge cost based on the market price for hedge costs at the time the customer takes service under AG-1. *Id.*, page 3.

Q. ONCE A CUSTOMER HAS SWITCHED TO AG-1, DOES THAT CUSTOMER THEN CAUSE APS TO INCUR ANY RETAIL GENERATION COST?

A. No. In addition, once the customer has paid the Historical Component of the PSA and the hedge costs, that customer has fully compensated the Company for generation costs incurred on its behalf that were not fully recovered prior to the Customer switching to AG-1.

APS's Four Corners Adjustment Proposal

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S PROPOSED FCA?

A. My understanding of the proposed FCA is that it is the mechanism by which APS seeks to include in rates the rate base and expense costs associated with the acquisition of Southern California Edison's share of Four Corners generation Units 4 and 5, the retirement of Four Corners generation Units 1, 2, and 3, and any cost deferrals authorized in Docket No. E-01345A-10-0474. *See* Direct Testimony of Jeffrey B. Guldner, page 5, line 2 to line 5. In all, APS seeks recovery of an annual revenue requirement of $62.53 million related to Four Corners generation-related costs. *See* Direct Testimony of Elizabeth A. Blankenship, page 4, line 4 to line 5.

Q. DOES THE COMPANY PROPOSE THE FCA UNDER THE TERMS OF THE SETTLEMENT APPROVED BY THE COMMISSION IN THIS DOCKET IN DECISION NO. 73183?

A. Yes. Specifically, the Company refers to Section 10.2 of the Settlement, which keeps the instant docket open in order for APS to file such a request. *See* Direct Testimony of Jeffrey B. Guldner, page 4, line 11 to line 26.

Q. WAS WALMART A PARTY TO THE SETTLEMENT?

A. Yes. *See* Decision No. 73183, Exhibit A, page 3. Additionally, both Chris Hendrix, Director of Markets & Compliance for Wal-Mart Stores, Inc. and I filed testimony on behalf of Walmart supporting the settlement.

Q. HOW DOES APS PROPOSE TO RECOVER THE REVENUE REQUIREMENT FROM CUSTOMERS?

A. APS proposes to recover the revenue requirement from customers on an equal percentage basis applied to the base portion of customer bills, with certain exceptions. *Id.*, line 5 to line 7.

Q. WHAT EXCEPTIONS DOES APS PROPOSE?

A. APS proposes the following exceptions:

1) The generation service and imbalance service charges in AG-1;
2) The energy and ancillary service charge in Rate Schedule E-36 XL;
3) Credits for the purchase of excess generation under rate rider schedules EPR-2, EPR-6, and E-56R; and
4) Voluntary charges under rate rider schedules GPS-1, GPS-2, and GPS-3. *See* Attachment EAB-9, Schedule 5.

Q. **DOES THE COMPANY'S PROPOSAL INCLUDE APPLYING THE FCA CHARGE TO NON-GENERATION, OR "APS" PORTIONS OF AG-1 CUSTOMER BILLS?**

A. Yes. *See* Direct Testimony of Jeffrey B. Guldner, page 10, line 18 to line 21. My understanding is that, using E-32L as an example, the FCA would apply to the customer accounts, metering and billing, system benefits, transmission, and delivery charges. *See* A.C.C. No. 5813, page 2 to page 3.

Q. **WHAT IS THE PROPOSED FCA CHARGE AT THE COMPANY'S PROPOSED REVENUE REQUIREMENT?**

A. The proposed FCA charge is 2.2 percent. *See* Attachment EAB-9, Schedule 5.

FCA Application to AG-1 Customers

Q. **DOES WALMART HAVE CONCERNS WITH THE PROPOSED FCA?**

A. Yes. As I will explain below, the proposed FCA is inconsistent with the Settlement approved by the Commission in Decision No. 73183 and the resulting terms of AG-1, and associated cost causation principles.

Q. **ARE COSTS RELATED TO THE ACQUISITION OF FOUR CORNERS UNITS 4 AND 5 INCURRED ON BEHALF OF CUSTOMERS THAT TAKE GENERATION SERVICE FROM APS?**

A. Yes, and only those customers who take generation service from APS will receive benefits from those units. As such, per the matching principle, in which customers bear costs only when they are receiving a benefit, only those ratepayers who take generation service from APS and will benefit from the acquisition of those assets should bear the burden of those costs.

Q. **DOES CHARGING AG-1 CUSTOMERS THE FCA VIOLATE THE MATCHING PRINCIPLE?**

A. Yes. AG-1 customers will receive no benefit from the acquisition of Four Corners Units 4 and 5 and should not bear any related cost.

Q. **DOES THE AG-1 TARIFF CURRENTLY RECOGNIZE THAT AN AG-1 CUSTOMER CAUSES NO RETAIL GENERATION COST TO BE INCURRED BY THE COMPANY?**

A. Yes, and it specifically states that "the generation charges will not apply." *Id.*, page 4. This is consistent with cost causation and matching principles, which provide that costs for generation services should be recovered from customers who cause the utility to incur those costs.

Q. **DOES THE APPLICATION OF THE FCA TO PART OF AN AG-1 CUSTOMER BILL APPEAR TO VIOLATE THE PROVISION OF AG-1 THAT STATES THAT GENERATION CHARGES WILL NOT APPLY?**

A. Yes, as application of the proposed FCA would charge a "generation charge" to AG-1 customers.

Q. **WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?**

A. The Commission should reject APS's proposal to apply the FCA to the "APS" portions of AG-1 customer bills.

Q. **DO YOU RECOMMEND A MODIFICATION TO THE FCA LANGUAGE PROPOSED BY APS?**

A. Yes. I recommend the following modification to the Company's proposed FCA language:

"RATE

The FCA charge will be applied to the customer's monthly billed amount, excluding all other adjustments, sales tax, regulatory assessment and franchise fees. The resulting charged amount shall not be less than zero. In addition, the charge shall not apply to:

- Any portion of the monthly billed amount for a customer that takes service under Rate Rider Schedule AG-1."

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Exhibit SWC-1

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EXPERIENCE

July 2007 – Present
Wal-Mart Stores, Inc., Bentonville, AR
Senior Manager, Energy Regulatory Analysis (June 2011 – Present)
Manager, State Rate Proceedings (July 2007 – June 2011)

June 2003 – July 2007
Public Utility Commission of Oregon, Salem, OR
Senior Utility Analyst (February 2006 – July 2007)
a. **Economist** (June 2003 – February 2006)

January 2003 - May 2003
North Harris College, Houston, TX
Adjunct Instructor, Microeconomics

June 2001 - March 2003
Econ One Research, Inc., Houston, TX
Senior Analyst (October 2002 – March 2003)
Analyst (June 2001 – October 2002)

EDUCATION

2001	**Louisiana State University**	M.S., Agricultural Economics
1997-1998	**University of Florida**	Graduate Coursework, Agricultural Education and Communication
1997	**Texas A&M University**	B.S., Agricultural Development B.S., Horticulture

TESTIMONY BEFORE REGULATORY COMMISSIONS

2014

Minnesota Public Utilities Commission Docket No. E-002/GR-13-868: In the Matter of the Application of Northern States Power Company, for Authority to Increase Rates for Electric Service in Minnesota.

Utah Public Service Commission Docket No. 13-035-184: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.
Missouri Public Service Commission Case No. EC-2014-0224: In the Matter of Noranda Aluminum, Inc.'s Request for Revisions to Union Electric Company d/b/a Ameren Missouri's Large Transmission Service Tariff to Decrease its Rate for Electric Service.

Oklahoma Corporation Commission Cause No. PUD 201300217: Application of Public Service Company of Oklahoma to be in Compliance with Order No. 591185 Issued in Cause No. PUD 201100106 Which Requires a Base Rate Case to be Filed by PSO and the Resulting Adjustment in its Rates and Charges and Terms and Conditions of Service for Electric Service in the State of Oklahoma.

Public Utilities Commission of Ohio Case No. 13-2386-EL-SSO: In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.

2013
Oklahoma Corporation Commission Cause No. PUD 201300201: Application of Public Service Company of Oklahoma for Commission Authorization of a Standby and Supplemental Service Rate Schedule.

Georgia Public Service Commission Docket No. 36989: Georgia Power's 2013 Rate Case.

Florida Public Service Commission Docket No. 130140-EI: Petition for Rate Increase by Gulf Power Company.

Public Utility Commission of Oregon Docket No. UE 267: In the Matter of PACIFICORP, dba PACIFIC POWER, Transition Adjustment, Five-Year Cost of Service Opt-Out.

Illinois Commerce Commission Docket No. 13-0387: Commonwealth Edison Company Tariff Filing to Present the Illinois Commerce Commission with an Opportunity to Consider Revenue Neutral Tariff Changes Related to Rate Design Authorized by Subsection 16-108.5 of the Public Utilities Act.

Iowa Utilities Board Docket No. RPU-2013-0004: In Re: MidAmerican Energy Company.

South Dakota Public Utilities Commission Docket No. EL12-061: In the Matter of the Application of Black Hills Power, Inc. for Authority to Increase its Electric Rates. (filed with confidential stipulation)

Kansas Corporation Commission Docket No. 13-WSEE-629-RTS: In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Service.

Public Utility Commission of Oregon Docket No. UE 263: In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision.

Arkansas Public Service Commission Docket No. 13-028-U: In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.

Virginia State Corporation Commission Docket No. PUE-2013-00020: Application of Virginia Electric and Power Company for a 2013 Biennial Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Florida Public Service Commission Docket No. 130040-EI: Petition for Rate Increase by Tampa Electric Company.

South Carolina Public Service Commission Docket No. 2013-59-E: Application of Duke Energy Carolinas, LLC, for Authority to Adjust and Increase Its Electric Rates and Charges.

Public Utility Commission of Oregon Docket No. UE 262: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.

New Jersey Board of Public Utilities Docket No. ER12111052: In the Matter of the Verified Petition of Jersey Central Power & Light Company For Review and Approval of Increases in and Other Adjustments to Its Rates and Charges For Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith; and for Approval of an Accelerated Reliability Enhancement Program ("2012 Base Rate Filing")

North Carolina Utilities Commission Docket No. E-7, Sub 1026: In the Matter of the Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Public Utility Commission of Oregon Docket No. UE 264: PACIFICORP, dba PACIFIC POWER, 2014 Transition Adjustment Mechanism.

Public Utilities Commission of California Docket No. 12-12-002: Application of Pacific Gas and Electric Company for 2013 Rate Design Window Proceeding.

Public Utilities Commission of Ohio Docket Nos. 12-426-EL-SSO, 12-427-EL-ATA, 12-428-EL-AAM, 12-429-EL-WVR, and 12-672-EL-RDR: In the Matter of the Application of the Dayton Power and Light Company Approval of its Market Offer.

Minnesota Public Utilities Commission Docket No. E-002/GR-12-961: In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota.

North Carolina Utilities Commission Docket E-2, Sub 1023: In the Matter of Application of Progress Energy Carolinas, Inc. For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

2012

Public Utility Commission of Texas Docket No. 40443: Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs.

South Carolina Public Service Commission Docket No. 2012-218-E: Application of South Carolina Electric & Gas Company for Increases and Adjustments in Electric Rate Schedules and Tariffs and Request for Mid-Period Reduction in Base Rates for Fuel.

Kansas Corporation Commission Docket No. 12-KCPE-764-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Kansas Corporation Commission Docket No. 12-GIMX-337-GIV: In the Matter of a General Investigation of Energy-Efficiency Policies for Utility Sponsored Energy Efficiency Programs.

Florida Public Service Commission Docket No. 120015-EI: In Re: Petition for Rate Increase by Florida Power & Light Company.

California Public Utilities Commission Docket No. A.11-10-002: Application of San Diego Gas & Electric Company (U 902 E) for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design.

Utah Public Service Commission Docket No. 11-035-200: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Virginia State Corporation Commission Case No. PUE-2012-00051: Application of Appalachian Power Company to Revise its Fuel Factor Pursuant to § 56-249.6 of the Code of Virginia.

Public Utilities Commission of Ohio Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM: In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form on an Electric Security Plan and In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.

New Jersey Board of Public Utilities Docket No. ER11080469: In the Matter of the Petition of Atlantic City Electric for Approval of Amendments to Its Tariff to Provide for an Increase in

Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and For Other Appropriate Relief.

Public Utility Commission of Texas Docket No. 39896: Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs.
Missouri Public Service Commission Case No. EO-2012-0009:In the Matter of KCP&L Greater Missouri Operations Notice of Intent to File an Application for Authority to Establish a Demand-Side Programs Investment Mechanism.

Colorado Public Utilities Commission Docket No. 11AL-947E: In the Matter of Advice Letter No. 1597-Electric Filed by Public Service Company of Colorado to Revise its Colorado PUC No. 7-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Changes Effective December 23, 2011.

Illinois Commerce Commission Docket No. 11-0721: Commonwealth Edison Company Tariffs and Charges Submitted Pursuant to Section 16-108.5 of the Public Utilities Act.

Public Utility Commission of Texas Docket No. 38951: Application of Entergy Texas, Inc. for Approval of Competitive Generation Service tariff (Issues Severed from Docket No. 37744).

California Public Utilities Commission Docket No. A.11-06-007: Southern California Edison's General Rate Case, Phase 2.

2011
Arizona Corporation Commission Docket No. E-01345A-11-0224: In the Matter of Arizona Public Service Company for a Hearing to Determine the Fair Value of Utility Property of the Company for Ratemaking Purposes, to Fix and Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return.

Oklahoma Corporation Commission Cause No. PUD 201100087: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

South Carolina Public Service Commission Docket No. 2011-271-E: Application of Duke Energy Carolinas, LLC for Authority to Adjust and Increase its Electric Rates and Charges.

Pennsylvania Public Utility Commission Docket No. P-2011-2256365: Petition of PPL Electric Utilities Corporation for Approval to Implement Reconciliation Rider for Default Supply Service.

North Carolina Utilities Commission Docket No. E-7, Sub 989: In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Florida Public Service Commission Docket No. 110138: In Re: Petition for Increase in Rates by Gulf Power Company.

Public Utilities Commission of Nevada Docket No. 11-06006: In the Matter of the Application of Nevada Power Company, filed pursuant to NRS 704.110(3) for authority to increase its annual revenue requirement for general rates charged to all classes of customers to recover the costs of constructing the Harry Allen Combined Cycle plant and other generating, transmission, and distribution plant additions, to reflect changes in the cost of capital, depreciation rates and cost of service, and for relief properly related thereto.

North Carolina Utilities Commission Docket Nos. E-2, Sub 998 and E-7, Sub 986: In the Matter of the Application of Duke Energy Corporation and Progress Energy, Inc., to Engage in a Business Combination Transaction and to Address Regulatory Conditions and Codes of Conduct.

Public Utilities Commission of Ohio Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM: In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form on an Electric Security Plan and In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.

Virginia State Corporation Commission Case No. PUE-2011-00037: In the Matter of Appalachian Power Company for a 2011 Biennial Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Illinois Commerce Commission Docket No. 11-0279 and 11-0282 (cons.): Ameren Illinois Company Proposed General Increase in Electric Delivery Service and Ameren Illinois Company Proposed General Increase in Gas Delivery Service.

Virginia State Corporation Commission Case No. PUE-2011-00045: Application of Virginia Electric and Power Company to Revise its Fuel Factor Pursuant to § 56-249.6 of the Code of Virginia.

Utah Public Service Commission Docket No. 10-035-124: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Maryland Public Utilities Commission Case No. 9249: In the Matter of the Application of Delmarva Power & Light for an Increase in its Retail Rates for the Distribution of Electric Energy.

Minnesota Public Utilities Commission Docket No. E002/GR-10-971: In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota.

Michigan Public Service Commission Case No. U-16472: In the Matter of the Detroit Edison Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

2010

Public Utilities Commission of Ohio Docket No. 10-2586-EL-SSO: In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service.

Colorado Public Utilities Commission Docket No. 10A-554EG: In the Matter of the Application of Public Service Company of Colorado for Approval of a Number of Strategic Issues Relating to its DSM Plan, Including Long-Term Electric Energy Savings Goals, and Incentives.

Public Service Commission of West Virginia Case No. 10-0699-E-42T: Appalachian Power Company and Wheeling Power Company Rule 42T Application to Increase Electric Rates.

Oklahoma Corporation Commission Cause No. PUD 201000050: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and Terms and Conditions of Service for Electric Service in the State of Oklahoma.

Georgia Public Service Commission Docket No. 31958-U: In Re: Georgia Power Company's 2010 Rate Case.

Washington Utilities and Transportation Commission Docket No. 100749: 2010 Pacific Power & Light Company General Rate Case.

Colorado Public Utilities Commission Docket No. 10M-254E: In the Matter of Commission Consideration of Black Hills Energy's Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act."

Colorado Public Utilities Commission Docket No. 10M-245E: In the Matter of Commission Consideration of Public Service Company of Colorado Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act."

Public Service Commission of Utah Docket No. 09-035-15 *Phase II*: In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.

Public Utility Commission of Oregon Docket No. UE 217: In the Matter of PACIFICORP, dba PACIFIC POWER Request for a General Rate Revision.

Mississippi Public Service Commission Docket No. 2010-AD-57: In Re: Proposal of the Mississippi Public Service Commission to Possibly Amend Certain Rules of Practice and Procedure.

Indiana Utility Regulatory Commission Cause No. 43374: Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to Ind. Code § 8-1-2.5-1, *ET SEQ.*, for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance with Ind. Code §§ 8-1-2.5-1 *ET SEQ.* and 8-1-2-42 (a); Authority to Defer Program Costs Associated with its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs, Including the Powershare® Program in its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Clause Earnings and Expense Tests.

Public Utility Commission of Texas Docket No. 37744: Application of Entergy Texas, Inc. for Authority to Change Rates and to Reconcile Fuel Costs.

South Carolina Public Service Commission Docket No. 2009-489-E: Application of South Carolina Electric & Gas Company for Adjustments and Increases in Electric Rate Schedules and Tariffs.

Kentucky Public Service Commission Case No. 2009-00459: In the Matter of General Adjustments in Electric Rates of Kentucky Power Company.

Virginia State Corporation Commission Case No. PUE-2009-00125: For acquisition of natural gas facilities Pursuant to § 56-265.4:5 B of the Virginia Code.

Arkansas Public Service Commission Docket No. 10-010-U: In the Matter of a Notice of Inquiry Into Energy Efficiency.

Connecticut Department of Public Utility Control Docket No. 09-12-05: Application of the Connecticut Light and Power Company to Amend its Rate Schedules.

Arkansas Public Service Commission Docket No. 09-084-U: In the Matter of the Application of Entergy Arkansas, Inc. For Approval of Changes in Rates for Retail Electric Service.

Missouri Public Service Commission Docket No. ER-2010-0036: In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.

Public Service Commission of Delaware Docket No. 09-414: In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Charges.

2009

Virginia State Corporation Commission Case No. PUE-2009-00030: In the Matter of Appalachian Power Company for a Statutory Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Public Service Commission of Utah Docket No. 09-035-15 *Phase I*: In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.

Public Service Commission of Utah Docket No. 09-035-23: In the Matter of the Application of Rocky Mountain Power for Authority To Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations.

Colorado Public Utilities Commission Docket No. 09AL-299E: Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No. 1535 – Electric.

Arkansas Public Service Commission Docket No. 09-008-U: In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs.

Oklahoma Corporation Commission Docket No. PUD 200800398: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

Public Utilities Commission of Nevada Docket No. 08-12002: In the Matter of the Application by Nevada Power Company d/b/a NV Energy, filed pursuant to NRS §704.110(3) and NRS §704.110(4) for authority to increase its annual revenue requirement for general rates charged to all classes of customers, begin to recover the costs of acquiring the Bighorn Power Plant, constructing the Clark Peakers, Environmental Retrofits and other generating, transmission and distribution plant additions, to reflect changes in cost of service and for relief properly related thereto.

New Mexico Public Regulation Commission Case No. 08-00024-UT: In the Matter of a Rulemaking to Revise NMPRC Rule 17.7.2 NMAC to Implement the Efficient Use of Energy Act.

Indiana Utility Regulatory Commission Cause No. 43580: Investigation by the Indiana Utility Regulatory Commission, of Smart Grid Investments and Smart Grid Information Issues

Contained in 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. § 2621(d)), as Amended by the Energy Independence and Security Act of 2007.

Louisiana Public Service Commission Docket No. U-30192 *Phase II (February 2009)*: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

South Carolina Public Service Commission Docket No. 2008-251-E: In the Matter of Progress Energy Carolinas, Inc.'s Application For the Establishment of Procedures to Encourage Investment in Energy Efficient Technologies; Energy Conservation Programs; And Incentives and Cost Recovery for Such Programs.

2008

Colorado Public Utilities Commission Docket No. 08A-366EG: In the Matter of the Application of Public Service Company of Colorado for approval of its electric and natural gas demand-side management (DSM) plan for calendar years 2009 and 2010 and to change its electric and gas DSM cost adjustment rates effective January 1, 2009, and for related waivers and authorizations.

Public Service Commission of Utah Docket No. 07-035-93: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge.

Indiana Utility Regulatory Commission Cause No. 43374: Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission Approve an Alternative Regulatory Plan for the Offering of Energy Efficiency, Conservation, Demand Response, and Demand-Side Management.

Public Utilities Commission of Nevada Docket No. 07-12001: In the Matter of the Application of Sierra Pacific Power Company for authority to increase its general rates charged to all classes of electric customers to reflect an increase in annual revenue requirement and for relief properly related thereto.

Louisiana Public Service Commission Docket No. U-30192 *Phase II*: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

Colorado Public Utilities Commission Docket No. 07A-420E: In the Matter of the Application of Public Service Company of Colorado For Authority to Implement and Enhanced Demand Side Management Cost Adjustment Mechanism to Include Current Cost Recovery and Incentives.