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DATE: MAY 2, 2012

DOCKET NO.: E-01345A-11-0224

TO ALL PARTIES:

Enclosed please find the recommendation of Administrative Law Judge Lyn Farmer. The recommendation has been filed in the form of an Opinion and Order on:

ARIZONA PUBLIC SERVICE COMPANY
(RATES)

Pursuant to A.A.C. R14-3-110(B), you may file exceptions to the recommendation of the Administrative Law Judge by filing an original and thirteen (13) copies of the exceptions with the Commission's Docket Control at the address listed below by **12:00** p.m. on or before:

MAY 11, 2012

The enclosed is NOT an order of the Commission, but a recommendation of the Administrative Law Judge to the Commissioners. Consideration of this matter has tentatively been scheduled for the Commission's Open Meeting to be held on:

TO BE DETERMINED

For more information, you may contact Docket Control at (602) 542-3477 or the Hearing Division at (602) 542-4250. For information about the Open Meeting, contact the Executive Director's Office at (602) 542-3931.

ERNEST G. JOHNSON
EXECUTIVE DIRECTOR

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE - Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

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.	DOCKET NO. E-01345A-11-0224 DECISION NO. ____________ **OPINION AND ORDER**

DATES OF HEARING: July 18, 2011 (Procedural Conference); October 7, 2011 (Public Comments – Sun City, Arizona); December 16, 2011 (Special Open Meeting); January 19, 2012 (Public Comments – Phoenix, Arizona); January 19, 2012 (Pre-Hearing Conference); January 26, 27, 30, 31, February 1, 2, and 3, 2012.

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Lyn Farmer

IN ATTENDANCE:
Gary Pierce, Chairman
Bob Stump, Commissioner
Sandra D. Kennedy, Commissioner
Paul Newman, Commissioner
Brenda Burns, Commissioner

APPEARANCES:

Ms. Meghan H. Grabel and Mr. Thomas L. Mumaw, Law Department, PINNACLE WEST CAPITAL CORPORATION, on behalf of the Applicant;

Mr. Michael M. Grant, GALLAGHER & KENNEDY, PA, on behalf of Arizona Investment Council;

Mr. Craig A. Marks, CRAIG A. MARKS, PLC, on behalf of AARP;

Mr. Timothy M. Hogan, ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST; on behalf of Southwest Energy Efficiency Project, Western Resource Advocates, Arizona School Boards Association, and Arizona Association of School Business Officials;

Ms. Cynthia Zwick, in propria persona;

Mr. Scott S. Wakefield, RIDENOUR, HEINTON & LEWIS, PLLC, on behalf of Wal-Mart Stores, Inc.;

Mr. Jeffrey W. Crockett, BROWNSTEIN, HYATT, FARBER SCHRECK, LLP, on behalf of Arizona Association of Realtors;

Mr. Lawrence V. Robertson, Jr., MUNGER CHADWICK, P.L.C., on behalf of Southwestern Power Group, Bowie Power Station, Noble Americas Energy Solutions, LLC, Constellation NewEnergy, Inc., Direct Energy, LLC, and Shell Energy North America, (US), LP;

Mr. C. Webb Crockett, FENNEMORE CRAIG, PC, on behalf of Freeport-McMoRan Copper & Gold, Inc., and Arizonans for Electric Choice and Competition;

Mr. Nicholas L. Enoch, LUBIN & ENOCH, PC, on behalf of Locals 387, 640 and 769 of the International Brotherhood of Electrical Workers;

Captain Samuel Miller; AIR FORCE UTILITY LAW FIELD SUPPORT CENTER, on behalf of the Federal Executive Agencies;

Ms. Laura E. Sanchez, on behalf of the Natural Resources Defense Council;

Mr. Greg Patterson, of Counsel, MUNGER CHADWICK, P.L.C. on behalf of the Arizona Competitive Power Alliance;

Ms. Jody M. Kyler, BOEHM, KURTZ & LOWRY, on behalf of the Kroger Company;

Mr. Daniel Pozefsky, Chief Counsel, on behalf of the Residential Utility Consumer Office; and

Ms. Maureen A. Scott, Senior Staff Counsel, Ms. Janet Wagner, Assistant Chief Counsel, Mr. Charles O. Hains and Mr. Scott Hesla, Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

BY THE COMMISSION:

On June 1, 2011, Arizona Public Service Company ("APS" or "Company") filed with the Arizona Corporation Commission ("Commission") an application 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. The application requested a net increase in base rates of $95.5 million, or 3.3 percent, to become effective July 1, 2012. The requested increase was based upon adjusted test year sales and expenses for the Company's electric operations during the twelve months ending December 31, 2010 ("test year").

On July 1, 2011, the Commission's Utilities Division ("Staff") filed a Letter of Sufficiency indicating that the application had met the sufficiency requirements of Arizona Administrative Code ("A.A.C.") R14-2-103 and classifying the Company as a Class A utility.

Intervention was requested and granted to Freeport-McMoRan Copper & Gold, Inc. ("Freeport-McMoRan"); Arizonans for Electric Choice and Competition ("AECC"); the Residential Utility Consumer Office ("RUCO"); the Town of Wickenburg ("Wickenburg"); Barbara Wyllie-Pecora; Western Resource Advocates ("WRA"); Southwest Energy Efficiency Project ("SWEEP"); The Kroger Co. ("Kroger"); Arizona Association of Realtors ("AAR"); the Town of Gilbert ("Gilbert"); Tucson Electric Power Company ("TEP"); Cynthia Zwick; Arizona Investment Council ("AIC"); Federal Executive Agencies ("FEA"); Arizona Competitive Power Alliance ("Alliance"); Local Union 387, International Brotherhood of Electrical Workers, AFL-CIO, CLC, Local Union 640, International Brotherhood of Electrical Workers, AFL-CIO, CLC, and Local Union 769, International Brotherhood of Electrical Workers, AFL-CIO, CLC (together, "IBEW"); Southwestern Power Group II, L.L.C. and Bowie Power Station, L.L.C. ("SWPG/Bowie"); Natural Resources Defense Council ("NRDC"); the Arizona School Boards Association and the Arizona Association of School Business Officials (together, "ASBA/AASBO"); AzAg Group; Wal-Mart Stores, Inc. and Sam's West, Inc. (together, "Wal-Mart"); Noble Americas Energy Solutions LLC, Constellation NewEnergy, Inc., Direct Energy, LLC and Shell Energy North America (US), L.P. (together, "Noble/Constellation/Direct/Shell"); Mel Beard; AARP; and Interwest Energy Alliance ("Interwest"). [1]

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[1] Mr. Beard filed a Motion to rescind his intervention on November 29, 2011, which was granted by Procedural Order issued on December 2, 2011. On November 18, 2011, SCA Tissue North America ("SCA") requested intervention and by Procedural Order issued December 2, 2011, ruling on the intervention was stayed pending SCA's compliance with the requirements of the Procedural Order. SCA did not pursue its intervention. On January 6, 2012, the Community Information and Referral Services filed a Motion to Intervene which was opposed by several parties and which was denied during the January 19, 2012 pre-hearing conference.

By Procedural Order issued July 29, 2011, the hearing was set to commence on January 19, 2012, and other procedural timeframes were established.

On December 22, 2011, Staff filed a Request for a Modification to the Procedural Schedule requesting that the date of filing the Settlement Agreement be extended until January 6, 2012, and also proposing other changes to the procedural schedule.

By Procedural Order issued December 23, 2011, the hearing was rescheduled to commence on January 26, 2012, and the date for filing any settlement agreement was extended until January 6, 2012.

On January 6, 2012, a proposed Settlement Agreement ("Settlement Agreement") attached hereto as Exhibit A, and signed by 22 parties[2] was filed. Although nine parties did not sign the Settlement Agreement,[3] only two, SWEEP and NRDC, expressed partial opposition.

The evidentiary hearing on the Settlement Agreement was held on January 26, 27, 30, 31, and February 1, 2, and 3, 2012. Jeffrey Guldner, Charles Meissner, and Leland Snook testified on behalf of APS; Stephen Baron testified on behalf of Kroger; Larry Blank testified on behalf of the FEA; Nancy Brockway testified on behalf of AARP; Mary Lynch testified on behalf of Noble/Constellation/Direct/Shell; Steve Chriss testified on behalf of Wal-Mart; Ms. Zwick testified on her own behalf; Jeffrey Schlegel testified on behalf of SWEEP; Ralph Cavanagh testified on behalf of NRDC; Frank Radigan and Jodi Jerich testified on behalf of RUCO; Steven Fetter and Gary Yaquinto testified on behalf of AIC; Kevin Higgins testified on behalf of Freeport-McMoRan and AECC; G. David Vandever testified on behalf of IBEW; Tom Farley testified on behalf of AAR; and Steve Olea and Howard Solganick testified on behalf of Staff.[4]

On February 29, 2012, the Joint Initial Post-Hearing Brief of Parties Supporting the Settlement (Except Commission Staff)[5], SWEEP's Opening Brief, and Staff's Opening Brief were filed. On March 1, 2012, the NRDC's Opening Brief was filed. No party filed a Reply Brief.

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[2] APS, Staff, RUCO, Ms. Zwick, FEA, Kroger, Freeport-McMoRan, AECC, Wal-Mart, IBEW, AzAg, Alliance, AARP, AAR, Ms. Wyllie-Pecora, AIC, SWPG/Bowie, and Noble/Constellation/Direct/Shell.

[3] ASBA/AASBO, Interwest, NRDC, SWEEP, TEP, Gilbert, Wickenburg, and WRA.

[4] APS' testimony filed with the application and the parties' witness testimony filed in November and December 2011 were also admitted into the record.

[5] Hereafter, "Joint Signatories".

DISCUSSION

APS' current base rates were implemented pursuant to Commission Decision No. 71448 (December 30, 2009) based upon a test year ending December 31, 2007.[6] In Decision No. 71448, APS was granted a total rate increase of $344.7 million, comprised of a non-fuel base rate increase of $196.3 million;[7] a fuel-related increase of $11.2 million; and $137.2 million of base fuel costs that previously had been collected through the Power Supply Adjustor ("PSA").

APS Rate Application

In this application, APS originally proposed a net increase in base rates of $95.5 million, composed of (1) a non-fuel increase of $194.1 million; (2) the transfer into base rates of $44.9 million in revenue requirement related to assets which are or are expected to be recovered through the Renewable Energy Surcharge ("RES"); and the transfer of a negative PSA balance into base rates.[8] APS' October 26, 2011 updated application reduced the requested increase to $85 million. APS also proposed establishment of a full revenue per customer decoupling mechanism called the Efficiency and Infrastructure Account ("EIA"); an Environmental and Reliability Account ("ERA") which would allow APS to recover certain investment associated with government mandated environmental improvements, new or acquired generation plant capacity additions, and plant investment between rate cases; modifications to the PSA to eliminate the 90/10 sharing provision and allow recovery of certain chemical costs; and also proposed amendments to its PSA and its Transmission Cost Adjustor ("TCA").

Pre-Settlement Positions of Parties

Staff's revenue requirement recommendation included two proposed alternatives: alternative one used a fair value rate of return ("FVROR") of 5.74 percent and resulted in a revenue decrease of approximately $49 million; alternative two used a FVROR of 6.05 and resulted in a revenue decrease of approximately $7.5 million.[9] Staff recommended use of alternative two in this case. Staff also recommended that the Commission reject the Company's EIA proposal because Staff found that it

[6] Updated to include post-test year plant through June 30, 2009.

[7] Including the $65.2 million interim increase approved in Decision No. 70667 (December 24, 2008).

[8] Although the base rate increase would be 3.3 percent, the customer bill impact would be approximately 6.6 percent on average, due to the removal of the PSA credit. June 1, 2011 rate application at 4.

[9] Staff Ex. 1, Smith November 18, 2011 Direct Testimony at 7.

was very broad and addressed weather and other economic conditions. Instead of the EIA, Staff recommended approval of a Lost Fixed Cost Recovery ("LFCR") mechanism.[10] Staff also recommended that the Commission deny the proposed ERA mechanism;[11] that the Commission deny APS' proposal to recover chemical costs through the PSA; and that the Commission also deny the request to consolidate the unbundled transmission service charges in the TCA.[12] Staff agreed with the request to eliminate the 90/10 PSA sharing provision[13] and the request to amend the TCA to allow the FERC-approved transmission rate to become effective for retail customers on the date it becomes effective for wholesale customers.[14] Staff recommended that Schedule 9 be rejected and that APS undertake a cost of service study as part of its next rate case. Staff also recommended that beginning with APS' 2013 REST Plan, APS no longer be allowed carrying costs for renewable energy-related capital investments, and that the proportionality requirement associated with the Renewable Energy Standard ("RES") adjustor rate and associated caps be removed.[15] Staff also recommended that APS no longer be allowed carrying costs for Demand Side Management ("DSM") related capital investments beginning with APS' 2013 DSM Implementation Plan.[16] Finally, Staff proposed a modified performance incentive structure to measure APS' implementation of its energy efficiency programs.[17]

RUCO recommended a FVROR of 6.10 percent, for a net rate decrease of $0 million, comprised of a base rate increase of $140 million ($98 million in base rate increase and transfer of $42 million of the AZ Sun program funding from the RES to base rates) offset by a credit of $140 million from the PSA.[18] RUCO recommended that the Commission reject the ERA proposal, the EIA proposal, the proposal to include chemical costs in the PSA, the low income adjustment, the coal mine reclamation cost adjustment, the request to consolidate the unbundled transmission service

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[10] Staff Ex. 5, Solganick November 18, 2011 Direct Testimony at 15.
[11] Staff Ex. 6, McGarry November 18, 2011 Direct Testimony at 17.
[12] *Id.* at 30.
[13] *Id.* at 19.
[14] *Id.* at 32.
[15] Staff Ex. 9, Furrey December 2, 2011 Direct Testimony at 2.
[16] *Id.*
[17] *Id.* at 6-11.
[18] RUCO Ex. 5, Rigsby November 18, 2011 Direct Testimony at 50; RUCO Ex. 1, Radigan November 18, 2011 Direct Testimony at 7.

charges in the TCA, and the elimination of the 90/10 sharing provision in the PSA.[19]

The AECC recommended that APS' requested revenue increase be reduced by at least $75.392 million; that APS' System Benefit charge be reduced by $8.704 million per year to reflect the reduction in decommissioning costs associated with the Palo Verde Nuclear Generating Station life extension; that the 90/10 PSA sharing provision not be eliminated; that the EIA be rejected for all customers and if some form of decoupling is approved by the Commission, that customers with billing demands greater than 400 kW be excluded; that the ERA proposal be rejected; and that while APS' Cost of Service Study should be adopted, other changes were necessary to some of APS' rate schedules.[20]

Kroger recommended that the Commission reject the EIA proposal, and that any decoupling mechanism that may be adopted by the Commission should exclude customers taking service on Rate E-32 L and large industrial customers taking service on Rates E-34 and E-35.[21]

The FEA recommended that the Commission reject the EIA proposal, the 90/10 sharing elimination, and the request to move $44.9 million out of the RES and into base rates.[22] The FEA recommended that APS be required to maintain its unbundled rate billing capabilities and allow customers that billing option.[23]

Ms. Zwick recommended that the Commission reject the request for an increase in rates for low-income customers; deny the change in policy relating to the exemption of low-income customers from the PSA and DSM charges unless there is another discount; and to expand the eligibility of the shareholder bill assistance program to up to 200 percent of the federal poverty level.

The AARP recommended that the Commission reject the ERA and EIA proposals,[24] and the redesigned low-income rates.[25]

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[19] RUCO Ex. 1, Radigan November 18, 2011 Direct Testimony at 6-7; RUCO Ex. 2, Radigan November 23, 2011 Direct Testimony at 3.
[20] AECC Ex. 1, Higgins November 18, 2011 Direct Testimony at 4-6; AECC Ex. 2, Higgins December 2, 2011 Direct Testimony at 2-4.
[21] Kroger Ex. 1, Baron November 18, 2001 Direct Testimony at 6.
[22] FEA Ex. 1, Blank November 18, 2011 Direct Testimony at 3; FEA Ex. 2, Blank December 2, 2011 Direct Testimony at 2.
[23] FEA Ex. 2, Blank December 2, 2011 Direct Testimony at 2.
[24] AARP Ex. 1, Brockway November 18, 2011 Direct Testimony at iii.
[25] AARP Ex. 2, Brockway December 2, 2011 Direct Testimony at 5.

Wal-Mart recommended that if the Commission approves a decoupling mechanism, the demand-metered General Service schedules should be excluded, but if not excluded, then decoupling should be calculated separately for residential and commercial and industrial customers and there should be a cap imposed on the allowed fixed cost recovery for commercial and industrial customers; APS should be required to explore rate design changes to the demand-metered General Service schedules to improve fixed cost recovery; the ERA should be rejected; and if the ERA and EIA are adopted, the Commission should consider the effect of those mechanisms on revenue and earnings when setting the rate of return.[26] Wal-Mart did not oppose APS' proposed revenue allocation, but made several recommendations concerning rate design.[27]

IBEW recommended that the Commission grant sufficient rate relief for APS to address recruiting and hiring efforts necessary to address its "aging workforce problem."[28]

The AIC supported APS' requested EIA and ERA proposals.[29]

NRDC supported APS' proposal for an EIA mechanism which it found to be consistent with the Commission's decoupling statement.[30]

SWEEP recommended a new energy efficiency performance incentive with changes to the cap and the design of the incentive mechanism,[31] and supported the exclusion of only the largest customers from full decoupling or lost revenue recovery mechanisms when shown that they do not contribute to the recovery of fixed costs.[32] SWEEP supported the revenue per customer decoupling mechanism proposed by APS with the exception that SWEEP disagreed with APS' cap and the not as timely or current decoupling adjustments APS would make under its mechanism.[33] SWEEP also recommended that APS' ERA be rejected and that APS' bill should be redesigned to lessen customer

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[26] Wal-Mart Ex. 1, Chriss November 18, 2011 Direct Testimony at 7-8.
[27] Wal-Mart Ex. 2, Chriss December 2, 2011 Direct Testimony at 3-4.
[28] IBEW Ex. 1, Vandever November 18, 2011 Direct Testimony at 6-12.
[29] AIC Ex. 2, Fetter November 18, 2011 Direct Testimony at 23-24; AIC Ex. 2, Hansen November 18, 2011 Direct Testimony at 13.
[30] NRDC Ex. 1, Cavanagh November 18, 2011 Direct Testimony at 2-4. ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures signed December 29, 2010 and filed in Docket Nos. E-00000J-08-0314 and G-00000C-08-0314.
[31] SWEEP Ex. 1, Schlegel November 18, 2011 Direct Testimony at 8-9.
[32] SWEEP Ex. 2, Schlegel December 2, 2011 Direct Testimony at 4.
[33] SWEEP Ex. 1, Schlegel November 18, 2011 Direct Testimony at 11.

confusion and provide customers with more useful information.[34]

Settlement Agreement

The Settlement Agreement is signed by twenty-two parties and partially opposed by two parties, SWEEP and NRDC.[35] APS filed a Notice of settlement discussions on November 18, 2011 and discussions began on November 30, 2011. According to the Settlement Agreement and the testimony of witnesses and statements of attorneys, the discussions were "open, transparent, and inclusive of all parties" who desired to participate. Staff filed a Preliminary Term Sheet on December 9, 2011, and the Commission held a Special Open Meeting on December 16, 2011 to discuss the Staff Preliminary Term Sheet. The Settlement Agreement was docketed on January 6, 2012.

The Joint Signatories characterize the Settlement Agreement as one that offers broad benefits to APS and its customers and allows APS to continue to provide reliable electric service and pursue Arizona's energy goals, while leaving resolution of policy issues to policy-making dockets.[36] Staff believes that the Settlement Agreement is designed to continue the momentum resulting from the Settlement Agreement approved in Decision No. 71448 (improve APS' financial standing, provide predictability with rate case filings, and establish a strong commitment in Arizona's energy future) while at the same time, preserve the Commission's flexibility to implement policy objectives in Energy Efficiency and Renewable Energy.[37] According to Staff, the Settlement Agreement is the product of "many hours of intense, transparent, and robust negotiations between multiple parties with divergent interests."[38] Staff believes that there are significant benefits in the Settlement Agreement and recommends that it be adopted. SWEEP participated in the settlement discussions, which it characterized as "open, transparent and inclusive of all parties to the Docket who desired to

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[34] *Id.* at 13.

[35] Interwest filed a statement on January 18, 2012 stating that while it did not sign the Settlement Agreement and would not be offering testimony, it did believe that the "settlement process was a fair and open process." WRA filed a statement that it was not a signatory to the Settlement Agreement and would not be filing testimony. Wickenburg and Gilbert indicated during the January 19, 2012 Procedural Conference that they would not be filing testimony or cross-examining witnesses. January 19, 2012 Procedural Conference Tr. at 15. ASBA/AASBO indicated at the January 19, 2012 Procedural Conference that they did not take a position and did not intend to file testimony. January 19, 2012 Procedural Conference Tr. at 13.

[36] Joint Signatories Opening Brief at 4.

[37] Staff Opening Brief at 5-7.

[38] *Id.* at 7.

participate."[39] While SWEEP thinks that "there is a lot to like" in the Settlement Agreement, SWEEP is in partial opposition because "(1) the Agreement limits the Commission's options and flexibility for addressing utility financial disincentives to energy efficiency; (2) full revenue decoupling was not included in the Settlement Agreement, not even as an option for Commission consideration as part of its review of the Agreement; and (3) the energy efficiency performance incentive for APS should be addressed in the Energy Efficiency Implementation Plan process rather than in this rate case."[40] The NRDC partially opposes the Settlement Agreement because it does not include full revenue decoupling and the NRDC believes that it is inconsistent with Commission policy, precedent, and the public interest in enhanced energy efficiency and lower electricity bills.[41]

Terms and Conditions of the Settlement Agreement

The Settlement Agreement contains approximately 22 pages of text describing the terms and conditions of the negotiated agreement. The major Sections of the Settlement Agreement are as follows:[42]

I. Recitals – This Section identifies the benefits of the Settlement Agreement as:

- an overall zero dollar base rate increase;
- a zero percent bill impact for the remainder of 2012 (Commission-approved adjustors (including the possibility of a Four Corners rider pursuant to paragraph 10.2) may increase customer bills after December 21, 2012);
- a four year rate case stay out, in which APS agrees not to raise base rates as a result of any new general rate case filing prior to July 1, 2016;
- a buy-through rate for industrial and large commercial customers;
- a narrowly-tailored Lost Fixed Cost Recovery ("LFCR") mechanism that supports energy efficiency ("EE") and distributed generation ("DG") at any level or pace set by this Commission;
- an opt-out rate design for residential customers who choose not to participate in the

[39] SWEEP Opening Brief at 1.
[40] *Id.* at 1-2.
[41] NRDC Opening Brief at 2-4.
[42] This is a summary of some, but not all provisions contained in the Settlement Agreement.

LFCR;

- a process for simplifying customers' bill format; and
- bill assistance for additional low income customers, at shareholder expense.

This Section also requests that the Commission find the Settlement Agreement's terms and conditions are just and reasonable and in the public interest and approve the Settlement Agreement and order that it and its rates become effective July 1, 2012.

II. Rate Case Stability Provisions – This Section provides that APS will not file a general rate case prior to May 15, 2015; that the test year will be no earlier than December 31, 2014; and that no resulting new base rates will be effective before July 1, 2016.

III. Rate Increase – This Section provides that APS' revenue requirement is a zero dollar base rate increase consisting of (1) a non-fuel base rate increase of $116.3 million based upon post-test year plant in service as of March 31, 2012; (2) a fuel base rate decrease of $153.1 million; and (3) a transfer of cost recovery from the RES to base rates. This Section determines APS' jurisdictional fair value rate base to be $8,167,126,000, and total adjusted test year revenues of $2,868,858,000.

IV. Bill Impact – This Section provides that customers will have on average a 0.0 percent bill impact when new rates become effective due to the continuation of the negative PSA credit until the next reset on February 1, 2013; that the annual 4 mill cap will then be applied after the impact of the expiration of the then-current PSA credit; and that the percentage bill impact spread for General Service customers among various segments of that customer class will be equal as set forth in Attachment A.

V. Cost of Capital – This Section adopts a capital structure of 46.06 percent debt and 53.94 percent common equity; adopts a return on common equity of 10.0 percent and an embedded cost of debt of 6.38 percent; and adopts a fair value rate of return of 6.09 percent.[43]

VI. Depreciation/Amortization and Decommissioning – This Section adopts APS' proposed depreciation rates, except for Account Nos. 370.01, 370.02, and 370.03 which retain their current rates; adopts APS' annual nuclear decommissioning amounts; and requires APS to file a request to

[43] The fair value rate of return includes a fair value increment.

adjust the System Benefit Charge related to the full funding of Palo Verde Unit 2 so that the reduction can occur by January 2016.

VII. Fuel and Power Supply Adjustment Provisions – This Section adopts a new lower base fuel rate of $0.032071 per kWh; withdraws the proposed recovery of chemicals through the PSA; eliminates the 90/10 sharing provision from the PSA and requires APS to apply interest annually with different rates for over and under-recoveries; subjects APS to periodic fuel and power procurement audits performed by Staff-selected consultants and funded by APS in amounts up to $100,000 per audit; and includes amendments to the Plan of Administration.

VIII. Renewable Energy – This Section provides that the portion of the APS-owned renewable energy projects currently collected through the RES that have been closed to plant in service as of March 31, 2012 (as set forth in Attachment D) shall be rate based and the costs recovered through base rates; that the only capital carrying costs of renewable energy-related capital investments to be recovered through the RES adjustor will be those APS makes in compliance with Decision No. 71448 until and unless they are specifically authorized for recovery in another adjustor or in base rates; that upon the effective date of the new rates, the RES adjustor for 2012 will be reduced to reflect removal of the projects in Attachment D; the renewable energy-related purchased power agreement costs that were moved from the RES to the PSA in Decision No. 72737 (January 18, 2012) will be moved back to the RES; and Decision No. 67744's requirement that changes to RES charges and caps must be allocated between customer classes according to certain set proportions is eliminated in order that the Commission has greater flexibility in setting RES adjustor rates and caps.

IX. Energy Efficiency/Lost Fixed Cost Recovery/Opt-Out Residential Rate/Large General Service Customer Exclusion – This Section provides that the signatories support energy efficiency as a low cost energy resource; they recognize that APS' volumetric rate design recovers a significant portion of fixed costs of service through kilowatt-hour ("kWh") sales; and that the EE and DG rules' requirement to sell fewer kWh prevents APS from recovering a portion of fixed costs embedded in energy rates. The signatories agree that a LFCR mechanism with residential opt-out rates that allows the Commission the flexibility to adjust the EE and DG requirements and gives APS the opportunity to recover a portion of the distribution and transmission costs associated with those residential, commercial and industrial customers' verified lost kWh sales attributed to EE and DG requirements (and not attributable to other factors such as weather or general economic conditions), should be adopted.

The provisions of the LFCR mechanism include:

- recovery of only a portion of distribution and transmission costs related to sales level that are reduced by EE and DG and exclusion of the portion of distribution and transmission costs recovered through the Basic Service Charge ("BSC") and 50 percent of the costs that are recovered through non-generation/non-TCA demand charges;
- annual LFCR and compliance filings by January 15;
- annual adjustments for the unrecovered costs as demonstrated by the Measurement, Evaluation and Reporting ("MER") conducted for EE programs and by statistical verification, output profile, or meter data for DG systems until December 31, 2014 and thereafter by only meter data to calculate DG system savings;
- annual adjustments must be approved by the Commission, with the first adjustment occurring no sooner than March 1, 2013;
- an annual 1 percent year over year adjustment cap based on total Company revenues, with any excess being deferred with interest to be collected in a future annual adjustment, and the cap to be evaluated in the next rate case;
- General Service customers taking service under rate schedules E-32 L, E-32 L TOU, E-34, E-35 and E-36 XL, and unmetered General Service customers under E-30 and lighting schedules are excluded, but those rate schedules are modified in Attachment K to address unrecovered fixed costs through changes in rate design, including distribution demand and BSC charges and a corresponding adjustment to energy charges;
- Residential customers can opt out of the LFCR adjustor by choosing the optional BSC which is graduated by kWh monthly usage and is designed to replicate the effects of

the LFCR;

- APS shall implement a customer outreach program to inform and educate customers about the LFCR and the voluntary residential op-out rates, based upon input sought by APS from stakeholders;
- The LFCR is subject to Commission review at any time but no later than APS' next rate case and if the Commission were to suspend, terminate, or materially modify the LFCR mechanism prior to then without addressing fixed cost erosion, the moratorium for filing a rate case terminates; and
- The LFCR is designed to maximize the Commission's policy options regarding EE and DG and the signatories agree that if the LFCR or other mechanism is not adopted that will adequately address fixed cost revenue erosion, APS will be "granted relief from either the relevant EE and DG requirements or the financial impacts of EE and DG during that time."

This Section also includes provisions related to DSM, including: beginning with APS' 2013 DSM Implementation Plan, carrying costs for DSM-related capital investments will not be recovered through the DSM adjustment Clause (except for DSM-related capital investments already authorized by the Commission); base rates will continue to collect $10 million of DSM costs; APS' performance incentive is modified to (1) eliminate the top two tiers of percentages applied to Net Benefits or Percent of Program Costs and (2) to change the fourth tier to include any achievement relative to the energy efficiency standard greater than 105 percent; APS will use Staff's inputs and methodology to calculate the present value of benefits and costs for DSM measures in its Societal Cost test; APS will work with Staff and stakeholders to develop and file a new performance incentive structure that "optimizes the connection between energy efficiency, rates and utility business incentives and that creates a clear connection between the level of performance incentive and achievement of cost-effective energy savings" by December 31, 2012, and this docket will remain open to allow for Commission consideration and approval to include the new performance incentive structure in the DSM Adjustment Clause; every five years an independent evaluator will review APS' DSM programs and associated energy savings; and APS will compile a technical reference manual that is updated annually documenting program and measure savings assumptions and incremental costs.

X. Rate Treatment Related to any Acquisition by APS of Southern California Edison's Share of Four Corners Units 4-5 – This Section provides that this docket will remain 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 (1) the acquisition of Southern California Edison's ("SCE") ownership interest in Four Corners Units 4 and 5, and (2) the retirement of Units 1-3, as well as any cost deferral authorized in the Commission's Decision in the Four Corners acquisition docket; that APS is authorized to request amendments to the PSA Plan of Administration to include 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; that any filing seeking a rate adjustment must include specific schedules and any proposed adjustment rider must spread the costs on an equal percentage basis across all rate schedules and will not become effective before July 1, 2013; and that rates are adjusted only if the Commission finds the Four Corners transaction to be prudent.

XI. Modification to Environmental Improvement Surcharge – This Section withdraws the proposed ERA mechanism; revises the existing Environmental Improvement Surcharge ("EIS") to recover the capital carrying costs associated with government-mandated environmental controls, subject to a cap; resets the existing EIS to zero; and revises the EIS Plan of Administration to implement these changes.

XII. Cost Deferral Related to Changes in Arizona Property Tax Rate – This Section allows APS to defer without interest for future recovery: 25 percent of the prorated property tax rate increase in 2012, 50 percent in 2013, and 75 percent each year thereafter, and 100 percent of all property tax rate decreases; recovery will begin after the next general rate case with recovery of a positive balance spread over 10 years and a negative balance over three years; and the signatories may review the deferrals for reasonableness and prudence.

XIII. Transmission Cost Adjustment Mechanism – This Section provides that the current level of transmission costs in base rates will remain in base rates; APS will file its revised TCA tariff and supporting documents by May 15 of each year, and the annual TCA adjustment will become effective

June 1 of each year unless Staff requests review or the Commission orders otherwise; and the TCA Plan of Administration is modified to include the new provisions.

XIV. Low Income Programs – This Section provides that funds remaining in the bill assistance program approved in Decision No. 69663 may be used to assist customers whose incomes are less than or equal to 200 percent of the Federal Poverty Income Guidelines; and that the billing method for low income customers will be simplified by including PSA and the Demand Side Management Adjustor Charge ("DSMAC") charges to their rate schedule and then applying a discount to the total bill, such that there will be no bill impact to low income customers as a result of the billing method change.

XV. Service Schedule 3 (Line Extensions) – This Section provides that Version 12 of Service Schedule 3, as approved in Decision No. 72684 (November 18, 2011), will become effective on the date that rates set herein are effective.

XVI. Bill Presentation – This Section provides that APS will initiate stakeholder meetings within 90 days that will address issues related to making APS' bill easier for customers to understand and requires APS to file an application for any authorization needed to modify its bill presentation and explain how stakeholder input during the process was included.

XVII. Rate Design – This Section provides that APS' proposed Experimental Rate Schedule AG-1, a buy-through rate for large commercial and industrial customers (that does not address the subject of retail competition), should be approved as modified and set forth in Attachment J; that if there are any unmitigated lost fixed generation costs related to the AG-1 Experimental Rate in APS' next rate case, APS should explain why and shall not propose to recover such costs from residential customers; that APS shall file a study in its next rate case to support costs of various charges in Service Schedule 1, taking into account the impact Smart Grid technology may have on the costs; the request to establish Service Schedule 9, an economic development schedule is withdrawn in favor of the use of Commission-approved special contracts; and other rate design issues are resolved in Attachment K.

XVIII. Compliance Matters – This Section provides that within ten days of this Decision, APS shall file compliance schedules for Staff's review and that subject to that review, the schedules will become effective on the effective date of new rates; that on or before May 31 each year, APS shall file a report with the Commission that identifies the extent of the challenges regarding workforce planning, the specific actions that APS is taking to address the issue, and the progress it is making toward meeting those goals; and provides that the rating agencies communications report filing requirement found in Decision No. 70667 is eliminated.

XIX. Force Majeure Provision – This Section sets out the conditions whereby APS, the Commission, or a signatory may request a change in or review of base rates.

XX. Commission Evaluation of Proposed Settlement – This Section provides that if the Commission fails to issue an order adopting all material terms of the Settlement Agreement, any or all of the signatories may withdraw from the agreement and pursue without prejudice their respective remedies at law; provides that for purposes of the Settlement Agreement, whether a term is material is in the discretion of the signatory choosing to withdraw from the Settlement Agreement, and if a signatory withdraws from the Settlement Agreement and files an application for rehearing, the other signatories except for Staff, shall support the application for rehearing.

XXI. Miscellaneous Provisions – This Section provides that the signatories shall support and defend the Settlement Agreement and shall make reasonable and good faith efforts to obtain a Commission order approving the Settlement Agreement; and that to the extent any provision of the Settlement Agreement is inconsistent with any existing Commission order, rule, or regulation, the Settlement Agreement shall control and that each term is in consideration of all other terms and the terms are not severable.

Benefits of the Settlement Agreement as Identified by the Parties

Staff

Staff finds that the provisions of the proposed Settlement Agreement are in the public interest and that the Commission should approve it. Staff explains that the goal of the 2009 settlement agreement approved by the Commission was to improve APS' standing in the investment community, provide predictability with rate case filings and timing, and establish a strong commitment to Arizona's energy future.[44] This Settlement Agreement is designed to build upon the progress toward those goals while preserving the Commission's flexibility to implement policy objectives in energy efficiency and renewables. Staff believes that the Settlement Agreement was the product of a transparent and open process involving a diverse group of stakeholders, and that the end result balances APS' financial stability with benefits to customers.

Those benefits include:

- An overall zero dollar base rate increase;
- A zero percent bill impact for the remainder of 2012 (Commission-approved adjustors (including the possibility of a Four Corners rider pursuant to paragraph 10.3 of the Agreement) may increase customer bills after December 31, 2012);
- An increase in rate stability, including a four year period without base rate increases;
- A buy-through rate for industrial and large commercial customers that holds residential customers harmless in the event that there are stranded fixed costs;
- A narrowly-tailored Lost Fixed Cost Recovery ("LFCR") mechanism that supports energy efficiency ("EE") and distributed generation ("DG") at any level or pace set by the Commission;
- An opt-out rate design for residential customers who choose not to participate in the LFCR;
- A process for simplifying customer bills; and
- Bill assistance for additional low income customers at shareholder expense.[45]

Staff explains that the Signatories intended to provide the Commission with maximum flexibility in setting EE and DG policy and therefore, there are no specific EE or RES targets or requirements built into the Settlement Agreement. Staff noted that there are components of the Settlement Agreement that will allow continued improvement in APS' financial standing, including; the settlement itself, which reflects "the positive climate of the Commission's process;"[46] the inclusion of 15 months of post test year plant; a 10 percent return on equity; the LFCR; and the other parts of the Settlement Agreement that support the Company's ability to accept a four year stay out.

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[44] Staff's Opening Brief at 5.
[45] Staff Opening Brief at 6.
[46] Tr. at 26, AIC Opening Statement.

Staff argues that the Settlement Agreement appropriately balances consumer and shareholder interests and identifies the following provisions that will benefit consumers:

1) Rate Case Filing Moratorium – Staff believes that the four year stay-out whereby APS will not file its next general rate case before May 31, 2015 and new base rates will not take affect before July 1, 2016, will provide customers with rate stability while also providing APS with sufficient revenue to provide safe and reliable electric service. Staff disagrees with SWEEP's argument that the stay out provision should be shortened to three years, because Staff believes that stay-out provisions encourage utilities to control costs, which can lead to lower rates in future rate cases. Staff also believes that the Settlement Agreement was "crafted to permit maximum flexibility to the Commission in the implementation of new policy while providing a means to make the Company whole."[47]

2) No Base Rate Increase – Staff notes that although APS initially proposed a $95.49 million total rate increase, the proposed Settlement Agreement provides no base rate increase. The change to base rates includes a non-fuel base rate increase of $116.3 million (including post test year plant in service as of March 31, 2012), a fuel base rate decrease of $153.1 million, and a transfer of cost recovery from the RES to base rates in the amount of approximately $36.8 million. The base cost of fuel and purchased power will decrease from $0.037571 per kWh to $0.032071 per kWh. Staff believes that even though adjustor mechanisms may continue to fluctuate and increase bills, "the fact that base rates will remain constant for a four-year period is a significant benefit to customers."[48]

3) A Bill Impact of Zero or Slightly Negative Once New Rates Take Effect for the Remainder of 2012 - APS has agreed to delay recovery of a portion of its fuel and purchased power costs until early 2013 and this delay will allow a zero or slightly negative bill impact until February 1, 2013.[49] This benefits customers by not increasing base rates during the summer when usage is typically higher and by decreasing the frequency of bill impacts associated with the reset of fuel and purchased power costs which would have occurred in July 2012.

4) A Rate of Return on Equity that is 100 Basis Points Below APS' Existing Return on

[47] Staff Opening Brief at 38.
[48] *Id.* at 13.
[49] The PSA reset will occur in February 2013 and true-up its recovery of fuel and purchased power expenses.

Equity – Staff notes that the return on equity is somewhat lower than recent ROEs authorized in other jurisdictions for vertically integrated electric utilities, but combined with APS' capital structure, APS should still be able improve its financial condition and credit ratings over time. Customers will benefit from rates based upon lower financing costs for plant.

5) The Low Income Provisions Benefit Consumers - Staff believes that expanding the bill assistance program to include customers whose incomes are less than 200 percent of the Federal Poverty Level Income Guidelines is a benefit of the Settlement Agreement. The other modification to the low income program will allow low income customers to benefit from credits when they occur with the PSA and the DSMAC adjustors. Currently, low income customers do not pay those adjustors, and as a way to simplify billing methods, the low income schedules will be eliminated and the customers will instead receive a discount to the total bill (that includes the PSA and DSMAC) that will effectuate a zero impact on the bill.

6) Lost Fixed Cost Recovery Mechanism and Residential Consumer Opt-Out Provision - Staff noted that the Commission had received many comments from consumers in this docket opposed to adoption of full revenue decoupling. Staff agrees with APS that the

> major difference between decoupling and lost fixed cost recovery is that lost fixed cost recovery is tied to measured and approved Corporation Commission programs for energy efficiency and for distributed generation. Decoupling is indifferent as to what's causing the effect of the lower or higher sales. And so whether it's economic conditions or weather or energy efficiency or anything else, the decoupling mechanism says conceptually, you don't care now, you're divorced from the effect of sales volumes affecting your revenues.[50]

Staff believes that unlike the LFCR, full revenue decoupling shifts all risk of lower per kWh sales from the utility to the customers, particularly risks related to weather and the economy.[51]

Staff believes that many residential customers have expressed concern with full revenue decoupling because of the "potential for widely varying bill impacts from year to year"[52] and that the unique opt-out provision of the Settlement Agreement's LFCR adjustor will benefit those opt-out customers by providing more certainty with their bills. The increased basic service charge will be

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[50] Tr. at 203-204.
[51] Staff Opening Brief at 15.
[52] *Id.* at 15.

implemented with the first LFCR adjustment in 2013 and will remain fixed for the duration of the Settlement Agreement. Staff noted that the "opt-out" does not prevent customers from participating in EE or DG, and that RUCO would not likely have supported the Settlement Agreement without the opt-out rate.[53]

7) A Lower System Benefit Charge in 2016 – Customers pay costs to decommission Palo Verde Unit 2 via the Systems Benefits Charge ("SBC") which is part of base rates. Because Unit 2 is anticipated to be fully funded by 2016, APS agreed to seek Commission approval of a corresponding reduction in the amount collected by the SBC. This will amount to a reduction in the revenue requirement of approximately $14 million.

8) A Process For Simplifying Customer Bills – APS will begin stakeholder meetings to gather input on how to make its bill presentation easier for customers to understand. The results will be presented to the Commission for approval.

Staff also identified provisions in the Settlement Agreement that it believes provide important benefits to APS but also balance the consumer interests, including provisions that are intended to more closely align the interests of APS and consumers, as follows:

1) Energy Efficiency and Distributed Generation and Recouping Lost Fixed Costs – Staff noted that although the Commission's December 29, 2010 Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures ("Policy Statement") expressed a preference for full revenue decoupling, it also provided the opportunity for a utility to propose an alternative mechanism for addressing disincentives in its next general rate case. Staff explained that the LFCR mechanism adopted in the Settlement Agreement is such an alternative and is similar to the LFCR mechanism Staff proposed in its original direct testimony in this matter. Staff believes that the LFCR mechanism is narrowly tailored to allow recovery of certain documented and verified fixed costs that were not recovered due to reductions in volumetric sales from Commission-approved EE and DG programs. It excludes recovery of 50 percent of demand charges because if a customer reduces energy consumption in response to a program, it is not likely there will be a

[53] *Id.* at 16.

proportional reduction in the demand level. It also excludes generation costs because APS forecasts that sales will increase in the near future, and because APS has the ability to make off-system, ACC non-jurisdictional sales to sell any excess energy.[54] According to Staff, not all customers are subject to the LFCR mechanism, because either no fixed costs will remain unrecovered or other rate designs will be in place to address lost fixed costs. The LFCR uses existing processes to determine the applicable sales reductions that are recoverable through the mechanism on an annual basis. Under the Plan of Administration, APS will file its Annual LFCR Adjustment for the previous year each January 15th and Staff has committed to using its best efforts to process the adjustment by March 1 of each year, with the first LFCR adjustment not appearing on customer bills until approved by the Commission, and no sooner than to March 1, 2013. Annual adjustments are limited to one percent of total Company revenues and based upon expected EE and DG programs, Staff testified that adjustments are estimated to be below that level, so no deferrals are expected.[55]

Staff explained that unlike full revenue decoupling, both weather and business risk are not transferred to customers but stay with APS, so no rate of return adjustment is necessary. Staff acknowledges that while "the LFCR does not break the incentive to increase sales volumes to achieve higher revenues, it does break the disincentive to not invest in EE and DG due to lower sales volumes."[56] The cumulative impact on customers of the LFCR is expected to be approximately $16 million in 2014; $30 million in 2015; and $40 million in 2016. Comparatively, the cumulative impacts with full revenue decoupling would be approximately $26.9 million in 2014; $49 million in 2015; and $70 million in 2016.[57]

In response to SWEEP and NRDC's partial opposition, Staff's witness identified potential problems with full decoupling, including the "pancaking" of increases; the ability of the utility to benefit from prolonged outage events; the incentive to game inputs; and the problem of how to appropriately reflect the level of risk in the cost of equity when setting the Company's rates. Staff also disagreed with the NRDC's suggestion that the Commission is bound by the precedent of the

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[54] Staff Ex. 12, Solganick January 18, 2012 Direct Settlement Agreement Testimony at 4.
[55] *Id.*; Staff Opening Brief at 20.
[56] Staff Opening Brief at 19.
[57] Tr. at 192-194; Staff Opening Brief at 20-21.

Southwest Gas rate case and the Policy Statement, noting that there are different considerations in each case, and that as administrative agency, the Commission is not bound by the doctrine of *stare decisis*. According to Staff, the residential opt-out of the LFCR mechanism is a benefit that is critical for some parties and would have been complex and unworkable with full revenue decoupling.[58] Staff also noted that the LFCR is a "more practical alternative in light of the number of interests that are opposed to full revenue decoupling."[59]

2) <u>The Proposed Changes to the RES Surcharge Are In the Public Interest</u> – Staff explained that the Settlement Agreement contains important changes to the RES surcharge. One of those changes requires APS' 2013 REST Plan to eliminate recovery of carrying costs for renewable energy-related capital investments, with the exception of those investments made in compliance with Decision No. 71448. Staff believes that plant associated with renewable energy projects should be treated no differently than how other plant investments are treated, and the portion of renewable projects closed to plant in service as of March 31, 2012 will be recovered through base rates. Another change is to eliminate Decision No. 67744's proportionality requirement associated with the RES adjustor rate and associated caps. This change is designed to give the Commission greater flexibility in setting the RES adjustor rates and caps.

3) <u>The Provisions Relating to APS' DSM Programs Are In the Public Interest</u> – Staff also believes that the Settlement Agreement's provision that the Company's 2013 DSM Implementation Plan not include carrying costs for DSM-related capital investments is appropriate because there is no reason to treat such investment differently from other plant investments. Staff noted that the top two tiers of percentages in the current performance incentive were eliminated and that APS "committed in the proposed Agreement to use the inputs and methodology that Staff uses in calculating the net present value of benefits and costs for DSM measures in its Societal Test."[60] Staff explained that the LFCR "makes the Company indifferent to sales lost as a result of DSM and DG programs" but the purpose of a performance incentive is "to encourage the Company to achieve the most cost-effective energy savings possible through its DSM programs, which, ultimately, will

[58] Staff Opening Brief at 35.
[59] *Id.* at 34.
[60] *Id.* at 22.

save the ratepayers money."[61] Staff also cited the Settlement Agreement's requirement that APS' DSM programs and savings be independently reviewed every five years by a Staff-selected evaluator paid for by APS shareholders, and the requirement that APS must create and docket a DSM technical manual by December 31, 2012, as promoting the public interest. In response to SWEEP's proposal that the performance incentive be developed sooner in the Company's EE Implementation Plan, Staff explained that because "a performance incentive impacts Company revenues, a strong argument can be made that any change or adjustments to the performance incentive structure or DSMAC adjustor plan of administration needs to occur in the context of a rate case."[62]

4) A Buy-Through Rate For Industrial and Large Commercial Customers – APS' Experimental Rate Service Rider Schedule AG-1 is a four year program with a buy-through rate for large commercial and industrial customers offered as an option to standard generation that will give larger customers greater control over their energy costs. This program was developed in response to customer input and allows Generation Service Providers ("GSP") to provide wholesale power to APS on behalf of specific customers. APS will purchase and manage generation on behalf of the customer for a management fee of $.0006 per Kwh. Capped at 200 megawatts, applicants must be able to aggregate into a 10 megawatt group. A collaborative process will be used to develop program guidelines including the customer enrollment process, APS' provision of imbalance energy, energy scheduling and billing and competitive bidding processes.[63] As explained by Noble/Constellation/Direct/Shell witness Lynch, the electric service provided under proposed rate schedule AG-1 differs from retail electric competition in that "the GSP will transfer title to the electricity the GSP bought, at the direction of an eligible Rate Schedule AG-1 customer, to APS at a delivery point outside of APS' network delivery" and "APS remains the load serving entity for the retail customer providing all services, including the generation delivery and billing under a Commission approved rate schedule."[64]

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[61] *Id.* at 23.
[62] *Id.* at 23.
[63] Tr. at 615-617; Staff Opening Brief at 25.
[64] Noble/Constellation/Direct/Shell Ex. 1, Lynch January 18, 2012 Direct Testimony in Support of the Settlement Agreement at 10-11.

5) Rate Treatment Related to APS Proposed Acquisition of Four Corners – Staff explained that APS believes that this provision is essential to the four year rate moratorium, noting that the non-fuel related annual revenue requirement associated with the Four Corners transaction amounts to approximately $70 million annually. Staff also explained that the Settlement Agreement would lower the balance of the cost deferrals, because the costs would begin to be collected sooner.[65] Any recovery of costs would occur only upon a finding by the Commission that the transaction and costs were prudent.

6) Elimination of the 90/10 Sharing Is In the Public Interest – Staff believes that the elimination of the 90/10 sharing provision and two new PSA provisions will produce benefits for customers when there are lower fuel prices and will provide incentives for APS to manage its PSA balance. The PSA is "a cost tracking mechanism designed to allow APS to recover costs associated with obtaining power supplies in a more effective manner due to the short-term volatility in power costs" and tracks how much actual fuel and purchased power costs deviate from the amount recovered through APS' base cost of fuel and purchased power collected in base rates.[66] The 90/10 sharing provision splits the over or under collection of fuel costs between ratepayers and the Company. When actual fuel costs exceed base fuel rates, APS can collect 90 percent of those costs, and when actual fuel costs are less than base fuel rates, APS can keep 10 percent of those savings. The PSA sharing mechanism is designed to give APS a financial incentive to prudently plan for and acquire its purchased power and fuel. Under the Settlement Agreement, the 90/10 sharing provision is replaced with periodic audits of APS' fuel and power procurement, with the first audit for calendar year 2014; and with the application of interest rates that vary depending upon whether there is an under or over collection of the PSA balance. Staff believes that these provisions will produce benefits for customers when fuel prices are lower and will provide incentives for APS to better manage its PSA balances.

7) The EIS and Property Tax Deferrals Were Important In Achieving A Longer Stay-Out And Are In the Public Interest As Well - Staff believes that the changes to the EIS are in the public

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[65] Staff Opening Brief at 27.
[66] Staff Ex. 4, Solganick November 18, 2011 Direct Testimony at 17.

interest because now APS will invest its own funds to pay for government-mandated environmental controls, and the EIS will only collect the capital carrying costs, subject to a cap equal to the charge currently in place for the EIS. The EIS will be reset to zero on the effective date of new rates adopted in this Decision. The property tax deferral was an important component of APS' ability to agree to a four year stay out, and as Staff explains, the amount to be deferred is limited and any positive balance will be recovered over 10 years while any negative balance will be refunded over 3 years.

Staff believes that the Settlement Agreement results in just and reasonable rates and that the impact on customers' bills will be reasonable. Staff notes the following bill impacts from adopting the Settlement Agreement, and also from various adjustors and surcharges:

- A modest reduction across customer classes, generally around one percent on the effective date of the new rates, expected to be July 1, 2012, resulting from delaying the reset of the existing PSA to reflect new base fuel rates;
- In early 2013 when the PSA resets, average residential customer bills will increase by approximately 6.4 percent;
- If the Four Corners transaction closes in 2012, there would be a reduction in the PSA forward component, resulting in a negative 2.9 percent PSA impact, and the February 2013 PSA reset would be approximately 3.5 percent instead of 6.4 percent;
- When the first LFCR adjustment is approved by the Commission, a 0.2 percent adjustment to bills would occur on March 1, 2013;
- If the Four Corners transaction closes, then no earlier than July 2013, a 3 percent nonfuel increase to the average residential customer bill is possible if approved by the Commission; and
- Other adjustor charges could impact customer bills, including the DSMAC, the TCA, and the RES.[67]

Joint Signatories

[67] Staff Opening Brief at 31-32. These are estimates and not rates adopted in this Decision.

The Joint Signatories believe that the Settlement Agreement represents "many weeks of extensive, detailed, and often-times contentious negotiations" that serves not only their individual interests, but the public interest.[68] They believe that several provisions required significant concessions by APS that could not have resulted from a litigated proceeding and that the result is an agreement that has broad-ranging benefits to customers and the Company, allows APS to continue to provide safe and reliable electric service while still pursuing Arizona's energy goals, and that leaves the resolution of policy issues to other, policy-making dockets.

The Joint Signatories identified the benefits of the Settlement Agreement as follows:

- Provides base rate stability for customers;
- Provides customers with additional rate options;
- Creatively resolves significant customer and stakeholder concerns regarding how to recover lost fixed costs that result from Commission-authorized energy efficiency and distributed generation;
- Protects the low-income members of our community, at shareholder expense;
- Gathers information useful to future policy and ratemaking discussions;
- Starts the process of simplifying the APS bill;
- Supports APS financially, enabling it to continue to provide reliable electric service and achieve Arizona's energy goals; and
- Preserves the Commission's flexibility to direct energy policy.[69]

1) <u>Base Rate Stability for Customers</u> – The Joint Signatories identify the primary benefit to customers as the combination of three provisions impacting the rates customers will pay over the next four years: 1) a zero dollar base rate increase; 2) a bill decrease on average for all APS customers through the end of 2012; and 3) the stability of base rates for four years.[70] Witnesses for RUCO, Kroger, Wal-Mart, and AARP testified that this rate stability is beneficial to customers,[71]

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[68] Joint Signatories Opening Brief at 1.
[69] *Id.* at 3.
[70] *Id.* at 5.
[71] RUCO Ex. 4, Radigan January 18, 2012 Direct Testimony in Support of Settlement Agreement at 4-5; Kroger Ex. 3, Baron January 18, 2012 Direct Testimony in Support of Settlement Agreement at 3; Wal-Mart Ex. 3, Chriss January 18,

and the FEA believes that the four year stay out will benefit all federal executive agencies, especially military installations in Arizona by allowing commanders to more accurately allocate budget dollars towards their mission.[72] The Joint Signatories acknowledge that adjustor mechanisms will have bill impacts during the four year stay out, but note that most of those would occur even without the Settlement Agreement. Further, the bill impacts that result from provisions in the Settlement Agreement will be more gradual, and one impact will be a decrease when the SBC is reduced when Palo Verde 2's decommissioning is fully funded. In response to SWEEP's concerns about the stay-out provision limiting the Commission's ability to implement policy options, the Joint Signatories state that the Settlement Agreement's flexibility "substantially minimizes any perceived risk that an issue will arise in the EE-policy arena over the next four years that would require a rate case to resolve ... [and] the Settlement in no way purports to constrain the Commission's ratemaking authority."[73]

2) Additional Rate Options for Customers - The combination of the Commission's rules related to EE and DG and APS' volumetric rate design creates a scenario where APS may not be able to recover some of its fixed costs of service. To address this situation, APS and energy efficiency advocates recommended full revenue per customer decoupling, which was opposed by many customers and parties in this case. The Joint Signatories believe that the Settlement Agreement represents a balanced compromise in how it addresses this issue: a narrowly-tailored LFCR mechanism combined with 1) the ability for residential customers to opt-out of the adjustor by choosing a higher basic service charge and 2) the exclusion of commercial customers from the adjustor. RUCO would not have signed a Settlement Agreement without the opt-out provision;[74] AARP would not have signed the Settlement Agreement with full revenue decoupling;[75] the FEA would consider rejection of the LFCR in favor of full revenue decoupling a "substantive change" to the Settlement Agreement;[76] and the AIC believes that the LFCR mechanism "was an essential

2012 Direct Testimony in Support of Settlement Agreement at 3-4; and AARP Ex. 3, Brockway January 18, 2012 Direct Testimony Supporting Settlement Agreement at 4.

72 Tr. at 63-65.

73 Joint Signatories Opening Brief at 36-37.

74 Tr. at 1120-1121.

75 Tr. at 491.

76 Tr. at 399.

component of the Settlement Agreement from AIC's standpoint."[77]

The Joint Signatories believe the following features of the LFCR are beneficial to customers: recovery is limited to only a portion of the verified lost fixed costs resulting from Commission authorized-EE and DG programs and does not include the impact of other factors, such as weather or general economic conditions; the yearly adjustment is capped; residential customers who prefer rate stability will have the option to pay a higher basic service charge that is designed to recover, on average, the same amount of revenues as would the LFCR adjustor; customers will have the ability in the first year to switch between the LFCR mechanism and the opt-out rate one time to help them decide which rate is best for them, with the ability make further switches after 12 months on a rate; an outreach program will be developed to help customers understand their rate options; and that the opt-out rate does not prevent customers from supporting or participating in EE or DG programs and may help customers gain acceptance of decoupling.[78] Although General Service Customers taking service under rate schedules E-32L, E-32L TOU, E-34 and E-35 are not included in the LFCR mechanism, those customers pay a demand charge that recovers a relatively large portion of APS' fixed costs to provide them service. The Settlement Agreement provides that the rate design for those customers will be changed so the distribution demand component will recover even more fixed costs.[79] Smaller commercial customers are included in the LFCR mechanism and the FEA believes that they will benefit from the LFCR mechanism by not assuming the risks that should be borne by the Company, such as economic and weather risks.[80] The Joint Signatories believe that NRDC's assertion that the LFCR mechanism will encourage DSM programs that may "test well" but not produce real energy savings, is speculative and that the Settlement Agreement's provisions requiring demonstrated actual lost kWh sales attributable to DSM and DG be calculated using the MER results and metered data for DG eliminate the possibility of such "gaming."[81]

The Joint Signatories believe that the proposed Alternative Generation Rate Schedule ("AG-1") provides APS' large customers increased flexibility to manage their energy costs by creating an

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[77] AIC Ex. 4 at 3.
[78] Joint Signatories Opening Brief at 8-10.
[79] Tr. at 517-518.
[80] Tr. at 65.
[81] Joint Signatories Opening Brief at 34-35.

experimental buy-through rate option that will insulate all other customers from any cost shifting. Customers with an aggregated load of at least 10 MW may select a GSP and negotiate a price whereby APS will purchase the power from the GSP in a wholesale transaction and deliver the power to the customer. The program cap of 200 MW and the limited 4 year term will help limit any under-recovery of fixed costs, and APS is also required to take commercially reasonable steps (including maximizing off-system sales) to eliminate or mitigate any unrecovered costs resulting from the program. The Commission retains the ability to decide whether and how any unrecovered costs should be recognized in APS' next rate case. The AECC believes that AG-1 has the "potential to enable Arizona businesses to improve their economic health through energy cost savings- at no risk to other customers" and although AECC continues to "advocate for the reactivation of direct access service in Arizona" in the meantime, AG-1 "can provide substantial benefits to customers through the buy-through option." [82]

The Joint Signatories believe that the 2 new experimental demand response programs will give customers additional opportunities to manage their energy payments.[83] The new residential peak time rebate program allows enrolled customers to earn a rebate based upon the amount of energy a customer saves during notified critical peak periods. APS intends to compare results from this new program with results from its existing residential critical peak pricing program to see whether positive or negative reinforcement is more effective in promoting conservation.[84] Extra large business customers can also subscribe to an experimental interruptible rate rider schedule that will pay the customer an incentive rebate for reducing consumption during a designated time period, with the size of the rebate based upon options chosen by the customer related to the amount of notice required and duration of the interruption.[85]

3) Protection of Low-Income Customers – Ms. Zwick testified that the "poverty rate in Arizona is currently the second highest in the country, having increased significantly during the last

[82] AECC Ex. 3, Higgins January 18, 2012 Direct Settlement Testimony at 10.
[83] Joint Signatories Opening Brief at 13-14.
[84] Tr. at 576-578.
[85] Tr. at 577-578, 607.

two years, making the low-income community larger and more vulnerable than ever."[86] According to the Joint Signatories, two provisions in the Settlement Agreement are designed to help APS' most vulnerable customers: expanding the targeted group of low-income customers to include families whose incomes fall below 200 percent of the federal poverty level (instead of only between 150-200 percent) in the bill assistance program funded by shareholders and approved in Decision No. 69663;[87] and modifying the low-income rate structure to apply a discount to the total bill, instead of exempting adjustor mechanisms. Ms. Zwick, a low-income advocate, RUCO, and AARP all support the change to the low-income rate structure.

4) Useful Information is Gathered for Future Policy and Ratemaking Discussions – The Joint Signatories identify provisions in the Settlement Agreement that will assist the Commission and interested parties in gathering useful information about: the costs and benefits of buy-through rates; the performance of the LFCR compared to APS' original full revenue per customer decoupling mechanism; certain demographics related to APS' workforce; how well APS is performing in areas of fuel and power procurement, and DSM programs and associated energy savings; and about tiered conservation rates, time-of-use and other demand response rates, plans for canceling rates, and ideas for new rate offerings and designs.[88]

5) The Process is Started to Simplify APS' Bill – The Joint Signatories believe that APS' bill format needs to be revised to make it easier for customers to understand, but they do not necessarily agree on how it should be done. The Settlement Agreement requires APS to initiate stakeholder meetings and obtain input with a goal of making the bill more understandable and useful for customers.

6) APS is Supported Financially During the Four Year Stay Out – The Joint Signatories believe that APS needs to remain financially healthy for customers to benefit from high quality service and for APS to achieve Arizona's energy goals.[89] They identified the following provisions as material to APS' financial condition: the LFCR; the 10 percent cost of equity; the Four Corners

[86] Zwick Ex. 1, Zwick December 2, 2011 Direct Testimony at 3. Arizona's poverty rate is 21.2 percent, with 31 percent of children under 18 living in poverty, as reported by the United State Census Bureau.
[87] $4.7 million of the $5 million remains to be distributed. Tr. at 529.
[88] Joint Signatories Opening Brief at 21-23.
[89] *Id.* at 24.

Rate Rider; deferral of Arizona property tax expense; elimination of the PSA 90/10 sharing component; modifications to the EIS; inclusion of post-test year plant; and procedural modifications to the TCA.

The 10 percent cost of equity adopted in the Settlement Agreement is 100 basis points below APS' currently authorized 11 percent return on equity, but was proposed by RUCO in its direct testimony and is very close to Staff's 9.9 percent original recommendation. APS and the Joint Signatories believe that the 10 percent return on equity will be adequate within the context of the Settlement Agreement as a whole and will be viewed positively by the financial community.[90] APS witness Guldner testified that because of the potential size of deferrals, APS likely could not agree to a four year stay out if the Settlement Agreement did not keep this docket open to allow the Commission to approve a rate rider for prudently incurred costs associated with the Four Corners transaction.[91] APS witness Guldner also explained why the ability to defer a portion of any increase in property tax expense related to a tax rate increase is important to APS and its ability to keep base rates stable for four years.[92] RUCO's Director agrees that this provision is a benefit to both APS and to its customers, because if the tax rate decreases, ratepayers will benefit in the next rate case.[93] APS views the elimination of the 90/10 sharing mechanism as a material condition necessary to maintain its financial condition over the four year stay out, and other parties who had opposed elimination, such as the FEA and RUCO, agreed to the elimination as part of the negotiated Settlement Agreement.[94] The Joint Signatories believe that the changes to the EIS will benefit customers and protect APS.[95] RUCO's witness, Ms. Jerich, testified that under the Settlement Agreement, the existing EIS adjustor will be zeroed out on July 1, so the average E-12 customer paying 11 cents currently will see that decrease to zero.[96] APS will benefit because amounts paid

[90] AIC Ex. 5, Fetter January 18, 2012 Direct Testimony in Support of Settlement at 2, 8.
[91] Tr. at 111-113.
[92] APS' assessed plant values are based upon book values, not market value, and combined with recent significant property tax rate increases, APS believes that its property tax expense could continue to increase over the next four years. APS Ex. 2, Guldner January 18, 2012 Direct Settlement Testimony at 27.
[93] Tr. at 1118-1119; "[A]ny reductions in property tax expense due to tax rate decreases would be 100% deferred for the future benefit of customers." Joint Signatories Opening Brief at 28.
[94] Tr. at 402; 808-810.
[95] Joint Signatories Opening Brief at 32.
[96] Tr. at 1118.

under the EIS will no longer be treated as contributions-in-aid of construction, but as revenues that are collected more timely and that will help "the company continue on that path of financial health."[97] The Joint Signatories believe that the change to the TCA was discussed in Decision No. 72430 (June 27, 2011) and that allowing annual TCA adjustments to become effective without affirmative Commission approval unless Staff requests review or the Commission orders otherwise, is appropriate, given Staff's "active and diligent participation in FERC formula rate proceedings."[98]

7) Preserves the Commission's Flexibility to Direct Energy Policy – The Joint Signatories explain that the Settlement Agreement was designed to respond to the Commission's interest in retaining the flexibility to set energy and other policies as it deems appropriate in the future. They negotiated rate mechanisms that will allow APS to adapt to Commission policies as they are determined in other, generic policy dockets. Examples of this flexibility cited by the Joint Signatories include: the resolution of the decoupling issue with the adoption of the LFCR; the treatment of the DSM Performance Incentive to modify it on an interim basis while keeping the record open to develop the new Performance Incentive; the treatment of renewable energy cost recovery issues by giving more flexibility in how RES charges and caps are allocated and reducing the RES surcharge by moving cost recovery of certain APS-owned renewable resources from the RES surcharge to base rates; and by undoing the link between a revenue stream and a specific Commission policy in the area of line extensions.[99]

In response to SWEEP's proposal that the Performance Incentive be modified sooner rather than on the timeline set forth in the Settlement Agreement, the Joint Signatories note that Staff has clearly stated that given its workload priorities and staffing level, it is unable to develop and process a new Performance Incentive before the date set in the Settlement Agreement.[100]

In response to SWEEP's recommendation that the level of energy efficiency funding in base rates should increase from $10 million to $70 million, with the DSM adjustment mechanism collecting or refunding energy efficiency funding amounts above or below $70 million, APS

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[97] Tr. at 1144.
[98] Joint Signatories Opening Brief at 32.
[99] *Id.* at 17-21.
[100] Staff Ex. 11, Olea January 25, 2012 Responsive Testimony in Support of Settlement Agreement at 4-5; Tr. at 1027-1028.

indicated that although it is neutral on the issue, it would affect APS customers in different ways and that policy arguments support both methods of recovery of these costs. The Joint Signatories did not attempt to resolve this policy issue, and left the current collection method in place.[101]

Finally, in response to SWEEP's proposed adjustment to test year sales to account for the energy savings and load-reducing effects of the EE Standard requirements, APS responded that although APS had proposed a similar adjustment in its last two rate cases that was not adopted, it is not necessary with the LFCR mechanism. The Joint Signatories believe that the LFCR mechanism is preferable because it is an after-the-fact adjustment for actual, not projected, sales reductions.[102]

Opposition to the Settlement Agreement

SWEEP

As discussed above, SWEEP identified three primary reasons why it partially opposed the proposed Settlement Agreement. According to SWEEP, the Commissioners expressed concerns at the December 16, 2011 Open Meeting about settlements limiting options and flexibility, and although the Settlement Agreement leaves decisions about energy efficiency programs and savings to reduce customers bills to the Commission, SWEEP believes that by not including full revenue decoupling as an option, the Settlement Agreement limits the Commission's review of other regulatory policies to address utility disincentives to energy efficiency. SWEEP recommends that the Commission approve the Settlement Agreement but instead of the LFCR mechanism, substitute full revenue decoupling as proposed in the original APS application, but with the 3 percent cap recommended in SWEEP's direct testimony.[103] SWEEP criticizes the LFCR because it represents an automatic rate increase, it does not provide a credit when actual revenues are higher than forecasted (for example, when electricity sales increase from an improved economy), and it does nothing to reduce the utility's financial incentive to increase sales or customer use of more electricity, so it fails to align the financial incentives of the utility with the interests of customers.[104] SWEEP argues that full revenue decoupling is important not only for utility support for EE

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[101] Joint Signatories Opening Brief at 37.
[102] *Id.* at 38.
[103] The 3 percent cap is a total cap on all decoupling adjustments (revenues relative to the revenue per customer level set in the rate case) in a year. SWEEP Opening Brief at 4.
[104] SWEEP Opening Brief at 3-5.

programs, but also for support of "building codes and appliance standards, broad energy education and marketing, state and local government energy conservation efforts and federal energy policies."[105]

SWEEP cites TEP's current rate case stay-out provision as support for its argument that that stay-out provisions can constrain Commission options and actions related to achievement of EE and the Commission's review of EE Implementation Plans. SWEEP believes that if the Settlement Agreement is adopted, the Commission should either shorten the stay-out period to 3 years, or after 3 years, initiate a review to determine if APS' rates are just and reasonable and whether to continue the stay-out.

SWEEP recommends that instead of keeping the record open in this rate case, the new Performance Incentive should be developed by mid-2012 and filed by APS as part of its 2013 EE Implementation Plan for Commission review. Although Arizona Administrative Code ("A.A.C.") R-14-2-2411 allows a Performance Incentive to be proposed in either an implementation plan or in a rate case, SWEEP believes that it is critical for the Commission to oversee and modify Performance Incentive design during the energy efficiency implementation plan process. In the event that the Commission adopts the Settlement Agreement and delays consideration of the Performance Incentive until later in the year, SWEEP recommends that the Commission adopt the following objectives and design criteria for the Performance Incentive:

Objectives

1. It encourages the Company to pursue cost-effective energy efficiency;
2. It is designed in such a way to avoid any perverse incentives;
3. It is based on clearly-defined goals and activities that are sufficiently monitored, quantified, and verified;
4. It is available only for activities for which the Company plays a distinct and clear role in bringing about the desired outcome; and
5. It is kept as low as possible while balancing and meeting the objectives and principles mentioned above.[106]

Design Criteria

- Encourage the achievement of energy savings and net benefits for customers through a

[105] *Id.* at 3.
[106] SWEEP Ex. 6, Schlegel January 18, 2012 Testimony in Partial Opposition to the Proposed Settlement Agreement at 9.

performance incentive with an eligible incentive level equivalent to 7 % of net benefits on a pre-tax basis;

- Include new components and metrics that emphasize increased comprehensiveness of energy efficiency program services provided to customers and result in higher percent savings, encourage cost-efficiency in the use of ratepayer funds (i.e., total net benefits to customers per dollar of ratepayer funding provided), and target the achievement of specific performance goals such as serving a targeted number of low income customers and/or issuing a specific targeted number of residential loans or a targeted total loan amount; and,
- Have an absolute dollar cap on the total incentive amount that the Company may earn, set at 115% of the eligible incentive level (determined at 100% of target performance), thereby not incenting increased program spending through the design of the performance incentive mechanism or its incentive cap.[107]

SWEEP also recommended that the level of energy efficiency funding in base rates should increase from $10 million to $70 million, with the DSM adjustment mechanism collecting or refunding energy efficiency funding amounts above or below $70 million, as needed to implement and deliver energy efficiency programs to customers.[108] Finally, SWEEP proposed that to insure that the rate-setting process takes account of Commission-adopted policies, an adjustment to test year sales to account for the energy savings and load-reducing effects of the EE Standard requirements is appropriate.

NRDC

NRDC partially opposes the Settlement Agreement in that it urges the Commission to adopt the full revenue decoupling mechanism that APS proposed in its original application. NRDC argues that the full revenue decoupling mechanism is the "very type endorsed and solicited in the Final Policy Statement adopted unanimously by the Commission less than a year earlier"[109] and very similar to the per-customer decoupling mechanism option included in the Southwest Gas Settlement Agreement and adopted by the Commission in the recent rate case. NRDC witness Cavanagh testified that revenue decoupling makes more sense for electric utilities than gas utilities because electric utilities recover a higher percentage of fixed costs in variable charges and therefore have a significantly stronger link between financial health and commodity sales.[110] By proposing to

[107] SWEEP Ex. 6, Schlegel January 18, 2012 Testimony in Partial Opposition to the Proposed Settlement Agreement at 9.
[108] *Id.* at 10.
[109] NRDC Opening Brief at 1, referring to the Commission's Policy Statement.
[110] Tr. at 760-762.

substitute decoupling for the LFCR in the Settlement Agreement, the NRDC is "framing for the Commission the same choice it faced in the Southwest Gas case."[111] NRDC's witness testified that the residential "opt-out" provision requires customers to accept higher fixed charges and would discourage efficient energy usage;[112] that the LFCR mechanism is an automatic rate increase, where decoupling can either raise or reduce rates;[113] and because the LFCR affects only a portion of distribution and transmission costs and does not include generation costs, NRDC argues that "APS would be better off financially if it gave up the savings and received instead equivalent increases in retail sales."[114]

ANALYSIS AND CONCLUSION

APS is Arizona's largest and longest serving electric public service corporation and its rates and charges affect millions of individuals, businesses, organizations, and governmental entities located throughout in the state. It has approximately 6,800 employees and provides service to more than 1.1 million retail and wholesale customers in eleven counties in Arizona. APS is the largest property tax payer in Arizona, paying about $128 million in property taxes in 2010.[115] According to the Company, its mission is to "safely and efficiently generate and deliver reliable electric power and related services to our customers."[116]

APS filed this rate application in compliance with the General Rate Case Filing Plan contained in the 2009 Settlement Agreement and adopted by the Commission in Decision No. 71448. Pursuant to that Decision, rates adopted herein will not become effective until July 1, 2012. The 2009 Settlement Agreement was designed to create a balanced rate and stability program that would ultimately improve APS' financial metrics and bond ratings, thereby benefiting customers in the long run through lower costs of capital.[117] APS witness Guldner explained that the 2009 Settlement Agreement was viewed positively by the investment community and that APS is now in a "stronger financial position to attract the approximately $20 billion in new capital investments that

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[111] NRDC Opening Brief at 5.
[112] NRDC Ex. 2, Cavanagh January 18, 2012 Testimony in Partial Opposition to the Proposed Settlement Agreement at 6.
[113] *Id.* at 7.
[114] *Id.* at 8.
[115] APS Ex. 4, Robinson June 1, 2011 Direct Testimony at 5.
[116] *Id.* at 6.
[117] Decision No. 71448, Exhibit A, Settlement Agreement Section 1.15 at 7-8.

customers will require between now and 2015."[118] Mr. Guldner also testified that when APS filed this rate application, it was "aware of the difficulties our customers face in the current economic climate" and so it looked to moderate the bill impact to customers.[119]

As in all APS rate cases, there are many parties with different perspectives and interests. The parties to this matter include representatives from all customer classes as well as representatives of groups or organizations concerned about or interested in specific policy matters or programs. All parties agree that the Settlement Agreement was the result of an open and transparent process where every party had the opportunity to participate and provide input. Although not every party signed the Settlement Agreement, even those in partial opposition found that there was much to like about the other provisions. It is clear from a comparison of the parties' positions prior to the Settlement Agreement and the positions adopted in the Settlement Agreement, that Staff and the Joint Signatories were able to negotiate a package deal that represented both the requirements and compromises they each were able to accept as necessary for the public interest to be served.

The customer benefits identified by Staff and the Joint Signatories are significant – no base rate increase for four years at a time when many customers are struggling financially; modifications to the low-income rates that will allow more customers to qualify for bill assistance and to benefit from the PSA; a way to continue to fund programs to meet the Commission's EE and DG rules while giving APS the opportunity to recover certain verified lost fixed costs due to Commission-approved programs; the option for residential customers to pay lost fixed costs either through the LFCR adjustor or through a stable basic service charge; the experimental AG-1 buy-through rate that will offer large customers the opportunity to explore other generation sources; the opportunity to develop a new Performance Incentive tied to the achievement of cost-effective energy savings; the new demand response programs for both residential and commercial customers; and the start of the process to make APS' bill easier for customers to understand.

The provisions of the Settlement Agreement that benefit APS include changes to the PSA that will improve collection of prudently incurred fuel and purchased power costs; a 10 percent return on

[118] APS Ex. 4, Guldner June 1, 2011 Direct Testimony at 6.
[119] *Id.*

equity; the LFCR mechanism that will allow APS to recover certain verified lost fixed costs due to reduced sales from Commission-approved energy efficiency or distributed generation programs; the opportunity to seek recovery of the Four Corners transaction costs through a rider prior to the next rate case; modifications to the environmental improvement surcharge; the ability to defer property tax expense related to tax rate increases; the modification to the transmission cost adjustor; the inclusion of post-test year plant in rate base; and the various requirements to provide information that will assist the Commission and parties, including the workforce planning report.

These benefits are clear and substantial. Although the Settlement Agreement is partially opposed by two parties, that opposition was at least partly intended to give the Commission the opportunity to choose full revenue per customer decoupling instead of the LFCR. Witnesses for Staff and the Joint Signatories have testified why full revenue decoupling is not appropriate for APS customers at this time, specifically arguing that the risks associated with weather and the economy should not be shifted from shareholders to ratepayers.

Energy efficiency raises not only issues of what costs should be recovered, but how to recover those costs without either penalizing the utility or creating an undeserved windfall for APS at ratepayers' expense. The advocates for full revenue per customer decoupling argue that the LFCR does not break the link between increased sales and increased earnings. The advocates for the LFCR argue that full revenue per customer decoupling burdens ratepayers by making them pay for economic and weather-related risks in addition to energy efficiency savings. While the Policy Statement adopted by the Commission expressed a preference for full revenue decoupling, it did not require it, but instead allowed for alternatives to be proposed in rate cases. Conceptual discussions of policies can help with understanding issues, address problems, and plan for the future, but until a policy is applied to an actual situation, it is difficult to foresee or understand all implications of the policy and how it will affect those involved.

We believe that the decision on the appropriate method to address the revenue impacts of energy efficiency should be made on a case-by-case basis, based upon the unique circumstances of each utility and the service it provides. We agree with Staff and the Joint Signatories that the LFCR mechanism is the appropriate mechanism for APS at this time. Although it may not eliminate the incentive for APS to increase sales volumes to increase earnings, it does reduce the disincentive for APS to not invest in EE and DG due to reduced sales. Because the Settlement Agreement requires that the annual lost fixed costs APS proposes to recover from its ratepayer must be documented and verified, customers will have confidence that the funds they pay for EE and DG are being appropriately and well spent. The LFCR allows residential customers a choice as to how they pay the lost fixed costs and will give them some experience to help them understand how energy efficiency savings affect a utility. It will address lost fixed cost recovery for large customers through rate design changes. APS' annual compliance filing reports will allow us to compare the revenue recovered through the LFCR to the revenue that would have been recovered through the Company's original full revenue per customer decoupling proposal. This information will assist us in assessing how lost fixed cost recovery may be addressed in the future.

The Settlement Agreement provides that the LFCR mechanism will adjust "annually to account for the unrecovered costs associated with a portion of distribution and transmission costs resulting from EE programs as demonstrated by the Measurement, Evaluation and Reporting ("MER") conducted for EE programs and from DG as demonstrated pursuant to the means described in Section 9.5 below."[120] This is the basis for the Joint Signatories and Staff's argument that the LFCR recovery is "narrowly tailored" and is "tied to measured and approved Corporation Commission programs for energy efficiency and for distribution."[121] As explained by APS witness Snook, the LFCR mechanism does not currently have a balancing account, because they took a "simplifying approach."[122] We believe that a balancing account is necessary if APS is to recover its verified lost fixed costs as allowed in the Settlement Agreement and will require APS to clarify its Plan of Administration to include a balancing account to insure that it recovers the costs allowed in the Settlement Agreement.[123]

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[120] Staff Ex. 16, January 6, 2012 Settlement Agreement Section 9.4 at 11.
[121] Staff Opening Brief at 19.
[122] Tr. at 886.
[123] The LFCR is to be collected through a percentage applied to a customer's bill. Without a balancing account, if annual sales decrease, the total lost fixed cost revenue for the previous year would not recovered; and if annual sales increase, the total lost fixed cost revenues for the previous year would be over-recovered, and the risk related to non-LFCR factors would have inappropriately shifted from shareholders to customers. Clearly, Staff and the Joint Signatories desired the LFCR to recover the appropriate revenues, as it allows deferral of amounts in excess of the one percent cap for recovery in another year. APS' PSA employs a balancing account that works well.

We find that an important ratepayer benefit of the Settlement Agreement is the four year stay out provision. Pursuant to Decision No. 71448, APS could file a rate case after June 1, 2013, less than a year after rates in this matter go into effect. The Settlement Agreement does not allow APS to file a general rate case until May 31, 2015. Although SWEEP recommended that a three year stay out was appropriate, APS, Staff and the Joint Signatories believe that the provisions of the Settlement Agreement will allow APS to remain financially stable and able to provide reliable and safe electric service, while preserving the Commission's flexibility to implement policy as it chooses. We agree.

We also find that SWEEP's timing for development of a new performance incentive is not workable for Staff or the Commission, given the complexity of the issue and the existing workload of Staff. We find that SWEEP's list of Performance Incentive objectives is a good starting point for discussions about modifications to the Performance Incentive, and encourage Staff and the parties to work cooperatively to address the Performance Incentive. The issue of moving an additional $60 million of energy efficiency funding in base rates was not supported by the Joint Signatories, apparently because it would affect different customers differently. We have insufficient testimony and evidence in this docket to decide whether and how a change to efficiency energy funding should be accomplished. We also believe that the LFCR mechanism that collects actual, verified and documented lost fixed cost savings with a balancing account is more accurate and appropriate than using an adjustment to test year sales as recommended by SWEEP.

Accordingly, based upon the testimony and evidence presented in this matter, we find that the Settlement Agreement and its provisions as discussed herein, are in the public interest and should be approved.

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Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. APS is a public service corporation principally engaged in furnishing electricity in the State of Arizona. APS provides either retail or wholesale electric service to substantially all of

Arizona, with the major exceptions of the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. APS also generates, sells, and delivers electricity to wholesale customers in the western United States.

2. APS' current rates and charges were established in Decision No. 71448 (December 30, 2009).

3. On June 1, 2011, APS filed with the Commission an application for a rate increase, seeking a $95.5 million net increase in base rates.

4. On June 28, 2011, APS filed a revised Residential Rate Schedule ECT-1R, L, which corrected the bundled and unbundled rates, and also filed its revised Standard Filing Requirements H-3 and H-4.

5. On July 1, 2011, Staff filed a Letter of Sufficiency indicating that the application had met the sufficiency requirements of A.A.C. R14-2-103 and classifying the Company as a Class A utility.

6. By Procedural Order issued July 29, 2011, the hearing was set to commence on January 19, 2012, and other procedural timeframes were established.

7. Notice of the application and hearing was mailed to customers and published in the *Arizona Republic*, the *Casa Grande Dispatch*, the *Yuma Sun*, the *Sierra Vista Herald*, the *Bisbee Daily Review*, and the *Prescott Daily Courier* on August 23 and 27, 2011; in the *Market Place (TMC)* on August 24, 2011; and in the *Arizona Daily Sun* on August 27 and September 15, 2011.[124]

8. Intervention was granted to Freeport-McMoRan; AECC; RUCO; Wickenburg; Barbara Wyllie-Pecora; WRA; SWEEP; Kroger; AAR; Gilbert; TEP; Cynthia Zwick; AIC; the FEA; the Alliance; IBEW Locals; SWPG/Bowie; NRDC; ASBA/AASBO; AzAg Group; Wal-Mart; Noble/Constellation/Direct/Shell; AARP; and Interwest.

9. On October 7, 2011, the Commission held a public comment session in Sun City, Arizona.

10. On November 18, 2011, the Commission issued Decision No. 72684, approving

[124] APS certification of mailing/publication filed on September 26, 2011.

Version 12 of APS Service Schedule 3 as set forth in the Decision, to become effective upon the effective date of rates set in this docket.[125]

11. On December 9, 2011, Staff filed a Preliminary Term Sheet and requested that the Commission schedule an open meeting for discussion.

12. On December 14, 2011, APS filed its Statement of Position; AIC filed its Position Statement in Support of the Preliminary Term Sheet; WRA filed its Comments on Preliminary Term Sheet; and Wal-Mart filed its Statement in Support of Settlement Agreement.

13. On December 15, 2011, Ms. Zwick filed her Statement in Support of Settlement Agreement; Kroger filed its Statement in Support of Settlement Agreement; the Alliance filed its Comments on the Preliminary Term Sheet; and AECC filed its Statement in Support of the Preliminary Settlement Term Sheet.

14. On December 16, 2011, Interwest filed its Statement in Support of Settlement Agreement.

15. On December 16, 2011, the Commission held a Special Open Meeting to discuss the Preliminary Term Sheet.

16. On December 19, 2011, Staff filed a Notice of Errata, correcting portions of the direct testimony of its witness, Michael J. McGarry.

17. On December 22, 2011, Staff filed a Request for a Modification to the Procedural Schedule requesting that the date for filing a settlement agreement be extended until January 6, 2012 and also proposing other changes to the procedural schedule.

18. By Procedural Order issued December 23, 2011, the hearing was rescheduled to commence on January 26, 2012, and the date for filing any settlement agreement was extended until January 6, 2012.

19. On January 6, 2012, Staff filed a proposed Settlement Agreement entered into by APS, Staff, RUCO, Ms. Zwick, the FEA, Kroger, Freeport-McMoRan, AECC, Wal-Mart, IBEW, AzAg, the Alliance, AARP, AAR, Ms. Wyllie-Pecora, AIC, SWPG/Bowie, and Noble/Constellation/ Direct/

[125] Docket No. E-01345A-11-0207.

Shell.

20. On January 19, 2012, the record was opened for public comments and a pre-hearing conference was held at the Commission's offices.

21. On January 19, 2012, a Motion to Associate Samuel Miller as Counsel Pro Hac Vice was filed and granted during the pre-hearing conference.

22. On January 20, 2012, Staff filed Notice of Rate Case Hearing.

23. The evidentiary hearing was held on January 26, 27, 30, 31, and February 1, 2, and 3, 2012. Jeffrey Guldner, Charles Meissner, and Leland Snook testified on behalf of APS; Stephen Baron testified on behalf of Kroger; Larry Blank testified on behalf of the FEA; Nancy Brockway testified on behalf of AARP; Mary Lynch testified on behalf of Noble/Constellation/Direct/Shell; Chris Hendrix and Steve Chriss testified on behalf of Wal-Mart; Ms. Zwick testified on her own behalf; Jeff Schlegel testified on behalf of SWEEP; Ralph Cavanagh testified on behalf of NRDC; Frank Radigan and Jodi Jerich testified on behalf of RUCO; Steven Fetter and Gary Yaquinto testified on behalf of AIC; Kevin Higgins testified on behalf of Freeport-McMoRan and AECC; G. David Vandever testified on behalf of IBEW; Tom Farley testified on behalf of AAR; and Steve Olea and Howard Solganick testified on behalf of Staff.

24. On February 1, 2012, Staff filed its Request for Clarification.

25. On February 8, 2012, APS filed its Late-Filed Exhibit 17.

26. On February 9, 2012, Jody Kyler was admitted pro hac vice on a permanent basis on behalf of Kroger.[126]

27. On February 9, 2012, APS filed a revision to its Late-Filed Exhibit 17.

28. On February 29, 2012, the Joint Initial Post-Hearing Brief of Parties Supporting the Settlement (Except Commission Staff), SWEEP's Opening Brief, and Staff's Opening Brief were filed. On March 1, 2012, the NRDC's Opening Brief was filed.

29. On March 2, 2012, Chairman Pierce docketed a letter to the parties.

30. On March 7, 2012, APS on behalf of the Joint Initial Brief Signatories; SWEEP; and

[126] Ms. Kyler was granted temporary admission on January 26, 2012.

Staff each filed Notices indicating that they would not be filing Reply Briefs.

31. On March 9, 2012, NRDC filed its Notice that it would not be filing a Reply Brief.

32. The settlement discussions were open, transparent, and inclusive of all parties who desired to participate. All parties were notified of the settlement proceedings and had the opportunity to be heard and have their issues fairly considered.

33. The Settlement Agreement and its provisions are in the public interest and should be approved as set forth herein.

34. The LFCR Plan of Administration should include a balancing account as set forth herein.

35. APS' original cost rate base is $5,662,998,000 and the fair value of APS' jurisdictional rate base for the test year ending December 31, 2010 is $8,167,126,000.

36. APS' total adjusted test year revenue is $2,868,858,000.

37. A capital structure comprised of 46.06 percent debt and 53.94 percent common equity is appropriate for establishing rates in this matter.

38. A return on common equity of 10.0 percent and an embedded cost of debt of 6.38 percent are appropriate estimates of the cost of capital for purposes of this Settlement Agreement.

39. A fair value rate of return of 6.09 percent on APS' fair value rate base produces rates that are just and reasonable.

40. APS should be authorized a zero dollar base rate increase comprised of an increase in its non-fuel base rates by $116.3 million; a fuel base rate decrease of $153.1 million; and a transfer of cost recovery from the RES to base rates as described in the Settlement Agreement in Paragraph VIII.

41. A Base Cost of Fuel and Power of $0.032071 per kWh is appropriate under the terms of the Settlement Agreement.

42. The record in this matter should remain open as described herein.

CONCLUSIONS OF LAW

1. APS is a public service corporation within the meaning of Article XV of the Arizona Constitution, A.R.S. §§ 40-203, -204, -221, -250, -251, and -361, and A.A.C. R14-2-801 et. seq.

2. The Commission has jurisdiction over APS and the subject matter of the application.

3. Notice of the application and hearing was provided in accordance with the law.

4. Adoption of the Settlement Agreement as discussed herein is in the public interest.

5. The rates and charges produced by the Settlement Agreement are just and reasonable.

ORDER

IT IS THEREFORE ORDERED that the Settlement Agreement dated January 6, 2012 and attached to this Decision as Exhibit A, is hereby approved as discussed herein.

IT IS FURTHER ORDERED that Arizona Public Service Company is hereby directed to file with the Commission on or before June 29, 2012, revised schedules of rates and charges and Plans of Administration consistent with Exhibit A and the findings herein.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after July 1, 2012.

IT IS FURTHER ORDERED that Arizona Public Service Company shall notify its affected customers of the revised schedules of rates and charges authorized herein by means of an insert in its next regularly scheduled billing and by posting on its website, in a form acceptable to the Commission's Utilities Division Staff.

IT IS FURTHER ORDERED that Arizona Public Service Company shall implement and comply with the terms of the Settlement Agreement, including filing all reports, studies, and plans as set forth in the Settlement Agreement and herein.

IT IS FURTHER ORDERED that record in this matter shall remain open to allow Arizona Public Service Company to file by December 31, 2012, an application for consideration and approval of a new Performance Incentive structure in the Demand Side Management Adjustor Clause, as discussed herein.

IT IS FURTHER ORDERED that record in this matter shall remain open to allow Arizona Public Service Company to file by December 31, 2013, an application for approval to adjust its rates to reflect the acquisition of Four Corners Units 4 and 5, as discussed in Decision No. 73130 and herein.

IT IS FURTHER ORDERED that Version 12 of Service Schedule 3, as approved in Decision No. 72684 (November 18, 2011) is effective as of July 1, 2012.

IT IS FURTHER ORDERED that the reporting requirement contained in Decision No. 70667 (December 24, 2008) is eliminated as of July 1, 2012.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN		COMMISSIONER
COMMISSIONER	COMMISSIONER	COMMISSIONER

IN WITNESS WHEREOF, I, ERNEST G. JOHNSON, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this ______________ day of __________________ 2012.

ERNEST G. JOHNSON
EXCUTIVE DIRECTOR

DISSENT ______________________

DISSENT ______________________

SERVICE LIST FOR: ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO.: E-01345A-11-0224

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EXHIBIT A

ARIZONA PUBLIC SERVICE COMPANY

PROPOSED SETTLEMENT AGREEMENT

DOCKET NO. E-01345A-11-0224

January 6, 2012

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PROPOSED SETTLEMENT AGREEMENT OF DOCKET NO. E-01345-A-11-0224 ARIZONA PUBLIC SERVICE COMPANY REQUEST FOR RATE ADJUSTMENT

The purpose of this Settlement Agreement ("Agreement") is to settle disputed issues related to Docket No. E-01345A-11-0224, Arizona Public Service Company's ("APS" or "Company") application to increase rates. This Agreement is entered into by the following entities:

Arizona Corporation Commission Utilities Division ("Staff")
Arizona Public Service Company ("APS")
Residential Utility Consumer Office ("RUCO")
Cynthia Zwick
Federal Executive Agencies ("FEA")
Kroger Co. ("Kroger")
Freeport-McMoRan Copper & Gold Inc. ("Freeport-McMoRan")
Arizonans for Electric Choice and Competition ("AECC")
Wal-Mart Stores, Inc. and Sam's West, Inc. ("Wal-Mart")
IBEW Locals 387, 640, 769 ("IBEW")
AzAg Group ("AzAG")
Arizona Competitive Power Alliance ("AzCPA")
AARP ("AARP")
Arizona Association of Realtors ("AAR")
Barbara Wyllie-Pecora ("Wyllie-Pecora")
Arizona Investment Council ("AIC")
Southwestern Power Group II, LLC ("SWPG")
Bowie Power Station, LLC ("Bowie")
Noble Americas Energy Solutions LLC ("Noble")
Constellation NewEnergy, Inc. ("Constellation")
Direct Energy, LLC ("Direct")
Shell Energy North America (US), L.P. ("Shell")

These entities shall be referred to collectively as "Signatories;" a single entity shall be referred to individually as a "Signatory."

I. RECITALS

1.1 APS filed the rate application underlying Docket No. E-01345A-11-0224 on June 1, 2011. Staff found the application sufficient on July 1, 2011.

1.2 Subsequently, the Arizona Corporation Commission ("Commission") approved applications to intervene filed by AARP, Arizona Association of Realtors, AzCPA, AIC, ASBA, Association of School Business Officials, AZAg Group, Barbara Wyllie-Pecora, Cynthia Zwick, FEA, Freeport-McMoRan and AECC (collectively "AECC"), IBEW Locals 387, 640 and 769, Interwest, Kroger, Mel Beard, Noble et al, NRDC, RUCO, SWEEP, SWPG, Bowie, TEP, the Town of Gilbert, the Town of Wickenburg, Wal-Mart and Sam's Club, and WRA. Mel Beard subsequently withdrew as an intervenor in the case.

1.3 APS filed a notice of settlement discussions on November 18, 2011. Settlement discussions began on November 30, 2011. The settlement discussions were open, transparent, and inclusive of all parties to this Docket who desired to participate. All parties to this Docket were notified of the settlement discussion process, were encouraged to participate in the negotiations, and were provided with an equal opportunity to participate. Commission Staff filed a Preliminary Term Sheet regarding this matter on December 9, 2011, which was discussed in a Special Open Meeting held on December 16, 2011.

1.4 The terms of this Agreement are just, reasonable, fair, and in the public interest in that they, among other things, establish just and reasonable rates for APS customers; promote the convenience, comfort and safety, and the preservation of health, of the employees and patrons of APS; resolve the issues arising from this Docket; and avoid unnecessary litigation expense and delay.

1.5 The Signatories believe that this Agreement balances the interests of both APS and its customers. These benefits include:

- an overall zero dollar base rate increase;
- a zero percent bill impact for the remainder of 2012 (Commission-approved adjustors (including the possibility of a Four Corners rider pursuant to paragraph 10.3) may increase customer bills after December 31, 2012);

- a four year rate case stay out, in which APS agrees not to raise base rates as a result of any new general rate case filing prior to July 1, 2016;
- a buy-through rate for industrial and large commercial customers;
- a narrowly-tailored Lost Fixed Cost Recovery ("LFCR") mechanism that supports energy efficiency ("EE") and distributed generation ("DG") at any level or pace set by this Commission;
- an opt-out rate design for residential customers who choose not to participate in the LFCR;
- a process for simplifying customers' bill format; and
- bill assistance for additional low income customers, at shareholder expense.

1.6 The Signatories agree to ask the Commission (1) to find that the terms and conditions of this Agreement are just and reasonable and in the public interest, along with any and all other necessary findings, and (2) to approve the Agreement and order that it and the rates contained herein become effective on July 1, 2012.

TERMS AND CONDITIONS

II. RATE CASE STABILITY PROVISION

2.1 APS agrees not to file its next general rate case prior to May 31, 2015. The test year end date for the base rate increase filing contemplated in this section shall be no earlier than December 31, 2014 but need not coincide with the end of a calendar year. No new base rates resulting from APS's next general rate case will be effective before July 1, 2016.

III. RATE INCREASE

3.1 APS shall receive a base rate increase of zero dollars ("revenue requirement"). This amount is comprised of: (1) a non-fuel base rate increase of $116.3 million, which includes providing for a return on and of plant that is in service as of March 31, 2012 ("Post-Test Year Plant"); (2) a fuel base rate decrease of

$153.1 million; and (3) a transfer of cost recovery from the Renewable Energy Surcharge ("RES") to base rates described in Paragraph VIII herein.

3.2 The Company's jurisdictional fair value rate base used to establish the rates agreed to herein is $8,167,126,000. The Company's total adjusted Test Year revenue is $2,868,858,000.

IV. BILL IMPACT

4.1 When new rates become effective, customers will have on average a 0.0% bill impact or less. This zero percent or slightly negative bill impact will be achieved by allowing the negative credit that exists in the Company's Power Supply Adjustor ("PSA") to continue until February 1, 2013, at which time it will reset. The annual 4 mill cap will be applied after the impact of the expiration of the then-current PSA credit.

4.2 Subsequent to the PSA reset for General Service customers in February 2013, the percentage bill impact spread resulting from this Settlement among the various segments of that customer class shall be equal. This shall be accomplished as set forth in Attachment A.

4.3 A zero percent bill impact will continue for the remainder of 2012 (Commission-approved adjustors (including the possibility of a Four Corners rider pursuant to paragraph 10.3) may increase customer bills after December 31, 2012).

V. COST OF CAPITAL

5.1 A capital structure comprised of 46.06% debt and 53.94% common equity shall be adopted.

5.2 A return on common equity of 10.0% and an embedded cost of debt of 6.38% shall be adopted.

5.3 A fair value rate of return of 6.09%, which includes a return on the fair value rate base increment of 1.0%, shall be adopted.

5.4 The provisions set forth herein regarding the quantification of cost of capital, fair value rate base, fair value rate of return, and the revenue requirement are made for purposes of settlement only and should not be construed as admissions against interest or waivers of litigation positions related to other or future cases.

VI. DEPRECIATION/AMORTIZATION AND DECOMMISSIONING

6.1 With the exception of Uniform System of Accounts 370.01 (electronic meters), 370.02 (electro-mechanical meters), and 370.03 (AMI meters), the depreciation and amortization rates proposed by APS and contained in Attachment REW-2 to Dr. Ron White's Pre-filed Direct Testimony shall be adopted until further order of the Commission. For Accounts 370.01, 370.02 and 370.03, the current depreciation rates will be retained, as proposed by Commission Staff Witness Ralph Smith.

6.2 The annual nuclear decommissioning amounts reflected in the rates agreed to herein are those shown in APS Witness Jason LaBenz workpaper JCL_WP22, page 4, attached hereto as Attachment B.

6.3 APS shall file a request that the Commission adjust the Company's System Benefit Charge ("SBC") and reduce such charge to reflect a corresponding reduction of the decommissioning trust funding obligations collected through the SBC related to the full funding of Palo Verde Unit 2. Such filing shall be made in sufficient time for the reduction to occur by January 2016.

VII. FUEL AND POWER SUPPLY ADJUSTMENT PROVISIONS

7.1 The base fuel rate shall be lowered from $0.037571 per kWh as set in Commission Decision No. 71448 to $0.032071 per kWh. This change shall take effect on the effective date of the new rates contained in this Agreement, in accordance with the current approved Plan of Administration for the Power Supply Adjustor ("PSA").

7.2 For purposes of this case, APS will withdraw its request to recover through the PSA the cost of chemicals required for environmental compliance at APS's power plants, and APS shall not raise this request before its next general rate case.

7.3 The 90/10 sharing provision in APS's PSA will be eliminated. The PSA shall be modified to require APS to apply interest on the PSA balance annually, rather than monthly, at the following rates: any over-collection existing at the end of the PSA year will accrue interest at a rate equal to the Company's authorized ROE or APS's then-existing short term borrowing rate, whichever is greater, and will be refunded to customers over the following 12 months; any under-collection existing at the end of the PSA year will accrue interest at a rate equal to the Company's authorized ROE or APS's then-existing short term borrowing rate, whichever is less, and will be recovered from customers over the following 12 months. APS may, at any time during the PSA year, request to reduce the PSA rate through the Transition Component. Any such request shall become effective beginning with the first billing cycle of the month following the filing date of the request.

7.4 To incent prudent fuel and power procurement and use, APS shall be subject to periodic audits. The first audit shall be for calendar year 2014. Commission Staff shall select a consultant to perform this audit and subsequent audits. Each audit shall be funded by APS in an amount not to exceed $100,000 per audit.

7.5 The PSA Plan of Administration shall be amended as set forth in Attachment C.

VIII. RENEWABLE ENERGY

8.1 APS currently collects the costs associated with certain APS-owned renewable energy projects through the RES. Consistent with the treatment of other Post-Test Year Plant adopted in this Agreement, the portion of those renewable projects that have been closed to plant in service as of March 31, 2012, shall be rate based and recovery of those costs shall be accomplished through base rates. The specific projects to be rate based pursuant to this Section are identified in Attachment D.

8.2 Effective with the date of the Commission's order in this matter, the capital carrying costs[1] for any APS renewable energy-related capital investments shall not be recovered through the RES adjustor, except that capital carrying costs for renewable energy-related capital investments that APS makes in compliance with Commission Decision No. 71448 shall be recovered in the RES adjustor unless and until specifically authorized for recovery in another adjustor or in base rates.

8.3 On the effective date of the new rates contained in this Agreement, the RES adjustor rate established for 2012 in Docket No. E-01345A-11-0264 shall be reduced to reflect the removal of the projects identified in Attachment D. At the same time, the renewable energy-related purchased power agreement costs that were moved from the RES to the PSA pursuant to the Commission's

[1] Capital carrying costs include (1) a return at the Company's Weighted Average Cost of Capital approved by the Commission in this rate case; (2) depreciation expense; (3) income taxes; (4) property taxes; (5) deferred taxes and tax credits where appropriate; and (6) associated O&M.

Decision in Docket No. E-01345A-11-0264, shall be transferred back to the RES.

8.4 To provide the Commission with greater flexibility in setting RES adjustor rates and related caps, the requirement established in Decision No. 67744 that any changes to RES charges and caps must be allocated between customer classes according to certain set proportions shall be eliminated.

IX. ENERGY EFFICIENCY/LOST FIXED COST RECOVERY/OPT-OUT RESIDENTIAL RATE/LARGE GENERAL SERVICE CUSTOMER EXCLUSION

9.1 The Signatories support energy efficiency as a low cost energy resource. The Signatories also recognize that, under APS's current volumetric rate design, the Company recovers a significant portion of its fixed costs of service through kilowatt-hour ("kWh") sales. Commission rules related to EE and Distributed Generation ("DG") require APS to sell fewer kWh, which, in turn, prevents the Company from being able to recover a portion of the fixed costs of service embedded in its energy rates.

9.2 The Signatories also recognize the Commission's interest in directing EE and DG policy. In signing this Agreement, the Signatories intend that a Lost Fixed Cost Recovery ("LFCR") mechanism with residential opt-out rates shall be adopted that allows APS relief from the financial impact of verified lost kWh sales attributable to Commission requirements regarding EE and DG while preserving maximum flexibility for the Commission to adjust EE and DG requirements, either upward or downward, as the Commission may deem appropriate as a matter of policy. Nothing in this Agreement is intended to bind the Commission to any specific EE or DG policy or standard.

9.3 To address the goals of Sections 9.1 and 9.2, the Signatories propose that the Commission adopt for APS an LFCR, similar to that recommended by Staff in this proceeding. The LFCR shall recover a portion of distribution and transmission costs associated with residential, commercial and industrial customers when sales levels are reduced by EE and DG. It shall not recover lost fixed costs attributable to other potential factors, such as weather or general economic conditions. The LFCR mechanism shall exclude the portion of distribution and transmission costs that is recovered through the Basic Service Charge ("BSC") and fifty (50) percent of such costs recovered through non-generation/non-TCA demand charges.

9.4 The LFCR shall be adjusted annually to account for the unrecovered costs associated with a portion of distribution and transmission costs resulting from EE programs as demonstrated by the Measurement, Evaluation and Reporting ("MER") conducted for EE programs and from DG as demonstrated pursuant to the means described in Section 9.5 below. An annual 1% year over year cap based on Total Company revenues will be applied to the adjustment. Any amount in excess of the 1% cap will be deferred (with interest at the nominal one-year Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15 or its successor publication) for collection until the first future adjustment period in which including such costs, would not cause the annual increase to exceed the 1% cap. The amount of any cap level set herein shall be evaluated in APS's next rate case.

9.5 For the purpose of the LFCR mechanism, APS shall be allowed to use statistical verification, output profile, or meter data for DG systems until December 31, 2014. Beginning January of 2015, APS shall only use meter data to calculate DG system savings

9.6 APS will file with the Commission to adjust its LFCR by January 15 of each year, and Staff will use its best efforts to process the matter by March 1 of each year. Each annual LFCR adjustment will not go into effect unless approved by the Commission. The annual adjustment will use actual data for the period through September and forecast data for the remainder of the year. The following year's adjustment shall be trued-up for verified EE MER and metered or otherwise verified DG results. The first adjustment will not occur before March 1, 2013. The March 1, 2013 adjustment shall include reduced sales from EE and DG for 2012 and will be pro-rated from the date rates become effective pursuant to a Commission decision on this Agreement. Subsequent adjustments shall reflect the full impact of reduced sales in the prior year plus the cumulative impact from previous adjustments, subject to the cap described in Section 9.4 herein.

9.7 The LFCR mechanism shall not apply to large General Service customers taking service under rate schedules E-32 L, E-32 L TOU, E-34, E-35 and E-36 XL, or to unmetered General Service customers under E-30 and lighting schedules. These rate schedules shall be modified in accordance with Attachment K to address unrecovered fixed costs through changes in rate design with enhanced distribution demand and BSC charges and a corresponding adjustment to energy charges.

9.8 Residential customers shall have a rate schedule choice to opt out of the LFCR by electing an optional BSC, graduated by kWh monthly usage. That option is attached hereto as Attachment E. The optional BSC will be incorporated into each residential rate schedule to provide customers with the maximum flexibility to opt out without requiring a shift to a different rate schedule. The purpose of this opt out rate is to replicate, on average, the effects of the LFCR.

9.9 APS shall seek stakeholder input regarding the development of a customer outreach program to inform and educate customers about both the LFCR and voluntary opt-out rates and shall implement this outreach program.

9.10 On January 15 of each year, APS shall file compliance reports with the Commission consistent with the schedules attached to the LFCR Plan of Administration. These reports shall include a comparison of the revenues recovered through the LFCR to those that would have been recovered had the Company's revenue per customer decoupling (full decoupling) proposal been adopted.

9.11 The LFCR shall be subject to Commission review at any time, the first to occur no later than APS's next general rate case. If the Commission decides to suspend, terminate, or materially modify the LFCR mechanism prior to the Company's next general rate case, and does not provide alternative relief that adequately addresses fixed cost revenue erosion, the moratorium for filing general rate case applications shall terminate.

9.12 The LFCR Plan of Administration is attached hereto as Attachment F.

9.13 The LFCR was designed to be a flexible means to maximize the policy options available to the Commissioners and to customers, allowing the pursuit of EE and DG programs at any level or pace directed by the Commission. The Signatories agree that if the Commission declines to adopt the LFCR or an alternative mechanism that adequately addresses fixed cost revenue erosion in this case, APS shall be granted relief from either the relevant EE and DG requirements or the financial impacts of EE and DG during that time.

9.14 For future Demand-Side Management ("DSM") Implementation Plan filings:

(a) Beginning with APS's 2013 DSM Implementation Plan (filed in 2012), and excluding DSM-related capital investments already authorized by the

Commission, carrying costs for DSM-related capital investments shall not be recovered through the DSM Adjustment Clause.

(b) APS's performance incentive shall be modified (1) to eliminate the top two tiers of percentages to be applied to Net Benefits or Percent of Program Costs based on APS's achievement relative to the EE Standard, and (2) to change the fourth tier to include any achievement greater than 105%. The first three tiers remain unchanged.

Achievement Relative to the Energy Efficiency Standard	Performance Incentive as % of Energy Efficiency Net Benefits	Performance Incentive Capped at % of Energy Efficiency Program Costs	Proposed Change from Current
<85%	0%	0%	No Change
85% to 95%	6%	12%	No Change
96% to 105%	7%	14%	No Change
>105%	8%	16%	New
~~106% to 115%~~	~~8%~~	~~16%~~	Eliminated
~~116% to 125%~~	~~9%~~	~~18%~~	Eliminated
~~>125%~~	~~10%~~	~~20%~~	Eliminated

(c) APS shall use the inputs and methodology that Commission Staff uses when calculating the present value of benefits and costs for DSM measures in its Societal Cost test. Commission Staff will regularly re-evaluate such inputs and methodologies, considering comments from APS and other stakeholders.

(d) APS will work with stakeholders and Staff to develop and file for Commission consideration a new performance incentive structure by December 31, 2012 that optimizes the connection between energy efficiency, rates and utility business incentives and that creates a clear connection between the level of performance incentive and achievement of cost-effective energy savings. This rate case shall be held open to allow for Commission approval of including the new performance incentive structure in the DSM Adjustment Clause. At that time, the Commission should determine the plan year to which the new performance incentive structure shall apply. The Signatories shall recommend that any new performance incentive structure adopted should apply to the first plan year filed after its adoption.

(e) APS's DSM programs and associated energy savings shall be independently reviewed every five years by an evaluator selected by Staff and paid for by APS in an amount not to exceed $100,000. The first review shall occur in APS's next general rate case or within five (5) years of a Commission order in this case, whichever is sooner.

9.15 APS shall compile and make available to all parties of the docket a technical reference manual documenting program and measure saving assumptions and incremental costs no later than December 31, 2013. This manual would be updated on an annual basis as part of the DSM implementation plan process and would serve as a reference tool for the LFCR analysis.

9.16 APS currently collects $10 million of DSM costs in base rates, which level will be retained.

9.17 The DSM Adjustment Clause Plan of Administration shall be modified to reflect the terms of this Agreement as set forth in Attachment G.

X. RATE TREATMENT RELATED TO ANY ACQUISITION BY APS OF SOUTHERN CALIFORNIA EDISON'S SHARE OF FOUR CORNERS UNITS 4-5.

10.1 In Docket No. E-01345A-10-0474, APS has sought Commission permission to pursue acquisition of Southern California Edison's ("SCE") current ownership interest in Four Corners Units 4 and 5 and to retire Four Corners Units 1-3 (the "proposed Four Corners transaction").

10.2 Except as provided in Section 9.14(d), this 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.

10.3 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 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.

10.4 The Signatories shall not raise any issues in the rate adjustment proceeding other than those specifically described in Section 10.2. The Signatories shall use good faith efforts to process this rate adjustment request within a reasonable time.

10.5 If, at any time, APS determines that the Four Corners Transaction will not close, it shall so inform the Commission and the Signatories by filing a Notice to that effect in this Docket.

XI. MODIFICATION TO ENVIRONMENTAL IMPROVEMENT SURCHARGE

11.1 For purposes of this proceeding, APS shall withdraw its request for approval of the proposed Environmental and Reliability Account ("ERA") mechanism, and APS shall not raise this request before its next general rate case.

11.2 APS shall implement a revised version of the existing Environmental Improvement Surcharge ("EIS"). As amended, APS shall no longer receive customer dollars through the EIS to pay for government-mandated environmental controls. However, when APS invests capital to fund any government-mandated environmental controls, the EIS will recover the associated capital carrying costs, subject to a cap equal to the charge currently in place for the EIS. Adjustments to the EIS shall become effective each April 1st unless Staff requests Commission review or unless otherwise ordered by the Commission. APS will not request a change in the rate cap prior to its next general rate case.

11.3 APS will be held responsible for demonstrating that the environmental controls were government-mandated and represented a reasonable and prudent option available to the Company at that time sufficient to meet the environmental requirements.

11.4 The EIS Plan of Administration shall be revised as set forth in Attachment H.

11.5 The existing EIS will be reset to zero on the effective date of the new rates contained in this Agreement.

XII. COST DEFERRAL RELATED TO CHANGES IN ARIZONA PROPERTY TAX RATE

12.1 APS shall be allowed to defer for future recovery, in accordance with the provisions of Accounting Standards Codification ("ASC") 980 (formerly SFAS

No. 71), the following portions of Arizona property tax expense above or below the test year level of $141.5 million caused by changes to the applicable Arizona composite property tax rate (not changes in the assessed value of property).

(a) When the property tax rate increases:

- For 2012: 25% (prorated with an assumed July 1 rate effective date);
- For 2013: 50%; and
- For 2014 and all subsequent years: 75%.

(b) When the property tax rate decreases: 100% in all years.

No interest shall be applied to the deferred balance.

12.2 Beginning with the effective date of the Commission decision resulting from APS's next general rate case, any final property tax rate deferral that has a positive balance will be recovered from customers over 10 years and any deferral that has a negative balance will be refunded to customers over 3 years.

12.3 The Signatories reserve the right to review APS's property tax deferrals for reasonableness and prudence such that the deferrals can be recognized in accordance with the provisions of ASC-980 (formerly SFAS No. 71).

XIII. TRANSMISSION COST ADJUSTMENT MECHANISM

13.1 The level of transmission costs presently in APS's base rates will remain in base rates until further order of the Commission.

13.2 The annual TCA adjustment will become effective June 1 of each year without the need for affirmative Commission approval, unless Staff requests Commission review or unless otherwise ordered by the Commission.

13.3 APS shall file a notice with Docket Control that includes its revised TCA tariff, along with a copy of its FERC information filing of its annual update of transmission service rates pursuant to its Open Access Transmission tariff ("OATT"). This notice shall be filed with the Commission by May 15 of each year.

13.4 The TCA Plan of Administration shall be modified as set forth in Attachment I.

XIV. LOW INCOME PROGRAMS

14.1 In Section 16.3 of the 2009 Settlement, APS committed to augment the bill assistance program approved in Decision No. 69663 by funding $5 million to assist customers whose incomes exceed 150% of the Federal Poverty Income Guidelines but are less than or equal to 200% of the Federal Poverty Income Guidelines. This Agreement provides that any funds remaining of that $5 million funding requirement may be used to so assist customers whose incomes are less than or equal to 200% of the Federal Poverty Income Guidelines.

14.2 PSA and DSMAC adjustor rates shall apply to low-income customers. The billing method for low income customers shall be simplified by transferring customers to their corresponding non-low income rate schedule and applying the PSA and DSMAC rate schedules to those bills, but then applying a discount to the total bill such that low income customers, like other APS customers, will have no bill impact in this case as a result of the billing method change.

XV. SERVICE SCHEDULE 3 (LINE EXTENSIONS)

15.1 Version 12 of Service Schedule 3, as approved in Decision No. 72684 (November 18, 2011), shall become effective on the date that rates from this case become effective.

XVI. BILL PRESENTATION

16.1 Within 90 days following approval of this Agreement, APS will initiate stakeholder meetings to address issues related to the APS bill presentation with a goal of making the bill easier for customers to understand. APS shall thereafter file an application with the Commission for any authorization needed to modify its bill presentation. Such application shall explain how the APS bill presentation proposal reflects the input of stakeholders during the stakeholder meeting process.

XVII. RATE DESIGN

17.1 The Company's proposed Experimental Rate Schedule AG-1, a buy through rate for large commercial and industrial customers, should be capped at 200 MW and should be approved as modified herein, as should corresponding changes to the PSA. Proposed Experimental Rate Schedule AG-1 is set forth in Attachment J. Proposed Experimental Rate Schedule AG-1 does not address the subject of retail electric competition.

17.2 APS shall make commercially reasonable efforts to eliminate or mitigate all unrecovered costs resulting from the AG-1 experimental program established in this docket. If there are any lost fixed generation costs related to the AG-1 experimental rate, in its next general rate case, APS shall provide testimony that explains why it was unable to eliminate all lost fixed generation costs. Because AG-1 is an experimental program that may benefit certain General Service customers, and because residential customers cannot participate in the program, any APS proposal in APS's next general rate case that seeks to collect lost fixed generation costs related to the AG-1 experimental rate shall not propose to recover such costs from residential customers.

17.3 As recommended by Staff Witness McGarry, APS shall file a study in its next General Rate Case Application to support the cost basis of the various charges in Service Schedule 1, taking into account the impact Smart Grid technology may have on these costs.

17.4 APS shall withdraw its request to establish Service Schedule 9, an economic development service schedule. In its place, APS is authorized to pursue economic development opportunities through the use of Commission-approved special contracts.

17.5 The remaining rate design issues presented by this case shall be resolved as set forth in Attachment K.

XVIII. COMPLIANCE MATTERS

18.1 Within ten days after the Commission issues a written order in this matter, APS shall file compliance schedules associated with this Docket for Staff review. Subject to Staff review, such compliance schedules will become effective on the effective date of the new rates contained in this Agreement.

18.2 APS shall report to the Commission identifying the extent of the challenges regarding workforce planning, the specific actions that APS is taking to address the issue, and the progress APS is making toward meeting those goals. The workforce planning report, which shall be filed on an annual basis in this docket on or before May 31, shall be limited to the following job classifications: Electrician-Journeyman, Lineman-Journeyman, Technician-E&I, and Operator-Power Plant (a/k/a Auxiliary Operators and Control Operators). At a minimum, the workforce planning report shall set forth: (1) the number of employees then currently holding these positions; (2) the present mean and median ages of APS's workforce with respect to those job classifications; (3) the share of retirement-eligible employees, both as a percentage and in absolute terms, in each of these job classifications; and (4) anticipated hiring and attrition levels for each of these job classifications.

18.3 Decision No. 70667, as a compliance item, requires APS to periodically file with the Commission certain communications with rating agencies. It is appropriate to eliminate this filing requirement at this time.

XIX. FORCE MAJEURE PROVISION

19.1 Nothing in this Agreement shall prevent APS from requesting a change to its base rates in the event of conditions or circumstances that constitute an emergency. For the purposes of this Agreement, the term "emergency" is limited to an extraordinary event that, in the Commission's judgment, requires base rate relief in order to protect the public interest. This provision is not intended to preclude APS from seeking rate relief or any Signatory from petitioning the Commission to examine the reasonableness of APS's rates pursuant to this Section in the event of significant developments that materially impact the financial results expected under the terms of this Agreement. This provision is not intended to preclude any party, including any Signatory to this Agreement, from opposing an application for rate relief filed by APS pursuant to this paragraph. Nothing in this provision is intended to limit the Commission's ability to change rates at any time pursuant to its lawful authority.

XX. COMMISSION EVALUATION OF PROPOSED SETTLEMENT

20.1 All currently filed testimony and exhibits shall be offered into the Commission's record as evidence.

20.2 The Signatories recognize that Staff does not have the power to bind the Commission. For purposes of proposing a settlement agreement, Staff acts in the same manner as any party to a Commission proceeding.

20.3 This Agreement shall serve as a procedural device by which the Signatories will submit their proposed settlement of APS's pending rate case, Docket No. E-01345A-11-0224, to the Commission.

20.4 The Signatories recognize that the Commission will independently consider and evaluate the terms of this Agreement. If the Commission issues an order adopting all material terms of this Agreement, such action shall constitute

Commission approval of the Agreement. Thereafter, the Signatories shall abide by the terms as approved by the Commission.

20.5 If the Commission fails to issue an order adopting all material terms of this Agreement, any or all of the Signatories may withdraw from this Agreement, and such Signatory or Signatories may pursue without prejudice their respective remedies at law. For purposes of this Agreement, whether a term is material shall be left to the discretion of the Signatory choosing to withdraw from the Agreement. If a Signatory withdraws from the Agreement pursuant to this paragraph and files an application for rehearing, the other Signatories, except for Staff, shall support the application for rehearing by filing a document with the Commission that supports approval of the Agreement in its entirety. Staff shall not be obligated to file any document or take any position regarding the withdrawing Signatory's application for rehearing.

XXI. MISCELLANEOUS PROVISIONS

21.1 This case has attracted a large number of participants with widely diverse interests. To achieve consensus for settlement, many participants are accepting positions that, in any other circumstances, they would be unwilling to accept. They are doing so because this Agreement, as a whole, is consistent with their long-term interests and with the broad public interest. The acceptance by any Signatory of a specific element of this Agreement shall not be considered as precedent for acceptance of that element in any other context.

21.2 No Signatory is bound by any position asserted in negotiations, except as expressly stated in this Agreement. No Signatory shall offer evidence of conduct or statements made in the course of negotiating this Agreement before this Commission, any other regulatory agency, or any court.

21.3 Neither this Agreement nor any of the positions taken in this Agreement by any of the Signatories may be referred to, cited, or relied upon as precedent in any proceeding before the Commission, any other regulatory agency, or any court for any purpose except to secure approval of this Agreement and enforce its terms.

21.4 To the extent any provision of this Agreement is inconsistent with any existing Commission order, rule, or regulation, this Agreement shall control.

21.5 Each of the terms of this Agreement is in consideration of all other terms of this Agreement. Accordingly, the terms are not severable.

21.6 The Signatories shall make reasonable and good faith efforts necessary to obtain a Commission order approving this Agreement. The Signatories shall support and defend this Agreement before the Commission. Subject to paragraph 20.5, if the Commission adopts an order approving all material terms of the Agreement, the Signatories will support and defend the Commission's order before any court or regulatory agency in which it may be at issue.

21.7 This Agreement may be executed in any number of counterparts and by each Signatory on separate counterparts, each of which when so executed and delivered shall be deemed an original and all of which taken together shall constitute one and the same instrument. This Agreement may also be executed electronically or by facsimile.

ARIZONA CORPORATION COMMISSION

By ______________________________

ARIZONA PUBLIC SERVICE COMPANY

By ______________________________

RESIDENTIAL UTILITY CONSUMER OFFICE

By ______________________________

Docket No. E-01345A-11-0224

By ____________________
Cynthia Zwick

DATED: January 5, 2012

Docket No. E-01345A-11-0224

By Karen S White

Karen S. White
Federal Executive Agencies

DATED: January 6, 2012

Docket No. E-01345A-11-0224

By K Boehm

Kurt J. Boehm, Esq.
Attorney for Kroger Co.

DATED: 1-6-12, 2012

Docket No. E-01345A-11-0224

By ______________________
C.Webb Crockett
Patrick J. Black
Fennemore Craig, P.C.
Attorneys for Freeport-McMoRan Copper & Gold Inc.

DATED: January 6, 2012

Docket No. E-01345A-11-0224

By ______________________________
C.Webb Crockett
Patrick J. Black
Fennemore Craig, P.C.
Attorneys for Arizonans for Electric Choice and Competition

DATED: January 6, 2012

WAL-MART STORES, INC. and
SAM'S WEST, INC.

By: Scott S. Wakefield

Scott S. Wakefield
Ridenour, Hienton & Lewis, PLLC
201 N. Central Ave., Suite 3300
Phoenix, AZ 85004
Attorneys for Wal-Mart Stores, Inc. and
Sam's West, Inc.

Dated: January 6, 2012

By: ____________________
Nicholas J. Enoch, Esq.
Attorney for Intervenors IBEW Locals 387, 640 & 769

DATED: January 6, 2012

Docket No. E-01345A-11-0224

AZAG GROUP

By: ______________________

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602-274-9135 – fax

DATED: January 6, 2012

Docket No. E-01345A-11-0224

By

Greg Patterson
Arizona Competitive Power Alliance
Director:

DATED: January 6, 2012

Docket No. E-01345A-11-0224

By Craig A. Marks
Craig A. Marks
AARP

DATED: 1/6, 2012

ARIZONA ASSOCIATION OF REALTORS, INC.

By: ______________________

Tom Farley, Chief Executive Officer

DATED: January 6, 2012

Docket No. E-01345A-11-0224

By Barbara Wyllie Pecora

BARBARA WYLLIE - PECORA

DATED: 1-6-12, 2012

Docket No. E-01345A-11-0224

By ______________________________

Gary Yaquinto, Its President
Arizona Investment Council

DATED: January 5, 2012

Docket No. E-01345A-11-0224

By Lawrence V. Robertson, Jr.

Lawrence V. Robertson, Jr.

On behalf of Southwestern Power Group II, L.L.C.

DATED: January 6, 2012

Docket No. E-01345A-11-0224

By Lawrence V. Robertson, Jr.

Lawrence V. Robertson, Jr.

On behalf of Bowie Power Station, L.L.C.

DATED: January 6, 2012

Docket No. E-01345A-11-0224

By Lawrence V. Robertson, Jr.

Lawrence V. Robertson, Jr.

On behalf of Noble Americas Energy Solutions LLC

DATED: January 6, 2012

Docket No. E-01345A-11-0224

By Lawrence V. Robertson, Jr.

Lawrence V. Robertson, Jr.

On behalf of Constellation NewEnergy, Inc.

DATED: January 6, 2012

Docket No. E-01345A-11-0224

By Lawrence V. Robertson, Jr.

Lawrence V. Robertson, Jr.

On behalf of Direct Energy, LLC

DATED: January 6, 2012

Docket No. E-01345A-11-0224

By Lawrence V. Robertson, Jr.

Lawrence V. Robertson, Jr.

On behalf of Shell Energy North America (US), L.P.

DATED: January 6, 2012

Attachment A

Arizona Public Service Company
Equalize Impact of Transferring Fuel from Base Rates to PSA
Across General Service Rate Classes

153,087,000	Fuel transfer to PSA
27,689,606,547	Test Year Retail kWh
0.00553	PSA impact /kWh

1.	Adjusted kWh 2.	Adjusted Present Revenue ($) 3.	PSA Impact ($) 4.	PSA Impact (%) 5.	Equal % PSA Impact (%) 6.	Equal % PSA Impact ($) 7.	PSA Delta ($) 8.	Equalization Charge $/kWh 9.	Base Rate Increase (%) 10.
E-20	36,664,060	$ 3,885,908	$ 202,752	5.218%	5.82%	$ 226,004	$ 23,252	0.00063	0.60%
E-32 XS	1,418,941,092	199,176,817	7,846,744	3.940%	5.82%	11,584,124	3,737,380	0.00263	1.88%
E-32 S	2,551,982,755	290,020,650	14,112,465	4.866%	5.82%	16,867,601	2,755,136	0.00108	0.95%
E-32 M	3,279,541,910	317,315,278	18,135,867	5.715%	5.82%	18,454,236	318,369	0.00010	0.10%
E-32 L	3,647,138,613	303,798,301	20,168,677	6.639%	5.82%	17,668,909	(2,499,768)	(0.00069)	-0.82%
E-32 TOU XS	4,608,869	632,665	25,487	4.029%	5.82%	36,796	11,309	0.00245	1.79%
E-32 TOU S	41,567,188	4,454,447	229,867	5.160%	5.82%	259,071	29,204	0.00067	0.66%
E-32 TOU M	69,936,556	6,385,132	386,749	6.057%	5.82%	371,359	(15,390)	(0.00022)	-0.24%
E-32 TOU L	295,613,941	22,916,517	1,634,745	7.133%	5.82%	1,332,825	(301,920)	(0.00103)	-1.32%
E-34	1,086,047,211	80,597,093	6,005,841	7.452%	5.82%	4,687,527	(1,318,314)	(0.00121)	-1.64%
E-35	1,673,368,627	112,009,467	9,253,729	8.262%	5.82%	6,514,471	(2,739,258)	(0.00163)	-2.45%
	14,105,410,822	$ 1,341,192,275	$ 78,002,923	5.816%	5.82%	$ 78,002,923	$ -		

Attachment B

ARIZONA PUBLIC SERVICE COMPANY
Palo Verde Decommissioning/ISFSI Trust Amounts
Test Year 12 Months Ended 12/31/10
(Dollars in Thousands)

YEAR	6/1/2045 UNIT 1	4/24/2046 UNIT 2	11/25/2047 UNIT 3	TOTAL	ACC Jurisdictional Amount[1]
2011	$ 4,558	$ 6,047	$ 5,414	$ 16,019	$ 15,630
2012	449	14,968	1,832	17,249	16,830
2013	449	14,968	1,832	17,249	16,830
2014	449	14,968	1,832	17,249	16,830
2015	449	14,968	1,832	17,249	16,830
2016	449	-	1,832	2,281	2,226
2017	449	-	1,832	2,281	2,226
2018	449	-	1,832	2,281	2,226
2019	449	-	1,832	2,281	2,226
2020	449	-	1,832	2,281	2,226
2021	449	-	1,832	2,281	2,226
2022	449	-	1,832	2,281	2,226
2023	449	-	1,832	2,281	2,226
2024	449	-	1,832	2,281	2,226
2025	449	-	1,832	2,281	2,226
2026	449	-	1,832	2,281	2,226
2027	449	-	1,832	2,281	2,226
2028	449	-	1,832	2,281	2,226
2029	449	-	1,832	2,281	2,226
2030	449	-	1,832	2,281	2,226
2031	449	-	1,832	2,281	2,226
2032	449	-	1,832	2,281	2,226
2033	449	-	1,832	2,281	2,226
2034	449	-	1,832	2,281	2,226
2035	449	-	1,832	2,281	2,226
2036	449	-	1,832	2,281	2,226
2037	449	-	1,832	2,281	2,226
2038	449	-	1,832	2,281	2,226
2039	449	-	1,832	2,281	2,226
2040	449	-	1,832	2,281	2,226
2041	449	-	1,832	2,281	2,226
2042	449	-	1,832	2,281	2,226
2043	449	-	1,832	2,281	2,226
2044	449	-	1,832	2,281	2,226
2045	225	-	1,832	2,056	2,006
2046	-	-	1,832	1,832	1,787
2047	-	-	1,832	1,832	1,787
	$ 19,604	$ 65,919	$ 71,360	$ 156,883	$ 153,071

[1] ACC Jurisdictional share is approximately 97.57%

Power Supply Adjustment
Plan of Administration

Table of Contents

1. General Description

This document describes the plan for administering the Power Supply Adjustment mechanism ("PSA") approved for Arizona Public Service Company ("APS") by the Commission on June 28, 2007 in Decision No. 69663, amended by the Commission on December 30, 2009 in Decision No. 71448, and as further amended by the Commission on [insert date] in Decision No. xxxxx. The PSA provides for the recovery of fuel and purchased power costs, to the extent that actual fuel and purchased power costs deviate from the amount recovered through APS' Base Cost of Fuel and Purchased Power ($0.032071 per kWh) authorized in Decision No. xxxxx, from [insert date]. It also provides for refund or recovery of the net margins from sales of emission allowances, to the extent the actual sales margins deviate from the base rate amount of ($0.000001) per kWh[1].

The PSA described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs and margins on the sales of emission allowances ("PSA Costs") to set a rate that is then reconciled to actual costs experienced.

This PSA includes a limit of $0.004 per kilowatt-hour (kWh) on the amount the PSA rate may change in any one year absent express approval of the Commission. This PSA also provides a mechanism for mid-year rate adjustment in the event that conditions change sufficiently to cause extraordinarily high balances to accrue under application of this PSA.

[1] *($0.000001) per kWh is the result of the following: (2010 net gains from sales of SO_2 allowances of $21,178)/(2010 test year native load sales of 28,075,248 MWh)/1000.*

2. PSA Components

The PSA Rate will consist of three components designed to provide for the recovery of actual, prudently incurred PSA Costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PSA Year (each February 1 through January 31 period shall constitute a PSA Year) PSA Costs and those embedded in base rates.
2. The Historical Component, which tracks the differences between the PSA Year's actual fuel and purchased power costs and those recovered through the combination of base rates and the Forward Component, and which provides for their recovery during the next PSA Year.
3. The Transition Component, which provides for:
   a. The opportunity to seek mid-year changes in the PSA rate in cases where variances between the anticipated recovery of fuel and purchased power costs for the PSA Year under the combination of base rates and the Forward Component become so large as to warrant recovery/refund, should the Commission deem such an adjustment to be appropriate.
   b. The tracking of balances resulting from the application of the Transition Components, in order to provide a basis for the refund or recovery of any such balances.

Except for circumstances when the Commission approves new base rates, a PSA Year begins on February 1 and ends on the ensuing January 31. In the event that new base rates become effective on a date other than February 1, the Commission may, at its discretion, adjust any or all of the PSA components to reflect the new base rates.

On or before September 30 of each year, APS will submit a PSA Rate filing, which shall include a calculation of the three components of the proposed PSA Rate. This filing shall be accompanied by such supporting information as Staff determines to be required. APS will supplement this filing with Historical Component and Transition Component filings on or before December 31 in order to replace estimated balances with actual balances, as explained below.

a. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) PSA Costs embedded in base rates and (2) the forecast PSA Costs over a PSA Year that begins on February 1 and ends on the ensuing January 31. APS will submit, on or before September 30 of each year, a forecast for the upcoming calendar year (January 1-December 31) of its PSA Costs. It will also submit a forecast of kWh sales for the same calendar year, and divide the forecast costs by the forecast sales to produce the cents/kWh unit rate required to collect those costs over those sales. The result of subtracting the Base PSA Costs from this unit rate shall be the Forward Component.

APS shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record APS' over/under-recovery of its actual PSA Costs as compared to the Base PSA Costs recovered in revenue. The balance calculated as a result of these steps is then reduced by the current month's collection of Forward Component revenue. This account will operate on a PSA Year basis (i.e.; February to January), and its balances will be used to administer this PSA's Historical Component, which is described immediately below.

b. Historical Component Description

The Historical Component in any current PSA Year is intended to refund or recover the balances accumulated in the Forward Component Tracking Account (described above) and Historical Component Tracking Account (described below) during the immediately preceding PSA Year. The sum of the projected Forward Component Tracking Account balance on January 31 of the following calendar year and the projected Historical Component Tracking Account balance on January 31 of the following calendar year is divided by the forecast kWh sales used to set the Forward Component for the coming PSA Year. That result comprises the proposed Historical Component for the coming PSA year.

APS shall maintain and report monthly the balances in a Historical Component Tracking Account, which will reflect monthly collections under the Historical Component and the amounts approved for use in calculating the Historical Component.

Each annual September 30 APS filing will include an accumulation of Forward Component Tracking Account balances and Historical Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the current PSA Year). The APS filing shall use these balances to calculate a preliminary Historical Component for the coming PSA Year[2]. On or before December 31, APS will submit a supplemental filing that recalculates the preliminary Historical Component. This recalculation shall replace estimated monthly balances with those actual monthly balances that have become available since the September 30 filing.

The September 30 filing's use of estimated balances for September through January (with supporting workpapers) is required to allow the PSA review process to begin in a way that will support its completion and a Commission decision, if necessary, prior to February 1. The December 31 updating will allow for the use of the most current balance information available prior to the time when a Commission decision, if necessary, is expected. In addition to the December 31 update filing, APS monthly filings (for the months of September through December) of Forward Component Tracking Account balance information and Historical Component Tracking Account balance information will include a recalculation (replacing estimated balances with actual balances as they become known) of the projected Historical Component unit rate required for the next PSA Year.[3]

The Historical Component Tracking Account will measure the changes each month in the Historical Component balance used to establish the current Historical Component as a result of collections under the Historical Component in effect. It will subtract each month's Historical

[2] For example, the September 30, 2008 filing would include actual balances for February through August of 2008 and estimated balances for September 2008 through January 2009.
[3] This updating to replace estimated with actual information will allow for the Commission to use the latest available balance information in determining what Historical Component is appropriate to establish for the coming PSA Year.

Component collections from the Historical Component balance. The Historical Component Account will also include Applicable Interest on any balances. APS shall file the amounts and supporting calculations and workpapers for this account each month.

c. Transition Component Description

The Transition Component will be used as the method for incorporating any future, approved mid-year changes to the PSA rate. APS or Staff may request at any timea change in the PSA rate through an adjustment to the Transition Component to address a significant imbalance between anticipated collections and costs for the PSA Year under the Forward Component element of this PSA. After the review of such request, the Commission may provide for the refund or collection of such balance (through a change to the Transition Component Balance) over such period as the Commission determines appropriate through a unit rate ($/kWh) imposed as part of the Transition Component. The Commission on its own motion may also change the PSA rate as described above.

Notwithstanding the preceding paragraph, APS may at any time during the PSA Year request to reduce the PSA through the Transition Component, which request shall become effective beginning with the first billing cycle of the month following the filing of such a request, provided APS files the request within the first 15 days of a month and Staff does not file opposition to the request.

A Transition Component Tracking Account will measure the changes each month in the Transition Component balance. APS, Staff, or the Commission on its own motion may request that the balance in any Transition Component Tracking Account at the end of the period set for recovery be included in the establishment of the Transition Component for the coming PSA Year.

The Transition Component Account will also include Applicable Interest as determined by the Commission. APS shall file the amounts and supporting calculations and workpapers for this account each month.

As it must do for the Historical Component filing, APS shall file on or before September 30 of each year an accumulation of Transition Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the prior PSA Year). Those balances will form the basis for setting the preliminary Transition Component for the coming PSA Year. On or before December 31, APS will submit a supplemental filing to update the Transition Component calculation in the same manner as required for the Historical Component.

3. Calculation of the PSA Rate

The PSA rate is the sum of the three components; *i.e.,* Forward Component, Historical Component, and Transition Component. The PSA rate shall be applied to customer bills. Unless the Commission has otherwise acted on a new PSA rate by February 1, the proposed PSA rate (as amended by the updated December 31 filing) shall go into effect. However, the PSA rate may not change from the prior year's PSA rate by more than plus or minus $0.004 per kWh without an offsetting change in the Base Cost of Fuel and Purchased Power. The PSA rate shall be applicable to APS' retail electric rate schedules (with the exception of E-36 XL, AG-1, Direct Access service and any other rate that is exempt from the PSA) and is adjusted annually. The PSA Rate shall be applied to the customer's bill as a monthly kWh charge that is the same for all customer classes.

The PSA rate shall be reset on February 1 of each year, and shall be effective with the first February billing cycle unless suspended by the Commission. It is not prorated.

4. Filing and Procedural Deadlines

a. September 30 Filing

APS shall file the PSA rate with all Component calculations for the PSA year beginning on the next February 1, including all supporting data, with the Commission on or before September 30 of each year. That calculation shall use a forecast of kWh sales and of PSA Costs for the coming calendar year, with all inputs and assumptions being the most current available for the Forward Component. The filing will also include the Historical Component calculation for the year beginning on the next February 1, with all supporting data. That calculation shall use the same forecast of sales used for the Forward Component calculation. The Transition Component filing shall also include a proposed method for addressing the over or under recovery of any Transition Component balances that result from changes in the sales forecasts or recovery periods set or any additions to or subtractions from Transition Component balances reviewed or approved by the Commission since the last February 1 resetting of the new PSA.[4]

b. December 31 Filing

APS shall by December 31 update the September 30 filing. This update shall replace estimated Forward Component Tracking Account balances, the Historical Component Tracking Account balances, and the Transition Component Tracking Account balances with actual balances and with more current estimates for those months (December and January) for which actual data are not available. Unless the Commission has otherwise acted on the APS calculation by February 1, the PSA rate proposed by APS shall go into effect with the first February billing cycle.[5]

c. Additional Filings

APS shall also file with the Commission any additional information that the Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PSA.

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[4] This method assumes that the Commission defers the recovery of any approved Transition Component Balance changes until the next February 1 PSA resetting. The Commission may also, as part of the approval of any such Transition Component Balance change, make a PSA change effective on dates and across periods as it determines to be appropriate when it approves such a Transition Component Balance change.

[5] No reference in this plan to effectiveness in the absence of Commission action shall be interpreted as precluding the normal application of the balance reconciliation provisions generally established for the PSA.

d. Review Process

The Commission Staff and interested parties shall have an opportunity to review the September 30 and December 31 forecast, balances, and supporting data on which the calculations of the three PSA components have been based. Any objections to the September 30 calculations shall be filed within 45 days of the APS filing. Any objections to the December 31 calculations shall be filed within 15 days of the APS filing.

5. Verification and Audit

The amounts charged through the PSA shall be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded through the Transition Component.

6. Definitions

Applicable Interest – Interest is applied on the PSA balance annually at the following rates: any over-collection existing at the end of the PSA year will be credited an amount equal to interest at a rate equal to the Company's authorized Return on Equity ("ROE") or APS's then-existing short term borrowing rate, whichever is greater, and will be refunded to customers over the following 12 months; any under-collection existing at the end of the PSA Year will be debited an amount equal to interest at a rate equal to the Company's authorized ROE or APS's then-existing short term borrowing rate, whichever is less, and will be recovered from customers over the following 12 months.

Base Cost of Fuel and Purchased Power - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost embedded in the base rates as approved by the Commission in APS's most recent rate case. The Base Cost of Fuel and Purchased Power recovered in base revenue is the approved rate per kWh times the applicable sales volumes. Decision No. xxxxx set the base cost at $0.0.032071 per kWh effective on [insert date].

Base Net Margins on the Sale of Emission Allowances - An amount generally expressed as a rate per kWh, which reflects the net margins on sales of SO_2 emission allowances embedded in the base rates as approved by the Commission in APS's most recent rate case. The Base Net Margins on the Sale of Emission Allowances is set at ($0.000001) per kWh effective on [insert date].

Base PSA Costs - A rate equal to the sum of Base Cost of Fuel and Purchased Power and the Base Net Margins on the Sale of Emission Allowances.

Forward Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February. The Forward Component for the PSA Year will adjust for the difference between the forecast PSA

Costs generally expressed as a rate per kWh less the Base PSA Costs generally expressed as a rate per kWh embedded in APS's base rates. The result of this calculation will equal the Forward Component, generally expressed as a rate per kWh.

Forward Component Tracking Account - An account that records on a monthly basis APS's over/under-recovery of its actual PSA Costs as compared to the actual Base PSA Costs recovered in revenue and Forward Component revenue, plus Applicable Interest. The balance of this account as of the end of each PSA Year is, subject to periodic audit, reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Historical Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PSA Year tracking account balances to be refunded/collected from customers in the coming year's PSA rate.

Historical Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Historical Component rate as compared to the actual Historical Component revenues; plus Applicable Interest; The balance of which at the close of the preceding PSA Year is, subject to periodic audit, then reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

ISFSI - Costs associated with the Independent Spent Fuel Storage Installation that stores spent nuclear fuel.

Mark-to-Market Accounting - Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load - Native load includes customer load in the APS control area for which APS has a generation service obligation and PacifiCorp Supplemental Sales.

Net Margins on the Sale of Emission Allowances - Revenues incurred from the sale of emission allowances net of the costs incurred to produce the excess allowances.

PacifiCorp Supplemental Sales - The PacifiCorp Supplemental Sales agreement is a long-term contract from 1990 which requires APS to offer a certain amount of energy to PacifiCorp each year. It is a component of the set of agreements that led to the sale of Cholla Unit 4 to PacifiCorp and the establishment of the seasonal diversity exchange with PacifiCorp.

Preference Power - Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

PSA - The Power Supply Adjustment mechanism approved by the Commission in Decision No. 69663, amended by the Commission in Decision No. 71448, and further amended by the

Commission in Decision No. xxxxx, which is a combination of three rate components that track changes in the cost of obtaining power supplies based upon forward-looking estimates of PSA Costs that are eventually reconciled to actual costs experienced. This PSA allows for special Commission consideration of extreme volatility in costs or recovery by means of a mid-year rate correction, and provides for a reconciliation between actual and estimated costs of the last two months of estimated costs used in Historical Component calculations.

<u>PSA Costs</u> - The combination of System Book Fuel and Purchased Power Costs net of the System Book Off-System Sales Revenues as adjusted herein for Rate Schedule AG-1 plus the Net Margins on the Sales of Emission Allowances.

<u>PSA Year</u> - A consecutive 12-month period generally beginning each February 1.

<u>Rate Schedule AG-1</u> – Experimental Alternative Generation Rate Schedule approved by the Commission in Decision No. XXXXX. Resale of capacity and energy displaced by Rate Schedule AG-1 shall be excluded from the PSA on a pro-rata basis, by dividing the amount of monthly metered sales to AG-1 customers by the net monthly total of off-system sales and multiplying that result by total off-system sales margins. The portion of capacity and energy sales margins that is not the result of displacement from Rate Schedule AG-1 will continue to be a credit to the PSA.

<u>System Book Fuel and Purchased Power Costs</u> - The costs recorded for the fuel and purchased power used by APS to serve both Native Load and off-system sales, less the costs associated with applicable special contracts, E-36 XL, AG-1, RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs are included; broker fees are included up to the level in the Base Cost of Fuel and Purchased Power authorized in Decision No.xxxxx.

<u>System Book Off-System Sales Revenue</u> - The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

<u>Traditional Sales-for-Resale</u> - The portion of load from Native Load wholesale customers that is served by APS, excluding the load served with Preference Power.

<u>Transition Component</u> - An amount generally expressed as a rate per kWh charge to be applied when necessary to provide for significant changes between estimated and actual costs under the Forward Component.

<u>Transition Component Tracking Account</u> - An account that records on a monthly basis the account balance to be collected via the Transition Component as compared to the actual Transition Component revenues, plus applicable interest; the balance of which upon Commission consideration may then be reflected in the next Transition Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of APS's electricity over transmission facilities owned by others.

7. Schedules

Samples of the following schedules are attached to this Plan of Administration

Schedule 1	Power Supply Adjustment (PSA) Rate Calculation
Schedule 2	PSA Forward Component Rate Calculation
Schedule 3	PSA Year Forward Component Tracking Account
Schedule 4	PSA Historical Component Rate Calculation
Schedule 5	Historical Component Tracking Account
Schedule 6	PSA Transition Component Rate Calculation
Schedule 7	PSA Transition Tracking Account

8. Compliance Reports

APS shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Principal Officer, as listed in the Company's annual report filed with the Commission's Corporations Division, shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PSA Rate Calculation (Schedule 1); Forward Component, Historical Component, and Transition Component Calculations (Schedules 2, 4, and 6); Annual Forward Component, Historical Component, and Transition Component Tracking Account Balances (Schedules 3, 5, and 7). Additional information will provide other relative inputs and outputs such as:
    a. Total power and fuel costs.
    b. Margins on the sale of excess emission allowances.
    c. Off-system sales margins attributable to capacity freed up due to Rate Schedule AG-1.
    d. Customer sales in both MWh and thousands of dollars by customer class.
    e. Number of customers by customer class.
    f. A detailed listing of all items excluded from the PSA calculations.
    g. A detailed listing of any adjustments to the adjustor reports.
    h. Total off-system sales revenues.
    i. System losses in MW and MWh.
    j. Monthly maximum retail demand in MW.

2. Identification of a contact person and phone number from APS for questions.

APS shall provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports will be provided confidentially.

A. Information for each generating unit shall include the following items:
1. Net generation, in MWh per month, and 12 months cumulatively.
2. Average heat rate, both monthly and 12-month average.
3. Equivalent forced-outage rate, both monthly and 12-month average.
4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
5. Total fuel costs per month.
6. The fuel cost per kWh per month.

B. Information on power purchases shall include the following items per seller (information on economy interchange purchases may be aggregated):
1. The quantity purchased in MWh.
2. The demand purchased in MW to the extent specified in the contract.
3. The total cost for demand to the extent specified in the contract.
4. The total cost of energy.

C. Information on off-system sales shall include the following items:
1. An itemization of off-system sales margins per buyer.
2. Details on negative off-system sales margins.

D. Fuel purchase information shall include the following items:
1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume by contract.

E. APS will also provide:
1. Monthly projections for the next 12-month period showing estimated (Over)/under-collected amounts.
2. A summary of unplanned outage costs by resource type.
3. A summary of the net margins on the sale of emission allowances.
4. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.
5. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund if those costs are found to be imprudently incurred.

9. Allowable Costs

a. Accounts

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. And, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. Additionally, the net margins on the sale of emission allowances will also be refunded or recovered through the PSA. The allowable cost components include the following Federal Energy Regulatory Commission ("FERC") accounts:

- 501 Fuel (Steam)
- 518 Fuel (Nuclear) less ISFSI regulatory amortization
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)
- 411 O&M (Margins on the Sale of Emission Allowances)

Additionally, broker fees recorded in FERC account 557 are allowable up to the limit set in Decision No. xxxxx.

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

b. Directly Assignable Power Supply Costs Excluded

Decision No. 66567 provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS standard offer service, including special contract rates, for a competitive generation supplier and then return to standard offer service. For administrative purposes, customers who were direct access customers since origination of service and request standard offer service would be considered to be returning customers. A direct assignment or special adjustment may be applied that recognizes the cost differential between the power purchases needed to accommodate the returning customer and the power supply cost component of the otherwise applicable standard offer service rate. This process is described in the Returning Customer Direct Access Charge rate schedule and associated Plan for Administration filed with the Commission.

In addition, if APS purchases power under specific terms on behalf of a standard offer special contract customer, the costs of that power may be directly assigned. In both cases, where specific power supply costs are identified and directly assigned to a large returning customer or standard offer special contract customer or group of customers, these costs will be excluded from the Adjustor Rate calculations. Schedule E-36 XL, and AG-1 customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming power from the APS system so their power supply costs and kWh usage are excluded from the PSA.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
Power Supply Adjustment (PSA) Rate Calculation
($/kWh)

Line No.	PSA Rate Calculation	Current February 1, XXXX	Proposed February 1, XXXX [1]	Increase/(Decrease) $/kWh	Increase/(Decrease) %
1	Forward Component Rate - FC (Schedule 2, L13)	$ -	$ -	N/A	N/A
2	Historical Component Rate - HC (Schedule 4, L5) [2]	#.######	$ -	N/A	N/A
3	PSA Transition Component Rate (Schedule 6, L3) [3]	$ -	$ -	N/A	N/A
4	**PSA Rate (L1+ L2 + L3)**	#.######	$ -	N/A	N/A

Notes:

[1] Proposed levels of the PSA rate components are provided in the September 30 filing and updated in the December 31 filing of each year.

[2] A Historical Component is a true up related to respective prior period PSA activity.

[3] Provides for Mid-Period Corrections when necessary.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
PSA Forward Component Rate Calculation
($ in thousands; Forward Component Rate in $/kWh)

Line No.	PSA Forward Component Rate - Calculation	Current February 1, XXXX	Proposed February 1, XXXX[1]	Increase/(Decrease) $ Values	Increase/(Decrease) %
1	Projected Fuel and Purchased Power Costs	$ #,###,###	$ -	N/A	N/A
2	Projected Off-System Sales Revenue	$ #,###,###	-	N/A	N/A
3	PSA Adjustments to Fuel and Purchased Power Costs[2]	$ (#,###,###)	-	N/A	N/A
4	Net Fuel and Purchased Power Cost (L1 through L3)	$ #,###,###	$ -	N/A	N/A
5	Projected Net Margins on the Sale of Emission Allowances	-	-	N/A	N/A
6	Projected Billed Native Load Sales, excluding E-36XL, AG-1 (MWhs)[3]	##,###,###	-	N/A	N/A
7	Projected Average Net Fuel Cost $/kWh (L4 / L6)	#.######	$ -	N/A	N/A
8	Projected Average Margin on Emission Allowances $/kWh (L5 / L6)	$ -	$ -	N/A	N/A
9	Total Projected Average PSA Cost $/kWh (L7+L8)	#.######	$ -	N/A	N/A
10	Authorized Base Cost of Fuel and Purchased Power Rate $/kWh[4]	$ 0.032071	$ -	N/A	N/A
11	Authorized Base Net Margins on the Sale of Emission Allowances Rate $/kWh[4]	$ (0.000001)	$ -	N/A	N/A
12	Total Authorized Base Cost $/kWh	$ 0.032070	$ -	N/A	N/A
13	Forward Component Rate $/kWh (L9 - L12)	#.######	$ -	N/A	N/A

Notes:

[1] Proposed levels are provided in the September 30 filing and updated in the December 31 filing of each year.

[2] Includes costs associated with E-36XL, AG-1 and other direct assignment customers, ISFSI, and mark-to-market accounting adjustments.

[3] The Projected Billed Native Load Sales of X,XXX,XXX MWhs for the Current Rate represent forecast sales for XXXX as of December 30th, XXXX. They exclude ED 3 and City of Williams wholesale contracts that are excluded from the Proposed sales and fuel costs.

[4] Base Cost of Fuel and Purchased Power established in Decision No. _____.

Schedule presentation will appear to round up to $000s and MWh; however, calculations are performed on an actual $ and kWh basis with resultant Rates/kWh rounded up to $0.000000/kWh.

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ARIZONA PUBLIC SERVICE COMPANY

Schedule 3

XXXX PSA Year Forward Component Tracking Account - In Effect from February 1, XXXX to Jan 31, XXXX

($ in thousands; Forward Component Rate and Base Rate in $/kWh)

		Feb-XX	Mar-XX	Apr-XX	May-XX	Jun-XX	Jul-XX	Aug-XX	Sept-XX	Oct-XX	Nov-XX	Dec-XX	Jan-XX	XXXX Total
1 Prior Month's Balance	From L26													
Energy Sales														
2 PSA Retail Energy Sales[1]														
3 Wholesale Native Load Energy Sales[2]														
4 Total Native Load Energy Sales	L2 + L3	-	-	-	-	-	-	-	-	-	-	-	-	
5 Retail Energy Sales as a % of Total	L2 / L4													
6 Retail Billed Sales Excluding E-36XL, AG-1 Sales (MWh)[3]														
7 Metered Sales to AG-1 Customers														
8 Total Off-System Energy Sales														
9 Ratio of AG-1 sales to Total Off-System Sales	L7 / L8													
PSA Costs														
10 Fuel and Purchased Power Costs[4,5]														
11 Off System Revenue (Credit)[6]														
12 Off System Margin Displaced by AG-1 (Debit)														
13 Net Margins on Sale of Emission Allowances														
14 Net PSA Costs	sum(L10 to L13)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Retail PSA Costs														
15 Fuel and Purchased Power Costs	L5 * L10													
16 Off System Revenue (Credit)	L5 * L11													
17 Off System Margin Displaced by AG-1 (Debit)	L5 * L12													
18 Net Margins on Sale of Emission Allowances	L5 * L13													
19 Net Retail PSA Costs	sum(L15 to L18)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Base Rate Power Supply Recovery														
20 Fuel and Purchased Power Recovery	L28 * L2													
21 Net Margins on Sale of Emission Allowances	L29 * L2													
(Over) Under Recovery From Base Rate														
22 Fuel and Purchased Power (Over) Under Recovery	(L15 + L16+ L17) - L20													
23 Net Margins on Sale of Emission Allowances (Over) Under Recovery	L18 - L21													
24 Total (Over) Under Recovery	sum(L22 to L23)	-	-	-	-	-	-	-	-	-	-	-	-	
25 Forward Component Collections[7]	- L30 * L6												$ -	
26 Tracking Account Balance	L1 + L24 - L25	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
27 Annual Interest (Calculated only in January)														

28 Total Base Fuel Rate - ¢ per kWh	3.2071
29 Base Net Margin on the Sale of Emission Allowances - ¢ per kWh	(0.0001)
30 Forward Component Rate - ¢ per kWh	#.####

Notes:

[1] PSA Retail Energy Sales are the calendar month's MWh sales. XXXX PSA Year Cumulative Retail Energy Sales of XX,XXX MWhs under rate schedule E-36XL, AG-1 were excluded from the PSA Calculations.

[2] Includes traditional sales for resale, PacifiCorp supplemental sales, and other non-ACC jurisdictional sales. ED 3 and City of Williams energy sales are excluded from the PSA Calculation.

[3] Retail Billed Sales on Line 6 relate specifically to the Forward Component Collections. Due to billing adjustments and timing, this amount will differ from other components' Retail Billed Sales.

[4] Renewables costs exclude $X,XXX,XXX of XXXX PSA Year year-to-date costs that are currently being recovered through the RES rate schedule.

[5] Includes native load and off-system fuel and purchased power costs less those costs associated with E-36XL, AG-1 and other direct assignment customers, amortization of previously deferred ISFSI, Four Corners Coal Reclamation, and mark-to-market accounting adjustments.

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

[7] Generally, Line 30 * Line 6 = Line 25; however, differences may occur due to billing adjustments.

Schedule presentation will appear to round up to $000s; however, calculations are performed on an actual $ and kWh basis with resultant Rates/kWh rounded up to $0.000000/kWh

DECISION NO. ____________

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4
PSA Historical Component Rate Calculation
($ in thousands; Historical Component Rate in $/kWh)

Line No.	PSA Historical Component Rate Calculation	Current February 1, XXXX	Proposed February 1, XXXX [1]	Increase/(Decrease) $ Values	Increase/(Decrease) %
1	Forward Component Tracking Account Balance (Schedule 3, L26 + L27)	#,###	$ -	N/A	N/A
2	Historical Component Tracking Account Balance (Schedule 5, L9 + L10) [2]	#,###	-	N/A	N/A
3	Total Historical Amount to be (Refunded)/Collected Balance (L1+L2)	#,###	$ -	N/A	N/A
4	Projected Billed Retail Energy Sales without E-36 XL, AG-1 (MWh)	##,###,###	-	N/A	N/A
5	Applicable Historical Component Rate (L3 / L4)	#.######	$ -	N/A	N/A

Notes:
[1] Proposed levels are provided in the September 30 filing and updated in the December 31 filing of each year.
[2] The Current Rate Projected Billed Retail Energy Sales are for February XXXX through January XXXX.

Schedule presentation will appear to round up to $000s; however, calculations are performed on an actual $ and kWh basis with resultant Rates/kWh rounded up to $0.000000/kWh.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 5
Historical Component Tracking Account in Effect Feb 1, XXXX through Jan. 31, XXXX
($ in thousands Historical Component Rate in $/kWh)

Line No.		January	February	March	April	May	June	XXXX Data July	August	September	October	November	December	XXXX January
1	Projected HC Tracking Account Balance at Dec. 31, XXXX													
2	Projected FC Tracking Account Balance at Dec. 31, XXXX													
3	True-up from December - January Estimate[1]													
4	Prior Month's Ending Balance													
5	HC Adjusted Beginning Balance (L1+ L2 + L3 + L4)													
6	Applicable Historical Component Rate ($/kWh)[2]													
7	Retail Billed Sales Excluding E-36XL, AG-1 Sales (MWhs)[3]													
8	Less Revenue from Applicable HC (L6 x L7)[4]													
9	HC Ending Balance (L5 - L8)	$ -												
10	Annual Interest (Calculated only in January)													

Notes:
[1] True-up is the result of using estimated revenue and deferral for December and January since the actual amount was not available at the time of prior period PSA filing.
[2] Historical Component, Schedule 4, Line 5
[3] Sales amounts are for energy billed each period.
[4] Generally, Line 7 x Line 6 = Line 8; however, differences may occur due to billing adjustments.

Schedule presentation will appear to round up to $000s and MWh; however, calculations are performed on an actual $ and kWh basis with resultant Rates/kWh rounded up to $0.000000/kWh.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 6
PSA Transition Component Rate Calculation
($ in thousands; Transition Component Rate(s) in $/kWh)

Line No.		Current February 1, XXXX [1]	Proposed February 1, XXXX [1]	Increase/(Decrease) $ Values	Increase/(Decrease) %
1	PSA Transition - Approved (Refundable)/Collection Amount [1]	N/A	N/A	N/A	0.00%
2	Projected Energy Sales without E-36XL, AG-1 (MWh) XXX. X, XX to XXX. X,XX	N/A	N/A	N/A	0.00%
3	PSA Transition Component (Refundable)/Collection Rate (L1 / L2)	N/A	N/A	N/A	0.00%

Notes:
[1] Commission Decision No. XXXXXXXXXX

Schedule presentation will appear to round up to $000s and MWh; however, calculations are performed on an actual $ and kWh basis with resultant Rates/kWh rounded up to $0.000000/kWh.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 7
PSA Transition Tracking Account in Effect XX 1, 20XX through XX 31, 20XX
($ in thousands; Transition Component Rate in $/kWh)

Line No.		January	February	March	April	May	June	20XX Data July	August	September	October	November	December	20XX January
1	Transferred balance from FC Tracking Acct Per Decision No. XXXXX			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Prior Month's Ending Balance			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Transition Component TA Adjusted Beginning Balance (L1+ L2)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Applicable Transition TA Component Rate ($/kWh) [1]			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Retail Billed Sales Excluding E-36XL, AG-1 Sales (MWhs) [2]			-	-	-	-	-	-	-	-	-	-	-
6	Less Revenue from Applicable Transition Component (L4 x L5)[3]			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Ending Balance; (L3 - L6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:
[1] Transition Component, Schedule 6, Line 3
[2] Sales amounts are for energy billed each period.
[3] Generally, Line 4 x Line 5 = Line 6; however, differences may occur due to billing adjustments.

Schedule presentation will appear to round up to $000s and MWh; however, calculations are performed on an actual $ and kWh basis with resultant Rates/kWh rounded up to $0.000000/kWh.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 8
Summary of Monthly Calculations
Mo YYYY
($ in thousands)

Line No.		January	February	March	April	May	June (XXXX Data)	July	August	September	October	November	December	XXXX January
	XXXX Forward Component Tracking Account													
1	Beginning Balance													
2	Transfers to XXXX Historical Component Tracking Account													
3	Post-Sharing (Over)/Under Collection													
4	Less Revenue from Applicable Forward Component Rate													
5	Annual Interest (Calculated only in January)													
6	Ending Balance (Line 1 + Line 2 + Line 3 - Line 4 + Line 5)													
	XXXX Historical Component Tracking Account													
7	Beginning Balance													
8	Transfers from XXXX Forward Component Tracking Account													
9	Less Revenue from Applicable Historical Component Rate													
10	Annual Interest (Calculated only in January)													
11	Ending Balance (Line 7 + Line 8 - Line 9 + Line 10)													
12	**Combined Balance ([Line 6 + Line 11])[1]**													
13	Annual Interest Rate	#.##%												

Schedule presentation will appear to round up to $000s and MWh; however, calculations are performed on an actual $ and kWh basis with resultant Rates/kWh rounded up to $0.000000/kWh.

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ARIZONA PUBLIC SERVICE COMPANY
Schedule 9
YYYY Native Load Customer Counts, Sales and Revenue
Mo YYYY

Line No.	Class	January	February	March	April	May	June	July	August	September	October	November	December	Total[1]
	Customers													
1	Residential													#DIV/0!
2	Commercial													#DIV/0!
3	Industrial													#DIV/0!
4	Irrigation													#DIV/0!
5	Sales for Resale[2]													#DIV/0!
6	Streetlights & Other Public Authority													#DIV/0!
7	Less E-36XL, AG-1, ED 3 and CoW (includes adj. to prior mth)													#DIV/0!
8	Total													#DIV/0!
	Sales (MWh)													
9	Residential													-
10	Commercial													-
11	Industrial													-
12	Irrigation													-
13	Sales for Resale[2]													-
14	Streetlights & Other Public Authority													-
15	Less E-36XL, AG-1, ED 3 and CoW (includes adj. to prior mth)													-
16	Total													-
	Revenue ($000)													
17														$ -
18	Commercial													$ -
19	Industrial													$ -
20	Irrigation													$ -
21	Sales for Resale[2]													$ -
22	Streetlights & Other Public Authority													$ -
23	Less E-36XL, AG-1, ED 3 and CoW (includes adj. to prior mth)													$ -
24	Total													$ -
	Est. System Losses and Peak													
25	Est. Native Load Sys. Losses (MWh)													
26	Est. Native Load Sys. Losses (MW)													
27	Est. Native Load Sys. Peak (MW)[3]													

[1] The Customers total is the average of the customer class' monthly totals.
[2] Includes traditional sales for resale, PacifiCorp supplemental sales, ED 3, City of Williams (CoW), and other non-ACC jurisdictional sales. Off-System Interchange customers, sales and revenue are excluded from Sales for Resale.
[3] The Preliminary Native Load System Peak totals will be updated each month.

DECISION NO. ____________

Attachment D

Renewable Energy Projects Transferred from the Renewable Energy Surcharge ("RES") to Base Rates

Project Name	Project Description	In-Service Date
Paloma	17 MW photovoltaic utility-scale solar generating facility pursuant to AZ Sun Program approved in Decision No. 71502	September 2011
Hyder I	Phase I or 11 MW of a 16 MW photovoltaic utility-scale solar generating facility pursuant to AZ Sun Program approved in Decision No. 71502	October 2011
Hyder II	Phase II or 5 MW of a 16 MW photovoltaic utility-scale solar generating facility pursuant to AZ Sun Program approved in Decision No. 71502	March 2012
Cotton Center	17 MW photovoltaic utility-scale solar generating facility pursuant to AZ Sun Program approved in Decision No. 71502	October 2011
Schools & Government Program	0.7 MW of small solar systems on schools and government facilities pursuant to program approved in Decision No. 72174	As Built
Community Power Project - Flagstaff	1.35 MW of distributed renewable energy systems pursuant to the program approved in Decision No. 71646	As Built

ACC Jurisdiction of 15-Months of Solar Generation Post-Test Year Plant Additions:

Gross Utility Plant in Service	$ 232.573M
Less: Accumulated Depreciation & Amortization	3.391M
Net Utility Plant in Service	229.182M
Less: Total Deductions	2.476M
Total Additions	-
Total Rate Base	**$ 226.706M**

Attachment E

Settlement BSC for Residential Rates

kWh per Month	Total $ Bill	BSC Standard	BSC Opt-Out	Delta	Total % Bill
Rate E-12 (Non-Time of Use)					
0-400	49.70	8.55	9.15	0.60	1.21%
401-800	96.55	8.55	9.75	1.20	1.24%
801-2000	252.37	8.55	11.30	2.75	1.09%
2001+	652.67	8.55	15.05	6.50	1.00%
Rate ET-1 & ET-2 (Time of Use)					
0-400	58.06	16.68	17.28	0.60	1.03%
401-800	97.07	16.68	17.88	1.20	1.24%
801-2000	214.07	16.68	19.43	2.75	1.28%
2001+	506.49	16.68	23.18	6.50	1.28%
Rate ECT-1R & ECT-2 (Time of Use with Demand Charge)					
0-400	71.12	16.68	17.28	0.60	0.84%
401-800	100.60	16.68	17.88	1.20	1.19%
801-2000	177.81	16.68	19.43	2.75	1.55%
2001+	337.05	16.68	23.18	6.50	1.93%

These Opt-Out BSCs will remain fixed throughout the four-year rate period and until new rates are set.

Lost Fixed Cost Recovery ("LFCR")
Plan of Administration

Table of Contents

1. General Description

This document describes the plan of administration for the LFCR mechanism approved for Arizona Public Service Company ("APS" or "Company") by the Arizona Corporation Commission ("ACC") on [insert date] in Decision No. XXXXX. The LFCR mechanism provides for the recovery of lost fixed costs, as measured by revenue, associated with the amount of energy efficiency ("EE") savings and distributed generation ("DG") that is authorized by the Commission and determined to have occurred. Costs to be recovered through the LFCR include the portion of transmission costs included in base rates and a portion of distribution costs, other than what is already recovered by (1) the Basic Service Charge and (2) 50% of demand revenues associated with distribution and the base rate portion of transmission.

2. Definitions

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules, less the amount of revenue attributable to sales to Opt-Out residential customers.

Current Period – The most recent adjustment year.

Demand Stability Factor – Fifty percent of distribution and transmission demand-based revenue produced by base rates.

DG Savings – The amount of MWh sales reduced by DG. APS shall use statistical verification, output profile, or meter data for DG systems until December 31, 2014. Beginning January 2015, APS shall only use meter data to calculate DG system savings. Each year, APS will use actual data through September and forecast data for the remainder of the calendar year to calculate the savings. The calculation of DG Savings will consist of the following by class:

1. Current Period: The annual energy production (MWh) produced by the cumulative total of DG installations since the effective date of APS's most recent general rate case.

2. Excluded MWh Production: The reduction of recoverable DG Savings calculated as follows: (1) for residential Opt-Out customers by either, dividing the number of Opt-Out residential customers by the total number of residential customers and multiplying that result by total residential DG Savings or using actual metered production, and (2) for commercial and industrial customers, by subtracting the amount of DG produced by customers on Excluded Rate Schedules.

3. True-Up Prior Period: The reconciliation of APS's forecast data of DG sales reductions for the three months in the Prior Period to verified DG sales reductions in the Prior Period.

Distribution Revenue – The amount determined at the conclusion of a rate case by multiplying both residential and general service adjusted test year billing determinants (kW and kWh) by their approved delivery charges. Any demand (kW) based delivery revenue will be reduced by the Demand Stability Factor.

EE Programs – Any program approved in APS's annual implementation plan.

EE Savings – The amount of sales, expressed in MWh, reduced by EE as demonstrated by the Measurement, Evaluation, and Reporting ("MER") conducted for EE programs. EE Savings shall be pro-rated for the number of days that new base rates are in effect during the initial implementation of the LFCR. The calculation of EE Savings will consist of the following by class:

1. Cumulative Verified: The cumulative total MWh reduction as determined by the MER using the effective date of APS's most recent general rate case as a starting point.

2. Current Period: The annual EE related sales reductions (MWh). Each year, APS will use actual MER data through September and forecast data for the remainder of the year to calculate savings.

3. Excluded MWh reduction: The reduction of recoverable EE Savings calculated as follows: (1) for residential Opt-Out customers by, dividing the number of Opt-Out residential customers by the total number of residential customers and multiplying that result by Current Period Savings, and (2) for commercial and industrial customers, by subtracting the amount of EE Savings actually achieved by customers on Excluded Rate Schedules.

4. True-Up Prior Period: The reconciliation of APS's forecast data of EE sales reductions for the three months in the Prior Period to verified EE sales reductions in the Prior Period.

Excluded Rate Schedules – The LFCR mechanism shall not apply to large general service customers taking service under rate schedules E-32 L, E-32 L TOU, E-34, E-35 and E-36 XL, or to unmetered General Service customers under E-30 and lighting schedules.

LFCR Adjustment – An amount calculated by dividing Lost Fixed Cost Revenue by the Applicable Company Revenues. This adjustment percentage will be applied to all customer bills, excluding both those that have chosen to Opt-Out and those on Excluded Rate Schedules.

Lost Fixed Cost Rate – A rate determined at the conclusion of a rate case by taking the sum of allowed Distribution Revenue and base rate Transmission Revenue for each rate class and dividing each by their respective class adjusted test year kWh billing determinants.

Lost Fixed Cost Revenue – The amount of fixed costs not recovered by the utility because of EE and DG during the period. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable MWh Savings, by rate class.

Opt-Out – The rate schedule choice for residential customers to opt out of the LFCR in the form of an optional BSC. The number of Opt-Out customers will be expressed as the annual average number of customers "Opting-Out" over the Current Period. The LFCR mechanism shall not be applied to residential customers who choose the Opt-Out provision. This rate will be made available to customers at the time of the first LFCR adjustment.

Prior Period – The 12 months preceding the Current Period.

Recoverable MWh Savings – The sum of EE Savings and DG Savings by rate class.

Total Fixed Revenue – The total of Transmission Revenue and Distribution Revenue by Class.

Transmission Revenue – The amount of revenue determined at the conclusion of a general rate case by multiplying both residential and general service adjusted test year billing determinants (kW and kWh) by the approved base rate transmission charge within their respective rate schedules. Any demand (kW) base rate Transmission Revenue will be reduced by the Demand Stability Factor.

3. LFCR Annual Incremental Cap

The LFCR Adjustment will be subject to an annual 1% year over year cap based on Applicable Company Revenues. If the annual LFCR Adjustment results in a surcharge and the annual incremental increase exceeds 1% of Applicable Company Revenues, any amount in excess of the 1% cap will be deferred for collection until the first future adjustment period in which including such costs would not cause the annual increase to exceed the 1% cap. The one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15 or its successor publication will be applied annually to any deferred balance. The interest rate shall be adjusted annually and shall be that annual rate applicable to the first business day of the calendar year.

4. Filing and Procedural Deadlines

APS will file the calculated Annual LFCR Adjustment, including all Compliance Reports, with the Commission for the previous year by January 15th. The new LFCR Adjustment will not go into effect until approved by theCommission .

5. Compliance Reports

APS will provide comprehensive compliance reports to Staff and the Residential Utility Consumer Office. The information contained in the Compliance Reports will consist of the following schedules:

- Schedule 1: LFCR Annual Adjustment Percentage
- Schedule 2: LFCR Annual Incremental Cap Calculation
- Schedule 3: LFCR Calculation

- Schedule 4: LFCR Test Year Rate Calculation
- Schedule 5: Distribution and Transmission Revenue Calculation – General Service
- Schedule 6: Distribution and Transmission Revenue Calculation – Residential

Schedules 1 through 6, attached hereto, will be submitted with APS's annual compliance filing.

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 1: LFCR Annual Adjustment Percentage
($000)

	(A)	(B)		(C)
Line No.	**Annual Percentage Adjustment**	**Reference**		**Total**
1.	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 13	$	-
2.	Applicable Company Revenues	Schedule 2, Line 1		-
3.	% Applied to Customer's Bills	(Line 1 / Line 2)		0.0000%

Note: For the Current Period, the full revenue per customer decoupling mechanism that was proposed in APS's June 1, 2011 rate application (including all customers and offering no residential Opt-Out alternative) would have resulted in a total revenue adjustment of $X and average customer bill impact of Y%.

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 2: LFCR Annual Incremental Cap Calculation
($000)

Line No.	(A) LFCR Annual Incremental Cap Calculation	(B) Reference		(C) Totals
1.	Applicable Company Revenues		$	-
2.	Allowed Cap %			1.00%
3.	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$	-
4.	Total Lost Fixed Cost Revenue	Schedule 3, Line 38, Column C	$	-
5.	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 11, Column C		-
6.	Annual Interest Rate			0.00%
7.	Interest Accrued on Deferred Balance	(Line 5 * Line 6)		-
8.	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 5 + Line 7)	$	-
9.	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 13, Column C	$	-
10.	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9)	$	-
11.	Amount in Excess of Cap to Defer	(Line 10 - Line 3)	$	-
12.	Incremental Period Adjustment as %	[(Line 10 - Line 11) / Line 1]		0.00%
13.	Total Lost Fixed Cost Revenue for Current Period	(Line 8 - Line 11)	$	-

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation
($000)

Line No.	(A) Lost Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Residential				
	Energy Efficency Savings				
1.	Current Period			-	MWh
2.	% of Residential Customers on Opt-Out			0.0%	
3.	Excluded MWh reduction	(Line 1 * Line 2)		-	MWh
4.	Net - Current Period	(Line 1 - Line 3)		-	MWh
5.	Prior Period	Previous Filing, Schedule 3, Line 4, Column C		-	MWh
6.	Verified - Prior Period			-	MWh
7.	True-Up Prior Period	(Line 6 - Line 5)		-	MWh
8.	Cumulative Verified	(Previous Filing, Schedule 3, Line 8, Column C + Line 6)		-	MWh
9.	Total Recoverable EE Savings	(Line 4 + Line 7 + Line 8)		-	MWh
	Distributed Generation Savings				
10.	Current Period			-	MWh
11.	Excluded MWh Production			-	MWh
12.	Net - Current Period	(Line 10 - Line 11)		-	MWh
13.	Prior Period	Previous Filing, Schedule 3, Line 12, Column C		-	MWh
14.	Verified - Prior Period			-	MWh
15.	True-Up Prior Period	(Line 14 - Line 13)		-	MWh
16.	Total Recoverable DG Savings	(Line 12 + Line 15)		-	MWh
17.	Total Recoverable MWh Savings	(Line 9 + Line 16)		-	MWh
18.	Residential - Lost Fixed Cost Rate	Schedule 4, Line 5, Column C	$	-	$/kWh
19.	Residential - Lost Fixed Cost Revenue	(Line 17 * Line 18)	$	-	
	C&I				
	Energy Efficency Savings				
20.	Current Period			-	MWh
21.	Excluded MWh reduction			-	MWh
22.	Net - Current Period	(Line 20 - Line 21)		-	MWh
23.	Prior Period	Previous Filing, Schedule 3, Line 22, Column C		-	MWh
24.	Verified - Prior Period			-	MWh
25.	True-Up Prior Period	(Line 24 - Line 23)		-	MWh
26.	Cumulative Verified	(Previous Filing, Schedule 3, Line 26, Column C + Line 24)		-	MWh
27.	Total Recoverable EE Savings	(Line 22 + Line 25 + Line 26)		-	MWh
	Distributed Generation Savings				
28.	Current Period			-	MWh
29.	MWh DG Savings from Rate Scedules Excluded from LFCR			-	MWh
30.	Net - Current Period	(Line 28 - Line 29)		-	MWh
31.	Prior Period	Previous Filing, Schedule 3, Line 30, Column C		-	MWh
32.	Verified - Prior Period			-	MWh
33.	True-Up Prior Period	(Line 32 - Line 31)		-	MWh
34.	Total Recoverable DG Savings	(Line 30 + Line 33)		-	MWh
35.	Total Recoverable MWh Savings	(Line 27 + Line 34)		-	MWh
36.	C&I - Lost Fixed Cost Rate	Schedule 4, Line 10, Column C	$	-	$/kWh
37.	C&I - Lost Fixed Cost Revenue	(Line 35 * Line 36)	$	-	
38.	**Total Lost Fixed Cost Revenue**	**(Line 19 + Line 37)**	**$**	**-**	

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 4: LFCR Test Year Rate Calculation
($000)

Line No.	(A) Lost Fixed Cost Rate Calculation	(B) Reference		(C) Total
	Residential Customers			
1.	Distribution Revenue	Schedule 6, Line 13, Column H	$	-
2.	Transmission Revenue	Schedule 6, Line 13, Column I	$	-
3.	Total Fixed Revenue	(Line 1 + Line 2)	$	-
4.	MWh Billed	Schedule 6, Line 12, Column C / 1,000		-
5.	Lost Fixed Cost Rate	(Line 3 / Line 4)	$	-
	C & I Customers			
6.	Distribution Revenue	Schedule 5, Line 13, Column H	$	-
7.	Transmission Revenue	Schedule 5, Line 13, Column I	$	-
8.	Total Fixed Revenue	(Line 6 + Line 7)	$	-
9.	MWh Billed	Schedule 5, Line 12, Column C / 1,000		-
10.	Lost Fixed Cost Rate	(Line 8 / Line 9)	$	-

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 5: Distribution and Transmission Revenue Calculation
General Service

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) C*E*(1-G)	(I) C*F*(1-G)	(J) H+I
Line No.	Rate Schedule	Tariff Component	Adjusted Test Year Billing Determinants	Units	Delivery Charge	Transmission Charge	Demand Stability Factor	Distribution Revenue	Transmission Revenue	Total Revenue
1.	General Service Rate Schedule 1									
2.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
3.			-	kWh	$ -	$ -	0%	$ -	$ -	$ -
4.	**Sub Total**		-	**kW**				$ -	$ -	$ -
5.			-	**kWh**				$ -	$ -	$ -
6.	General Service Rate Schedule 2									
7.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
8.			-	kWh	$ -	$ -	0%	$ -	$ -	$ -
9.	**Sub Total**		-	**kW**				$ -	$ -	$ -
10.			-	**kWh**				$ -	$ -	$ -
11.	Total kW		-	**kW**				$ -	$ -	$ -
12.	Total kWh		-	**kWh**				$ -	$ -	$ -
13.	Total							$ -	$ -	$ -

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 6: Distribution and Transmission Revenue Calculation
Residential

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) C*E*(1-G)	(I) C*F*(1-G)	(J) H+I
Line No.	Rate Schedule	Tariff Component	Adjusted Test Year Billing Determinants	Units	Delivery Charge	Transmission Charge	Demand Stability Factor	Distribution Revenue	Transmission Revenue	Total Revenue
1.	Residential Rate Schedule 1									
2.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
3.			-	kWh	$ -	$ -	0%	$ -	$ -	$ -
4.		Sub Total	-	kW				$ -	$ -	$ -
5.			-	kWh				$ -	$ -	$ -
6.	Residential Rate Schedule 2									
7.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
8.			-	kWh	$ -	$ -	0%	$ -	$ -	$ -
9.		Sub Total	-	kW				$ -	$ -	$ -
10.			-	kWh				$ -	$ -	$ -
11.	Total kW		-	kW				$ -	$ -	$ -
12.	Total kWh		-	kWh				$ -	$ -	$ -
13.	Total							$ -	$ -	$ -

DEMAND SIDE MANAGEMENT ADJUSTMENT CHARGE
PLAN OF ADMINISTRATION
XXXX-XX-XX

1. GENERAL DESCRIPTION:

This document describes the plan for administering the Demand Side Management Adjustment Charge ("DSMAC") approved for Arizona Public Service Company ("APS") by the Arizona Corporation Commission ("Commission") in Decision No. 67744, and later revised by the Commission in Decision Nos. 71448 and XXXXXX. The DSMAC provides for the recovery of Demand Side Management ("DSM") program costs, including energy efficiency and demand response programs, and energy efficiency performance incentives. The DSMAC is applied to Standard Offer or Direct Access customer's bills as a monthly kilowatt-hour charge (for Residential customers and General Service customers served in accordance with non-demand billed rate schedules) or kilowatt demand charge (for General Service customers served in accordance with demand billed rate schedules). The charge will be filed with the Commission annually when APS submits the Energy Efficiency Implementation Plan ("EEIP") for approval. This will occur July 15, 2009 for the 2010 program year, and on June 1st of all subsequent years. If approved by the Commission, the charge will be effective each year beginning with billing cycle 1 of the March revenue month and will not be prorated.

Recovery of all applicable programs costs and incentives will be allowed for all programs that have been approved by the Commission.

2. RATE SCHEDULE APPLICABILITY:

The DSMAC shall be applied monthly to every retail Standard Offer or Direct Access service.

3. ALLOWABLE COSTS:

The types of allowable costs are as follows:

A. Program Costs (PC)

Allowable expenses include, but are not limited to:
Program development, implementation, promotion, administrative and general, training and technical assistance, marketing and communications, evaluation costs, monitoring and metering costs, advertising, educational expenditures, customer incentives, research and development, data collection (such as end-use), tracking systems, self direction costs, measurement evaluation and research (MER), demonstration facilities and all other activities required to design and implement cost-effective DSM programs (energy efficiency and demand response) that are approved by the Commission in the EEIP. For those DSM programs that generate revenue, the revenue, if any, will be credited back to the DSMAC. Unrecovered fixed costs will not be recoverable through the DSMAC.

B. Performance Incentives (PI)

Represents a percentage share of the net economic benefits (benefits minus costs) from approved energy-efficiency programs based on a graduated scale that is capped at a percentage of EE PC.

Achievement Relative to the Energy Efficiency Standard	Performance Incentive as % of Energy Efficiency Net Benefits	Performance Incentive Capped at % of Energy Efficiency Program Costs
< 85%	0%	0%
85% to 95%	6%	12%
96% to 105%	7%	14%
>105%	8%	16%

4. DETERMINATION OF TRUE-UP:

The actual allowable cost recovered for approved DSM programs will be compared to the actual revenues received by the Company through the DSMAC. The True-Up (TU) will be based on the amount in the TU balancing account. This balance will include past period PC, PI and DSMAC revenue collection accruals as of April 30th of the filing year. Past period PC and PI are found on Schedule 2 of the DSMAC calculations. Past period DSMAC revenue is found in Schedule 1 of the DSMAC calculations. The TU balancing account computation will be provided annually in Schedule 3 of the DSMAC calculations.

In the event that PC or PI are more or less than DSMAC revenues collected as of the last billing cycle of February, the over or under collection will be subtracted from or added to the DSMAC calculation in the subsequent period. Any over collection will accrue interest charges. Under collections will not accrue interest.

Illustrative Table of Events

Date	Included Items
7/15/2009 DSMAC includes:	File 2010 EEIP with 2010 DSMAC 2010 forecast of PC and PI 2009 forecast of PC and PI TU balancing account as of the last billing cycle of February
3/1/2010	DSMAC start from 2010 EEIP
6/1/2010 DSMAC includes:	File 2011 EEIP with 2011 DSMAC 2011 forecast of PC and PI TU balancing account as of the last billing cycle of February
3/1/2011	DSMAC start from 2011 EEIP
6/1/2011 DSMAC includes:	File 2012 EEIP with 2012 DSMAC 2012 forecast of PC and PI TU balancing account as of the last billing cycle of February

5. DETERMINATION OF THE ADJUSTOR CHARGE:

By July 15, 2009 and on June 1st of each subsequent year, APS will file a revised DSMAC with supporting documentation in the EEIP. The DSMAC will be calculated by projecting PC and PI for the upcoming year, adjusted by the over or under collection of previous periods. This calculation will be provided in the annual DSMAC calculation on Schedule 4.

The DSMAC for purposes of recovering PC and PI under the DSM Program will be developed based on the following formula:

$$\text{DSMAC} = \frac{PC + PI + TU + I}{\text{Sales}}$$

Where:

PC = Program Costs as defined in section 3 forecast for the upcoming year.

PI = Performance Incentives as defined in section 3 forecast for the upcoming year.

TU = Any "true-up" balance as defined in section 4.

I = Interest associated on any over recovery of DSMAC costs for the prior period. The interest rate is based on the one-year Nominal Treasury Maturities rate from the Federal Reserve H-15 or its successor publication. The interest rate shall be adjusted annually on the first business day of the calendar year.

Sales = Forecast energy (kWh) sales under applicable electric rate schedules during the Adjustor Period in which this adjustor will be effective.

Adjustor Period = The 12 month period beginning with the first billing cycle during March of the current year and ending with the last billing cycle of February of the next year.

DEMAND SIDE MANAGEMENT ADJUSTMENT CHARGE PLAN OF ADMINISTRATION XXXX-XX-XX

The DSMAC for General Service customers that are billed on demand will be calculated as a per kW charge. The DSMAC for General Service customers that are not billed on demand will be calculated as a per kWh charge. To calculate the per kW charge, the recoverable costs shall first be allocated to the General Service class based upon the number of kWh consumed by that class. The remainder of the recoverable costs allocated to the General Service class shall then be divided by the kW billing determinants for the demand billed customers in that class to determine the per kW DSMAC.

For residential billing purposes, the DSMAC and the Renewable Energy Surcharge ("RES") are combined and will appear on customer bills as the "Environmental Benefits Surcharge". For the billing of general service and other non-residential customers, the Company may, but is not required to, provide for such combined billing of the RES and DSMAC. In any event, each adjustor shall have separate rate schedules and will be kept separate in the Company's books, records, and reports to the Commission.

6. REVIEW PROCESS:

The proposed DSMAC for use during a specific Adjustor Period will be calculated as shown in Section 4. APS will file an updated adjustor charge each year with its EEIP. The first filing will be July 15, 2009, and June 1st each year thereafter. If approved by the Commission, changes in the DSMAC will go into effect on the first billing cycle of March in the Adjustor Period.

ATTACHMENT 1

ESTIMATED

ARIZONA PUBLIC SERVICE COMPANY
DEMAND SIDE MANAGEMENT PROGRAM
JUNE 20XX FILING

Line No.		(A) True-Up Period DSMAC Revenue for March 20XX - February 20XX
1	Total	

1 Recovery period is March 20XX-February 20XX for costs associated with the 20XX program year.

ATTACHMENT 1

ESTIMATED

ARIZONA PUBLIC SERVICE COMPANY
DEMAND SIDE MANAGEMENT PROGRAM
JUNE 20XX FILING

Line No.	Program	(A) True-Up Period 20XX[1]	(B) Forecast Period 20XX[2]
1	Energy Efficiency (EE) Program Costs (PC)	$ -	0
2	Performance Incentives (PI)	$ -	0
3	Sub Total	$ -	$ -
4	Demand Response (DR) PC	$ -	0
5	Total	$ -	$ -

1 Total 20XX EE and DR costs of $XX,XXX,XXX less $10,000,000 recovered in base rates
2 Projected costs of 20XX Implementation *Plan less $10,000,000* recovered in base rates.

ATTACHMENT 1

ESTIMATED

ARIZONA PUBLIC SERVICE COMPANY
DEMAND SIDE MANAGEMENT PROGRAM
JUNE 20XX FILING

Line No.	Date Period	Cost, Collection and Interest	Reference	Amount
1	March 20XX -February 20XX	DSMAC Revenue - TU	Schedule 1, Line 1, Column A	$ -
2	January 20XX - December 20XX	DSMAC Program Costs - TU	Schedule 2, Line 5, Column A	$ -
3a		Sub Total	(Line 1 - Line 2)	$ -
3b	Treasury constant maturities rate January 20XX [1]	Interest Rate		0.00%
4		Interest Amount	(Line 3a * 3b)	$ -
5		Total TU Balance Account	(Line 3a + Line 4)	$ -

1 Interest is only applied to over-collections

ATTACHMENT 1

ESTIMATED

ARIZONA PUBLIC SERVICE COMPANY
DEMAND SIDE MANAGEMENT PROGRAM
JUNE 20XX FILING

Line No.	DSMAC Calculations	Reference	Amount	Units
1	Program forecast costs for adjustor period in 20XX	Schedule 2, Line 5, Column B	$ -	
2A	Recovery of True-Up Account (over) under collection	Schedule 3, Line 5	$ -	
2B	Credit for Gains from Asset Sales (over) under collection		$ -	
3	Total amount to be collected	(Line 1 + Line 2)	$ -	Total Revenue Requirements
4	Forecast retail kWh sales for adjustor period		0	kWh
5	Proposed kWh adjustor charge for adjustor period[1]	(Line 3 / Line 4)	$ -	per kWh
6	Forecast General Service kWh sales for adjustor period[2]		0	kWh
7	Amount to be collected from General Service demand metered customers for adjustor period	(Line 5 * Line 6)	$ -	
8	Forecast General Service demand billed customer kW		0	kW
9	Proposed kW adjustor charge for forecast period[3]	(Line 7 / Line 8)	$ -	per kW

1 $/kWh charge for all Residential customers and General Service customers with no demand charge
2 Forecast General Service kWh for customers with demand charges
3 $/kW charge for General Service customers with demand charges

PLAN OF ADMINISTRATION
ENVIRONMENTAL IMPROVEMENT SURCHARGE

Environmental Improvement Surcharge
Plan of Administration

Table of Contents

1. General Description

This document describes the plan for administering the Environmental Improvement Surcharge ("EIS") approved for the Arizona Public Service Company ("APS") by the Arizona Corporation Commission ("ACC" or "Commission") on [insert date] in Decision No. XXXXX. The EIS provides for the recovery of the capital carrying costs effect of actual environmental investments made by APS and not already recovered in base rates approved in Decision No. XXXXX or recovered through another Commission approved adjustment. The EIS will be calculated annually based on the EIS Qualified Investments closed to plant-in-service during the preceding calendar year.

2. Definitions

EIS Qualified Investments – Investments in Qualified Environmental Improvement Projects. Each EIS Qualified Investments must: (1) be classified in one or more of the FERC plant accounts as listed in Section 3 of this document, or any other successor FERC account, upon going into service, (2) be tracked by a specific project number.

Qualified Environmental Improvement Projects - Projects designed to comply with established environmental standards required by federal, state, tribal, or local laws and regulations. These standards and criteria for water, waste, and air include but are not limited to limits for carbon dioxide (CO_2), sulfur oxide (SOx), nitrogen oxide (NOx), particulate matter (PM), volatile organic compounds (VOC), and toxics such as mercury (Hg), coal ash management, and requirements under the clean and safe drinking water acts.

Total kWh Sales – The total prior calendar year energy (kWh) sales served under applicable ACC jurisdictional electric rate schedules, except Rate Schedules E-36 XL andAG-1, as reported in the Company's FERC Form No. 1.

3. Qualified FERC Accounts

1. Steam Production
   - FERC Account 310 – Land and Land Rights
   - FERC Account 311 – Structures and Improvements
   - FERC Account 312 – Boiler Plant Equipment
   - FERC Account 313 – Engines and Engine-Driven Generators
   - FERC Account 314 – Turbogenerator Units
   - FERC Account 315 – Accessory Electric Equipment
   - FERC Account 316 – Miscellaneous Power Plant Equipment

2. Nuclear Production
   - FERC Account 320 – Land and Land Rights
   - FERC Account 321 – Structures and Improvements
   - FERC Account 322 – Reactor Plant Equipment
   - FERC Account 323 – Turbogenerator Units
   - FERC Account 324 – Accessory Electric Equipment
   - FERC Account 325 – Miscellaneous Power Plant Equipment

3. Other Production
   - FERC Account 340 – Land and Land Rights
   - FERC Account 341 – Structures and Improvements
   - FERC Account 342 – Fuel Holders, Products, and Accessories
   - FERC Account 343 – Prime Movers
   - FERC Account 344 – Generators
   - FERC Account 345 – Accessory Electric Equipment
   - FERC Account 346 – Miscellaneous Power Plant Equipment

Please note this list may expand to include other accounts approved by the ACC in the future.

4. Calculation of EIS Capital Carrying Costs

EIS capital carrying costs used in calculating the EIS $ per kWh rate will include: (1) Return on EIS Qualified Investments based on the Company's Weighted Average Cost of Capital ("WACC") approved by the Commission in Decision No. XXXXX; (2) depreciation expense; (3) income taxes; (4) property taxes; (5) deferred income taxes and tax credits where appropriate; and (6) associated O&M. EIS Qualified Projects and the EIS capital carrying costs calculation will be submitted by the Company to the ACC in the form of Schedule 1 and Schedule 2 as attached to this document.

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PLAN OF ADMINISTRATION
ENVIRONMENTAL IMPROVEMENT SURCHARGE

5. Calculation of EIS $ per kWh rate

The EIS rate to be applied to customers' bills will be calculated by dividing the total EIS Capital Carrying Costs by Total kWh Sales. The EIS rate will not exceed $0.00016 per kWh. The initial EIS rate will be set to zero.

6. Filing and Procedural Deadlines

APS will file the calculated EIS rate including all supporting data, with the Commission for the previous year on or before February 1st. See Schedules 1 and 2, attached.

The Commission Staff and interested parties shall have the opportunity to review the EIS filing and supporting data in the adjustor calculation. Unless the Commission has otherwise acted or Staff has filed an objection by April 1st, the new EIS rate proposed by APS will go into effect with the first billing cycle in April (without proration) and will remain in effect for the following 12-month period.

Schedule 1: Qualified Investments for EIS
Electric Plant in Service for Calendar Year 20XX

Line No.	(A) Project Tracking Number	(B) Project Name	(C) Purpose	(D) In-Service Date	(E) Total Cost	(F) ACC Jurisdictional Total Cost
	Environmental Improvement Projects					
1.	XXXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
2.	XXXXX	Project B	Project B Purpose Description	MM/YY	-	-
3.	XXXXX	Project C	Project C Purpose Description	MM/YY	-	-
4.		**Total**			**$ -**	**$ -**

Schedule 2: Capital Carrying Costs and Adjustor Calculation
Plant in Service for Calendar Year 20XX
Billing Period 4/1/20XX-3/30/XX

Line No.	EIS Rate Calculation		
	Qualified Net Plant		
1.	Environmental Improvement Projects (Schedule 1 - Total Line Column F)	$	-
2.	Accumulated Depreciation	$	-
3.	Cumulative Deferred Tax/Tax Credits	$	-
4.	Qualified Net Plant (Line 1 - Line 2 - Line 3)	$	-
5.	Pre-tax Weighted Average Cost of Capital		0.00%
	Capital Carrying Costs		
6.	Composite Return on EIS Net Plant (Line 4 * Line 5)	$	-
7.	Annual Depreciation of Plant In Service	$	-
8.	Applicable Property Tax	$	-
9.	Associated O&M Expense	$	-
10.	Total EIS Capital Carrying Costs (Line 6 + Line 7 + Line 8 + Line 9)	$	-
11.	Total Company Retail Sales (kWh)		-
12.	Calculated EIS Adjustment ($/kWh) (Line 10 / Line 11)	$	-
13.	EIS Rate Cap ($/kWh)	$	0.00016
14.	EIS Rate ($/kWh) (Lesser of Line 12 and Line 13)	$	-

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Transmission Cost Adjustment Plan of Administration

Table of Contents

1. General Description

The purpose of the Transmission Cost Adjustment ("TCA") is to provide a mechanism to recover transmission costs associated with serving retail customers at the level approved by the Federal Energy Regulatory Commission ("FERC") and at the same time as new transmission rates become effective for APS wholesale customers. APS shall file a notice with Docket Control that includes its revised TCA tariff, along with a copy of its FERC information filing of its annual update of transmission service rates pursuant to its Open Access Transmission Tariff ("OATT"). This notice shall be filed with the Commission at the same time that APS makes its FERC filing.

The TCA applies to Arizona Public Service Company's ("Company") Retail Electric Rate Schedules. For Standard Offer customers that are not demand billed, the TCA is applied to the bill as a monthly kWh charge. For Standard Offer customers that are demand billed, it is applied to the TCA as a kW charge. The charge and modifications to it will take effect in billing cycle 1 of the June revenue month without proration.

APS's Network Integration Transmission Service ("NITS") is calculated and filed annually with the FERC in accordance with APS's formula rate. The formula rate calculation is specified within the Company's OATT as filed and approved by the FERC.

2. Calculations

The calculated NITS Retail Transmission Rates are shown in Appendix A of the Company's FERC Informational Filing of its Annual Update of transmission service. NITS rates as determined for the following classes:

Residential Service Customers
General Service Customers less than or equal to 20 kW not demand billed
General Service Customers over 20 kW and less than 3 MW demand billed
General Service Customers equal to and greater than 3 MW

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PLAN OF ADMINISTRATION
ADJUSTMENT SCHEDULE TCA-1
TRANSMISSION COST ADJUSTMENT

In addition to NITS, APS charges retail customers for other transmission services in accordance with its OATT. These additional ancillary services include:

Schedule 1 – Scheduling, System Control and Dispatch Service
Schedule 3 – Regulation and Frequency Response Service
Schedule 4 – Energy Imbalance Service
Schedule 5 – Operating Reserve-Spinning Reserve Service
Schedule 6 – Operating Reserve – Supplemental Reserve Service

The total APS OATT rate is the sum of the rates for providing these services. The revenue requirement resulting from FERC APS OATT rate are collected by APS from its retail customers, partly in base rates and the remaining through the TCA rate. The table shown below is an illustrative example of the TCA calculation using the rates in effect as of December 20, 2011.

Line	**Service Type**	**Residential**	**GS ≤ 20 kW**	**GS ≥ 20kW and < 3MW**	**GS ≥ 3MW**
		$/kWh	$/kWh	$/kW	$/kW
		(A)	(B)	(C)	(D)
1.	NITS	0.008381	0.005864	2.108	2.036
2.	Scheduling	0.000069	0.000056	0.0208	0.0236
3.	Regulation & Frequency	0.000267	0.000217	0.0813	0.0919
4.	Spinning Reserve	0.000618	0.000502	0.1879	0.2124
5.	Operating Reserve	0.000078	0.000064	0.0238	0.0269
6.	Energy Imbalance	-	-	-	-
7.	Total	0.009413	0.006703	2.4218	2.3908
8.	Included In Retail Base Rates per OATT	0.005202	0.004239	1.5848	1.7758
9.	TCA (Line 7) - (Line 8)	0.004211	0.002464	0.837	0.615

APS's NITS rates shown on line 1 will change annually, where ancillary service charges shown on lines 2 through 6 will change only through a separate filing when made by the Company to FERC.

3. Filing and Procedural Deadlines

APS will file the calculated TCA rates, including all supporting data, with the Commission each year no later than May 15th of each year.

The Commission Staff and interested parties shall have the opportunity to review APS's FERC Informational Filing of its Annual Update of transmission service rates pursuant to the APS OATT Attachment H-2, Formula Rate Implementation Protocols. The calculated NITS Retail Transmission Rates are shown in Appendix A of the Company's FERC filing. The new TCA rates proposed by APS will go into effect with the first billing cycle in June (without proration), unless Staff requests Commission review or otherwise ordered by the Commission, and will remain in effect for the following 12-month period.

EXPERIMENTAL RATE RIDER SCHEDULE AG-1
ALTERNATIVE GENERATION
GENERAL SERVICE

AVAILABILITY

This experimental rate rider schedule is available in all territories 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 Standard Offer customers who have an Aggregated Peak Load of 10 MW or more and are served under Rate Schedules E-34, E-35, E32-L, or E-32 TOU L. An aggregated group may also include metered accounts that are served under Rate Schedules E-32 M or E-32 TOU M, if the accounts are located on the same premises and served under the same name as an otherwise eligible Customer.

Customers must have interval metering, Advanced Metering Infrastructure, or an alternative in place at all times of service under this schedule. If the Customer does not have such metering, the Company will install the metering equipment at no additional charge. However, the customer will be responsible for providing and paying for any communication requirements associated with the meter, such as a phone line.

All provisions of the customer's applicable rate schedule will apply in addition to this Schedule AG-1, except as modified herein. This rate rider schedule shall be available for four years from the effective date of Schedule AG-1, unless extended by the Commission. Total program participation shall be limited to 200 MW of customer load, 100 MW of which shall be initially reserved for Customers served under Rate Schedule E-32 L.

DEFINITIONS

Aggregated Peak Load: The sum of the maximum metered kW for each of the Customer's aggregated metered accounts over the previous 12 months, as determined by the Company and measured at the Customer's meter(s) at the time of application for service under this rate rider schedule.

Standard Generation Service: Power provided by the Company to a retail customer in conjunction with transmission and delivery services, at terms and prices according to a retail rate schedule other than Schedule AG-1.

Customer: A metered account or set of aggregated metered accounts that meet the eligibility requirements for service and enrollment as an aggregated load for service, under this rate rider schedule.

Generation Service Provider: A third party entity that provides wholesale power to the Company on behalf of a Customer. This entity must be legally capable of selling and delivering wholesale power to the Company.

Generation Service: Wholesale power delivered to APS by a Generation Service Provider.

Imbalance Energy: For each Generation Service Provider, Imbalance Energy will be calculated by the Company as the difference between the hourly delivered energy from the Generation Service Provider and the actual hourly metered load for each Customer for all Customers that have selected the Generation Service Provider under this rate rider schedule.

Imbalance Service: Calculating and managing the hourly deviations in energy supply for imbalance energy.

Total Load Requirements: The Customer's hourly load including losses from the point of delivery to the Company's transmission system to the Customer's sites for the duration of the contract.

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EXPERIMENTAL RATE RIDER SCHEDULE AG-1
ALTERNATIVE GENERATION
GENERAL SERVICE

CUSTOMER ENROLLMENT

The Company shall establish an initial enrollment period during which Customers can apply for service under this rate rider schedule. If the applications for service are greater than the program maximum amount, then Customers shall be selected for enrollment through a lottery process as detailed in the program guidelines, which may be revised from time-to-time during the term of this rate rider schedule.

AGGREGATION

Eligible customers may be aggregated if they have the same corporate name, ownership, and identity. In addition, (1) an eligible franchisor customer may be aggregated with eligible franchisees or associated corporate accounts, and (2) eligible affiliate customers may be aggregated if they are under the same corporate ownership, even if they are operating under multiple trade names.

DESCRIPTION OF SERVICES AND OBLIGATIONS

The Customer shall apply for service under this rate rider schedule.

The Company shall conduct the enrollment process in accordance with the provisions of this rate rider schedule.

The Customer shall select a Generation Service Provider to provide Generation Service in accordance with the timeline specified in the program guidelines

The Company shall enter into a contract with the Generation Service Provider to receive delivery and title to the power on the Customer's behalf.

The Generation Service Provider shall provide to the Company on behalf of the Customer firm power sufficient to meet the Customer's Total Load Requirements for each of the specified metered accounts, and will attest in its contract with the Company that this condition is met. For the purposes of this rate schedule, "firm power" refers to generation resources identified in Western System Power Pool Schedule C or a reasonable equivalent as determined by the Company.

The Company shall provide transmission, delivery and network services to the Customer according to normal retail electric service.

The Company will settle with the Generation Service Provider for Imbalance Service and other relevant costs on a monthly basis according to the program guidelines.

The Generation Service Provider shall bill the Company the monthly billed amounts for each customer for Generation Service and Imbalance Service according to the program guidelines.

The Company shall bill the customer for the Generation Service Provider's charged amounts and remit the amounts to the Generation Service provider.

The customer will be responsible for paying for the cost of the power provided by the Generation Service Provider, as specified in the contract and this rate rider schedule.

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EXPERIMENTAL RATE RIDER SCHEDULE AG-1
ALTERNATIVE GENERATION
GENERAL SERVICE

DELIVERY OF POWER TO THE COMPANY'S SYSTEM

Power provided by the Generation Service Provider must be firm power as defined above and delivered to the Company at the Palo Verde network delivery point, or other point of delivery as agreed to by the Company. The Generation Service Provider is responsible for the cost of transmission service to deliver the power to the Company's delivery point.

SCHEDULING

The Company shall serve as the scheduling coordinator. The Generation Service Provider shall provide monthly schedules of hourly loads along with day-ahead hourly load deviations from the monthly schedule to the Company according to the program guidelines. Line losses, in the amount of 7%, from the point of delivery to the Customer's sites shall be either scheduled or financially settled.

IMBALANCE SERVICE

The Company will provide Imbalance Service according to the terms and provisions in the Company's Open Access Transmission Tariff, Schedule 4. Imbalance Energy will be based on the Generation Service Provider's portfolio of Customer loads.

POWER SUPPLY ADJUSTER AND HEDGE COST TRUE-UP

The customer will be subject to the power supply adjustment – historical component for the first twelve months of service under this rate rider schedule. The customer will also pay for the hedge cost associated with the customer's Standard Generation Service at the time the customer takes service under this rate rider schedule. For the purpose of this rate rider schedule, the Company will determine the applicable pro rata hedge cost based on the market price for hedge costs at the time the customer takes service under this rate rider schedule.

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 select another Generation Service Provider within 60 days. Prior to execution of any new power contract, the Company shall provide the required power to the customer, which will be charged at the Dow Jones Electricity Palo Verde Hourly Index price for the power delivery date plus $10 per MWh. In addition, all other provisions of this rate rider schedule will continue to apply.

If the Customer is unable to select another Generation Service Provider within sixty days, the customer will automatically return to Standard Generation Service, and be subject to the conditions below.

RETURN TO COMPANY'S STANDARD GENERATION SERVICE

Customer may return to the Company's Standard Generation Service under their applicable retail rate schedule without charge if: (1) they provide one year notice (or longer) to the Company; or (2) if this rate rider schedule is discontinued at the end of the 4 year experimental period; or (3) if the Commission terminates the program prior to the initial four year experimental period. Absent one of these three conditions, the Company will provide the customer with generation service at the market index rate provided in the Company's Open Access Transmission Tariff until the Company is reasonably able to integrate the customer back into their generation planning and provide power at the applicable retail rate schedule. This transition will be at the Company's determination but no longer than 1 year. The returning customer must remain with the Company's Standard Generation Service for at least 1 year.

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**EXPERIMENTAL RATE RIDER SCHEDULE AG-1
ALTERNATIVE GENERATION
GENERAL SERVICE**

RATES

All provisions, charges and adjustments in the customer's applicable retail rate schedule will continue to apply except as follows:

1. The generation charges will not apply;
2. Adjustment Schedule PSA-1will 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; and
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.

Schedule AG-1 charges determined and billed by the Company include:

1. A monthly management fee of $0.00060 per kWh applied to the customer's metered kWh;
2. A monthly reserve capacity charge applied to 15% of the customer's billed kW (on-peak for Rate Schedules E-35 and E-32 TOU L) at the Company's applicable cost-based rate filed at the Federal Energy Regulatory Commission and revised from time to time, which is currently $6.985 per kW month;
3. An initial charge or credit for fuel hedging costs, as described herein;
4. Returning Customer charge, where applicable, as described herein;
5. Generation Service Provider Default charge, where applicable, as described herein.

Schedule AG-1 Generation Service and Imbalance Service charges billed by the Company include:

1. Generation Service charges shall be charged at a rate within the minimum and maximum limits as follows:

   a. When the contract provides for pricing that reflects a specific index price, the minimum price will be the specified index minus 35% and the maximum price will be the specified index plus 35%. The determination that a contract is consistent with this provision will be based on the specified index price applicable on the date the contract is executed.
   b. When the contract provides for a fixed price supply for the term of the contract, the minimum price will be the generation rate of the Customer's applicable retail rate schedule minus 35%, and the maximum price shall be the generation rate of the Customers applicable retail schedule plus 35%. If the Customer has more than one otherwise applicable retail rate schedule, the highest applicable retail rate schedule will be used for purposes of the consistency determination. The determination that a contract is consistent with this provision will be based on the Customer's otherwise applicable retail rate schedule in effect on the date the contract is executed.
   c. Losses from the delivery point to the Customer's meters and any charges assessed by the Company on the Customer, including charges for transmission and distribution, Capacity Reservation Charge, the Management Fee, Imbalance Service charges, PSA balance and hedging costs, and Returning Customer Charges, shall not be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule.

2. Imbalance Service charges shall be charged at a rate greater than $0.00 per kWh and less than or equal to the rate that the Company charges the Generation Service Provider for Imbalance Service as specified herein.

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EXPERIMENTAL RATE RIDER SCHEDULE AG-1
ALTERNATIVE GENERATION
GENERAL SERVICE

CONTRACT TERM AND REQUIREMENTS

The term of the contract with the Generation Service Provider shall be for not less than one year and shall not exceed four years.

The Generation Service Provider and Customer will enter into a contract or contracts 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 to the Company's management of the generation resource.

CREDIT REQUIREMENTS

A Generation Service Provider or its parent company must have at least an investment grade credit rating or demonstrate creditworthiness in the form of either a 3rd-party guarantee from an investment grade rated company, surety bond, letter of credit, or cash in accordance with the Company's standard credit support rules

Arizona Public Service Company
Summary of Rate Design Provisions
Rate Case Settlement (Test Year 2010)

Base Rate Increase

- Settlement base rates shall reflect an overall retail revenue increase of $0.00 which is a %0.0 increase over test year revenues from base rates.
- This includes a general non-fuel increase of $116,280,000, an additional non-fuel increase of $36,807,000 from transferring revenue requirements for the Renewable Energy Standard ("RES") to base rates, and a decrease in fuel costs recovered through base rates of $153,087,000.

Rate Spread

- The base rate impact for participating low-income customers will reflect a $1,535,000 reduction to compensate for the expected impact of removing their exemption to the Power Supply Adjustor ("PSA") and Demand Side Management Adjustor Clause ("DSMAC").
- This reduction in base rate revenue will be recovered from all other rate classes, allocated proportional to each class' present revenue. Street Lighting and Dusk to Dawn Lighting rate classes are excluded from this allocation.
- The base rate impact for general service rate classes shall reflect a re-allocation of fuel costs within the general service revenue class, designed to better equalize the combined fuel impact on base rates and the PSA adjustor rate within the general service revenue class. This adjustment will not impact any other revenue class.

General Issues

- The unbundled transmission charge shall remain in base rates and not be transferred to the TCA adjustor rate.
- The System Benefit Charge will be set at $0.002970 per kWh to reflect the cost of service, which includes the transfer of $36,807,000 in revenue requirements associated with Renewable Energy projects (see Attachment D of the proposed Settlement Agreement) from the RES to base rates.
- APS shall prepare and file a rate plan as proposed by Staff to provide information on such issues as tiered conservation rates, time-of-use and other demand response rates, plans for cancelling rates, ideas for new rate offerings, and other relevant rate design issues. The timing of the plan will be revised in the Settlement. In addition, APS and Staff will identify current rate related compliance reports that can be consolidated into this rate plan.

Residential Rates

- Basic service charges shall be retained at their current rate levels.
- Unbundled delivery charges for all residential rates shall be set at class cost of service level.
- All other charges will be set to the level necessary to achieve the targeted base rate change for each rate class reflected in the Settlement Schedule H-2, attached to the Settlement Testimony of Charles A. Miessner.
- Time of use rates shall maintain a similar ratio of on-peak to off-peak prices as approved by the Commission in the last general rate case, Decision No. 71448.
- The existing optional Rate schedule ET-EV for off-peak charging of electric vehicles will be revised consistent with the revised time-of-use Rate Schedule ET-2.

Arizona Public Service Company
Summary of Rate Design Provisions
Rate Case Settlement (Test Year 2010)

- Rate schedule PTR-RES, which is a new optional peak-time rebate program will be offered as proposed by APS.

Low-Income Rates

- The existing low-income rates will be consolidated with the corresponding non-low-income rate schedules. The low-income discounts will be increased to hold customers harmless (on-average) from this provision.

- The low-income exemption from the PSA and the DSMAC will be cancelled. The low-income discounts will be increased to hold customers harmless (on-average) from this provision.

- The current low income discount tier structure will be retained; the discount levels will be increased as provided above.

General Service Rates

- Basic service charges shall be retained at their current rate levels.

- All other charges will be set to the level necessary to achieve the targeted base rate change for each rate class reflected in the Settlement Schedule H-2.

- Contract minimum charges (or minimum bill provisions) shall be eliminated for general service Rate Schedules E-32 XS, E-32 S, E-32 M, E-32TOU XS, E-32 TOU S and E-32 TOU M.

- Minimum bill provisions for Rate schedules E-32 L and E-32 TOU L will be revised to be more consistent with the corresponding provisions in extra-large general service Rate Schedules E-34 and E-35, including a "ratchet" provision for the determination of monthly billing kW.

- The bundled demand and energy charges for Rate Schedules E-32 L, E-34, and E-35 shall be revised from the levels provided in APS's Application in this matter to better reflect cost of service. Specifically, the demand charges shall be increased and the energy charges decreased from the initial proposed levels, but at a level that achieves the overall targeted revenue change for each of these rate classes.

- Rate Rider Schedule E-54 for seasonal use shall continue to be available for customers served under "parent" Rate Schedules E-32 L and E-32 TOU L, but cancelled for other rates.

- Rate Schedule E-30 for non- metered usage shall be revised to reflect the language clarification proposed by APS.

- The new optional Rate Schedule IRR, interruptible service for extra-large general service customers, shall be offered as proposed by APS.

- The new optional Experimental Rate Schedule AG-1, which offers a generation buy-through provision for a limited number of large and extra general service customers, shall be offered as developed by a collaborative group of interested parties, with concurrence by the parties to the Rate Settlement.

Classified Rates

- Charges will be set to the level necessary to achieve the targeted base rate change for each rate class reflected in the Settlement Schedule H-2.

- Rate Rider Schedule SC-S (E-56R) for renewable partial requirement service shall be revised as proposed by APS.

Arizona Public Service Company
Summary of Rate Design Provisions
Rate Case Settlement (Test Year 2010)

- The new optional Rate Rider Schedule E-36 M for medium size station use customers shall be offered as proposed by APS, except that it will be subject to the PSA adjustor rate.

- Rate Schedules E-221 and E-221 8-T for water pumping service shall be revised as proposed by APS.

- E-20 (house of worship) shall be unfrozen for one year from the effective date of new rates in this matter.

- Area lighting rates shall be revised to reflect the new provisions as proposed by APS.

- GPS riders (green power) shall be revised to eliminate the exemption to adjustor rates.

Canceled Rates

- The following rates and rate options will be canceled because they are no longer necessary or appropriate given other proposed rate design charges, or because they have very low (or no) participation. Cancellations include: E-40 (wind machine), Solar -2 (off grid), Solar -3, Share the lights area lighting rates E-114, E-116, E-145, E-129, E-53 (sports field lighting), and E-221 TOW option (time-of-week pricing option for water pumping).

Service Schedules

- Service Schedule 1 shall be revised as proposed by APS

- The proposed optional Service Schedule 9 for economic development is withdrawn.

Plans of Administration

- The plans of administration for the PSA, DSMAC, Transmission Cost Adjustor ("TCA") and Environmental Improvement Surcharge ("EIS") will be revised to reflect the terms of the Settlement Agreement.

- A new Lost Fixed Cost Recovery ("LFCR") plan of administration will be developed to reflect the terms of the Settlement Agreement.

- The RES plan of administration will not be revised in this proceeding.

Settlement Rate Summary for Residential Rates

		E-12 Proposed
Bundled Rates		
BSC $/day	$	0.285
Summer		
First 400 kWh	$	0.09687
Next 400 kWh	$	0.13817
Next 2200 kWh	$	0.16167
Remaining kWh	$	0.17257
Winter		
All kWh	$	0.09417
Unbundled Rates		
Generation Charge		
Summer		
1st 400 kWh	$	0.06170
Next 400 kWh	$	0.10300
Next 2200 kWh	$	0.12650
Additional kWh	$	0.13740
Winter		
All kWh	$	0.05900
Transmission Charge		
kWh	$	0.00520
Delivery Charge		
kWh		0.02700
System Benefits Charge		
kWh	$	0.00297
BSC $/day		
Customer Accounts	$	0.063
Metering	$	0.090
Billing	$	0.070
Meter Reading	$	0.062
BCS Total	$	0.285

		ET-1 Proposed		ET-2 Proposed
Bundled Rates				
BSC $/day	$	0.556	$	0.556
Summer				
On-Peak kWh	$	0.17892	$	0.24477
Off-Peak kWh	$	0.05770	$	0.06118
Winter				
On-Peak kWh	$	0.14533	$	0.19847
Off-Peak kWh	$	0.05561	$	0.06116
Unbundled Rates				
Generation Charge				
Summer				
On-Peak kWh	$	0.14375	$	0.20960
Off-Peak kWh	$	0.02253	$	0.02601
Winter				
On-Peak kWh	$	0.11016	$	0.16330
Off-Peak kWh	$	0.02044	$	0.02599
Transmission Charge				
kWh	$	0.00520	$	0.00520
Delivery Charge				
kWh	$	0.02700	$	0.02700
System Benefits Charge				
kWh	$	0.00297	$	0.00297
BSC $/day				
Customer Accounts	$	0.238	$	0.238
Metering	$	0.186	$	0.186
Billing	$	0.070	$	0.070
Meter Reading	$	0.062	$	0.062
BCS Total	$	0.556	$	0.556

		ECT-1R Proposed		ECT-2 Proposed
Bundled Rates				
BSC $/day	$	0.556	$	0.556
Summer				
On-Peak kW	$	13.550	$	13.500
On-Peak kWh	$	0.07330	$	0.08867
Off-Peak kWh	$	0.04083	$	0.04417
Winter				
On-Peak kW	$	9.400	$	9.300
On-Peak kWh	$	0.05587	$	0.05747
Off-Peak kWh	$	0.03967	$	0.04107
Unbundled Rates				
Generation Charge				
Summer				
On-Peak kW	$	9.650		9.000
On-Peak kWh	$	0.04973		0.06650
Off-Peak kWh	$	0.01726		0.02200
Winter				
On-Peak kW	$	7.100		6.900
On-Peak kWh	$	0.03070		0.03340
Off-Peak kWh	$	0.01450		0.01700
Transmission Charge				
kWh	$	0.00520	$	0.00520
Delivery Charge				
Summer				
On-Peak kW		3.900		4.500
On-Peak kWh		0.01540		0.01400
Winter				
On-Peak kW		2.300		2.400
On-Peak kWh		0.01700		0.01590
System Benefits Charge				
kWh	$	0.00297	$	0.00297
BSC $/day				
Customer Accounts	$	0.238		0.238
Metering	$	0.186		0.186
Billing	$	0.070		0.070
Meter Reading	$	0.062		0.062
BCS Total	$	0.556		0.556

Settlement Rate Summary for Residential Rates

Bundled Rates	**ET-SP Proposed**
BSC $/day	$ 0.556
Summer Peak	
Super Peak kWh	$ 0.46517
On-Peak kWh	$ 0.24477
Off-Peak kWh	$ 0.05517
Summer	
On-Peak kWh	$ 0.24477
Off-Peak kWh	$ 0.05517
Winter	
On-Peak kWh	$ 0.19847
Off-Peak kWh	$ 0.05517

Unbundled Rates	
Generation Charge	
Summer Peak	
Super Peak kWh	0.43000
On-Peak kWh	0.20960
Off-Peak kWh	0.02000
Summer	
On-Peak kWh	0.20960
Off-Peak kWh	0.02000
Winter	
On-Peak kWh	0.16330
Off-Peak kWh	0.02000
Transmission Charge	
kWh	$ 0.00520
Delivery Charge	
Super Peak	
kWh	0.02700
Summer	
kWh	0.02700
Winter	
kWh	0.02700
System Benefits Charge	
Summer kWh	$ 0.00297
BCS $/day	
Customer Accounts	0.238
Metering	0.186
Billing	0.070
Meter Reading	0.062
BCS Total	0.556

Bundled Rates	**ET-EV Proposed**
BSC $/day	0.556
Summer	
Super Off-Peak kWh	0.04195
On-Peak kWh	0.24784
Off-Peak kWh	0.06460
Winter	
Super Off-Peak kWh	0.04195
On-Peak kWh	0.20165
Off-Peak kWh	0.06460

	CPP-RES Proposed
kWh charge	$ 0.250000
kWh discount	$ (0.012143)

	PTR-RES Proposed
kWh Rebate	$ 0.25000

Settlement Rate Summary for General Service Rates

	E-30 Proposed
Bundled Rates	
Summer	
BSC $/day	$ 0.311
Energy Charge	$ 0.14455
Winter	
BSC $/day	$ 0.311
Energy Charge	$ 0.12984
Unbundled Rates	
Summer	
BSC $/day	$ 0.243
Billing	$ 0.068
Systems Benefits	$ 0.00297
Transmission	$ 0.00424
Delivery	$ 0.05032
Generation kWh	$ 0.08702
Winter	
BSC $/day	$ 0.243
Billing	$ 0.068
Systems Benefits	$ 0.00297
Transmission	$ 0.00424
Delivery	$ 0.05032
Generation kWh	$ 0.07231

	E-32 XS Proposed
Bundled Rates	
BSC $/day	
Self-Contained	$ 0.672
Instrument-Rated	$ 1.324
Primary Voltage	$ 3.415
Transmission Voltage	$ 26.163
Energy Charge	
Summer	
kWh (1st 5000 / mo.) (Secondary)	$ 0.13537
kWh (over 5000 / mo.) (Secondary)	$ 0.07427
kWh (1st 5000 / mo.) (Primary)	$ 0.13209
kWh (over 5000 / mo.) (Primary)	$ 0.07100
Winter	
kWh (1st 5000 / mo.) (Secondary)	$ 0.11769
kWh (over 5000 / mo.) (Secondary)	$ 0.05658
kWh (1st 5000 / mo.) (Primary)	$ 0.11438
kWh (over 5000 / mo.) (Primary)	$ 0.05329
Unbundled Rates	
Generation Charge	
Summer	
kWh (1st 5000 / mo.)	$ 0.08641
kWh (over 5000 / mo.)	$ 0.05396
Winter	
kWh (1st 5000 / mo.)	$ 0.06880
kWh (over 5000 / mo.)	$ 0.03634
System Benefits Charge	
kWh	$ 0.00297
Transmission Charge	
kWh	$ 0.00424
Delivery Charge	
Summer	
Delivery (1st 5000 kWh per mo.) (Secondary)	$ 0.04175
Delivery (over 5000 kWh per mo.) (Secondary)	$ 0.01310
Delivery (1st 5000 kWh per mo.) (Primary)	$ 0.03847
Delivery (over 5000 kWh per mo.) (Primary)	$ 0.00983
Winter	
Delivery (1st 5000 kWh per mo.) (Secondary)	$ 0.04168
Delivery (over 5000 kWh per mo.) (Secondary)	$ 0.01303
Delivery (1st 5000 kWh per mo.) (Primary)	$ 0.03837
Delivery (over 5000 kWh per mo.) (Primary)	$ 0.00974
BSC $/day	
BSC Self-Contained	$ 0.126
BSC Instrument-Rated	$ 0.126
BSC Primary Voltage	$ 0.126
BSC Transmission Voltage	$ 0.126
Revenue Cycle $/day	
Metering Self-Contained	$ 0.403
Metering Instrument-Rated	$ 1.055
Metering Primary	$ 3.146
Metering (Transmission)	$ 25.894
Billing	$ 0.075
Meter Reading	$ 0.068

	E-32 S Proposed	E-32 M Proposed
Bundled Rates		
BSC $/day		
Self-Contained	$ 0.672	$ 0.672
Instrument-Rated	$ 1.324	$ 1.324
Primary Voltage	$ 3.415	$ 3.415
Transmission Voltage	$ 26.163	$ 26.163
Demand Charge		
1st 100 kW (Secondary)	$ 9.828	$ 10.235
Over 100 kW (Secondary)	$ 5.214	$ 5.385
1st 100 kW (Primary)	$ 9.116	$ 9.488
Over kW (Primary)	$ 4.502	$ 4.695
1st 100 kW (Transmission)	$ 7.101	$ 7.368
Over kW (Transmission)	$ 2.487	$ 2.519
Energy Charge		
Summer		
1st 200 kWh/kW	$ 0.10337	$ 0.09884
over 200 kWh/kW	$ 0.06257	$ 0.06091
Winter		
1st 200 kWh/kW	$ 0.08718	$ 0.08378
over 200 kWh/kW	$ 0.04638	$ 0.04586
Unbundled Rates		
Generation Charge		
Summer		
1st 200 kWh/kW	$ 0.09617	$ 0.08938
over 200 kWh/kW	$ 0.05537	$ 0.05145
Winter		
1st 200 kWh/kW	$ 0.07998	$ 0.07432
over 200 kWh/kW	$ 0.03918	$ 0.03640
System Benefits Charge		
kWh	$ 0.00297	$ 0.00297
Transmission Charge		
kW	$ 1.585	$ 1.585
Delivery Charge		
Delivery 1st 100 kW (Secondary)	$ 8.243	$ 8.650
Delivery All Addl kW (Secondary)	$ 3.629	$ 3.800
Delivery 1st 100 kW (Primary)	$ 7.531	$ 7.903
Delivery All Addl kW (Primary)	$ 2.917	$ 3.110
Delivery 1st 100 kW (Transmission)	$ 5.516	$ 5.783
Delivery All Addl kW (Transmission)	$ 0.902	$ 0.934
Delivery - All kWh	0.00423	$ 0.00649
BSC $/day		
BSC Self-Contained	$ 0.126	$ 0.126
BSC Instrument-Rated	$ 0.126	$ 0.126
BSC Primary Voltage	$ 0.126	$ 0.126
BSC Transmission Voltage	$ 0.126	$ 0.126
Revenue Cycle $/day		
Metering Self-Contained	$ 0.403	$ 0.403
Metering Instrument-Rated	$ 1.055	$ 1.055
Metering Primary	$ 3.146	$ 3.146
Metering (Transmission)	$ 25.894	$ 25.894
Billing	$ 0.075	$ 0.075
Meter Reading	$ 0.068	$ 0.068

Settlement Rate Summary for General Service Rates

Bundled Rates		E-32 L Proposed
BSC $/day		
Self-Contained	$	1.068
Instrument-Rated	$	1.627
Primary Voltage	$	3.419
Transmission Voltage	$	22.915
Demand Charge		
1st 100 kW (Secondary)	$	21.149
Over 100 kW (Secondary)	$	14.267
1st 100 kW (Primary)	$	19.091
Over kW (Primary)	$	13.209
1st 100 kW (Transmission)	$	14.284
Over kW (Transmission)	$	9.105
Energy Charge		
Summer		
kWh	$	0.05517
Winter		
kWh	$	0.03804
Unbundled Rates		
Generation Charge		
Summer		
kWh	$	0.05209
Winter		
kWh	$	0.03496
kW	$	4.496
System Benefits Charge		
kWh	$	0.00297
Transmission Charge		
kW	$	1.585
Delivery Charge		
Delivery 1st 100 kW (Secondary)	$	15.068
Delivery All Addl kW (Secondary)	$	8.186
Delivery 1st 100 kW (Primary)	$	13.010
Delivery All Addl kW (Primary)	$	7.128
Delivery 1st 100 kW (Transmission)	$	8.203
Delivery All Addl kW (Transmission)	$	3.024
Delivery - All kWh	$	0.00011
BSC $/day		
BSC Self-Contained	$	0.601
BSC Instrument-Rated	$	0.601
BSC Primary Voltage	$	0.601
BSC Transmission Voltage	$	0.601
Revenue Cycle $/day		
Metering (self-contained)	$	0.345
Metering (instrument-rated)	$	0.904
Metering (primary)	$	2.696
Metering (transmission)	$	22.192
Billing	$	0.064
Meter Reading	$	0.058

Bundled Rates		E-32 XS TOU Proposed
BSC $/day		
Self-Contained	$	0.710
Instrument-Rated	$	1.324
Primary Voltage	$	3.415
Transmission Voltage	$	26.163
Energy Charge - Summer		
Secondary Service		
On Peak kWh (1st 5000 / mo.)	$	0.17033
All additional kWh	$	0.08564
Off Peak kWh (1st 5000 / mo.)	$	0.12686
All additional kWh	$	0.04755
Primary Service		
On Peak kWh (1st 5000 / mo.)	$	0.16698
All additional kWh	$	0.08150
Off Peak kWh (1st 5000 / mo.)	$	0.12350
All additional kWh	$	0.04420
Energy Charge - Winter		
Secondary Service		
On Pk kWh (1st 5000 / mo.)	$	0.15310
All additional kWh	$	0.06837
Off Peak kWh (1st 5000 / mo.)	$	0.10959
All additional kWh	$	0.03496
Primary Service		
On Peak kWh (1st 5000 / mo.)	$	0.14974
All additional kWh	$	0.06423
Off Peak kWh (1st 5000 / mo.)	$	0.10624
All additional kWh	$	0.03160
Unbundled Rates		
Basic Service Charge	$	0.126
Self Contained (per day)	$	0.441
Instrument-Rated	$	1.055
Primary Voltage	$	3.146
Transmission Voltage	$	25.894
Meter Reading	$	0.068
Billing	$	0.075
System Benefits Charge		
kWh	$	0.00297
Transmission Charge		
kWh	$	0.00424
Delivery Charge		
Secondary Service		
Delivery On Peak (1st 5000 kWh per mo.)	$	0.05065
Delivery all additional kWh	$	0.01316
Delivery Off Peak (1st 5000 kWh per mo.)	$	0.04174
Delivery all additional kWh	$	0.00962
Primary		
Delivery On Peak (1st 5000 kWh per mo.)	$	0.04730
Delivery all additional kWh	$	0.00902
Delivery Off Peak (1st 5000 kWh per mo.)	$	0.03838
Delivery all additional kWh	$	0.00627
Winter		
Secondary		
Delivery On Peak (1st 5000 kWh per mo.)	$	0.05057
Delivery all additional kWh	$	0.01304
Delivery Off Peak (1st 5000 kWh per mo.)	$	0.04164
Delivery all additional kWh	$	0.00954
Primary		
Delivery On Peak (1st 5000 kWh per mo.)	$	0.04721
Delivery all additional kWh	$	0.00890
Delivery Off Peak (1st 5000 kWh per mo.)	$	0.03829
Delivery all additional kWh	$	0.00618
Generation Charge		
Summer		
On Peak (1st 5000 kWh per mo.)	$	0.11247
On Peak all additional kWh	$	0.06527
Off Peak (1st 5000 kWh per mo.)	$	0.07791
Off Peak all additional kWh	$	0.03072
Winter		
On Peak (1st 5000 kWh per mo.)	$	0.09532
On Peak all additional kWh	$	0.04812
Off Peak (1st 5000 kWh per mo.)	$	0.06074
Off Peak all additional kWh	$	0.01821

Settlement Rate Summary for General Service Rates

Bundled Rates	E-32 S TOU Proposed	E-32 M TOU Proposed	E-32 L TOU Proposed
BSC $/day			
Self-Contained	$ 0.710	$ 0.710	$ 0.710
Instrument-Rated	$ 1.324	$ 1.324	$ 1.324
Primary Voltage	$ 3.415	$ 3.415	$ 3.415
Transmission Voltage	$ 26.163	$ 26.163	$ 26.163
Demand Charge			
Secondary Service			
On Peak 1st 100 kW	$ 14.303	$ 15.166	$ 14.915
On Peak all additional kW	$ 9.713	$ 10.013	$ 9.784
Off Peak 1st 100 kW	$ 5.484	$ 5.897	$ 5.814
Off Peak all additional kW	$ 3.054	$ 3.168	$ 3.097
Primary Service			
On Peak 1st 100 kW	$ 13.845	$ 14.651	$ 14.402
On Peak all additional kW	$ 9.645	$ 9.936	$ 9.708
Off Peak 1st 100 kW	$ 4.909	$ 5.251	$ 5.170
Off Peak all additional kW	$ 2.975	$ 3.079	$ 3.008
Transmission Service			
On Peak 1st 100 kW	$ 12.208	$ 13.730	$ 13.486
On Peak all additional kW	$ 9.038	$ 9.619	$ 8.601
Off Peak 1st 100 kW	$ 4.042	$ 4.522	$ 4.444
Off Peak all additional kW	$ 2.837	$ 2.959	$ 2.888
Energy Charge - Summer			
On Peak kWh	$ 0.07367	$ 0.06566	$ 0.06555
Off Peak kWh	$ 0.05873	$ 0.05432	$ 0.05359
Energy Charge - Winter			
On Peak kWh	$ 0.05665	$ 0.05275	$ 0.05193
Off Peak kWh	$ 0.04170	$ 0.04142	$ 0.03997
Unbundled Rates			
Basic Service Charge	$ 0.126	$ 0.126	$ 0.126
Self-Contained	$ 0.441	$ 0.441	$ 0.441
Instrument-Rated	$ 1.055	$ 1.055	$ 1.055
Primary Voltage	$ 3.146	$ 3.146	$ 3.146
Transmission Voltage	$ 25.894	$ 25.894	$ 25.894
Meter Reading	$ 0.068	$ 0.068	$ 0.068
Billing	$ 0.075	$ 0.075	$ 0.075
System Benefits Charge			
kWh	$ 0.00297	$ 0.00297	$ 0.00297
Transmission Charge			
kW	$ 1.585	$ 1.585	$ 1.585
Delivery Charge			
Secondary Service			
On Peak 1st 100 kW	$ 5.775	$ 8.318	$ 7.776
On Peak all additional kW	$ 1.185	$ 3.165	$ 2.645
Off Peak 1st 100 kW	$ 2.842	$ 3.894	$ 3.701
Off Peak all additional kW	$ 0.412	$ 1.165	$ 0.984
per kWh	$ -	$ 0.00910	$ 0.00607
Primary			
On Peak 1st 100 kW	$ 5.317	$ 7.803	$ 7.263
On Peak all additional kW	$ 1.117	$ 3.088	$ 2.569
Off Peak 1st 100 kW	$ 2.267	$ 3.248	$ 3.057
Off Peak all additional kW	$ 0.333	$ 1.076	$ 0.895
per kWh	$ -	$ 0.00910	$ 0.00607
Transmission			
On Peak 1st 100 kW	$ 3.680	$ 6.882	$ 6.347
On Peak all additional kW	$ 0.510	$ 2.771	$ 1.462
Off Peak 1st 100 kW	$ 1.400	$ 2.519	$ 2.331
Off Peak all additional kW	$ 0.195	$ 0.956	$ 0.775
per kWh	$ -	$ 0.00910	$ 0.00607
Generation Charge			
Summer			
On Peak kW	$ 6.943	$ 5.263	$ 5.554
Off Peak kW	$ 2.642	$ 2.003	$ 2.113
On Peak kWh	$ 0.07070	$ 0.05359	$ 0.05651
Off Peak kWh	$ 0.05576	$ 0.04225	$ 0.04455
Winter			
On Peak kW	$ 6.943	$ 5.263	$ 5.554
Off Peak kW	$ 2.642	$ 2.003	$ 2.113
On Peak kWh	$ 0.05368	$ 0.04068	$ 0.04289
Off Peak kWh	$ 0.03873	$ 0.02935	$ 0.03093

Bundled Rates	E-34 Proposed
BSC $/day	
Self-Contained	$ 1.135
Instrument-Rated	$ 1.776
Primary Voltage	$ 3.828
Transmission Voltage	$ 26.161
Demand Charge	
Secondary Service	$ 19.930
Primary Service	$ 18.649
Transmission Service	$ 12.278
Primary Substation - Military Base	$ 13.392
Energy Charge	$ 0.03665
Unbundled Rates	
BSC $/day	$ 0.601
Metering per day	
Self-Contained	$ 0.395
Instrument-Rated	$ 1.036
Primary Voltage	$ 3.088
Transmission Voltage	$ 25.421
Meter Reading	$ 0.066
Billing	$ 0.073
System Benefits Charge	
kWh	$ 0.00297
Transmission Charge	
kW	$ 1.776
Delivery Charge	
Secondary Service	$ 8.027
Primary Service	$ 6.746
Transmission Service	$ 0.375
Primary Substation - Military Base	$ 1.489
Generation Charge	
kW	$ 10.127
kWh	$ 0.03368

Settlement Rate Summary for General Service Rates

		E-35 Proposed
Bundled Rates		
BSC $/day		
Self-Contained	$	1.183
Instrument-Rated	$	1.795
Primary Voltage	$	3.881
Transmission Voltage	$	26.574
Demand Charge		
Secondary Service		
On-Peak	$	16.768
Off-Peak	$	3.064
Primary Service		
On-Peak	$	15.792
Off-Peak	$	2.966
Transmission Service		
On-Peak	$	10.755
Off-Peak	$	2.462
Primary Substation - Military Base		
On-Peak	$	12.108
Off-Peak	$	2.597
Energy Charge		
On-Peak	$	0.04076
Off-Peak	$	0.03219
Unbundled Rates		
BSC $/day	$	0.601
Revenue Cycle Service Charges		
Self-Contained	$	0.440
Instrument-Rated	$	1.052
Primary Voltage	$	3.138
Transmission Voltage	$	25.831
Meter Reading	$	0.068
Billing	$	0.074
System Benefits Charge		
kWh	$	0.00297
Transmission Charge		
On-Peak kW	$	1.776
Delivery Charge		
Secondary Service		
On-Peak	$	6.461
Off-Peak	$	0.646
Primary Service		
On-Peak	$	5.485
Off-Peak	$	0.548
Transmission Service		
On-Peak	$	0.448
Off-Peak	$	0.044
Primary Substation - Military Base		
On-Peak	$	1.801
Off-Peak	$	0.179
Generation Charge		
On-Peak kW	$	8.531
Off-Peak kW	$	2.418
On-Peak kWh	$	0.03779
Off-Peak kWh	$	0.02922

E-54		
Minimum 12-Month Charge	$	603.49

Interruptible Rate Ride (IRR)				Proposed
1 Yr Agreement				
Option 1	(4 hrs)	30 Minute ($/kW-Yr)	$	7.975
		30 Minute ($/kWh)	$	0.09969
		2 Hour ($/kW-Yr)	$	7.178
		2 Hour ($/kWh)	$	0.08972
Option 2	(8 hrs)	30 Minute ($/kW-Yr)	$	5.995
		30 Minute ($/kWh)	$	0.07493
		2 Hour ($/kW-Yr)	$	5.395
		2 Hour ($/kWh)	$	0.06745
5 Yr Agreement				
Option 1	(4 hrs)	30 Minute ($/kW-Yr)	$	9.882
		30 Minute ($/kWh)	$	0.12353
		2 Hour ($/kW-Yr)	$	8.894
		2 Hour ($/kWh)	$	0.11117
Option 2	(8 hrs)	30 Minute ($/kW-Yr)	$	7.428
		30 Minute ($/kWh)	$	0.09285
		2 Hour ($/kW-Yr)	$	6.685
		2 Hour ($/kWh)	$	0.08356

Settlement Rate Summary for Classified Rates

		E-20 Proposed
Bundled Rates		
Summer		
BSC $/day	$	1.065
On-peak Demand	$	2.391
Excess Demand	$	1.196
On-peak kWh	$	0.14457
Off-peak kWh	$	0.07014
Winter		
BSC $/day	$	1.065
On-peak Demand	$	2.156
Excess Demand	$	1.078
On-peak kWh	$	0.12719
Off-peak kWh	$	0.06294

		E-36 M Proposed	
Unbundled Basic Service Charge:			
For E-32 M and E-32 L			
Self-Contained Meters		$1.344	per day, or
Instrument-Rated Meters		$1.322	per day, or
Primary Voltage Meters		$6.830	per day
Revenue Cycle Service Charges:			
Metering:			
E-32 XS			
Self-Contained Meters	$	0.403	per day, or
Instrument-Rated Meters	$	1.055	per day, or
Primary Voltage Meters:	$	3.146	per day
Meter Reading	$	0.068	per day
Billing	$	0.075	per day
E-32 L			
Self-Contained Meters	$	0.345	per day, or
Instrument-Rated Meters	$	0.904	per day, or
Primary Voltage Meters	$	2.696	per day, or
Transmission	$	22.192	per day
Meter Reading	$	0.058	per day
Billing	$	0.064	per day

		E-36 XL Proposed	
BSC	$	6,912	monthly
Secondary	$	3.605	$/kW
Primary	$	3.423	$/kW
Transmission	$	0.035	$/kW
Power Supply			
Uplift Charge	$	0.00057	kWh
(plus hourly pricing proxy)			

Settlement Rate Summary for Classified Rates

Company Owned Fixture Type		E-47 Proposed
9500 HPS ACORN	$	27.06
16,000 HPS ACORN	$	30.04
9500 HPS ARCHITECTURAL	$	15.38
16,000 HPS ARCHITECTURAL	$	17.96
30,000 HPS ARCHITECTURAL	$	21.31
50,000 HPS ARCHITECTURAL	$	26.29
14,000 MH ARCHITECTURAL	$	21.51
21,000 MH ARCHITECTURAL	$	24.42
36,000 MH ARCHITECTURAL	$	30.54
8,000 LPS ARCHITECTURAL	$	22.35
13500 LPS ARCHITECTURAL	$	26.36
22,500 LPS ARCHITECTURAL	$	30.11
33,000 LPS ARCHITECTURAL	$	36.22
5800 HPS COBRA/ROADWAY	$	8.73
9500 HPS COBRA/ROADWAY	$	10.28
16,000 HPS COBRA/ROADWAY	$	12.87
30,000 HPS COBRA/ROADWAY	$	15.52
50,000 HPS COBRA/ROADWAY	$	21.06
14,000 MH COBRA/ROADWAY	$	14.97
21,000 MH COBRA/ROADWAY	$	17.49
36,000 MH COBRA/ROADWAY	$	23.03
8,000 FL COBRA/ROADWAY	$	17.20
9500 HPS DECORATIVE TRANSIT	$	37.09
16,000 HPS DECORATIVE TRANSIT	$	36.88
30,000 HPS DECORATIVE TRANSIT	$	42.46
30,000 HPS FLOOD	$	20.61
50,000 HPS FLOOD	$	25.56
21,000 MH FLOOD	$	22.00
36,000 MH FLOOD	$	26.82
8,000 FL COLONIAL GRAY POST TOP	$	18.54
9500 HPS COLONIAL GRAY POST TOP	$	10.60
9500 HPS COLONIAL BLACK POST TOP	$	12.21
9500 HPS DECORATIVE POST TOP	$	32.47
4,000 INC FROZEN	$	9.78
7,000 MV FROZEN	$	12.67
20,000 MV FROZEN	$	24.92
BRACKETS FROZEN	$	1.72
Trip Charge per Lamp	$	100.00

Customer Owned Lamp Type		E-47 Proposed
9500 HPS ACORN	$	9.22
16,000 HPS ACORN	$	11.65
9500 HPS ARCHITECTURAL	$	7.34
16,000 HPS ARCHITECTURAL	$	9.82
30,000 HPS ARCHITECTURAL	$	12.60
50,000 HPS ARCHITECTURAL	$	18.13
14,000 MH ARCHITECTURAL	$	11.79
21,000 MH ARCHITECTURAL	$	14.54
36,000 MH ARCHITECTURAL	$	20.00
8,000 LPS ARCHITECTURAL	$	9.82
13500 LPS ARCHITECTURAL	$	11.84
22,500 LPS ARCHITECTURAL	$	14.45
33,000 LPS ARCHITECTURAL	$	17.02
5800 HPS COBRA/ROADWAY	$	5.16
9500 HPS COBRA/ROADWAY	$	6.32
16,000 HPS COBRA/ROADWAY	$	8.82
30,000 HPS COBRA/ROADWAY	$	11.46
50,000 HPS COBRA/ROADWAY	$	16.37
14,000 MH COBRA/ROADWAY	$	10.20
21,000 MH COBRA/ROADWAY	$	12.69
36,000 MH COBRA/ROADWAY	$	17.63
8,000 FL COBRA/ROADWAY	$	5.04
9500 HPS DECORATIVE TRANSIT	$	11.11
16,000 HPS DECORATIVE TRANSIT	$	6.31
30,000 HPS DECORATIVE TRANSIT	$	16.02
30,000 HPS FLOOD	$	12.81
50,000 HPS FLOOD	$	17.77
21,000 MH FLOOD	$	13.53
36,000 MH FLOOD	$	18.35
8,000 FL COLONIAL GRAY POST TOP	$	5.23
9500 HPS COLONIAL GRAY POST TOP	$	6.65
9500 HPS COLONIAL BLACK POST TOP	$	6.88
9500 HPS DECORATIVE POST TOP	$	10.24
4,000 INC FROZEN	$	5.47
7,000 MV FROZEN	$	7.27
20,000 MV FROZEN	$	14.12
BRACKETS FROZEN	$	-
Trip Charge per Lamp	$	100.00

Company Owned Pole Type		E-47 Proposed
Anchor Flush, Round, 1X, 12ft	$	12.17
Anchor Flush, Round, 1X, 22ft	$	13.70
Anchor Flush, Round, 1X, 25ft	$	14.82
Anchor Flush, Round, 1X, 30ft	$	17.03
Anchor Flush, Round, 1X, 32ft	$	17.89
Anchor Flush, Round, 2X, 12ft	$	12.98
Anchor Flush, Round, 2X, 22ft	$	14.91
Anchor Flush, Round, 2X, 25ft	$	15.55
Anchor Flush, Round, 2X, 30ft	$	18.07
Anchor Flush, Round, 2X, 32ft	$	19.28
Anchor Flush, Square, 5", 13ft	$	13.95
Anchor Flush, Square, 5", 15ft	$	12.47
Anchor Flush, Square, 5", 23ft	$	14.79
Anchor Flush, Square, 5", 25ft	$	16.26
Anchor Flush, Square, 5", 28ft	$	18.05
Anchor Flush, Square, 5", 32ft	$	17.95
Anchor Flush, Concrete, 12ft	$	41.58
Anchor Flush, Fiberglass, 12ft	$	35.21
Anchor Flush, Dec Transit Ped, 4", 16f	$	34.33
Anchor Flush, Dec Transit, 6", 30ft	$	66.28
Anchor Pedstl, Round, 1X, 12ft	$	11.71
Anchor Pedstl, Round, 1X, 22ft	$	13.24
Anchor Pedstl, Round, 1X, 25ft	$	14.35
Anchor Pedstl, Round, 1X, 30ft	$	16.58
Anchor Pedstl, Round, 1X, 32ft	$	17.41
Anchor Pedstl, Round, 2X, 12ft	$	12.51
Anchor Pedstl, Round, 2X, 22ft	$	13.97
Anchor Pedstl, Round, 2X, 25ft	$	15.08
Anchor Pedstl, Round, 2X, 30ft	$	17.61
Anchor Pedstl, Round, 2X, 32ft	$	18.81
Anchor Pedstl, Round, 3 Bolt, 32ft	$	21.62
Anchor Pedstl, Square, 5", 13ft	$	13.50
Anchor Pedstl, Square, 5", 15ft	$	13.80
Anchor Pedstl, Square, 5", 23ft	$	14.32
Anchor Pedstl, Square, 5", 25ft	$	15.80
Anchor Pedstl, Square, 5", 28ft	$	17.56
Anchor Pedstl, Square, 5", 32ft	$	18.23
Direct Bury, Round, 19ft	$	18.42
Direct Bury, Round, 30ft	$	14.38
Direct Bury, Round, 38ft	$	17.55
Direct Bury, Self-Support, 40ft	$	21.62
Direct Bury, Stepped, 49ft	$	64.99
Direct Bury, Square, 4", 34ft	$	15.87
Direct Bury, Square, 5", 20ft	$	15.07
Direct Bury, Square, 5" 30ft	$	15.71
Direct Bury, Square, 5" 38ft	$	17.05
Deecorative Transit 41- 6	$	20.47
Deecorative Transit 47	$	25.50
Direct Bury, Steel Dist Pole, 35ft	$	23.54
Post Top, Dec Transit, 16ft	$	35.07
Post Top, Gray Steel/Fiberglass, 23ft	$	12.16
Post Top, Black Steel, 23ft	$	13.41
FROZEN, Wood Poles, 30ft	$	8.95
FROZEN, Wood Poles, 35ft	$	8.95
FROZEN, Wood Poles, 40ft	$	12.73
Flush, 4ft	$	9.91
Flush, 6ft	$	11.82
Pedestal, 8ft	$	13.54
Pedestal, 32' round steel pole, 4ft 6"	$	9.39
1. 100' OH, UG if conduit by custome:	$	3.50
2. HPS not accessible by bucket	$	2.80
3. MH not accessible by bucket	$	6.04

Settlement Rate Summary for Classified Rates

		E-56 Proposed	
Back-up Power			
Rate Schedule E-34 Customer	$	0.590	per kW day
Rate Schedule E-32 L Customer	$	0.120	per kW day
Excess Power Charges			
Secondary Service:	$	54.802	per kW
Primary Service:	$	52.019	per kW
Transmission Service:	$	38.187	per kW

Company Owned Lamp Type		E-58 Proposed	Customer Owned Lamp Type		E-58 Proposed
9500 HPS ACORN	$	27.06	9500 HPS ACORN	$	9.22
16,000 HPS ACORN	$	30.04	16,000 HPS ACORN	$	11.65
9500 HPS ARCHITECTURAL	$	15.38	9500 HPS ARCHITECTURAL	$	7.34
16,000 HPS ARCHITECTURAL	$	17.96	16,000 HPS ARCHITECTURAL	$	9.82
30,000 HPS ARCHITECTURAL	$	21.31	30,000 HPS ARCHITECTURAL	$	12.60
50,000 HPS ARCHITECTURAL	$	26.29	50,000 HPS ARCHITECTURAL	$	18.13
14,000 MH ARCHITECTURAL	$	21.51	14,000 MH ARCHITECTURAL	$	11.79
21,000 MH ARCHITECTURAL	$	24.42	21,000 MH ARCHITECTURAL	$	14.54
36,000 MH ARCHITECTURAL	$	30.54	36,000 MH ARCHITECTURAL	$	20.00
8,000 LPS ARCHITECTURAL	$	22.35	8,000 LPS ARCHITECTURAL	$	9.82
13500 LPS ARCHITECTURAL	$	26.36	13500 LPS ARCHITECTURAL	$	11.84
22,500 LPS ARCHITECTURAL	$	30.11	22,500 LPS ARCHITECTURAL	$	14.45
33,000 LPS ARCHITECTURAL	$	36.22	33,000 LPS ARCHITECTURAL	$	17.02
5800 HPS COBRA/ROADWAY	$	8.73	5800 HPS COBRA/ROADWAY	$	5.16
9500 HPS COBRA/ROADWAY	$	10.28	9500 HPS COBRA/ROADWAY	$	6.32
16,000 HPS COBRA/ROADWAY	$	12.87	16,000 HPS COBRA/ROADWAY	$	8.82
30,000 HPS COBRA/ROADWAY	$	15.52	30,000 HPS COBRA/ROADWAY	$	11.46
50,000 HPS COBRA/ROADWAY	$	21.06	50,000 HPS COBRA/ROADWAY	$	16.37
14,000 MH COBRA/ROADWAY	$	14.97	14,000 MH COBRA/ROADWAY	$	10.20
21,000 MH COBRA/ROADWAY	$	17.49	21,000 MH COBRA/ROADWAY	$	12.69
36,000 MH COBRA/ROADWAY	$	23.03	36,000 MH COBRA/ROADWAY	$	17.63
8,000 FL COBRA/ROADWAY	$	17.20	8,000 FL COBRA/ROADWAY	$	5.04
9500 HPS DECORATIVE TRANSIT	$	37.09	9500 HPS DECORATIVE TRANSIT	$	11.11
16,000 HPS DECORATIVE TRANSIT	$	36.88	16,000 HPS DECORATIVE TRANSIT	$	12.41
30,000 HPS DECORATIVE TRANSIT	$	42.46	30,000 HPS DECORATIVE TRANSIT	$	16.02
30,000 HPS FLOOD	$	20.61	30,000 HPS FLOOD	$	12.81
50,000 HPS FLOOD	$	25.56	50,000 HPS FLOOD	$	17.77
21,000 MH FLOOD	$	22.00	21,000 MH FLOOD	$	13.53
36,000 MH FLOOD	$	26.82	36,000 MH FLOOD	$	18.35
8,000 FL COLONIAL GRAY POST TOP	$	18.54	8,000 FL COLONIAL GRAY POST TOP	$	5.23
9500 HPS COLONIAL GRAY POST TOP	$	10.60	9500 HPS COLONIAL GRAY POST TOP	$	6.65
9500 HPS COLONIAL BLACK POST TOP	$	12.21	9500 HPS COLONIAL BLACK POST TOP	$	6.88
9500 HPS DECORATIVE POST TOP	$	32.47	9500 HPS DECORATIVE POST TOP	$	10.24
4,000 INC FROZEN	$	9.78	4,000 INC FROZEN	$	5.47
7,000 MV FROZEN	$	12.67	7,000 MV FROZEN	$	7.27
11,000 MV FROZEN	$	15.87	11,000 MV FROZEN	$	9.68
20,000 MV FROZEN	$	24.92	20,000 MV FROZEN	$	14.12
Trip Charge per Lamp	$	100.00	Trip Charge per Lamp	$	100.00

Settlement Rate Summary for Classified Rates

Company Owned Pole Type		E-58 Proposed	Customer Owned Pole Type		E-58 Proposed
Anchor Flush, Round, 1X, 12ft	$	12.17	Anchor Flush, Round, 1X, 12ft	$	1.68
Anchor Flush, Round, 1X, 22ft	$	13.70	Anchor Flush, Round, 1X, 22ft	$	1.88
Anchor Flush, Round, 1X, 25ft	$	14.82	Anchor Flush, Round, 1X, 25ft	$	2.05
Anchor Flush, Round, 1X, 30ft	$	17.03	Anchor Flush, Round, 1X, 30ft	$	2.34
Anchor Flush, Round, 1X, 32ft	$	17.89	Anchor Flush, Round, 1X, 32ft	$	2.37
Anchor Flush, Round, 2X, 12ft	$	12.98	Anchor Flush, Round, 2X, 12ft	$	1.79
Anchor Flush, Round, 2X, 22ft	$	14.91	Anchor Flush, Round, 2X, 22ft	$	2.06
Anchor Flush, Round, 2X, 25ft	$	15.55	Anchor Flush, Round, 2X, 25ft	$	2.14
Anchor Flush, Round, 2X, 30ft	$	18.07	Anchor Flush, Round, 2X, 30ft	$	2.49
Anchor Flush, Round, 2X, 32ft	$	19.28	Anchor Flush, Round, 2X, 32ft	$	2.66
Anchor Flush, Square, 5", 13ft	$	13.95	Anchor Flush, Square, 5", 13ft	$	1.92
Anchor Flush, Square, 5", 15ft	$	12.47	Anchor Flush, Square, 5", 15ft	$	1.72
Anchor Flush, Square, 5", 23ft	$	14.79	Anchor Flush, Square, 5", 23ft	$	2.03
Anchor Flush, Square, 5", 25ft	$	16.26	Anchor Flush, Square, 5", 25ft	$	2.23
Anchor Flush, Square, 5", 28ft	$	18.05	Anchor Flush, Square, 5", 28ft	$	2.48
Anchor Flush, Square, 5", 32ft	$	17.95	Anchor Flush, Square, 5", 32ft	$	2.47
Anchor Flush, Concrete, 12ft	$	41.58	Anchor Flush, Concrete, 12ft	$	5.73
Anchor Flush, Fiberglass, 12ft	$	35.21	Anchor Flush, Fiberglass, 12ft	$	4.85
Anchor Flush, Dec Transit Ped, 4", 16ft	$	34.33	Anchor Flush, Dec Transit Ped, 4", 16ft	$	4.73
Anchor Flush, Dec Transit, 6", 30ft	$	66.28	Anchor Flush, Dec Transit, 6", 30ft	$	9.13
Anchor Pedstl, Round, 1X, 12ft	$	11.71	Anchor Pedstl, Round, 1X, 12ft	$	1.61
Anchor Pedstl, Round, 1X, 22ft	$	13.24	Anchor Pedstl, Round, 1X, 22ft	$	1.82
Anchor Pedstl, Round, 1X, 25ft	$	14.35	Anchor Pedstl, Round, 1X, 25ft	$	1.98
Anchor Pedstl, Round, 1X, 30ft	$	16.58	Anchor Pedstl, Round, 1X, 30ft	$	2.29
Anchor Pedstl, Round, 1X, 32ft	$	17.41	Anchor Pedstl, Round, 1X, 32ft	$	2.40
Anchor Pedstl, Round, 2X, 12ft	$	12.51	Anchor Pedstl, Round, 2X, 12ft	$	1.72
Anchor Pedstl, Round, 2X, 22ft	$	13.97	Anchor Pedstl, Round, 2X, 22ft	$	1.92
Anchor Pedstl, Round, 2X, 25ft	$	15.08	Anchor Pedstl, Round, 2X, 25ft	$	2.07
Anchor Pedstl, Round, 2X, 30ft	$	17.61	Anchor Pedstl, Round, 2X, 30ft	$	2.42
Anchor Pedstl, Round, 2X, 32ft	$	18.81	Anchor Pedstl, Round, 2X, 32ft	$	2.59
Anchor Pedstl, Round, 3 Bolt, 32ft	$	21.62	Anchor Pedstl, Round, 3 Bolt, 32ft	$	2.97
Anchor Pedstl, Square, 5", 13ft	$	13.50	Anchor Pedstl, Square, 5", 13ft	$	1.86
Anchor Pedstl, Square, 5", 15ft	$	13.80	Anchor Pedstl, Square, 5", 15ft	$	1.89
Anchor Pedstl, Square, 5", 23ft	$	14.32	Anchor Pedstl, Square, 5", 23ft	$	1.98
Anchor Pedstl, Square, 5", 25ft	$	15.80	Anchor Pedstl, Square, 5", 25ft	$	2.19
Anchor Pedstl, Square, 5", 28ft	$	17.56	Anchor Pedstl, Square, 5", 28ft	$	2.42
Anchor Pedstl, Square, 5", 32ft	$	18.23	Anchor Pedstl, Square, 5", 32ft	$	2.50
Direct Bury, Round, 19ft	$	18.42	Direct Bury, Round, 19ft	$	2.54
Direct Bury, Round, 30ft	$	14.38	Direct Bury, Round, 30ft	$	2.66
Direct Bury, Round, 38ft	$	17.55	Direct Bury, Round, 38ft	$	2.73
Direct Bury, Self-Support, 40ft	$	21.62	Direct Bury, Self-Support, 40ft	$	3.42
Direct Bury, Stepped, 49ft	$	64.99	Direct Bury, Stepped, 49ft	$	8.96
Direct Bury, Square, 4", 34ft	$	15.87	Direct Bury, Square, 4", 34ft	$	2.75
Direct Bury, Square, 5", 20ft	$	15.07	Direct Bury, Square, 5", 20ft	$	2.49
Direct Bury, Square, 5" 30ft	$	15.71	Direct Bury, Square, 5" 30ft	$	2.59
Direct Bury, Square, 5" 38ft	$	17.05	Direct Bury, Square, 5" 38ft	$	2.96
Deecorative Transit 41- 6	$	20.47	Deecorative Transit 41- 6	$	3.01
Deecorative Transit 47	$	25.50	Deecorative Transit 47	$	3.75
Direct Bury, Steel Dist Pole, 35ft	$	23.54	Direct Bury, Steel Dist Pole, 35ft	$	3.10
Post Top, Dec Transit, 16ft	$	35.07	Post Top, Dec Transit, 16ft	$	4.82
Post Top, Gray Steel/Fiberglass, 23ft	$	12.16	Post Top, Gray Steel/Fiberglass, 23ft	$	2.00
Post Top, Black Steel, 23ft	$	13.41	Post Top, Black Steel, 23ft	$	2.21
FROZEN, Wood Poles, 30ft	$	8.95	FROZEN, Wood Poles, 30ft	$	1.55
FROZEN, Wood Poles, 35ft	$	8.95	FROZEN, Wood Poles, 35ft	$	1.48
Existing distribution pole	$	1.48	Existing distribution pole	$	-
Flush, 4ft	$	9.91	Flush, 4ft	$	1.36
Flush, 6ft	$	11.82	Flush, 6ft	$	2.05
Pedestal, 8ft	$	13.54	Pedestal, 8ft	$	2.36
Pedestal, 32' round steel pole, 4ft 6"	$	9.39	Pedestal, 32' round steel pole, 4ft 6"	$	1.63

E-59 TYPE		Proposed Service Charge Per Lamp		Transmission Proposed Charge Per kWh
1000 INC	$	2.79	$	0.06088
11000 MV	$	2.79	$	0.06088
13500L LPS ARCH	$	2.79	$	0.06088
14000L MH ARCH	$	2.79	$	0.06088
14000L MH ROADWAY	$	2.79	$	0.06088
16000L ACORN	$	2.79	$	0.06088
16000L HPS ARCH	$	2.79	$	0.06088
16000L HPS ROADWAY	$	2.79	$	0.06088
16000 HPS DECORATIVE TRANSIT	$	2.79	$	0.06088
20000L MV	$	2.79	$	0.06088
21000L MH ARCH	$	2.79	$	0.06088
21000L MH FLOOD	$	2.79	$	0.06088
21000L MH ROADWAY	$	2.79	$	0.06088
22500L LPS ARCH	$	2.79	$	0.06088
2500 INC	$	2.79	$	0.06088
30000L HPS ARCH	$	2.79	$	0.06088
30000L HPS FLOOD	$	2.79	$	0.06088
30000L HPS ROADWAY	$	2.79	$	0.06088
33000L LPS ARCH	$	2.79	$	0.06088
36000L MH ARCH	$	2.79	$	0.06088
36000L MH FLOOD	$	2.79	$	0.06088
36000L MH ROADWAY	$	2.79	$	0.06088
4000 INC	$	2.79	$	0.06088
50000L HPS ARCH	$	2.79	$	0.06088
50000L HPS FLOOD	$	2.79	$	0.06088
50000L HPS ROADWAY	$	2.79	$	0.06088
5800 HPS ROADWAY	$	2.79	$	0.06088
6000 INC	$	2.79	$	0.06088
7000 MV	$	2.79	$	0.06088
8000L LPS ARCH	$	2.79	$	0.06088
9500L HPS ACORN	$	2.79	$	0.06088
9500L HPS ARCH	$	2.79	$	0.06088
9500L HPS COBRA/ROADWAY	$	2.79	$	0.06088
9500L HPS POST TOP BLACK	$	2.79	$	0.06088
9500L HPS POST TOP GRAY	$	2.79	$	0.06088
2300 LED COBRA	$	2.79	$	0.06088
Trip Charge per Lamp	$	100.00		

Settlement Rate Summary for Classified Rates

	E-67 Proposed
$/kWh	$ 0.05193

	Bundled Rates	E-221 Proposed
E-221	BSC $/day	$ 0.588
	kW	$ 2.357
	kWh Block 1	$ 0.11228
	kWh Block 2	$ 0.07633
	kWh Block 3	$ 0.06270
Minimum	BSC $/day	$ 0.558
	kW	$ 2.357
E-221-8T	BSC $/day	$ 0.964
	On-Peak kW	$ 5.608
	Off-Peak kW	$ 3.351
	On-Peak kWh	$ 0.09205
	Off-Peak kWh	$ 0.04952
Minimum	BSC $/day	$ 0.964
	kW	$ 3.351

Bundled Rates	GS-SCHOOLS M Proposed	GS-SCHOOLS L Proposed
BSC $/day		
Self-Contained	$ 0.672	$ 1.068
Instrument-Rated	$ 1.324	$ 1.627
Primary Voltage	$ 3.415	$ 3.419
Transmission Voltage	$ 26.163	$ 22.915
Demand Charge		
1st 100 kW (Secondary)	$ 9.612	$ 9.311
Over 100 kW (Secondary)	$ 5.113	$ 4.954
1st 100 kW (Primary)	$ 8.919	$ 8.636
Over kW (Primary)	$ 4.419	$ 4.282
1st 100 kW (Transmission)	$ 6.953	$ 6.736
Over kW (Transmission)	$ 2.454	$ 2.377
Energy Charge		
Summer Peak (Jun-Aug)		
On-Pk kWh	$ 0.17343	$ 0.15355
Should-Pk kWh	$ 0.12847	$ 0.11374
Off-Pk kWh	$ 0.06487	$ 0.06285
Summer Shoulder (May, Sep & Oct)		
On-Pk kWh	$ 0.14977	$ 0.13260
Should-Pk kWh	$ 0.11095	$ 0.09821
Off-Pk kWh	$ 0.05602	$ 0.05428
Winter (Nov-Apr)		
On-Pk kWh	$ 0.11607	$ 0.10276
Should-Pk kWh	$ 0.08599	$ 0.07612
Off-Pk kWh	$ 0.04342	$ 0.04206

Settlement Rate Summary for Classified Rates

Community Power - Flagstaff (CMPW-01)

Solar Charge $/kWh		
Applicable Rate Schedules		
E-12	$	0.11242
ET-2	$	0.13480
E-32 S, E-32 M, E-32 L	$	0.09293
E-32TOU S, E-32TOU M, E-32TOU L	$	0.05855

Rural School Solar Program (RSSP)

Solar Charge $/kWh		
Applicable Rate Schedules		
E-32 S, E-32 M, E-32 L	$	0.09293
E-32TOU S, E-32TOU M, E-32TOU L	$	0.05855
GS-SCHOOLS M, GS-SCHOOLS L	$	0.07158

E-56 R

SC-S renamed
Charges are per special contract

Contract 12

	Proposed
Per Delivery Point $	16.44
$/kWh $	0.08479

Settlement Rate Summary for Low Income Discounts

E-3 Discount	Proposed
block1 (0-400 kWh)	65.0%
block2 (400-800 kWh)	45.0%
block3 (800-1200 kWh)	26.0%
block4 (over 1200 kWh) $/bill	31.75
E-4 Discount	
block1 (0-800 kWh)	65.0%
block2 (800-1400 kWh)	45.0%
block3 (1400-2000 kWh)	26.0%
block4 (over 2000 kWh) $/bill	$ 60.00