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August 11, 2009

Docket Control
Arizona Corporation Commission
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Phoenix, Arizona 85007

RE: ARIZONA PUBLIC SERVICE COMPANY ADDITIONAL SUPPLEMENTAL DIRECT TESTIMONY IN SUPPORT OF SETTLEMENT AGREEMENT
DOCKET NO. E-01345A-08-0172

Attached is Additional Supplemental Direct Settlement Testimony of Arizona Public Service Company witness David J. Rumolo. This testimony supplements the Direct Settlement Testimony that was previously filed on July 1, 2009 in this matter.

Sincerely,

Leland R. Snook

Leland R. Snook

LS/dst

Attachments

CC: Brian Bozzo
Terri Ford
Barbara Keene
Parties of Record

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ADDITIONAL SUPPLEMENTAL DIRECT SETTLEMENT TESTIMONY

OF DAVID J. RUMOLO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

August 11, 2009

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ADDITIONAL SUPPLEMENTAL DIRECT SETTLEMENT TESTIMONY OF DAVID J. RUMOLO

ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (Docket No. E-01345A-08-0172)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David J. Rumolo. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. ARE YOU THE SAME DAVID J. RUMOLO WHO PREVIOULSY FILED DIRECT TESTIMONY IN SUPPORT OF ARIZONA PUBLIC SERVICE COMPANY'S APPLICATION, DIRECT SETTLEMENT TESTIMONY, AND SUPPLEMENTAL TESTIMONY IN THIS DOCKET?

A. Yes, I filed Direct Testimony in support of Arizona Public Service Company's ("APS" or "Company") application for rate relief, Direct Settlement Testimony in support of the proposed Settlement Agreement ("Agreement") and Supplemental Testimony.

Q. WHAT IS THE PURPOSE OF YOUR ADDITIONAL SUPPLEMENTAL DIRECT SETTLEMENT TESTIMONY?

A. My Direct Settlement Testimony discussed the Plan of Administration ("POA") for the Demand Side Management Adjustment Charge (DSMAC) and the POA for the Power Supply Adjustment ("PSA"). The proposed Agreement rate schedules and service schedules were filed in this docket for review and comment. APS has received comments on the DSMAC POA and the PSA POA from the Staff of the Arizona Corporation Commission ("Staff"). Staff comments have been incorporated into the respective POAs.

My Additional Supplemental Testimony also provides a revised proposed line extension policy, Service Schedule 3. This revised policy incorporates comments APS has received from Staff.

II. PLANS OF ADMINISTRATION

Q. HAS APS DEVELOPED A REVISED DSMAC POA AND PSA POA?

A. Yes, the revised DSMAC POA and supporting schedules are attached to this Additional Supplemental Testimony and marked Attachment DJR-3-S (Supplemental). Similarly, the PSA POA has been attached and marked Attachment DJR-4-S(Supplemental).

Q. ARE THE CHANGES TO THE PLANS OF ADMINISTRATION SUBSTANTIVE?

A. No, they are primarily editorial and provide further clarification as to the mechanical aspects of the plans.

III. SERVICE SCHEDULE 3

Q. ARE YOU PROPOSING ANY OTHER CHANGES TO PREVIOUSLY FILED DOCUMENTS?

A. Yes. Attachment DJR-5-S(Supplemental) consists of a revised proposed Service Schedule 3 which is the APS line extension policy. The revisions consist of language changes suggested by Staff that capture language found in the Agreement. We have also eliminated the Statement of Charges that were proposed for 2011 and 2012. The Statement of Charges for 2010 will be effective until the next APS general rate case.

Q. DOES THIS CONCLUDE YOUR ADDITIONAL SUPPLEMENTAL DIRECT SETTLEMENT TESTIMONY?

A. Yes.

DEMAND SIDE MANAGEMENT ADJUSTMENT CHARGE PLAN OF ADMINISTRATION 2009-~~06~~08-~~24~~11

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 No. XXXXX. 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~~ 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, unless otherwise noted in any rate schedule~~ retail Standard Offer or Direct Access service with the exception of customers served on rate schedules E-3 and E-4, and solar rate Solar-2.

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~~ cost-effective DSM programs (energy efficiency and demand response) that are approved ~~or are pending approval~~ 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 an allowed program expense.

B. **Performance Incentives (PI)** — Represents a percentage share of the net economic benefits (benefits minus costs) from approved ~~and pending~~ energy-efficiency programs based on a graduated scale that is capped at a percentage of PC.

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 ~~are~~ 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 ~~April 30th~~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~~4/30/2009~~
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~~4/30/2010~~
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~~4/30/2011~~

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:

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

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.

DEMAND SIDE MANAGEMENT ADJUSTMENT CHARGE PLAN OF ADMINISTRATION

2009-~~06~~08-~~24~~11

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.

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") ~~adjustor~~ 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.

ARIZONA PUBLIC SERVICE COMPANY
DEMAND SIDE MANAGEMENT PROGRAM
DSMAC REVENUE AND EXPENSE BY MONTH

Line No.	True-Up Period[1]	(A) 3/31/20xx	(B) 4/30/20xx	(C) 5/31/20xx	(D) 6/30/20xx	(E) 7/31/20xx	(F) 8/31/20xx	(G) 9/30/20xx	(H) 10/31/20xx	(I) 11/30/20xx	(J) 12/31/20xx	(K) 1/31/20xx	(L) 2/28/20xx
1	Beginning Balance[2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	True-Up Balance[3]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Actual Costs[4]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Non-Demand Billed kWh	-	-	-	-	-	-	-	-	-	-	-	-
5	Demand Billed kW	-	-	-	-	-	-	-	-	-	-	-	-
6	$/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	$/kW	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	DSMAC Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Ending Balance[6]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

[1] True-Up Period reflects the charge period of March 20xx - February 20xx.
[2] Beginning Balance column A reflects the total amount of money spent January and February of 20xx over the amount collected in base rates. For the first few years this may be slightly different to reflect the change of a historical DSMAC to a more concurrent DSMAC.
[3] True-Up Balance column A reflects the amount of dollars that were to be collected or credited during the true-up period.
[4] Actual Costs reflects the actual program costs during that period.
[5] Line 8 = Line 4 * Line 6 + Line 5 * Line 7
[6] Line 9 = Line 1 + Line 2 + Line 3 - Line 8

ARIZONA PUBLIC SERVICE COMPANY
DEMAND SIDE MANAGEMENT PROGRAM

FORECAST PROGRAM COSTS AND INCENTIVES
FOR PROGRAM YEAR 20xx

Line No.	Program	Reference	Program Costs Forecast 20xx[1][2]
1	Energy Efficiency (EE) Program Costs (PC)		$ -
2	Performance Incentives (PI)		$ -
3	Sub Total	(Line 1 + Line 2)	$ -
4	Demand Response (DR) PC		$ -
5	Total	(Line 3 + Line 4)	$ -

[1]This is the forecast cost for EE PC, PI and DR PC based on the 20xx Implementation plan, less the amount to be collected in base rates.
[2]For the first filing this will reflect two years of forecast costs as we move from a historical DSMAC to a more concurrent DSMAC

ARIZONA PUBLIC SERVICE COMPANY
DEMAND SIDE MANAGEMENT PROGRAM

TRUE-UP (TU) BALANCING COMPUTATION

Line No.	Date Period	Cost, Collection and Interest	Reference	Amount
1	2/28/20xx	True-Up Period Ending Balance	Schedule 1, Line 9, Column L	$ -
2	Treasury constant maturities rate 1/2/2009[1]	Interest = 0.4%	(Line 1 * Interest Rate)	$ -
3		Total TU Balance	(Line 1 + Line 2)	$ -

[1]Interest is only applied to over-collections.

ARIZONA PUBLIC SERVICE COMPANY
DEMAND SIDE MANAGEMENT PROGRAM

DSMAC CALCULATION
FOR
MARCH 1, 20xx THROUGH FEBRUARY 28, 20xx

Line No.	DSMAC Calculations	Reference	Amount	Units
1	Program forecast costs for adjustor period in 20xx	Schedule 2, Line 5	$ -	
2	True-Up Balance	Schedule 3, Line 3	$ -	
3	Total amount to be collected	(Line 1 + Line 2)	$ -	
4	Forecast retail kWh sales for adjustor period[1]		-	kWh
5	Proposed kWh adjustor charge for adjustor period[2]	(Line 3 / Line 4)	$ -	per kWh
6	Forecast General Service kWh sales for adjustor period[3]		-	kWh
7	Amount to be collected from General Service demand metered customers for adjustor period	(Line 5 * Line 6)	$ -	
8	Forecast General Service demand metered customer kW		-	kW
9	Proposed kW adjustor charge for forecast period[4]	(Line 7 / Line 8)	$ -	per kW

[1]Forecast retail kWh sales excludes E-3 and E-4 kWh.
[2]$/kWh charge for all Residential customers and General Service customers with no demand charge.
[3]Forecast General Service kWh for customers with demand charges.
[4]$/kW charge for General Service customers with demand charges.

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 and amended by the Commission on XXXXX 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 ($0.037571 per kWh) authorized in Decision No. XXXXX, from January 1,2010. 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 (($0.000242) 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 ("~~Deferrable~~PSA Costs") to set a rate that is then reconciled to actual costs experienced. This PSA includes a 90/10 sharing mechanism under which APS absorbs 10 percent of the deviations between actual fuel and purchased power costs and the amount recovered through base rates. The demand component of long-term purchased power agreements (duration of three years or longer) acquired via a competitive procurement process, renewable energy costs not recovered through other mechanisms, and net margins from the sales of emission allowances are exempt from the 90/10 sharing. This PSA includes a limit of $0.004 per kilowatt-hour (kWh) on the amount the PSA rate may change in any one year. 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.

2. PSA Components

The PSA Rate will consist of three components designed to provide for the recovery of actual,

[1] *($0.000242) per kWh is the result of the following: (Normalized gains from SO2 allowances of ($7,044,934))/(ACC jurisdictional test year sales of 29,133,753 mWh)/1000.*

prudently incurred ~~Deferrable~~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) ~~deferrable~~PSA C~~c~~osts 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 a mid-year change 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, 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~~n~~ 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 proposed calculation of the three components of the 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) ~~deferrable~~PSA ~~costs~~ Costs embedded in base rates and (2) the ~~forecasted~~forecast ~~deferrable~~PSA ~~costs~~ 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 ~~deferrable~~PSA ~~costs~~Costs. It will also submit a forecast of kWh sales for the same calendar year, and divide the ~~forecasted~~forecast costs by the ~~forecasted~~forecast sales to produce the cents/kWh unit rate required to collect those costs over those sales. The result of subtracting the Base ~~Deferrable~~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 ~~deferrable~~PSA ~~costs~~ Costs as compared

[1] ($0.000242) per kWh is the result of the following: (Normalized gains from SO2 allowances of ($7,044,934))/(ACC jurisdictional test year sales of 29,133,753 mWh)/1000.

to the Base ~~Deferrable~~PSA Costs recovered in revenue. The over/under-recovery of costs is divided into two separate calculations to allow the application of the 90/10 sharing mechanism on those costs to which it applies. 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 3 1 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 ~~forecasted~~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[1]. 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.[2]

[1] 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.
[2] 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.

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 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, Staff, or the Commission on its own motion retain the ability to request at any time a 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.

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. The PSA rate shall be applicable to APS' retail electric rate schedules (with the exception of ~~Solar-1,~~ Solar-2~~, SP-1~~, E-3, E-4, E-36, 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 ~~deferrable~~PSA ~~costs~~ 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.[3]

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.[4]

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.

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

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[3] 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.

[4] 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.

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 - Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15. The interest rate is adjusted annually on the first business day of the calendar year.

Base ~~Deferrable~~PSA Costs- An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost and net margins from the sales of emission allowances embedded in the base rates as approved by the Commission in APS' most recent rate case. The Base ~~Deferrable~~PSA Costs recovered in base revenue is the approved rate per kWh times the applicable sales volumes. Decision No. XXXXX set the base cost at $0.037571 per kWh effective on January 1, 2010.

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' most recent rate case. The Base Net Margins on the Sale of Emission Allowances is set at (($0.000242) per kWh) effective on January 1, 2010.

~~Deferrable~~PSA Costs- The combination of System Book Fuel and Purchased Power Costs net of the System Book Off-System Sales Revenues plus the N~~n~~et M~~m~~argins on the S~~s~~ales 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 ~~forecasted~~forecast ~~deferrable~~PSA ~~costs~~ Costs generally expressed as a rate per kWh less the Base ~~Deferrable~~PSA Costs generally expressed as a rate per kWh embedded in APS' 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' over/under-recovery of its actual ~~deferrable~~PSA ~~costs~~ Costs as compared to the actual Base

~~Deferrable~~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.

PSA - The Power Supply Adjustment mechanism approved by the Commission in Decision No. ~~69633~~69663 and 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 ~~deferrable~~PSA ~~costs~~ 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.

PSA Year - A consecutive 12-month period generally beginning each February 1.

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

System Book Fuel and Purchased Power Costs - 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, 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. ~~69633~~XXXXX.

System Book Off-System Sales Revenue - 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.

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

Transition Component - 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.

Transition Component Tracking Account - 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' 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 Effective February 1, 20~~0~~10
Schedule 2	PSA Forward Component Rate Calculation Effective February 1, 2010
Schedule 3	PSA Year Forward Component Tracking Account (in effect February 1, 2010-January 31, 2011)
Schedule 4	PSA Historical Component Rate Calculation Effective February 1, 2010
Schedule 5	Historical Component Tracking Account (in effect February 1, 20~~0~~10-January 31, 2011)
Schedule 6	PSA Transition Component Rate Calculation
Schedule 7	PSA Transition Tracking Account (in effect XX 1, 20XX-XX 31, 20XX)

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~~b~~. Customer sales in both MWh and thousands of dollars by customer class.
    d~~c~~. Number of customers by customer class.
    e~~d~~. A detailed listing of all items excluded from the PSA calculations.
    f~~e~~. A detailed listing of any adjustments to the adjustor reports.
    g~~f~~. Total off-system sales revenues.
    h~~g~~. System losses in MW and MWh.
    i~~h~~. 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 them, 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.
34. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.
45. 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 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 are excluded from the PSA.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
Power Supply Adjustment (PSA) Rate Calculation Effective February 1, XXXX
($/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 Effective February 1, XXXX
($ 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-3, E-4, E-36 (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]	$ 0.037571	$ -	N/A	N/A
11	Authorized Base Net Margins on the Sale of Emission Allowances Rate $/kWh [4]	$ (0.000242)	$ -	N/A	N/A
12	Total Authorized Base Cost $/kWh	$ 0.037329	$ -	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-36 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 $s and MWh; however, calculations are performed on an actual $ and MWh basis with resultant Rates/kWh rounded up to $0.000000/kWh.

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 L31													
	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-3, E-4, E-36 Sales (MWh) [3]														
	PSA Costs														
7	Renewables Costs [4]														
8	PPA Fixed Costs														
9	Other Fuel and Purchased Power Costs [5]														
10	Off System Revenue (Credit) [6]														
11	Net Margins on Sale of Emission Allowances														
12	Net PSA Costs	sum(L7 to L11)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
	Retail PSA Costs														
13	Renewables Costs	L5 * L7													
14	PPA Fixed Costs	L5 * L8													
15	Other Fuel and Purchased Power Costs	L5 * L9													
16	Off System Revenue (Credit)	L5 * L10													
17	Net Margins on Sale of Emission Allowances	L5 * L11													
18	Net Retail PSA Costs	sum(L13 to L17)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
	Base Rate Power Supply Recovery														
19	Renewables Recovery	L32 * L2													
20	PPA Fixed Recovery	L33 * L2													
21	Other Fuel and Purchased Power Recovery	L34 * L2													
22	Net Margins on Sale of Emission Allowances	L36 * L2													
	(Over) Under Recovery From Base Rate														
23	Renewables (Over) Under Recovery	L13 - L19													
24	PPA Fixed (Over) Under Recovery	L14 - L20													
25	Other Fuel and Purchased Power (Over) Under Recovery	(L15 + L16) - L21													
26	Net Margins on Sale of Emission Allowances (Over) Under Recovery	L17 - L22													
27	Less 10% Sharing On Other (Over) Under Recovery	- 0.10 * L25													
28	Total (Over) Under Recovery	sum(L23 to L27)	-	-	-	-	-	-	-	-	-	-	-	-	
29	Interest Accrued on Prior Month's Balance	L38 * L1													
30	Forward Component Collections	- L37 * L6													
31	Tracking Account Balance	L1 + L28 + L29 - L30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

32	Renewable Costs In Base Fuel Rate - ¢ per kWh	0.0672
33	PPA Fixed Costs In Base Fuel Rate - ¢ per kWh	0.1212
34	Other Costs In Base Fuel Rate - ¢ per kWh	3.0607
35	Total Base Fuel Rate - ¢ per kWh	3.2491
36	Base Net Margin on the Sale of Emission Allowances - ¢ per kWh	-0.0242
37	Forward Component Rate - ¢ per kWh	#.####
38	Interest Rate -- 2010	#.##%

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-36 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-36 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 37 * Line 6 = Line 26; however, differences may occur due to billing adjustments.

E-36 Sales
12,194

2,666,474

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

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4
PSA Historical Component Rate Calculation Effective February 1, XXXX
($ 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, L31)	#,###	$ -	N/A	N/A
2	Historical Component Tracking Account Balance (Schedule 5, 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-3, E-4 and E-36 (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] Includes remaining balances from the Old PSA Annual Adjustor Account ($(4.3) million) and the July 2007 Surcharge Account ($+2.7 million).

Schedule presentation will appear to round up to $s and MWh; however, calculations are performed on an actual $ and MWh 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-3, E-4, E-36 Sales (MWhs) [3]													
8	Less Revenue from Applicable HC (L6 x L7) [4,5]													
9	Monthly Interest ([L5 * L11 / 12])													
10	HC Ending Balance ; (L5 - L8 + L9)	$ -												
11	Interest Rate -- XXXX [5]	#.##%												

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.
[5] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

Schedule presentation will appear to round up to $s and MWh; however, calculations are performed on an actual $ and MWh 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-3, E-4 and E-36 (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 $s and MWh; however, calculations are performed on an actual $ and MWh 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-3, E-4, E-36 Sales (MWhs) [2]			-	-	-	-	-	-	-	-	-	-	-
6	Less Revenue from Applicable Transition Component (L4 x L5) [3]			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Monthly Interest ([L2 * L9 / 12])			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Ending Balance; (L3 - L6 + L7)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Interest Rate [4]	x.xx%												

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.

[4] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

Schedule presentation will appear to round up to $s and MWh; however, calculations are performed on an actual $ and MWh 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.		XXXX Data January	February	March	April	May	June	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	Monthly Interest													
4	Post-Sharing (Over)/Under Collection													
5	Less Revenue from Applicable Forward Component Rate													
6	Ending Balance with Interest (Ln. 1, 2, 3, 4 - Ln. 5)													
	XXXX Historical Component Tracking Account													
7	Beginning Balance													
8	Transfers from XXXX Forward Component Tracking Account													
9	Monthly Interest													
10	Less Revenue from Applicable Historical Component Rate													
11	Ending Balance with Interest (Ln. 7, 8, 9 - Ln. 10)													
12	**Combined Balance (Ln. 6, 11)**													
13	Combined Monthly Interest (Ln. 3, 9)													

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

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-36, 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-36, 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-36, 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.

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or the relocation and upgrade to existing facilities. Costs for construction depend on the customer's location, scope of project, load size, and load characteristics and include but not limited to project management, coordination, engineering, design, surveys, permits, construction inspection, and support services. This schedule establishes the terms and conditions under which Company will extend, relocate, or upgrade its facilities in order to provide service.

All facility installations shall be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension as determined by Company. All proceeds received for new facility installations, relocations, or upgrades to existing facilities required to provide service under provisions of this schedule shall be booked as Other Electric Revenue.

The following provisons govern the installation of overhead and underground electric facilities to customers or developers whose requirements are deemed by Company to be usual and reasonable in nature.

DEFINITIONS

a. Conduit Only Design means the conduit layout design for the installation of underground Extension Facilities that will be required to serve a project. Extension Facilities are to be installed at a later date when service is requested.

b. Corporate Business & Industrial Development means a tract of land which has been divided into contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of buildings for commercial and/or industrial use.

c. Extension Facilities means the electrical facilities, inclusive of conductors, cables, transformers and meters, installed solely to serve an individual customer, developer, or groups of customers. For example, the Extension Facilities to serve a Residential Subdivision would consist of the line extension required to tie the subdivision to APS existing system as well as the Electrical Facilities constructed within the subdivision which would include primary and service lines, transformers, and meters.

d High Rise Development means buildings built with four or more floors, usually using elevators for accessing floors that may consist of either residential or non-residential use or both, such as a high-rise building where the first level is for commercial purposes and the upper floors are residential.

e. Irrigation means water pumping service. Agricultural pumping means water pumping for farms and farm-related pumping used to grow commercial crops or crop-related activity. Non-agricultural water pumping is pumping for purposes other than the growing of commercial crops, such as golf course irrigation or municipal water wells.

f. Master Planned Community Development means a development that consists of a number of separately subdivided parcels for different "Residential Subdivisions". Developments may also incorporate a variety of uses including multi-family, non-residential, and public use facilities.

g. Residential Custom Home "Lot Sale" Development means a tract of land that has been divided into four or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of a residential home.

h. Residential Subdivision means a tract of land which has been divided into four or more contiguous lots with an average size of one acre or less in which the developer is responsible for the construction of residential homes or permanent mobile home sites.

i. Residential Multi-family Development means a development consisting of apartments, condominiums, or townhouses.

j. Residential Single Family means a house, or a mobile home permanently affixed to a lot or site.

k. Statement of Charges means the list of charges that is used to determine the applicant's cost responsibility for the Extension Facilities. The Statement of Charges is attached to this Service Schedule as Attachment 1. An applicant requesting an extension will be provided a sketch showing the Extension Facilities and an itemized cost quote based on the Statement of Charges or other applicable details. The Statement of Charges is not applicable to Extension Facilities requiring the relocation, modification, or upgrade of existing facilities or for non-residential customers with estimated loads over 3 megawatts, or that require 3,000 kVA of transformer capacity or greater, or special requests involving primary metering, or specialized or additional equipment for enhanced reliability. When the Statement of Charges is not applicable, charges for Extension Facilities shall be determined by the Company based on project-specific cost estimates.

1.0 RESIDENTIAL

1.1 SINGLE FAMILY HOMES

1.1.1 Extension Facilities will be installed to new permanent residential customers or groups of new permanent residential customers. For purposes of this section, a "group" shall be defined as less than four homes. The cost of extending service to applicant will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

1.1.2 In instances where an applicant requests service directly from a customer-funded extension constructed in accordance with Section 1.1.1 hereof, the initial applicant may be eligible for refund on a pro-rata basis for a portion of the initial extension cost related to the shared Extension Facilities as determined by the Company.

1.1.3 The first applicant connecting to an extension completed under the provisons of this Section will be required to pay a pro-rata share of the cost of the initial extension plus the costs attributable to the applicant's own extension.

1.1.4 In no event shall the total of refund payments made to the initial customer be in excess of the total amount originally paid by the initial customer.

1.1.5 The refund eligibility period shall be five years from the execution date of APS' line extension agreement to the initial applicant.

1.2 RESIDENTIAL SUBDIVISION DEVELOPMENTS

Extension Facilities will be installed to residential subdivision developments of four or more homes in advance of application for service by permanent customers provided the applicant signs an extension agreement. The subdivision development plat shall be approved and recorded in the county having jurisdiction. The cost of extending service to applicant will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

1.3 RESIDENTIAL CUSTOM HOME "LOT SALE" DEVELOPMENTS

1.3.1 Extension Facilities will be installed for residential "lot sale" custom home developments in advance of application for service by permanent customers, provided the applicant sign an extension agreement. The charges for Extension Facilities will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

1.3.2 Extension Facilities will be installed for each permanent customer upon request for service in accordance with Section 1.1 of this service schedule.

1.3.3 Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required.

1.4 MASTER PLANNED COMMUNITY DEVELOPMENTS

1.4.1 Extension Facilities will be installed to Master Planned Community Developments in advance of application for service by permanent customers, provided the applicant signs an extension agreement. The charges for Extension Facilities will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

1.4.2 Extension Facilities will be installed to each subdivided tract within the planned development in advance of application for service by permanent customers in accordance with the applicable sections of this Service Schedule.

1.5 RESIDENTIAL MULTI-FAMILY DEVELOPMENTS

Extension Facilities will be installed to multi-family apartment, condominium or townhouse developments in advance of application for service by permanent customers provided the applicant signs an extension agreement. The charges for Extension Facilities will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

1.6 HIGH RISE DEVELOPMENTS

1.6.1 APS will provide service to this type of development at one point of delivery and it is the applicant's responsibility to provide and maintain the electrical facilities within the building.

1.6.2 Extensions will be made to High Rise Developments where the residential units are privately owned and either individually metered or master metered in accordance with Section 5.11.

1.6.3 Prior to the ordering of specialized materials or equipment required to provide service applicant will be required to pay the estimated cost of the material or equipment.

1.6.4 Extension Facilities will be installed to High Rise Developments in advance of application for service by permanent customers provided the applicant signs an extension agreement. The charges for Extension Facilities will be determined based on project-specific requirements and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

2.0 NON-RESIDENTIAL

Extension Facilities will be installed for applicants not meeting the definition of Residential or as provided for in Section 2.1, or Section 3.0 of this Schedule. For applicants with estimated loads of less than 3 megawatts or less than 3,000 kVA of transformer capacity, the charges for Extension Facilities will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

The charges for Extension Facilities installed for applicants with projected loads of 3 megawatts or greater, or requiring transformer capacity of 3,000 kVA or greater or applicants requiring primary metering or specialized or additional equipment for enhanced reliability will be in accordance with a cost estimate determined by the Company based on project-specific requirements. Payment is due at the time the extension agreement is executed by the applicant.

Prior to the ordering of specialized materials or equipment required to provide service applicant will be required to pay the estimated cost of the material or equipment.

2.1 CORPORATE BUSINESS & INDUSTRIAL PARK DEVELOPMENTS

2.1.1 Extension Facilities will be installed for Corporate Business & Industrial Park Developments in advance of application for service by permanent customers provided the applicant signs an extension agreement. For applicants with estimated loads of less than 3 megawatts or less than 3,000 kVA of transformer capacity, the charges for Extension Facilities will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

The charges for Extension Facilities installed for applicants with projected loads of 3 megawatts or greater, or requiring transformer capacity of 3,000 kVA or greater or applicants requiring primary metering or specialized or additional equipment for enhanced reliability will be in accordance with a cost estimate determined by the Company based on project-specific requirements. Payment is due at the time the extension agreement is executed by the applicant.

Prior to the ordering of specialized materials or equipment required to provide service applicant will be required to pay the estimated cost of the material or equipment.

2.1.2 Extension Facilities will be installed to individual lots (applicants/customers) within the Corporate and Business Park Development in accordance with the applicable sections of this Service Schedule.

3.0 OTHER CONDITIONS

3.1 IRRIGATION CUSTOMERS

Extension Facilities will be installed for Irrigation Customers provided the applicant signs an extension agreement. The charges for Extension Facilites will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant. Non-agricultural irrigation pumping service to permanent customers will be extended as specified in Section 2. Non-agricultural irrigation pumping service to temporary or doubtful permanency customers will be extended as specified in Section 3.2 or 3.3 below, as applicable.

3.2 TEMPORARY CUSTOMERS

Where a temporary meter or construction is required to provide service to the applicant, the applicant shall make a payment in advance of installation or construction equal to the cost of installing and removing the facilities required to provide service, less the salvage value of such facilities. Charges will be in accordance with a cost estimate determined by the Company based on project-specific requirements. Payment is due at the time the extension agreement is executed by the applicant.

When the use of service is discontinued or agreement for service is terminated, Company may dismantle its facilities and the materials and equipment provided by Company will be salvaged and remain Company property.

3.3 MUNICIPALITIES AND OTHER GOVERNMENTAL AGENCIES

Relocation of existing facilities and/or Extension Facility installations required to serve the loads of municipalities or other governmental agencies may be constructed prior to the receipt of an executed extention agreement. However, this does not relieve the municipality or governmental agency of the responsibility for payment of the extension costs in accordance with the applicable sections of this Service Schedule.

4.0 UNDERGROUND CONSTRUCTION

4.1 GENERAL UNDERGROUND CONSTRUCTION POLICY - With respect to all underground installations, Company may install underground facilities only if all of the following conditions are met:

4.1.1 The extension meets all requirements as specified in Sections 1.0, 2.0, or 3.0.

4.1.2 The customer or applicant(s) provides all earthwork including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications. Customer or applicant(s) may hire contractors to perform this work.

4.1.3 The customer or applicant(s) provides installation of equipment pads, pull-boxes, manholes, and conduits as required in accordance with Company specifications.

4.1.4 In lieu of customer or applicant(s) providing these services and equipment, the Company may provide and the customer or applicant(s) will make a payment equal to the cost of such work plus any administrative or inspection fees incurred by Company. Customers or applicants electing this option will be required to sign an agreement indemnifying and holding APS harmless against claims, liabilities, losses or damage (Claims) asserted by a person or entity other than APS' contractors, which Claims arise out of the trenching and conduit placement, provided the claims are not attributable to APS' gross negligence or intentional misconduct.

5.0 GENERAL CONDITIONS

5.1 VOLTAGE

All Extension Facility installations will be designed and constructed for operation at standard voltages used by Company in the area in which the extension is located. Company may deliver service for special applications of higher voltages with prior approval from Company's Engineering Department, applicant will be required to pay the costs of any required studies.

5.2 POINT OF DELIVERY

5.2.1 For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus riser.

5.2.2 For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's or development's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinets necessary for the installation of Company's underground service conductors.

5.2.3 For special applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, APS and customer shall mutually agree upon the designated point of delivery.

5.3 EASEMENTS

All suitable easements or rights-of-way required by Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be conveyed to the Company in Company's name by the customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

5.4 GRADE MODIFICATIONS

If subsequent to construction of electric facilities the final grade established by the customer or developer is changed in such a way as to require relocation of Company facilities or the customer's actions or those of his contractor results in damage to such facilities, the cost of relocation and/or resulting repairs shall be borne by customer or developer.

5.5 OWNERSHIP

Except for customer-owned facilities, all electric facilities installed in accordance with this Service Schedule will be owned, operated. and maintained by Company.

5.6 MEASUREMENT AND LOCATION

5.6.1 Measurement must be along the proposed route of construction.

5.6.2 Construction will be on public streets, roadways, highways. or easements acceptable to Company.

5.6.3 The extension must be a branch from, the continuation of. or an addition to, the Company's existing distribution facilities.

5.8 UNUSUAL CIRCUMSTANCES

In unusual circumstances as determined by Company, when the application and provisions of this policy appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when customer's estimated load will exceed 3,000 kW, Company will make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in Section 1.1 of Company's Schedule 1. Terms and Conditions for Standard Offer and Direct Access Service.

5.9 ABNORMAL LOADS

Company, at its option, may make extensions to serve certain abnormal loads (such as: transformer-type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics) and the costs of any distribution system modifications or enhancements required to serve the customer will be included in the payment described in previous sections of this Service Schedule.

5.10 UPGRADES, RELOCATIONS AND/OR CONVERSIONS

5.10.1 Company will upgrade, relocate or convert its facilities for the customer's convenience or aesthetics. The cost of upgrades, relocation or conversion will be as determined by the Company by a detailed estimate will be included in the payment described in previous sections of this Service Schedule.

5.10.2 When the relocation of Company facilities involve "prior rights" conditions, the customer will be required to make payment equal to the estimated cost of relocation as determined by the Company by a cost estimate.

5.11 MASTER METERING

5.11.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

5.11.2 Residential Apartment Complexes, Condominiums - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered unless the builder or developer can demonstrate that the installation meets the provisions of R14-2-205 of the Corporation Commission's Rules and Regulations or the requirements discussed in 5.11.3 below. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

5.11.3 Multi-Unit Residential Developments – Company will allow master metering for residential units where the residential units are privately owned provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

5.11.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

5.11.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

5.11.4 Company will convert its facilities from master metered system to a permanent individually metered system at the customer's request provided the customer makes a payment equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended on the basis specified in Section 1. Applicant is responsible for all costs related to the installation of new service entrance equipment.

5.12 CHANGE IN CUSTOMER'S SERVICE REQUIREMENTS

Company will rebuild, modify, or upgrade existing facilities to meet the customer's added load or change in service requirements. When the applicant authorizes Company to to proceed with contruction of the extension, the payment will be credited to the cost of the extension otherwise the payment shall be non-refundable. Charges for such changes will be in accordance with a cost estimate determined by the Company based on project-specific requirements.

5.13 STUDY AND DESIGN PAYMENT

Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost estimates will be required to make a payment to Company an amount equal to the estimated cost of preparation. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the applicant for upon request.

5.14 SETTLEMENT OF DISPUTES

Any dispute between the customer or prospective customer and Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may, by either party, be referred to the Arizona Corporation Commission or a designated representative or employee thereof for determination.

5.15 EXTENSION AGREEMENTS

All facility installations or equipment upgrades requiring payment by an applicant or customer shall be in writing and signed by both the applicant or customer and Company.

5.16 ADDITIONAL PRIMARY FEED

When specifically requested by an applicant or customer to provide an alternate primary feed (excluding transformation), Company will perform a special study to determine the feasibility of the request The applicant or customer will be required to pay for the added cost as well as the applicable rate for the additional feed requested. Installation cost will be based on a cost estimate based on project-specific requirements. Payment for the installation of facilities is due at the time the facilties agreement is executed by the applicant.

5.17 POLICY EXCEPTION

The Schedule 3 as stated herein is applicable to all applicants and customers unless specific exemptions are approved by the Arizona Corporation Commission. The following exemptions have been approved:

5.17.1 Residential Homes on Native American Land

Extensions for residential homes on Native American Reservations will be made in accordance with the provisions of Service Schedule 3 that was in effect April 1, 2005 through June 30, 2007. Application of this Section 5.17.1 is limited to Native American Reservations as defined by applicable Federal law.

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

ATTACHMENT I
SCHEDULE OF CHARGES

Year 2010

Category	Overhead	Underground						
Feeder	Cost per Circuit Foot	Cost per Circuit Foot 3-750	Pull Box 3-750	Manhole 3-750	Cost per Circuit Foot 6-750	Pull Box 6-750	Manhole 6-750	Pad Mount Switch Gear
Three Phase	$34 33	$24.73	$3,637	$8,447	$47.06	$6,284	$12,036	$14,422

Primary	Overhead	Underground		
	Cost per Circuit Foot	Cost per Circuit Foot	Pull Box	Pad Mount Switch Gear
Single Phase	$15.32	$5.75	$719	$3,770
Three Phase	$21.98	$16.66	$1,284	$14,422

	SES Size	Transformer Size	Overhead	Padmount
Transformer Single Phase	200 Amp	25kVA	$3,324	$3,393
	200 Amp	50kVA	$4,160	$4,740
	400 Amp	50kVA	$4,160	$4,740
	600 Amp	75kVA	$5,633	$5,649
	800 Amp	100kVA	$7,152	$6,754

	SES Size	Overhead				Padmount			
		120/208 Volts		277/480 Volts		120/208 Volts		277/480 Volts	
Transformer Three Phase	200 Amp	3-25kVA	$8,839	3-50kVA	$9,063	112.5kVA	$3,848	112.5kVA	$13,277
	400 Amp	3-50kVA	$11,349	3-75kVA	$11,033	112.5kVA	$3,848	225kVA	$15,841
	600 Amp	3-50kVA	$11,349	3-100kVA	$11,545	150kVA	$14,682	300kVA	$17,823
	800 Amp	3-75kVA	$15,753			225kVA	$15,692	500kVA	$19,870
	1000 Amp	3-75kVA	$15,753			225kVA	$15,692	500kVA	$19,870
	1200 Amp	3-100kVA	$20,112			300kVA	$18,413	750kVA	$25,391
	1600 Amp	3-167kVA	$23,638			500kVA	$21,843	1000kVA	$25,642
	2000 Amp					500kVA	$21,843	1000kVA	$25,642
	2500 Amp					750kVA	$23,415	1500kVA	$39,086
	3000 Amp					750kVA	$23,415	1500kVA	$39,086

Meters & Services	Single Phase	Service Line per Circuit Foot		Meter Cost
		Overhead	Underground	
Res & Non-Res	200 Amp	$4.57	$2.79	$224
Residential	400 Amp	$8.58	$3.27	$224
Non-Residential	400 Amp	$8.58	$3.27	$909
Res & Non-Res	600 Amp	$17.16	$6.54	$925
Res & Non-Res	800 Amp	$25.74	$9.87	$925

	Three Phase	Service Line per Circuit Foot		Meter Cost
		Overhead	Underground	
Meters & Services	200 Amp	$3.43	$5.10	$356
	400 Amp	$9.40	$10.18	$1,033
	600 Amp	$14.88	$11.42	$1,057
	800 Amp	$14.88	$25.32	$1,057
	1000 Amp	$29.76	$25.32	$1,094
	1200 Amp	$29.76	$31.65	$1,122
	1600 Amp	$29.76	$50.64	$1,138
	2000 Amp		$50.64	$1,138
	2500 Amp		$82.31	$1,180
	3000 Amp		$88.62	$1,180

Footnotes

1) For multiple services out of one three phase transformer, the service cost will be determined by each SES and the transformer cost will be determined from the combined of each SES size in amps, rounded up to the nearest SES size, limited to a combined maximum of 3,000 amps

2) Extension Facilities that do not qualify for using the Statement of Charges will be determined by a project specific cost estimate

3) Transformer cost for single family homes, residential subdivisions and multi-family projects will be determined by the transformer size indicated above for the "Transformer Single Phase" category

4) Cost per foot charges will be determined from termination at the source to the next device in the circuit. Footage for each circuit will be summed to determine charges.

5) Meter costs will be calculated by summing each meter required when multiple meter sockets are installed