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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

TOM FORESE – Chairman
BOB BURNS
DOUG LITTLE
ANDY TOBIN
BOYD W. DUNN

Arizona Corporation Commission
DOCKETED
AUG 18 2017
DOCKETED BY

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01345A-16-0036
IN THE MATTER OF FUEL AND PURCHASED POWER PROCUREMENT AUDITS FOR ARIZONA PUBLIC SERVICE COMPANY.	DOCKET NO. E-01345A-16-0123 DECISION NO. 76295 **OPINION AND ORDER**

DATE OF HEARING:	October 20, 2016 and January 11, 2017 (Procedural Conferences); April 20, 2017 (Pre-Hearing Conference); April 24, 25, 26, 27, 28, May 1 and 2.
PLACE OF HEARING:	Phoenix, Arizona
PUBLIC COMMENT HEARINGS:	March 15, 2017 (Douglas, Arizona); March 22, 2017 (Phoenix, Arizona); March 29, 2017 (Clarkdale, Arizona); April 3, 2017 (Flagstaff, Arizona); April 20, 2017 (Yuma, Arizona)
ADMINISTRATIVE LAW JUDGE:	Teena Jibilian
APPEARANCES:	Mr. Thomas Loquvam, Mr. Thomas Mumaw, Ms. Melissa Krueger, Ms. Amanda Ho, PINNACLE WEST CAPITAL CORPORATION, and Mr. Ray Heyman, SNELL & WILMER, LLP on behalf of Arizona Public Service Company;
	Ms. Meghan H. Grabel, OSBORN MALEDON, on behalf of Arizona Investment Council;
	Mr. Nicholas J. Enoch, LUBIN & ENOCH, PC, on behalf of Local Unions 387 and 769 of IBEW, AFL-CIO;
	Mr. Timothy J. Sabo, SNELL & WILMER, LLP, on behalf of REP America d/b/a ConservAmerica;

Mr. Garry D. Hays, LAW OFFICES OF GARRY D. HAYS, PC, on behalf of Arizona Solar Deployment Alliance;

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

Mr. David Bender and Ms. Chinyere Osuala, EARTHJUSTICE, on behalf of Vote Solar;

Mr. Giancarlo G. Estrada, KAMPER ESTRADA, LLP, on behalf of Solar Energy Industries Association;

Mr. Court S. Rich, ROSE LAW GROUP, PC, on behalf of Energy Freedom Coalition of America;

Mr. Craig A. Marks, CRAIG A. MARKS, PLLC, on behalf of Arizona Utility Ratepayer Alliance;

Mr. Kurt J. Boehm, BOEHM KURTZ & LOWRY, on behalf of The Kroger Co.;

Mr. Scott S. Wakefield, HEINTON & CURRY, PLLC, on behalf of Wal-Mart Stores, Inc. and Sam's West, Inc.;

Ms. Brittany L. DeLorenzo, on behalf of IO DATA CENTERS, LLC;

Mr. Patrick J. Black, FENNEMORE CRAIG, PC, on behalf of Freeport Minerals Corporation and Arizonans for Electric Choice and Competition;

Mr. Lawrence V. Robertson, Jr., on behalf of Calpine Energy Solutions, LLC, Constellation New Energy, Inc., and Direct Energy Business, LLC;

Mr. Greg Patterson, MUNGER CHADWICK, on behalf of Arizona Competitive Power Alliance;

Mr. Jason Moyes, MOYES SELLERS & HENDRICKS, LTD, on behalf of Electrical District Number Eight and McMullen Valley Water Conservation & Drainage District;

Mr. Albert H. Acken, RYLEY CARLOCK & APPLEWHITE, on behalf of Electrical District Number Six, Pinal County, Arizona, Electrical District Number Seven of the County of Maricopa, State of Arizona, Aguila Irrigation District, Tonopah Irrigation District, Harquahala Valley Power District, and Maricopa County Municipal Water Conservation District Number One;

Capt. Lanny L. Zieman and Capt. Natalie A. Cepak, on behalf of Federal Executive Agencies;

Mr. John B. Coffman, JOHN B. COFFMAN, LLC, and Ms. Ann-Marie Anderson, WRIGHT WELKER & PAUOLE, PLC, on behalf of AARP;

Mr. Greg Eisert, on behalf of Sun City Homeowners Association;

Mr. Al Gervenack, on behalf of Property Owners & Residents Association;

Mr. Richard Gayer, pro se; and

Mr. Warren Woodward, pro se;

Mr. Daniel W. Pozefsky, on behalf of the Residential Utility Consumer Office;

Ms. Maureen A. Scott, Senior Staff Counsel, Mr. Wesley C. Van Cleve, and Mr. Charles H. Hains, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

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BY THE COMMISSION:

I. PROCEDURAL HISTORY

On June 1, 2016, Arizona Public Service Company ("APS" or "Company") filed with the Arizona Corporation Commission ("Commission") the above-captioned Rate Case Application ("Application").[1] In the Application, which is based on a test year ending December 31, 2015, APS sought a $165.9 million net increase in base rates; changes in some of its adjustor mechanisms; establishment of a mandatory new three-part demand-based rate design for residential and small commercial rate design; reduction of on-peak time-of-use hours; and grandfathering of existing solar customers while modifying net metering arrangements for new solar customers.

On July 22, 2016, a Rate Case Procedural Order was issued setting the procedural schedule and associated procedural deadlines for the Application, and indicating that pursuant to Commission Decision No. 75047 (April 30, 2015), issues related to APS's proposed Automated Meter Opt-Out Service Schedule would also be addressed in this proceeding.

On August 1, 2016, a Procedural Order was issued granting a Motion by the Commission's Utilities Division ("Staff") to consolidate Docket No. E-01345A-16-0123 with the Application.

Parties to this docket are APS, the Commission's Utilities Division ("Staff"), Richard Gayer; Patricia Ferré; Warren Woodward; IO Data Centers, LLC ("IO"); Freeport Minerals Corporation ("Freeport"); Arizonans for Electric Choice and Competition ("AECC"); Sun City Home Owners Association ("SCHOA"); Western Resource Advocates ("WRA"); Arizona Investment Council ("AIC"); Arizona Utility Ratepayer Alliance ("AURA"); Property Owners and Residents Association of Sun City West ("PORA"); Arizona Solar Energy Industries Association ("AriSEIA"); Arizona School Boards Association ("ASBA"), Arizona Association of School Business Officials ("AASBO"); Cynthia Zwick (in her personal capacity); Arizona Community Action Association ("ACAA"); Southwest Energy Efficiency Project ("SWEEP"); the Residential Utility Consumer Office ("RUCO"); Vote Solar; Electrical District Number Eight and McMullen Valley Water Conservation & Drainage District (collectively, "ED8/McMullen"); The Kroger Co. ("Kroger"); Tucson Electric Power

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[1] On January 29, 2016, APS filed its Notice of Intent to File a Rate Case Application and Request to Open Docket.

Company ("TEP"); Pima County; Solar Energy Industries Association ("SEIA"); the Energy Freedom Coalition of America ("EFCA"); Wal-Mart Stores, Inc. and Sam's West, Inc. (collectively, "Walmart"); Local Unions 387 and 769 of the International Brotherhood of Electrical Workers, AFL-CIO (collectively, "the IBEW Locals"); Calpine Energy Solutions LLC ("Calpine")(formerly Noble Energy Solutions, LLC); the Arizona Competitive Power Alliance ("the Alliance"); Electrical District Number Six, Pinal County, Arizona ("ED 6"), Electrical District Number Seven of the County of Maricopa, State of Arizona ("ED7"), Aguila Irrigation District ("AID"), Tonopah Irrigation District ("TID"), Harquahala Valley Power District ("HVPD"), and Maricopa County Municipal Water Conservation District Number One ("MWD") (collectively, "Districts"); the Federal Executive Agencies ("FEA"); Constellation New Energy, Inc. ("CNE"); Direct Energy Business, LLC ("Direct Energy"); AARP; the City of Sedona ("Sedona"); Arizona Solar Deployment Alliance ("ASDA"); the City of Coolidge ("Coolidge"); REP America d/b/a ConservAmerica ("ConservAmerica"); and Granite Creek Power & Gas and Granite Creek Farms LLC (collectively, "Granite Creek").

The full procedural history of this proceeding is set forth in the Findings of Fact herein.

On May 17, 2017, APS, AIC, the IBEW Locals, ConservAmerica, ASDA, Vote Solar, EFCA, SEIA, AriSEIA, AURA, Freeport, AECC, Calpine, CNE, Direct Energy, Walmart, FEA, ED8/McMullen, the Districts, ACAA, SWEEP, AARP, Mr. Gayer, Mr. Woodward, RUCO, and Staff filed Initial Closing Briefs.[2]

On June 1, 2017, APS, AIC, the IBEW Locals, ConservAmerica, EFCA, SEIA, Freeport, AECC, Calpine, CNE, Direct Energy, SWEEP, Mr. Woodward, and Staff filed Reply Closing Briefs.[3]

Numerous public comments were filed.

Following the parties' filings of Initial Closing Briefs and Reply Closing Briefs, this matter was taken under advisement by the Administrative Law Judge pending the submission of a Recommended Opinion and Order for the consideration of the Commission.

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[2] Freeport, AECC, Calpine, CNE, and Direct Energy jointly filed an Initial Closing Brief. Mr. Gayer filed his Initial Closing Brief on May 15, 2017.

[3] Freeport, AECC, Calpine, CNE, and Direct Energy jointly filed a Reply Closing Brief. On June 1, 2017, RUCO filed notice that it would not be filing a Reply Closing Brief.

II. BACKGROUND

APS, which is the largest subsidiary of Pinnacle West Capital Corporation ("Pinnacle West"), is the largest electric provider in Arizona, and serves more than 1.2 million customers, in 11 of Arizona's 15 counties. APS employs more than 6,300 employees, including employees at jointly-owned generating facilities for which APS serves as the generating facilities manager. In addition to the Palo Verde Nuclear Generating Station, which APS co-owns and operates, APS owns and operates six natural gas plants, two coal-fired plants, and renewable energy power generating facilities. APS currently generates approximately 11 percent of its electricity from more than 1,200 MW of renewable resources. APS also owns and operates more than 35,000 miles of transmission and distribution lines to deliver energy to its customers.[4]

APS's current rates and charges were authorized by Decision No. 73183 (May 24, 2012) in Docket No. E-01345A-11-0224. Among other things, Decision No. 73183 approved a Lost Fixed Cost Recovery Mechanism ("LFCR") which allows for the recovery of lost fixed costs, as measured by revenue per kWh, associated with energy efficiency and distributed generation ("DG").

On December 3, 2013, the Commission issued Decision No. 74202 in Docket No. E-01345A-13-0248, which acted upon an Application by APS to begin to address, in the LFCR, a cost shift from DG customers to non-DG customers.

On December 23, 2014, the Commission issued Decision No. 74876, which authorized the Four Corners Rate Rider as contemplated by Decision No. 73183.[5]

On January 3, 2017, the Commission issued Decision No. 75859 in the generic Docket No. E-00000J-14-0023, In the Matter of the Commission's Investigation of the Value and Cost of Distributed Generation, which established methodologies to be used in electric utility rate cases before the Commission for calculating the value of DG exports. Decision No. 75859 was amended by Decision No. 75932 (January 13, 2017) to establish parameters for grandfathering of DG customers, and clarified by Decision No. 76149 (June 22, 2017) regarding publication of the spreadsheet model to be used for the Resource Comparison Methodology ("RCP") in rate cases as ordered by Decision No. 75859.

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[4] Hearing Exhibit APS-14 (Direct Testimony of Daniel Froetscher) at 3.

[5] Decision No. 74978 (February 9, 2015)(Order Granting Rehearing) amended Decision No. 74876 to add two additional Findings of Fact.

III. PARTIAL SETTLEMENT AGREEMENT

a. Overview

On March 1, 2017, a Settlement Term Sheet was filed in the case, indicating that many, but not all, parties to this case were in support of a Settlement Agreement, and outlining the terms. On March 27, 2017, the Settlement Agreement was filed. A copy of the signed Settlement Agreement, which was admitted into evidence during the hearing in this proceeding as Hearing Exhibit A-29, is attached hereto as Exhibit A.

b. Settling Parties

The parties to the Settlement Agreement are APS, AIC, the IBEW Locals, ConservAmerica, ASDA, Vote Solar, EFCA, SEIA, AriSEIA, AURA, Freeport, AECC, Direct Energy, CNE, Calpine, the Alliance, Walmart, Kroger, Granite Creek, FEA, Coolidge, WRA, ASBA, AASBO, SCHOA, PORA, ACAA, RUCO, and Staff ("Settling Parties").

c. Non-Settling Parties

Parties who did not sign the Settlement Agreement are Richard Gayer, Patricia Ferré, Warren Woodward, IO, Cynthia Zwick (in her personal capacity), SWEEP, ED8/McMullen, the Districts, AARP, and Sedona.[6]

d. Bifurcation of Section 30 of the Settlement Agreement

Pursuant to Commission Decision No. 74057 (April 30, 2015) and the Rate Case Procedural Order in these dockets, issues related to APS's Proposed Automated Meter Opt-Out Service Schedule were addressed in this proceeding.

Section 30 of the Settlement Agreement provides:

> 30.1 The AMI Opt-Out program will be approved as proposed by APS except the fees will be changed to reflect an upfront fee of $50 to change out a standard meter for a non-standard meter and monthly fee of $5. See Service Schedule 1, attached as Appendix M.
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> 30.2 Changes to Schedule 1 are attached in Appendix M.

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[6] IO appeared through counsel at the hearing but did not otherwise participate in the hearing or post-hearing briefing process as a party. Patricia Ferré, Cynthia Zwick, and Sedona, who did not sign the Settlement Agreement, did not participate in the hearing or post-hearing briefing process as parties.

The issues surrounding the Settlement Agreement Proposed AMI Opt-Out program were heavily litigated in this proceeding. These issues will be bifurcated from this Decision, and will be addressed in a forthcoming Decision.

e. Procedural Opposition to Settlement Agreement / Process

i. **ED8/McMullen**

ED8/McMullen states that it intervened in this case "in hopes of raising questions about the recurring trend of settled rate cases that have become almost automatic before the Arizona Corporation Commission, at least when it comes to APS."[7] ED8/McMullen assert that settlement agreements do not provide ratepayers assurances that they are not being taken advantage of by a monopoly.[8] ED8/McMullen are critical of the fact that APS opened settlement negotiations by presenting a compromise offer, and of Staff's and RUCO's testimony comparing the revenue requirement in the settlement agreement to the revenue requirement APS proposed in the Application.[9]

ED8/McMullen are critical of RUCO's position that the Settlement Agreement terms would provide benefits that would not be possible in a litigated case. ED8/McMullen opine that it is "wholly presumptuous to assert that a fully litigated case and subsequent decision by the Commissioners would be detrimental to the ratepayers when compared to the settlement agreement."[10] ED8/McMullen argue that none of the parties supporting the Settlement Agreement addressed the validity of the relief APS requested in its Application, defended APS's need for the relief the Settlement Agreement would provide, or explained the consequences of denying APS a rate increase.[11] ED8/McMullen propose that "the Settlement Agreement be rejected and this matter be opened for a full evidentiary proceeding on the merits."[12]

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[7] ED8/McMullen Initial Closing Brief ("Br.") at 6.
[8] *Id.*at 7.
[9] Although ED8/McMullen filed post-hearing briefs, they raised no objections to specific Settlement Agreement revenue requirement issues, and offered no substantive revenue requirement evidence.
[10] ED8/McMullen Br. at 11.
[11] ED8/McMullen Br. at 9, 11.
[12] ED8/McMullen Br. at 11.

ii. **Districts**

The Districts contend that "the proposed non-unanimous settlement is the flawed result of a flawed process," that its terms will require ratepayers to "pay hundreds of millions of dollars to provide a windfall to APS and to resolve APS's battles with EFCA," and that "[m]eanwhile the District's farmers are losing options for affordable power."[13] The Districts state that their wholesale contracts with APS index their contractual rate to the E-34 retail rate, and contend that the rising rates are unaffordable for the farmers the Districts serve.[14] The Districts are concerned that wholesale power from APS will not be a viable alternative to the power they currently procure from the Navajo Generating Station ("NGS").[15]

The Districts argue that Rule 408 of the Arizona Rules of Evidence ("Rule 408") does not protect the settling parties from being forced to answer questions regarding the settlement process;[16] that exclusion of "evidence regarding the settlement process's many flaws" was prejudicial error;[17] and that "[e]vidence regarding the settlement process must be allowed in an evidentiary hearing that is being held solely for the purpose of evaluating whether the settlement is in the public interest."[18] The Districts claim that "the settlement process failed to provide for a meaningful opportunity for all, and APS cannot meet its burden that the non-unanimous settlement agreement is in the public's interest."[19]

iii. **Mr. Gayer**

Mr. Gayer asserts that "the entire settlement process and resulting agreement (APS 29) should be set aside and this entire rate case should be litigated *ab initio*."[20] Mr. Gayer submits that Rule 408 is not a bar to use of settlement discussions when they are offered for a relevant purpose other than proving the validity of a claim or its amount.[21] Mr. Gayer believes that the Decision in this matter should reflect that the settlement negotiations and the Settlement Agreement constitute serious

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[13] Districts Br. at 2.
[14] *Id.* at 5. Although the Districts filed post-hearing briefs, they raised no objections to specific Settlement Agreement revenue requirement issues, and offered no substantive revenue requirement evidence.
[15] *Id.*
[16] Districts Br. at 4.
[17] *Id.* at 5.
[18] Districts Br. at 4.
[19] *Id.* at 5.
[20] Gayer Br. at 4. *See also* Gayer Reply Br. at 8.
[21] Gayer Br. at 4. citing to *Bradshaw v. State Farm Mutual Auto Ins. Co., 157 Ariz. 411, 420 (1988).*

violations of procedural due process, so that in the future there will be no such negotiations or agreements and that all rate cases will be fully litigated openly in the public.[22]

iv. **Mr. Woodward**

Mr. Woodward believes the settlement process was "fatally flawed,"[23] and supports the arguments of ED8/McMullen, the Districts, and Mr. Gayer against the Settlement Agreement.[24] Mr. Woodward is critical of RUCO's and Staff's support of the Settlement Agreement, claiming that RUCO is out of touch with and does not represent residential ratepayers;[25] that Staff is biased toward APS;[26] and that Staff's characterization of the settlement process as inclusive and transparent is incorrect.[27] Mr. Woodward is generally critical of APS's, and of all parties' defense of the Settlement Agreement,[28] contending that evidence he brought to the settlement discussions, and his initial objections to the settlement process itself, were ignored.[29] Mr. Woodward claims that the Settlement Agreement is not in the public interest,[30] and must be set aside in order to obtain a just outcome.[31]

v. **APS**

APS responds that the criticisms of the settlement process are not supported by the evidence, and that they reflect a misunderstanding of the role of settlements in Commission proceedings, and of the safeguards in the Commission's process that protect the public interest.[32] APS asserts that the parties critical of the settlement process fail to consider that settling disputed issues generally promotes good public policy, and fail to acknowledge the benefits the Settlement Agreement provides to

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[22] Gayer Br. at 15 and Reply Br. at 9.
[23] Woodward Br. at 40, citing to Hearing Exhibit Woodward-6 (Direct Testimony of Warren Woodward on the Settlement Agreement) and Hearing Exhibit Woodward-7 (Rebuttal Testimony of Warren Woodward on the Settlement Agreement); Woodward Reply Br. at 23, citing to Hearing Exhibit Woodward-6 (Direct Testimony of Warren Woodward on the Settlement Agreement) at Sections III.E, III.F, and to Hearing Exhibit Woodward-7 (Rebuttal Testimony of Warren Woodward on the Settlement Agreement) at Section VI.
[24] Woodward Br. at 40.
[25] *Id.* at 39, 40, citing to Woodward-7 (Rebuttal Testimony of Warren Woodward on the Settlement Agreement) at Section III.B and Woodward Reply Br. at 22,.
[26] Woodward Br. at 40, citing to Tr. at 1268, 1275-76, and 1304 (Staff witness Abinah).
[27] Woodward Br. at 30-34.
[28] Woodward Reply Br. at 22-28. For example, Mr. Woodward claims: "Indeed, the false notion that a fair consideration has occurred by an enlightened majority runs throughout the arguments of those parties in support of the Settlement Agreement." Woodward Reply Br. at 26.
[29] Woodward Reply Br. at 28-30.
[30] *Id.* at 28, 32.
[31] Woodward Reply Br. at 27.
[32] APS Br. at 52, 55.

customers.[33] APS points out that participation in the settlement discussions, which were led by the Director of the Commission's Utilities Division, was such that the discussions had to be held in the hearing room to accommodate all the participants.[34] APS states that all parties were allowed to participate in the settlement discussions, and that despite the divergent interests of the participants, the parties engaged in open, transparent, and arm's length negotiations over the nearly three month process; that the process was fair; and the outcome was just, reasonable, and in the public interest.[35] APS further states that the testimony in this case shows that "all parties were provided the opportunity to raise and discuss any issues they so chose during the Settlement negotiations, and had the opportunity to present their evidence at the hearing."[36] In particular, APS points to the testimony of non-signatory party witnesses that the settlement process was conducted in a fair manner, and that parties had the opportunity to be heard and have their issues fairly considered.[37]

APS contends that arguments in opposition to the structuring of the settlement process, and even the existence of a settlement process, should not be afforded weight because: 1) while it was necessary to initially bifurcate discussions into revenue requirement and rate design, there was no separate revenue requirement settlement; 2) complaints about the settlement process appear to be colored by dissatisfaction with the settlement outcome; and 3) in a large case with 40 parties, "[t]here is nothing procedurally or substantively improper about one-off meetings that don't involve all parties,

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[33] APS Reply Br. at 1.

[34] APS Br. at 52-53.

[35] *Id.* at 53, referring to Hearing Exhibit VoteSolar-1 (Direct Testimony of Briana Kobor on the Settlement Agreement); Hearing Exhibit Walmart-5 (Direct Testimony of Chris Hendrix on the Settlement Agreement); Hearing Exhibit AURA-3 at 2 (Direct Testimony of Patrick Quinn on the Settlement Agreement); Hearing Exhibit RUCO-6 at 2 (Direct Testimony of David Tenney on the Settlement Agreement); Hearing Exhibit ACAA-1 at 3 (Direct Testimony of Cynthia Zwick on the Settlement Agreement); Hearing Exhibit AIC-5 at 2 (Direct Testimony of Gary Yaquinto on the Settlement Agreement); Tr. at 1094-95 (RUCO witness Tenney); Tr. at 1281-82, 1266, 1274 (Staff witness Elijah Abinah).

[36] APS Br. at 55, citing to Tr. at 45 (Kroger counsel Boehm); Tr. at 74 (Staff counsel Van Cleve); Tr. at 184-185 (APS witness Lockwood); Tr. at 722 (AARP witness Coffman); Tr. at 906 (Gayer); Tr. 988 (Woodward); Tr. at 1164 (SWEEP witness Schlegel). APS also references Hearing Exhibit APS-X at 3-4 (Direct Testimony of Barbara Lockwood on the Settlement Agreement); Hearing Exhibit AARP-1 at 3 (Direct Testimony of John B. Coffman on the Settlement Agreement); Hearing Exhibit ACAA-1 at 3 (Direct Testimony of Cynthia Zwick on the Settlement Agreement); Hearing Exhibit AIC-5 at 2 (Direct Testimony of Gary Yaquinto on the Settlement Agreement); Hearing Exhibit AURA-3 at 2 (Direct Testimony of Patrick Quinn on the Settlement Agreement); Hearing Exhibit ConservAmerica-3 at 1-2 (Direct Testimony of Paul Walker on the Settlement Agreement); Hearing Exhibit RUCO-6 at 2 (Direct Testimony of David Tenney on the Settlement Agreement); Hearing Exhibit VoteSolar-2 at 1 (Direct Testimony of Briana Kobor on the Settlement Agreement).

[37] APS Br. at 53-54, citing to Hearing Exhibit AARP-1 (Direct Testimony of John B. Coffman on the Settlement Agreement), Hearing Exhibit SWEEP-3 (Direct Testimony of Jeff Schlegel on the Settlement Agreement), and Tr. at 575-76 (ED8/McMullen witness Jim Downing).

or meetings among smaller subsets of parties with unique interests."[38] APS asserts that settlements are not open meetings, but are confidential negotiations between litigants, with the outcome of the negotiations being made public and fully vetted at an evidentiary hearing.[39]

In response to the Districts' argument that the Settlement Agreement terms benefitting EFCA render the Settlement Agreement flawed and not of benefit to customers, APS points out that EFCA is only one party out of 29 Settling Parties with diverse interests, and that the agreement among these parties represents compromise and balance among all those interests, not an imbalance toward only one party's interests.[40] APS asserts that the diversity of the Settling Parties, which include representatives of several customer groups, including residential, limited-income, retiree, public schools and school business officials, federal agencies, and large industrial and commercial customers, is evidence in itself that the Settlement Agreement is in the public interest.[41] APS also points to the benefit of EFCA's agreement with the Signing Parties in this case, as the agreement has opened the door to collaboration in the future, as opposed to continual litigation of disputed issues surrounding the integration of DG.[42]

APS states that with the exception of the Districts, all parties who did not sign the Settlement Agreement, but participated in the evidentiary hearing, acknowledged that they had ample opportunity to participate in the settlement process and had a full and fair opportunity to present their case in the evidentiary hearing.[43] APS points out that the Districts acknowledged that they had the opportunity to present evidence in this case, and that they did not introduce testimony, by choice.[44] APS contends that after "declining to cross examine witnesses on substantive Settlement terms, and choosing to not put on their own evidence challenging the Settlement, the Districts cannot now complain that they have been shut out of the process."[45]

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[38] APS Br. at 54-55.
[39] *Id.* at 55.
[40] APS Reply Br. at 1.
[41] *Id.* at 2.
[42] APS Reply Br. at 1.
[43] *Id.* at 2, citing to Tr. at 722 (AARP witness Coffman); Tr. at 906 (Gayer); Tr. at 988 (Woodward); Tr. at 1164 (SWEEP witness Schlegel); and Tr. at 575-76 (ED8/McMullen witness Downing).
[44] APS Br. at 55; APS Reply Br. at 2-3, citing to Tr. at 1314 (Albert Acken, counsel for the Districts).
[45] APS Reply Br. at 3.

APS addresses the Districts' arguments appearing in their Initial Closing Brief that APS's rates are unaffordable to the farmers who are the Districts' retail customers.[46] APS states that the long-term wholesale power contracts between APS and the Districts are the result of negotiations between the parties, who agreed to the incorporation of APS's general service E-34 rate, and also include agreed-upon negotiated charges for transmission and distribution which are subject exclusively to Federal Energy Regulatory Commission ("FERC") jurisdiction.[47] Moreover, APS argues that over the last few years, the Districts have purchased little or no power from APS;[48] that the Districts admittedly have other power purchasing options; that the Districts have access to Federal preference power; and that the Districts are therefore not "captive" customers of APS.[49] APS is critical of the Districts' arguments regarding whether APS power would be an economic alternative if the NGS closes, stating that the Districts fail to acknowledge that they have other power options, including Federal preference power, self-generation, other utilities, or market purchases, and fail to explain why they should pay rates lower than cost, to be subsidized by other customers.[50]

vi. **AIC**

AIC believes that any criticism of the settlement process is unfounded.[51] AIC states that the Settlement Agreement is the result of a difficult but inclusive and collaborative effort; that AIC and other parties were provided advance notice of meetings for the discussion of the possibility of settlement; that parties were afforded ample opportunity to participate in the discussions; and that to aid discussions, term sheets and other supplemental materials were distributed prior to the meetings to allow parties to follow the progress of the settlement discussions.[52] AIC states that no party got everything it wanted, and that the terms of the Settlement Agreement demonstrate that the settlement was a compromise involving a collaborative effort of give and take.[53]

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[46] *Id.* at 3-5.
[47] APS Reply Br. at 4.
[48] *Id.*, citing to Tr. at 579 (ED8/McMullen witness Downing).
[49] APS Reply Br. at 4, citing to Districts Reply Br. at 5 and Tr. at 579 (ED8/McMullen witness Downing).
[50] APS Reply Br. at 4-5.
[51] AIC Br. at 12.
[52] *Id.*
[53] *Id.*

vii. **IBEW Locals**

The IBEW Locals state that the Settlement Agreement "was negotiated in an open and transparent process, is supported by the evidence, and is in the public interest."[54] The IBEW Locals state that they have a long history of negotiating differences with APS, and that the settlement process in this case involved "the *exact* same type of give and take exercise that transpired between the parties to reach the Settlement Agreement."[55] The IBEW Locals state that all intervenors were invited to participate in settlement discussions and were always notified of settlement meetings; term sheets and handouts were distributed in advance; each party had an opportunity to be present and heard; there was no attempt by any party to intimidate any other party into settlement; and while not all of the non-signatories' issues were resolved in the Settlement Agreement, neither were they ignored, and any issues not addressed in the Settlement Agreement were the subject of serious bargaining among capable, knowledgeable parties.[56] The IBEW Locals find the fact that only five of the 40 intervening parties filed testimony in opposition to the Settlement Agreement, while 29 signed on, should lend great weight to demonstrating that the Settlement Agreement is just, reasonable, and in the public interest.[57]

viii. **ConservAmerica**

ConservAmerica asserts that the settlement process was fair and appropriate;[58] that all the parties, which represent many divergent interests and differing perspectives, had a chance to participate, and many did; that the process was open and inclusive; and that all viewpoints were heard.[59]

ConservAmerica states that ED8/McMullen received a full evidentiary hearing on the merits, and that ED8/McMullen were free to cross-examine witnesses on all the pre-settlement testimony that was admitted into the record, and to raise any specific objections to the settlement revenue requirement,

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[54] IBEW Locals Br. at 2.
[55] *Id.* at 3 (emphasis in original).
[56] IBEW Locals Reply Br. at 3.
[57] *Id.*
[58] ConservAmerica Reply Br. at 1.
[59] ConservAmerica Br. at 1, citing to Hearing Exhibit ConservAmerica-3 (Direct Testimony of Paul Walker on the Settlement Agreement) at 1-2.

but chose not to do so.[60] ConservAmerica also points out that ED8/McMullen chose not to offer any substantive testimony of their own on revenue requirement or on any other issue.[61]

In response to the Districts' arguments that the settlement process suffered from unequal bargaining power, ConservAmerica states that many parties filed extensive revenue requirement testimony and were well represented by counsel, and that collectively, the parties have resources equal to or greater than APS.[62] ConservAmerica points out that the Districts offered no testimony in support of their allegation of unequal bargaining power tainting the settlement process; that the Districts are represented by one of the largest law firms in Arizona; and that as utilities, the Districts had the knowledge and resources to produce revenue requirement testimony, if they had chosen to do so.[63]

ConservAmerica responds to Mr. Woodward's allegations regarding RUCO and Staff as being "without any proof, much less the heavy proof needed to impeach the credibility of the public servants in Staff and RUCO."[64] ConservAmerica states that while it disagrees with Mr. Woodward on many things, it believes he is acting on his sincere beliefs, and that the same courtesy should be accorded other parties to this case.[65]

ix. **ASDA**

ASDA states that the settlement process was fair and inclusive, and that the resulting Settlement Agreement is in the public interest.[66] ASDA requests that the Commission approve the Settlement Agreement without modification.[67]

x. **Vote Solar**

Vote Solar states that "[l]ike all parties, Vote Solar had an opportunity to actively participate in settlement negotiations."[68] Vote Solar "worked with APS, Staff, and other parties to reach a compromise and contributed to drafting settlement terms that protect solar customers consistent with

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60 ConservAmerica Reply Br. at 1-2.
61 *Id.* at 1.
62 ConservAmerica Br. at 2.
63 ConservAmerica Reply Br. at 2.
64 *Id.* at 3.
65 *Id.*
66 ASDA Br. at 1-2, citing to Hearing Exhibit ASDA-1 (Direct Testimony of Sean Seitz on the Settlement Agreement) at 2.
67 ASDA Br. at 2.
68 Vote Solar Br. at 3.

this Commission's orders."[69] Vote Solar believes that the settlement "achieves a reasonable compromise on a range of issues affecting APS and its customers," and as a whole strikes a "delicate balance between competing issues on numerous interrelated issues among the signatory parties."[70] Vote Solar believes the Settlement Agreement is just, reasonable, fair, and in the public interest, and requests that it be approved without modification.[71]

xi. **EFCA**

EFCA states that the process leading to the Settlement Agreement was open, transparent, and all interested parties had an opportunity to be heard.[72] EFCA states that during the many settlement conferences that were held following notice to all parties of settlement discussions on December 29, 2016, each party had the opportunity to raise and have its issues considered multiple times during the negotiations.[73]

xii. **AURA**

AURA asserts that the negotiation process leading to the Settlement Agreement was fair and proper, and that a settlement process is an appropriate way to resolve this rate case.[74] AURA's witness testified that the Settlement Agreement is the result of many hours of negotiations and a willingness of the parties to compromise; that the negotiations were conducted fairly and reasonably with notice, in a way that allowed each party the opportunity to participate in every step of the negotiation, by teleconference, if necessary; that all documents were made available to all parties in the discussions; and that all parties were allowed to express their positions fully.[75]

xiii. **Freeport / AECC / Calpine / CNE / Direct Energy**

Freeport, AECC, Calpine, CNE, and Direct Energy state that the fact that all parties to this proceeding did not sign the Settlement Agreement does not mean that it is not in the public interest, but rather means that not all parties' viewpoints could be accommodated in the broader context of the

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[69] *Id.*
[70] *Id.*
[71] Vote Solar Br. at 2-8.
[72] EFCA Br. at 22.
[73] *Id.*
[74] AURA Br. at 1-2.
[75] *Id.*, citing to Hearing Exhibit AURA-3 (Direct Testimony of Patrick Quinn on the Settlement Agreement) at 2.

Settlement Agreement.[76] Freeport, AECC, Calpine, CNE, and Direct Energy state that many viewpoints were accommodated by the Settlement Agreement, as well as the broad spectrum of stakeholder interests represented by the Settling Parties.[77]

xiv. **ACAA**

ACAA states that the settlement process was fair and open, where all parties had a chance to be heard, and that ACAA attended the majority of the meetings and was able to participate fully in the development of the Settlement Agreement.[78] ACAA believes the Settlement Agreement is a reasonable outcome to the good faith negotiation between the parties; that it represents a just and reasonable outcome for APS's low-income customers; and that it deserves the Commission's approval.[79]

xv. **RUCO**

RUCO states that the Settlement Agreement's achievement of consensus by a substantial majority of the parties in this matter is extraordinary, given the diverse interests and the nature of the issues involved. RUCO contends that the Settlement Agreement "is a comprehensive solution to a litany of issues which is fair to all involved, results in fair and reasonable rates and is in the public interest."[80] RUCO states that its settlement position differs from its direct case position as a result of negotiation and give-and-take compromise; that it has conducted a forensic analysis of APS's rate request as far as residential interests are concerned; and that RUCO is very aware of what it is giving up and what it is getting in the Settlement Agreement.[81] RUCO "is completely satisfied that this Settlement is in the best interests of the ratepayers under the circumstances of this case," and believes it is unlikely that ratepayers would be better off in a litigated case than under the terms of the Settlement Agreement.[82] RUCO asserts that the Settlement Agreement is "very balanced and fair to everyone's interests overall" and that it achieves the agreement of the solar interests to withdraw any appeals of the Value of Solar Decisions, and to refrain from seeking to undermine the Settlement Agreement through ballot initiatives, legislation, or advocacy at the Commission, which is something that the

[76] Freeport, AECC, Calpine, CNE, and Direct Energy Br. at 8.
[77] *Id.*
[78] ACAA Br. at 3.
[79] *Id.* at 3-4.
[80] RUCO Br. at 1.
[81] *Id.* at 4, 7-8.
[82] *Id.* at 4-5, 8.

Commission could not order parties to do if the case is litigated.[83] While RUCO does not support every provision of the Settlement Agreement individually, it believes that when viewed in its entirety, the Settlement Agreement constitutes "a fair and reasonable resolution of a very complicated and contentious case for ratepayers and for the state of Arizona" and recommends that the Commission approve it.[84]

xvi. **Staff**

Staff states that the proposed Settlement Agreement is the result of a transparent and open process, and represents agreement among a diverse group of stakeholders.[85] Staff disputes the Districts' allegations that parties were shut out of the settlement process.[86] Staff states that throughout the settlement process, all parties were notified of settlement discussions and had multiple opportunities to be present and heard on their issues, and that although not all parties were signatories to the Settlement Agreement, it incorporates provisions that were either direct suggestions or were prompted by the express positions of non-signatories.[87] Staff finds it noteworthy that of the approximately 10 parties who did not sign the Settlement Agreement, only about six filed testimony in opposition to it, and several of those parties acknowledged and voiced support for many provisions in the Settlement Agreement.[88] Staff disputes the Districts' "power imbalance" allegations, emphasizing that Staff was an impartial participant and like RUCO, had no monetary interest in the outcome of this case. Staff states that its goal in cases before the Commission is "to assist the Commission in finding a resolution to each case that balances the interest of both the Company and its customers, that is in the public interest, and that it results in rates that are just and reasonable to consumers."[89] Staff disagrees with the Districts' contention that APS is receiving a "windfall" in the Settlement Agreement.[90] Staff states that the Districts filed no revenue requirement or rate design testimony in this case, and apparently rely on Staff's and RUCO's initial Direct Testimonies to support their allegations.[91] Staff believes that the

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[83] *Id.* at 2, 4.
[84] *Id.* at 4-5.
[85] Staff Br. at 7.
[86] Staff Reply Br. at 7
[87] Staff Br. at 8; Staff Reply Br. at 7.
[88] Staff Br. at 20-21, referencing SWEEP and AARP positions; Staff Reply Br. at 8.
[89] Staff Reply Br. at 7.
[90] *Id.* at 10.
[91] *Id.*; Staff Reply Br. at 10.

Settlement Agreement reasonably balances APS's interests with the interests of consumers and stakeholders with divergent interests.[92]

Staff disagrees with the Districts' allegations that they were prevented from introducing evidence to demonstrate that the settlement process was flawed.[93] While acknowledging that Rule 408 does not prohibit all uses of evidence of a compromise, Staff states that the objections Staff and other parties raised during cross-examination by the Districts' counsel were to the Districts' attempts to characterize the positions of parties during negotiations, which under Rule 408 is normally inadmissible.[94] Staff states that the fact that some smaller meetings were held between Staff and other parties does not mean that the process was closed and that some parties were favored over others, as the District implies.[95] Staff states that it met with any party that requested a meeting, and showed no favoritism.[96]

Staff states that the concern ED8/McMullen expressed that settlement of APS's rate cases in the past may have led to significant additions to rate base over the years without "thorough scrutiny" ignores the "extensive process Staff undertakes as part of each rate case to ensure that assets were prudently acquired and are used and useful in serving customers."[97] In response to Ed8/McMullen's criticism of Staff's testimony comparing the revenue requirement in the Settlement Agreement to the revenue requirement APS proposed in its rate application, instead of to Staff's initial proposal in prefiled Direct Testimony, Staff responds that it is not unusual for Staff's position to change in rate cases, based on other parties' testimony and on information received from applicants, and therefore the comparison to the Company's application is appropriate.[98]

Staff responds to Mr. Woodward's and Mr. Gayer's attacks on the settlement process and on Staff's role in the case, stating they are unwarranted.[99] Staff states that its role in cases before the

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[92] Staff Reply Br. at 8.
[93] *Id.* at 9.
[94] *Id.*, citing to *Murray v. Murray*, 239 Ariz. 174, 367 P.3d (App. 2016). Staff also notes, in response to arguments by Mr. Gayer, that "[i]f settlement discussions were disclosed, and parties' compromising of positions offered in the course of negotiations were made public, this would act to chill meaningful and candid discussions and would result in overall harm to the process. The ALJ's rulings regarding Rule 408 were appropriate in this case." Staff Reply Br. at 15.
[95] Staff Reply Br. at 9.
[96] *Id.*
[97] Staff Reply Br. at 10.
[98] *Id.*; Staff Reply Br. at 11.
[99] Staff Reply Br. at 11, 15.

Commission is to make reasonable recommendations that balance the interests of both ratepayers and the utility, and that that favoring the ratepayer interest too much can jeopardize the utility's financial health and can impair its ability to provide reasonable and cost effective service.[100] Staff states that all parties had an opportunity to participate in the settlement process, and that the hearing on the Settlement Agreement provided those parties in opposition to the Settlement Agreement an opportunity to effectively make their points, which are a part of the record that the Commission will consider when it decides whether or not to adopt the Settlement Agreement.[101] As a signatory to the Settlement Agreement, Staff believes that it reflects the appropriate balance between ratepayer and utility interests; that the process in arriving at the Settlement Agreement was fair; and that the provisions of the Settlement Agreement are in the public interest and should be adopted without any modification.[102]

xvii. **Resolution**

Having examined and considered all arguments made regarding procedural opposition to the settlement process that the parties to this proceeding undertook, we find that the arguments are without merit and pose no barrier to our consideration of the substance of the Settlement Agreement. We note the dissatisfaction of some parties with the outcome of the Settlement Agreement including the issues regarding non-AMI meters litigated in this proceeding. Given the large number of intervenors, and the broad range of interests they represent, it is understandable that a total consensus was not reached. However, there is no support in the record for a finding of impropriety in the settlement process, and the fact that an individual party did not have its position incorporated in the Settlement Agreement does not reflect a deficiency in the settlement process or the Settlement Agreement itself. Our forthcoming bifurcated Decision on the litigated issues regarding non-AMI meters will not revisit the issue of whether any alleged improprieties occurred.

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[100] *Id.* at 11.
[101] Staff Reply Br. at 15.
[102] *Id.* at 11, 17.

IV. SUBSTANTIVELY UNDISPUTED SETTLEMENT AGREEMENT ISSUES

a. Fair Value Rate Base and Revenue Requirement

While some parties contest the way the revenue requirement would be collected from customers, no party to this proceeding contests the revenue requirement.[103] Many of the Settling Parties completed a thorough analysis of APS's rate case filing prior to the time the parties began settlement negotiations.[104]

The uncontested Settlement Agreement fair value rate base ("FVRB") is $9,990,561,000; total adjusted test year revenue is $2,888,903,000; and the non-fuel, non-depreciation revenue requirement increase is $87.25 million.[105] When the Settlement Agreement reduction for base fuel of $53.63 million and the increase for depreciation of $61.00 million is taken into account, the result is a net base rate increase of $94.624 million, exclusive of the adjustor transfer of $267.95 million.[106]

After including the transferred adjustor mechanism amount of $267.95 million, the total base rate revenue requirement is $362.58 million.[107] This amount is comprised of (1) a non-fuel base rate increase of $148.250 million, which includes a return on and of post-test year plant in service as of December 31, 2016; (2) a base fuel rate decrease of $53.63 million; and (3) the transfer from adjustor mechanisms of $267.95 million to base rates.[108] APS agrees to impute, in future rate cases, net revenue growth for any revenue producing plant included in post-test year plant.[109]

The transferred adjustor mechanism amount includes a transfer to base rates, and a zeroing out or reduction of the revenue requirements currently collected through the Renewable Energy Adjustor

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[103] *See, e.g.,* SWEEP Br. at 6, AARP Br. at 5.

[104] *See, e.g.,* FEA Br. at 1-6, referring to Hearing Exhibit FEA-1 (Direct Testimony of Brian Andrews)(depreciation expense), Hearing Exhibit FEA-1 (Direct Testimony of Michael Gorman)(cost of capital), and Hearing Exhibit FEA-1 (Direct Testimony of Amanda Alderson)(cost of service study). FEA commented that it is a signatory to the Settlement Agreement because it represents a reasonable compromise on the many complex issues in the case concerning APS's revenue requirement, the revenue spread across rate classes, and rate design. Through its witnesses, FEA presented evidence concerning cost of capital, depreciation rates and expense, and a cost of service study. FEA is not opposing the cost of capital, or any of its components, filed in the Settlement Agreement, and states that while the Settlement Agreement does not address the concerns it raised regarding depreciation, FEA "agrees to the total settlement in aggregate, rather than individual elements of the settlement which comprise specific findings on revenue requirement, cost of service and rate design."

[105] Settlement Agreement Section 3 (page 8).

[106] *Id.*

[107] *Id.*

[108] *Id.*

[109] *Id.*

Clause ("REAC"), Demand Side Management Adjustor Clause ("DSMAC"), Transmission Cost Adjustor ("TCA"), Environmental Impact Surcharge ("EIS"), Four Corners Rate Rider ("FCRR"), and the System Benefits Charge ("SBC").[110]

b. Cost of Capital

The Settlement Agreement adopts, for ratemaking purposes, an original cost of capital structure comprised of 44.2 percent debt and 55.8 percent common equity; a return on common equity of 10.0 percent and an embedded cost of debt of 5.13 percent.[111] The Settling Parties agree to a fair value rate of return ("FVROR") of 5.59 percent, which includes a 0.8 percent return on the fair value increment.[112]

c. Base Fuel Rate

The Settlement Agreement adopts a base fuel rate of $0.030168 per kWh, which is lowered from the $0.032071 set by Decision No. 73183.

d. Bill Impact

The Settlement Agreement rates result in an average a 3.28 percent bill impact when new rates become effective, with an average 4.54 percent bill impact for residential customers, and an average 1.93 percent bill impact on general service customers.[113]

e. Rate Case Stability Provision

As part of the Settlement Agreement, APS agrees not to file its next general rate case before June 1, 2019, with a test year ending no earlier than December 31, 2018.[114]

f. Four Corners Units 4 and 5

The Settlement Agreement provides that this docket will remain open to allow APS to file a request that its rates be adjusted no later than January 1, 2019 to reflect its proposed addition of Selective Catalytic Reduction ("SCR") equipment at the Four Corners Generating Station, and sets forth filing requirements and parameters regarding such filing.[115] The Settlement Agreement authorizes APS to defer, for possible later recovery through rates, all non-fuel costs of owning,

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[110] *Id.*, Section 8 (page 11).
[111] Settlement Agreement Section 5 (page 9).
[112] *Id.*
[113] Settlement Agreement Section 4 (pages 8-9).
[114] *Id.*, Section 2 (page 8).
[115] *Id.*, Section 9 (page 12-13).

operating, and maintaining the Selective Catalytic Reduction environmental controls at the Four Corners Power Plant from the date such controls go into service until the inclusion of such costs into rates.

g. Ocotillo Modernization Project

The Settlement Agreement authorizes APS to defer, for possible later recovery through rates, all non-fuel costs of owning, operating, and maintaining the Ocotillo Modernization Project and retiring the existing steam generation at Ocotillo.[116]

h. Property Tax Rate Deferral

The Settlement Agreement provides that APS shall be allowed to defer for future recovery (or credit to customers) the Arizona property tax expense above or below the test year caused by changes to the applicable composite property tax rate, subject to the provisions set forth in the Settlement Agreement Section.[117]

i. Tax Expense Adjustor Mechanism

The Settlement Agreement provides that in the event that significant Federal income tax reform legislation is enacted and becomes effective prior to the conclusion of Arizona Public Service Company's next general rate case, and such legislation materially impacts the Company's annual revenue requirements APS will create a rate adjustment mechanism to enable the pass-through of income tax effects to customers.[118]

j. Other Significant Provisions

Section 1.5 of the Settlement Agreement cites several provisions that the Settling Parties note as significant in balancing the rate increase with benefits for APS's customers.[119]

k. Rate Design for Low-Income Customers

The Settlement Agreement includes changes to existing rate design provisions benefiting low-income customers.[120]

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[116] *Id.*, Section 10 (page 13).
[117] *Id.*, Section 11 (page 13).
[118] *Id.*, Section 16 (pages 16-17).
[119] *Id.*, Section 1.5 (page 6).
[120] *Id.* Section 29 (pages 26-27).

ACAA states that it intervened to ensure that low-income customers in Arizona had a voice in this rate case. ACAA states that nearly one in five Arizonans are in poverty, and that the energy burden for low-income households is much higher than the energy burden for the average APS customer. ACAA states that the Settlement Agreement:

> provides substantial assistance to make electricity bills more affordable for those least able to pay for them. Increasing the low-income discount and low-income medical discount will make bills more affordable for low-income customers. For a family of three at the poverty level in the test year, this will decrease the average energy burden from 8.1% to 6.0%. As was stated in direct testimony, a 6% energy burden is generally considered to be affordable; in this case, the discount has allowed someone with a previously unaffordable bill to now be able to better afford it.[121]

ACAA also points favorably to the Settlement Agreement's requirement that APS pay $1.25 million in crisis bill assistance per year, which ACAA states will help thousands of APS customers in hardship situations that render them unable to pay their electric bill. ACAA states that the provision of consistent funding from year to year ensures the availability of such crisis assistance for several years.[122]

Staff states that through the addition of the $1.25 million annually for the crisis bill program to assist customers with incomes less than or equal to 200% of the Federal Poverty Income Guidelines, these low-income ratepayers will receive direct assistance to defray the impact of the Settlement Agreement rate increase.[123] In addition to the crisis bill assistance program, the Settlement Agreement increases funding and simplifies the bill discount for the E-3 Energy Support Program for limited income customers, with a flat 25% bill discount.[124]

I. Rate Design for DG Customers

The Settlement Agreement proposes the following for customers with Distributed Generation:[125]

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[121] ACAA Br. at 2.
[122] *Id.* at 3.
[123] Staff Br. at 13.
[124] *Id.*, citing to Hearing Exhibit APS-6 (Direct Testimony of Charles Miessner on the Settlement Agreement) at 5 and Tr. at 316 (APS witness Lockwood).
[125] Settlement Agreement Section 18 (pages 19-20)

18.1 DG customers are eligible for four different rate schedules including all proposed TOU and Demand rates. DG customers that select TOU-E will be subject to a Grid Access Charge as reflected in Appendix F.

18.2 The self-consumption offset rate for TOU-E will be $0.105/kWh, which is inclusive of the Grid Access Charge, but exclusive of taxes and adjustors. This is an approximately $0.120/kWh offset rate after these adjustments. The offset rate is based on the load profile and production profile of APS customers with DG during the test year. Individual customer offset will vary based on individual usage patterns and DG system size, orientation, and production.

18.3 The Resource Comparison Proxy Rate ("RCP") for exported energy established in Decision No. 75859, as amended by Decision No. 75932, will be $0.129/kWh in year one, which is inclusive of undifferentiated transmission, distribution, and loss components. This export rate was calculated using a 2015 base year with an adjustment to achieve the final export rate. Attached as Appendix H is the RCP Rate Rider, POA and EPR-6 Legacy Rate Rider.

18.4 This first year export rate is the product of settlement negotiations and does not create any precedent, imply any change to the structure of or detail in the Resource Comparison Proxy, or otherwise change any aspect of Decision No. 75859.

18.5 DG customers that file a completed interconnection application before the rate effective date adopted in the Decision in this case shall be grandfathered consistent with Section 18.6 for a period of twenty years, with the twenty year period beginning from the date the system is interconnected with APS.

18.6 As contemplated in Decision No. 75859, grandfathered DG customers will continue to take service under full retail rate net metering and will continue to take service on their current tariff schedule for the length of the grandfathering period, which for APS are rate schedules E-12, ET-1, ET-2, ECT-1, or ECT-2. In its next rate case, APS will propose that the rates on each of these legacy tariffs will be updated with an equal percent increase applied to every rate component equal to the residential average base rate increase approved. In addition, grandfathered DG customers currently served on E-3 or E-4 will continue on the current E-3 or E-4 Rate Riders for as long as they meet the eligibility criteria and/or discontinue participation in the program.

Vote Solar states that it participated in this proceeding to advocate for fair rates and rate designs that benefit all customers and support the integration of DG in Arizona.[126] While the Settlement Agreement does not incorporate all the rate design options for DG customers that Vote Solar initially proposed, it provides them with more rate options than APS initially proposed.[127] Vote Solar states that

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[126] Vote Solar Br. at 2.
[127] *Id.* at 4.

the Settlement Agreement provisions, all taken together, including the negotiated Grid Access Charge, benefit existing DG customers and establish a just and reasonable RCP rate for new DG customers who sell their excess energy back to the grid.[128] Vote Solar believes that adoption of all the provisions of the Settlement Agreement together will provide a just, reasonable, and fair outcome in the public interest, and requests that the Settlement Agreement be approved without modification.

SEIA supports the Grid Access Charge established in the Settlement Agreement, as it is "within the range of possible outcomes presented for litigation."[129] SEIA emphasizes that "the Settlement Agreement's provision that DG customers are eligible for four different rate options is a fair and reasonable outcome that preserves customer choice and provides APS a reasonable opportunity to recover its costs of service"[130] and "treats DG and non-DG customers in a non-discriminatory manner."[131] SEIA is pleased that under the Settlement Agreement, residential DG customers can take service under the same TOU tariff that is available to non-DG customers. In regard to the settled RCP price, SEIA states that while it is below what SEIA would have recommended, SEIA supports the Settlement Agreement outcome as reasonable. SEIA is also supportive of the Settlement Agreement's grandfathering provisions for DG customers, because they preserve the expectations of solar DG customers at the time they invested in solar DG; they provide a reasonable window for customers currently pursuing solar DG to complete their installations; they are fair; and they are consistent with Decision No. 75859. SEIA states that the Settlement Agreement resolves policy disputes between APS, Staff, RUCO and the solar industry "in favor of stable solar policies and rates up through APS's next rate case so long as the Settlement Agreement is approved without material modification" and recommends its approval.[132]

EFCA states that the provisions of the Settlement Agreement that promote the continued expansion of DG (choice of rate schedules for DG customers, setting the RCP, and grandfathering solar DG customers) are of great benefit, because they will reduce the time and resources of the Commission

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[128] *Id.* at 5, 8.
[129] SEIA Br. at 4, citing to Hearing Exhibit SEIA-2 (Direct Testimony of Sara Birmingham on the Settlement Agreement) at 5.
[130] SEIA Br. at 4.
[131] *Id.* at 3.
[132] *Id.* at 2, 7.

that would otherwise be expended on litigation.[133] EFCA agrees with the Settling Parties that the Settlement Agreement presents a fair and balanced compromise, and will ultimately benefit APS's customers. EFCA recognizes that the Commission has the discretion to reject the Settlement Agreement in whole or in part, and reserves the right to object to and appeal any Commission Decision that denies or modifies any aspect of the Settlement Agreement.[134]

RUCO notes that a significant benefit of the Settlement Agreement is the progress it makes on modernizing rates and minimizing the cost shift from DG to non-DG customers, while still allowing the rooftop solar industry to transact.[135]

In regard to the Settlement Agreement provisions relating to rooftop solar, Staff states:

> A critical cornerstone of the heavily negotiated balance struck on these contentious issues is the agreement of parties to withdraw any appeals of the Commission's VOS orders, Decisions No. 75859 and 75932. Paragraph XXXV of the Settlement requires Signatories to withdraw any pending challenges to Decisions No. 75859 and 75932 and to refrain from pursuing any challenges to either Decision in any forum. Further, the Agreement requires a stay of any pending appeals of these Decisions until a final order is issued in the present matter that adopts the material terms of the Agreement. In concert with other provisions of the Settlement that require Signatories to mutually support and defend a Commission Order that adopts all material terms of the Settlement, a separate agreement was executed between APS, the solar providers and their respective affiliates as well as several others, wherein the signatories agree not to take steps to undermine the Agreement in any forum through ballot initiative, legislation, or advocacy.[136]

m. AG-X Program

Freeport and AECC (a customer group), along with Calpine, CNE, and Direct Energy (generation service providers, or "GSPs" who are serving customers under APS's current AG-1 tariff) support the Settlement Agreement as a whole, but their particular concern is the negotiated outcome of the AG-X program, which is detailed in Section 23 of the Settlement Agreement, and further depicted in Attachment K to the Settlement Agreement.[137] Freeport, AECC, Calpine, CNE, and Direct Energy state that the AG-X program modifies the existing AG-1 program which was initially approved in

133 EFCA Br. at 23.
134 EFCA Reply Br. at 19.
135 RUCO Br. at 4.
136 Staff Br. at 17.
137 Freeport, AECC, Calpine, CNE, and Direct Energy Br. at 4 and Reply Br. at 7.

Decision No. 73183 (May 24, 2012) in the form of APS's Experimental Rate Rider AG-1.[138] The AG-1 program is a "buy-through" program under which participating large commercial and industrial customers may obtain generation from third-party GSPs to serve all or a portion of their power requirements, and Freeport, AECC, Calpine, CNE, and Direct Energy state that it is an example of the "mixed competition-regulation" rate design model that has recently emerged in the electric utility industry and represents a means of effecting needed changes to the existing regulatory framework to accommodate changing conditions.[139] Participating AG-1 customers, who were selected by means of a lottery conducted by APS, remain APS customers for their other electric service needs, including transmission and distribution service.

The Settlement Agreement proposes continuation of the experimental AG-1 program in the form of the AG-X program, which is no longer characterized as experimental. Freeport, AECC, Calpine, CNE, and Direct Energy state that "the continuation of APS's existing AG-1 'buy-through' program, as modified in the form of the AG-X program, represents a constructive means for continuing to advance [current] rate design objectives with respect to large commercial and industrial customers on APS's system.[140] Freeport, AECC, Calpine, CNE, and Direct Energy describe the positions of various parties to adjust APS's existing rate schedules to "(i) more properly reflect the realities of a rapidly and significantly changing electric utility industry, and (ii) better match cost causation and rate recovery responsibility" and believe that the AG-X program proposed in the Settlement Agreement meets those rate design objectives.[141] Accordingly, Freeport, AECC, Calpine, CNE, and Direct Energy believe the Commission should approve the AG-X program, in conjunction with its approval of the Settlement Agreement in its entirety.

Walmart is also a participant in the current AG-1 program, and takes service from a GSP at 53 of its 73 retail locations in the APS service territory.[142] Noting that the Settlement Agreement, to which it is a party, includes provisions that APS will not file a new base rate application until at least June 1,

[138] Freeport, AECC, Calpine, CNE, and Direct Energy Br. at 2-3 (detailing the history of the AG-1 program from inception through the present).

[139] Freeport, AECC, Calpine, CNE, and Direct Energy Br. at 3; Freeport, AECC, Calpine, CNE, and Direct Energy Reply Br. at 4.

[140] Freeport, AECC, Calpine, CNE, and Direct Energy Reply Br. at 3.

[141] *Id.* at 3-6.

[142] Walmart Br. at 1, citing to Hearing Exhibit Walmart-1 (Direct Testimony of Gregory Tillman) at 3.

2019, and also that it retains a buy-through program, now to be known as AG-X, which is a somewhat modified, non-experimental version of the current AG-1 program, Walmart urges the Commission to adopt the Settlement Agreement.[143]

Staff states that the Settlement Agreement's AG-X program provides for a continuation of the AG-1 program with changes that anticipate and prevent the under-recovery issues presented by the AG-1 tariff, improve upon other aspects of the program, and expand it to allow more opportunity for qualifying General Service customers to participate.[144]

n. Power Procurement Audit

Decision No. 73183 required Staff to perform an audit of APS's fuel and purchase power activities. APS requests approval of Staff witness Dennis Schumaker's recommendations regarding the fuel and purchase power audit, with requested modifications from APS, agreed to by Staff.[145] APS proposes that the time allowed for APS to conduct an audit of its PSA filings as required by Staff Recommendation No. III-2 be extended from twelve months to eighteen months, in order to allow APS sufficient time to fully implement Staff's other recommendations prior to auditing the PSA filings.[146] Staff agreed to this modification.[147] APS also proposes that Staff Recommendation No. III-5, which would require APS to reconfigure its systems to disallow transactions when a counterparty is overexposed, be removed, due to unintended negative consequences to reliability that could result.[148] Staff also agreed to this modification, noting that APS has other ways built into its system to flag potential credit and over-exposure issues.[149]

The results of Staff's audit of APS's fuel and purchase power activities and resulting recommendations are reasonable and should be adopted. APS will be required to comply with Staff's

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[143] Walmart Br. at 1-2.

[144] Staff Br. at 15, citing to Hearing Exhibit APS-6 (Direct Testimony of Charles Miessner on the Settlement Agreement) at 15.

[145] APS Br. at 67, citing to Hearing Exhibit APS-3 (Rebuttal Testimony of Barbara Lockwood on the Settlement Agreement) at 10-11 and Tr. at 735-737 (Staff witness Schumaker).

[146] APS Br. at 67, citing to Hearing Exhibit APS-3 (Rebuttal Testimony of Barbara Lockwood on the Settlement Agreement) at 10.

[147] APS Br. at 67, citing to Tr. at 735-36 (Staff witness Schumaker).

[148] APS Br. at 67, citing to Hearing Exhibit APS-3 (Rebuttal Testimony of Barbara Lockwood on the Settlement Agreement) at 10-11.

[149] APS Br. at 67, citing to Tr. at 737 (Staff witness Schumaker).

recommendations, with the exception of the modifications to Staff Recommendation No. III-2 and Staff Recommendation No. III-5, as proposed by APS and agreed to by Staff.

V. SUBSTANTIVELY DISPUTED SETTLEMENT AGREEMENT ISSUES

a. Use of Unspent DSMAC Funds

To mitigate the first year bill impacts, the Settling Parties agreed that APS will refund to customers through the DSMAC $15 million in collected, but unspent DSMAC funds.[150]

i. SWEEP

SWEEP opposes this refund of DSMAC funds, and proposes instead that any use of, or any timely refund of, the DSMAC unspent funds be addressed in the DSM Implementation Plan proceeding instead of in this rate case proceeding.[151] SWEEP argues that its proposed process would provide adequate due process in a proceeding that is focused on DSM issues.[152] SWEEP is concerned that if the unspent DSMAC funds are not used to fund DSM programs, APS will have insufficient funds to adequately support those programs and customer projects.[153] SWEEP asserts that for the third year in a row, the funding for the APS DSM budget has been short of that needed to support DSM programs and meet customer needs, and that unspent funds could be used to make up the difference, as the Commission has ordered in the past.[154] SWEEP is concerned that if the unspent funds are ordered refunded in this proceeding, customers and stakeholders will not have been aware of the Settlement Agreement proposal or have had an opportunity to participate, and that the issues in this rate proceeding are not directly relevant to the scope and focus of the DSM proceeding.[155]

In response to Staff's statement on brief that the unspent DSMAC funds are not funding any programs that would be terminated as a result of the Settlement Agreement proposed refund, SWEEP states that it is concerned not just with termination of programs, but with reductions in spending and reductions in customer incentives.[156]

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[150] Settlement Agreement Section 4 (page 9).
[151] SWEEP Br. at 5, 19.
[152] *Id.* at 5.
[153] *Id.* at 19.
[154] *Id.*; SWEEP Reply Br. at 9.
[155] SWEEP Br. at 20; SWEEP Reply Br. at 11.
[156] SWEEP Reply Br. at 9.

SWEEP contends that "in April 2017, APS reduced custom incentive levels for its commercial and industrial customers by 45% and cut the incentives for customer studies by 50% because it has insufficient DSMAC funds to meet customer interest in the programs."[157] SWEEP charges that APS's arguments ignore that its DSM programs are facing a funding shortfall in 2017, and that DSMAC unspent funds could be used to provide adequate and stable funding for those programs, in the manner the Commission ordered in 2015 and 2016.[158]

SWEEP contends that the magnitude of the rate increase in the Settlement Agreement (4.54% for the residential class) does not require the gradualism that APS argues the refund of the unspent DSMAC funds would provide.[159]

ii. APS

APS states that the Settling Parties agreed that the $15 million of unspent and unallocated DSMAC funds should be returned to customers now. APS asserts that returning the funds to customers is always within the Commission's discretion, and that a refund at this time, rather than waiting for a subsequent proceeding, would provide some gradualism for any rate increase ordered in this matter. APS contends that using the unspent DSMAC funds would not impact existing DSM programs or customers, and that, to the extent needed, the Commission can modify the DSMAC to collect additional funds as necessary for the 2017 DSM Implementation Plan or budget. [160]

iii. Staff

Staff believes that SWEEP's opposition to refunding the $15 million of unspent DSMAC funds is without merit, and states that if it were adopted, the delicate balance reached by widely divergent parties to the Settlement Agreement would be disturbed.[161] Staff states that SWEEP acknowledges that the funds in question are not funding any current programs that would be terminated as a result of the refund of this ratepayer money, and admits that nothing would prevent the Commission from ordering a refund, either through approval of the Settlement Agreement, or through APS's DSM Implementation

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[157] *Id.*, citing to Hearing Exhibit SWEEP 4 (Rebuttal Testimony of Jeff Schlegel on the Settlement Agreement) at 13-14.
[158] SWEEP Reply Br. at 8-10.
[159] *Id.* at 11
[160] APS Br. at 55-56.
[161] Staff Br. at 24.

Plan proceeding.[162] Staff contends that the Commission retains the ability to modify the level of the DSMAC to collect sufficient funds to accomplish the Commission's priorities, which can address SWEEP's concerns regarding adequate support for programs and customer projects. Staff argues that SWEEP's due process arguments are without merit, because it is Staff's understanding that the $15 million refund to ratepayers will actually take place in the DSM docket, after approval of the Settlement Agreement in this proceeding.[163] Staff believes that the provision regarding the refund of $15 million in collected but unspent DSMAC funds to ratepayers to mitigate the first year rate impacts to ratepayers should be approved.

iv. Resolution

After examining and considering the facts and arguments presented regarding the Settlement Agreement's provision regarding the refund of $15 million in collected but unspent DSMAC funds to ratepayers to mitigate the first year rate impacts to ratepayers, we find that the provision is well-supported, reasonable, and in the public interest.

b. AZ Sun II

Section 28 of the Settlement Agreement pertains to approval of the proposed AZ Sun II program, under which APS will use third-party solar contractors, competitively selected through an RFP process, to install rooftop solar systems on the roofs of low- and moderate-income homeowners. Under the Settlement Agreement, APS will propose a program of $10 - $15 million per year in direct capital costs. The Settlement Agreement provides that expenses of the program eligible for recovery, including capital carrying costs, may be reviewed for prudence in each annual REST docket, and will be recoverable through APS's Renewable Energy Adjustment Clause until its next rate case, when APS may request that the capital costs of the installed solar systems be included in rate base.[164]

i. Mr. Gayer

Mr. Gayer asserts that the AZ Sun II program is "worthless," "wastes customers' money," and "unfairly competes with private solar installers."[165] Mr. Gayer argues that his Hearing Exhibit Gayer-

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[162] *Id.*, citing to Tr. at 1143, 1167-68 (SWEEP witness Schlegel).
[163] Staff Reply Br. at 6.
[164] Settlement Agreement Section 28 (pages 24-23).
[165] Gayer Br. at 14-15, citing to Tr. at 78-82 (public comment of Dru Bacon).

17 demonstrates that "all 1.2 million APS customers will pay 87 cents per month for AZ Sun II."[166] Mr. Gayer proposes that if the AZ Sun II proposal is approved, the Commission order that all of APS's customers should also share the cost of reading non-AMI meters.[167]

ii. APS

APS states that the AZ Sun II program is a creative and reasonable negotiation outcome that will help meet the needs and interests of various parties in this case, and emphasizes that the outcome is one which would not have resulted from a litigated proceeding. APS points out that the AZ Sun II provisions include an agreement by APS not to implement any additional utility-owned residential solar DG programs prior to APS's next general rate case.[168]

iii. ConservAmerica

ConservAmerica asserts that while the impact of the proposed AZ Sun II on residential customers would be small, the benefits would be great. ConservAmerica disputes the validity of the inputs to Hearing Exhibit Gayer-17, and of the conclusions Mr. Gayer attempts to draw from it. ConservAmerica explains that Hearing Exhibit Gayer-17 is flawed, because it assumes that the $10 to $15 million in AZ Sun II costs would be recovered directly from APS customers. Instead, as ConserveAmerica explains, the $10 to $15 million in capital costs would be APS-invested funds, which if put into rate base in a future rate case, would then be eligible to earn a return which would be calculated into the revenue requirement, and that only a portion of the resulting revenue requirement would be recovered from residential ratepayers.[169]

In response to Mr. Gayer's charge that the AZ Sun II program would create unfair competition with solar installers, ConservAmerica points out that Settling Parties to this case who represent actual solar companies do not share Mr. Gayer's view, and that Mr. Gayer cited to public comment, and not evidence, for this allegation. ConservAmerica asserts that AZ Sun II is targeted at the underserved market of low- and moderate- income APS customers, and will therefore have little effect on rooftop solar competition.[170]

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166 Gayer Br. at 15, citing to Hearing Exhibit Gayer-17.
167 Gayer Br. at 15, 16; Gayer Reply Br. at 10.
168 APS Br. at 15, 16.
169 ConservAmerica Reply Br. at 7.
170 *Id.*

ConservAmerica's witness testified that subsidized rooftop solar in Arizona benefits the wealthy, and leaves the poor behind.[171] ConservAmerica contends that this should change, and believes that the AZ Sun II program would provide a "small but good start at broadening access to rooftop solar in Arizona" with 65% of funding dedicated to low-income customers, and the remainder available for either low- or moderate-income customers.[172]

iv. ACAA

ACAA states that the AZ Sun II program will provide the option to "go solar" for thousands of low-income households who previously did not have such an opportunity, and that with a credit of up to $600 per year, electric bills will be much more affordable for these low-income customers.[173]

v. RUCO

RUCO states that the Settlement Agreement's AZ Sun II program will provide benefits to ratepayers beyond this rate case by making utility-owned solar DG available to low- and moderate-income APS customers, a segment of APS customers who have not heretofore been able to participate in solar DG for financial reasons.[174]

vi. Staff

Staff states that through adoption of the AZ Sun II program, lower- and moderate-income residential customers, as well as certain schools and rural municipalities, will have the opportunity to install rooftop solar facilities and receive a monthly bill credit in exchange for granting APS rooftop access.[175] The program requires APS to invest between $10 and $15 million annually over a term of three years, with at least 65 percent of each year's annual program expenditure dedicated to residential installations.[176]

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171 ConservAmerica Br. at 4-5; ConservAmerica Reply Br. at 7, 8 citing to Hearing Exhibit ConservAmerica-1 (Direct Testimony of Paul Walker) at 9-14 and Hearing Exhibit ConsevrAmerica-3 (Direct Testimony of Paul Walker on the Settlement Agreement) at 12-13 (wealthiest neighborhoods in Arizona have a solar penetration rate of 2.99% and poorest neighborhoods 0.82%).

172 ConservAmerica Br. at 5.

173 ACAA Br. at 3.

174 RUCO Br. at 3.

175 Staff Br. at 14.

176 *Id.*

vii. Resolution

After examining and considering the facts and arguments presented regarding the Settlement Agreement's provision regarding the AZ Sun II program, we find that the provision is well-supported, reasonable, and in the public interest.

Mr. Gayer's proposal regarding the costs of reading non-AMI meters will be addressed in a forthcoming separate Decision in this docket.

c. Disputed Rate Design Issues

i. **Basic Service Charges ("BSCs")**

The following table depicts the BSCs proposed by the Settlement Agreement, SWEEP, and AARP:

Settlement Agreement Rate Schedule	Residential Extra Small **R-XS**	Residential Basic **R-Basic**	Residential Basic Large **R-Basic Large**	Time of Use **R-TOU-E**	3-Part Demand Rates **R-2 & R-3**	On-Site Technology Pilot Program **R-Tech[177]**
Rate Schedule Qualifications	(≤ 600 kWh/month)	(600-1000 kWh/month)	(≥ 1000 kWh/month)	(Available to all customers)	(Available to all customers)	Appendix F to Settlement Agreement[178]
Current BSC On Current Similar Rate Schedule	$8.67 (E-12 Residential-Basic)	$8.67 (E-12 Residential-Basic)	$8.67 (E-12 Residential-Basic)	$17.00 (Time Advantage Rate)	$17.00 (Time Advantage Rate)	N/A
Settlement Agreement BSC[179]	$10.00	$15.00	$20.00	$13.00	$13.00	$15.00
APS Fixed Cost Calculations for BSC[180]	$24.51	$24.51	$24.51	$29.79	$34.12	N/A

[177] R-Tech is a TOU rate with on-peak and off-peak demand and energy charges, initially available to up to 10,000 customers, to help reduce APS's system peak. APS Br. at 10. This experimental rate was developed to incentivize technology adoption, RUCO Br. at 3, and is available to customers that adopt certain home energy technologies such as battery storage. Staff Br. at 17. The R-Tech three-part pilot rate program is for residential customers with two or more qualifying primary on-site technologies, that also includes a BSC, and one TOU rate available to all customers with a BSC for non-DG customers and a Grid Access Charge for DG customers. Vote Solar Br. at 7. The Settlement Agreement provides that the Commission will review the R-Tech rate once 6,000 customers have signed up for it. EFCA Reply Br. at 19-20, citing to Section 17.1 of the Settlement Agreement. The R-Tech rate is intended to lead to lower costs to ratepayers in the future. RUCO Br. at 3.

[178] Settlement Agreement at Appendix F.

[179] Settlement Agreement Sections 17.1-17.7 (pages 17-19)

[180] APS Reply Br. at 9, referring to Hearing Exhibit APS-32 (outlining fixed costs to serve by customer class and rate, from the Cost of Service Study).

SWEEP BSC (Based on its Fixed Cost Calculations)[181]	$8.00	$8.00 or $10.00	$8.00 or $10.00	$8.00	not addressed	not addressed
AARP BSC[182]	not opposed	$10.00 to $13.00	not opposed	not opposed	not addressed	not addressed

1. SWEEP

SWEEP does not contest the revenue requirement or the size of the R-XS, R-Basic, or Small General Service bill increases overall on average.[183] However, SWEEP opposes the BSCs proposed in the Settlement Agreement for residential, extra small general service, and small general service customers, based on its assertion that the Settlement Agreement BSCs are "very large increases in fixed charges."[184] SWEEP contends that the Settlement Agreement's increases to the BSCs would cause customers "with different usage levels" to experience "unfair, unjust, and unreasonable bill impacts."[185] SWEEP argues that because the Settlement Agreement rate design increases the BSC, which is a fixed charge portion of customers' bills, it "would result in the loss of customers' control over a significant portion of their utility bills."[186]

SWEEP finds it problematic that under the Settlement Agreement proposed BSCs, some customers will experience a higher percentage increase in their BSCs than in their overall bill amounts.[187] SWEEP contends that this leaves such customers with no meaningful opportunity to mitigate the effect of the overall bill increase.[188] SWEEP believes "[i]t is crucial for the Commission to examine and consider the range of significant bill impacts on real customers in its review of the Settlement Agreement."[189] SWEEP contends that the BSCs approved in TEP's recent rate Decision

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[181] SWEEP Br. at 5. SWEEP also proposes that the General Service Extra-Small BSC and the Small General Service BSC rates both be set at $12.00 as opposed to those rates set forth in Appendix G to the Settlement Agreement.
[182] AARP Br. at 3-6.
[183] SWEEP Br. at 6, citing to Tr. at 1118 (SWEEP witness Schlegel).
[184] *Id.*
[185] SWEEP Br. at 6, 14, citing to Tr. at 1118, 1134 (SWEEP witness Schlegel); SWEEP Reply Br. at 5-6, citing to Tr. at 1121 (SWEEP witness Schlegel).
[186] SWEEP Br. at 6, citing to Tr. at 1118, (SWEEP witness Schlegel); *See also* SWEEP Br. at 11, and SWEEP Reply Br. at 5, citing to Hearing Exhibit SWEEP-4 (Rebuttal Testimony of Jeff Schlegel on the Settlement Agreement) at 10, and SWEEP Br. at 14.
[187] SWEEP Br. at 10, SWEEP Reply Br. at 5, citing to Hearing Exhibit SWEEP-6. *See also* SWEEP Br. at 11-14, citing to Tr. at 1119-1121 and 1128-1135 (SWEEP witness Schlegel), and to Hearing Exhibit SWEEP-8A.
[188] SWEEP Br. at 10, SWEEP Reply Br. at 5, citing to Hearing Exhibit SWEEP-6.
[189] SWEEP Br. at 6, 14, citing to Tr. at 1121 (SWEEP witness Schlegel).

are the "appropriate point of comparison" for Commission consideration in this case.[190] SWEEP disagrees with APS that the Settlement Agreement proposed BSCs are consistent with those approved for TEP.[191]

SWEEP proposes that the Residential Basic rates be set at $7.97 (or rounded up to $8.00) for R-XS, R-Basic, R-Basic Large, and TOU-E rates.[192] SWEEP believes that its proposed BSCs "would eliminate or reduce the unfair effects of the Settlement-proposed rates and higher BSCs on customers and the bill impacts."[193] SWEEP alternatively proposes that should the Commission wish to incentivize uptake of the TOU-E rate through the BSC, the R-XS and TOU-E BSCs be set at $7.97 (or rounded up to $8.00), and set the R-Basic and R-Basic Large rates at $10.[194]

SWEEP contends that the Settlement Agreement BSCs for R-XS, R-Basic, R-Basic Large, General Service Extra-Small and the Small General Service, which were derived through the settlement compromise process, are not cost-based or cost justified, and that only SWEEP's proposed BSCs are cost-justified.[195] SWEEP disagrees with APS that the purpose of the BSCs should be to reflect the larger category of fixed costs of service.[196] SWEEP argues that only costs that vary with the number of customers should be used to determine the BSC, and not all the larger category of fixed costs, which do not vary with the number of customers.[197] SWEEP criticizes the Settlement Agreement BSCs because they include some distribution costs, and some costs that are not customer related.[198] SWEEP asserts that the Settlement Agreement BSCs should not include transformer costs, even though they are near a customer's residence, because transformer size and the number of transformers are both based on load, and not on the number of customers.[199] SWEEP asserts that the load a customer places on the

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[190] SWEEP Br. at 6, 15.
[191] *Id.* at 15.
[192] *Id.* at 5.
[193] *Id.* at 14, citing to Hearing Exhibit SWEEP-8A.
[194] SWEEP Br. at 5.
[195] *Id.* at 10; SWEEP Reply Br. at 5
[196] SWEEP Br. at 9-10; SWEEP Reply Br. at 4-5, citing to Tr. at 341 (APS witness Miessner) and 1122-23 (SWEEP witness Schlegel).
[197] SWEEP Br. at 9-10; SWEEP Reply Br. at 5, citing to Tr. at 341 (APS witness Miessner) and 1122-23 (SWEEP witness Schlegel).
[198] SWEEP Br. at 9; SWEEP Reply Br. at 4, citing to Hearing Exhibit APS-32 (APS Data Response Staff 5.23) and Hearing Exhibit SWEEP-3 (Direct Testimony of Jeff Schlegel on the Settlement Agreement) at 6.
[199] SWEEP Br. at 9.

system can vary greatly, depending on how much energy a given customer can consume (such as, for instance, the difference between a small apartment residence load and a 10,000 sq. ft. residence load).[200]

SWEEP states that the customer costs included in its proposed BSCs are based on FERC accounts and account numbers consistent with the Uniform System of Accounts for Public Utilities ("USOA").[201] SWEEP summed the customer costs contained in the FERC USOA accounts for APS's meters, meter reading, billing, and customer services costs in order to reach its recommended BSCs.[202] SWEEP states that it included APS's costs for the appropriate FERC USOA plant and expense accounts.[203] SWEEP contends that the end result of its BSC analysis is "an objective and evidence-based, bottom-up summation of the appropriate customer costs as the basis for the BSCs."[204] SWEEP contends that the Basic Service Method it used to calculate its proposed BSCs is based on cost causation and is the only equitable method for calculating BSCs.[205]

2. <u>AARP</u>

AARP opposes the Settlement Agreement's proposed BSCs, stating that it is concerned by the "dramatic increase in the fixed charge for most R-Basic customers to $15.00."[206] AARP contends that the BSC for R-Basic customers should be set at $10.00, or no higher than $13.00 per month, with the energy rate adjusted accordingly.[207] AARP states that such a change to the Settlement Agreement rate design "would be a very minor adjustment, a change that leaves APS revenue neutral. But nonetheless, it would be a change that could result in significant savings for many customers."[208] AARP states that this would make the R-Basic BSC more comparable with the Settlement Agreement proposed BSC for TOU customers.[209]

AARP is not requesting any change to the Settlement Agreement proposed BSCs for R-Basic Large customers of $20.00, or the Settlement Agreement proposed BSCs for R-XS customers of

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[200] *Id.*
[201] SWEEP Br. at 8-9; SWEEP Reply Br. at 4, citing to Hearing Exhibit SWEEP-5 and Tr. at 1125-1128 (SWEEP witness Schlegel).
[202] SWEEP Br. at 9, SWEEP Reply Br. at 4, citing to Tr. at 1124-1128 (SWEEP witness Schlegel).
[203] SWEEP Br. at 9, SWEEP Reply Br. at 4, citing to Tr. at 1124-1128 (SWEEP witness Schlegel).
[204] SWEEP Br. at 9, SWEEP Reply Br. at 4, citing to Tr. at 1128 (SWEEP witness Schlegel).
[205] SWEEP Br. at 7, SWEEP Reply Br. at 3.
[206] AARP Br. at 3.
[207] AARP Br. at 3-6.
[208] AARP Br. at 6.
[209] AARP Br. at 6.

\$10.00.[210] AARP believes that "[c]harging residential customers too much in the BSC, limits the ability of those customers to control their monthly bills and reduces the incentive for energy efficiency and energy conservation measures, especially for low usage customers."[211] AARP agrees with SWEEP's position that the BSC should include only direct costs which vary with the number of customers on the system, including meters, billing, the service drop, and customer installation expense,[212] and believes that SWEEP's methodology would produce a much lower BSC than the Settlement Agreement Proposal.[213] AARP contends that the BSC proposed in the Settlement Agreement for R-Basic customers does not meet the ratemaking principles of public acceptability, gradualism, or simplicity.[214]

3. Mr. Woodward

Mr. Woodward supports the arguments of AARP and SWEEP to lessen the BSCs on standard rates.[215]

4. APS

APS asserts that the Settlement Agreement's tiered BSCs are reasonable, cost-based, further good rate policy, and are consistent with prior Commission Decisions.[216] APS contends that the non-settling parties' objections to the BSCs agreed upon by the Settling Parties overlook actual fixed costs incurred to serve customers, and due to Distributed Generation, placing fixed costs in volumetric rates unduly risks exacerbating the cost shift.[217] APS states that the Settlement Agreement rate design would reduce BSCs for more than 50 percent of APS's customers.[218] APS contends that it incurs approximately \$28 per month in fixed costs to serve its customers, as measured by the straight Basic Customer Method,[219] and that the Settlement Agreement BSCs reflect compromises with a diverse

210 AARP Br. at 4.
211 AAPR Br. at 4, citing to Hearing Exhibit AARP-1 (Direct Testimony of John B. Coffman on the Settlement Agreement) at 3; AARP Br. at 5.
212 AARP Br. at 5, citing to Hearing Exhibit SWEEP-3 (Direct Testimony of Jeff Schlegel on the Settlement Agreement) at 6.
213 AARP Br. at 5.
214 AARP Br. at 5.
215 Woodward Br. at 42, Reply Br. at 23.
216 APS Br. at 61-66; APS Reply Br. at 7-10.
217 APS Br. at 61-66.
218 *Id.*, citing to Tr. at 299 (APS witness Lockwood) and 1153 (SWEEP witness Schlegel).
219 APS Br. at 62, citing to Tr. at 802 and 845 (APS witness Snook); APS Reply Br. at 8, referring to Hearing Exhibit APS-32 (the range by residential rate is between \$24 and \$34, and includes revenue cycle costs, such as metering, billing, customer service, and certain distribution related costs).

group of interests represented by the Settling Parties. APS contends that any BSC below $28.52 is cost-justified, regardless of SWEEP's assertions to the contrary.[220]

Customers receiving an increase in their BSC under the Settlement Agreement are free to choose the new TOU-E rate or a time-based demand rate, which have BSCs of $13 in addition to providing an opportunity to save money by shifting usage.[221] Additionally, the Settlement Agreement increases and simplifies assistance to low-income customers.[222]

APS criticizes SWEEP's calculation of BSCs because it omits the costs of service drops and customer facilities, both of which should be included when calculating a BSC under the Basic Customer Method.[223] APS points out that SWEEP's witness acknowledged that the Settlement Agreement's R-Basic BSC charge does not recover all APS's fixed costs.[224] APS asserts that SWEEP's position also overlooks the fact that because residential DG customers self-supply a portion of their volumetric needs, if recovery of fixed costs is left in volumetric rates instead of moved to BSCs, costs will be shifted to residential customers without DG, including limited income customers.[225] APS states that the dynamic caused by the integration of DG limits the flexibility of policy decisions regarding the nature and size of basic service charges.[226]

APS notes that neither SWEEP nor AARP contest the agreed upon revenue requirement, but that they are contesting only the allocation of costs between the BSCs and volumetric energy charges for the higher-usage customers on standard, non-time differentiated rates.[227] APS responds that the BSCs agreed to by the Settling Parties are cost-based, designed to recover fixed costs in a fair manner, and are supported by the evidence.[228] In response to SWEEP's claims that some customers could experience larger bill impacts than average, APS acknowledges that even using the best rate design practices, sometimes customers within a class, or near the border between two rate classes, will experience anomalous results, but such anomalies do not render a rate structure unfair, provided that

[220] APS Reply Br. at 8.
[221] APS Br. at 63.
[222] APS Br. at 63, citing to Settlement Agreement Sections 29.1-29.3 (pages 26-27).
[223] APS Br. at 64, citing to Tr. at 801-802 and 843-844 (APS witness Snook).
[224] APS Br. at 64-65, citing to Tr. at 1153 (SWEEP witness Schlegel).
[225] APS Br. at 65-66.
[226] *Id.* at 66.
[227] APS Reply Br. at 7.
[228] *Id.*

the overall impacts to the majority of customers are fair and reasonable.[229] APS believes that the support of the Settlement Agreement by a broad range of diverse customer interests attests to the fair and balanced nature of the rate design, and asserts that SWEEP's claims do not provide a reason to condemn the entire structure of the BSCs, but instead strengthens the case for offering a strong and effective customer education program regarding the transition to the new rate structure.[230]

APS asserts that the Settling Parties in this case are proposing a BSC structure consistent with that the Commission recently adopted in Decision Nos. 75697 (August 18, 2016)(UNS Electric, Inc. ("UNSE") Rates) and 75975 (February 24, 2017) (TEP Rates), in order to address the changing load characteristics of the residential customer class.[231] The BSC structure includes higher BSCs for higher-usage customers who choose to stay on standard two-part rates, in order to incent them to move to time- or demand-differentiated rates. APS argues that SWEEP's proposal for BSCs that collect the "bare minimum" of costs through the BSCs goes against the Commission's policy adopted in the recent UNSE and TEP Rate Decisions to incentivize customers to try rate plans that can benefit them with cost savings on their bills and potential system peak reductions.[232]

5. AIC

AIC submits that to keep up with the evolution of the electric power grid, utility rate design must evolve too, and that rates need to provide a utility with an opportunity to recover its fixed costs while also allowing customers options for installing cost-effective behind-the-meter technologies that offer them an opportunity to save energy and money.[233] AIC contends that the Settlement Agreement rate design appropriately uses the BSC to recover fixed costs while at the same time acting as a price signal to influence customer choice of rate plans.[234] AIC explains that charging a lower BSC for time-differentiated or time and demand-differentiated rate plans was deliberate on the part of the Settling Parties, in order to incentivize customers to choose such a plan, and to send a more accurate price signal to a greater number of customers.[235] AIC points out that if the Commission were to change the BSCs

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[229] APS Rely Br. at 9-10.
[230] *Id.* at 10.
[231] APS Reply Br. at 11, citing to Decision No. 75697 at 64, 66 and Decision No. 75975 at 64.
[232] APS Reply Br. at 12.
[233] AIC Br. at 1; AIC Reply Br. at 3.
[234] AIC Br. at 5.
[235] *Id.* at 6, citing to Tr. at 171 (APS witness Lockwood).

to a lower dollar amount as advocated by some parties, the energy rate would have to increase accordingly,[236] and stresses that putting cost recovery into the energy rate would exacerbate the shifting of cost recovery from those with consumption-lowering behind-the-meter technologies to those without such technologies.[237] AIC contends that the Settlement Agreement rate design reached an equitable balance, and that neither SWEEP's nor AARP's arguments to decrease the BSC warrant altering the Settlement Agreement at the expense of reducing the total benefit to all ratepayers.

AIC points out that SWEEP's and AARP's arguments overlook the fact that a customer with concerns about the BSC of a rate plan has a number of other rate plan options from which to choose. AIC believes that the compromise reached in the Settlement Agreement regarding BSCs is a balanced approach and should be adopted.[238]

6. ConservAmerica

ConservAmerica asserts that the current two-part rate design, which is focused on kWh sales for cost recovery, is broken in that it no longer makes sense from a social equity standpoint or from a cost-causation standpoint at a time when rooftop solar and other new technologies decrease billed kWh without reducing the fixed costs of the utility system.[239] ConservAmerica is concerned that because of the current decline in kWh (energy) sales, placing additional fixed costs in the energy usage charges "shifts these fixed costs from wealthier rooftop solar customers to poorer non-solar customers,"[240] and "will only enhance the growing inequities as more affluent customers adopt new technologies to limit or eliminate their kWh, while other customers are left behind to bear the costs."[241] ConservAmerica states that the amount of the fixed charges included in the BSCs is a matter of policy, and that there is no dispute that APS's fixed costs exceed any of the proposed BSCs in this proceeding. ConservAmerica argues that in a time when some customers have very little kWh usage but still cause significant fixed costs, fairness requires a BSC that adequately recovers fixed costs.

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236 AIC Br. at 6, citing to Tr. at 314 (APS witness Lockwood).
237 AIC Br. at 6.
238 *Id.*
239 ConservAmerica Br. at 2, citing to Hearing Exhibit ConservAmerica-2 (Direct Rate Design Testimony of Paul Walker) at 2, 10.
240 ConservAmerica Br. at 2, citing to Hearing Exhibit ConservAmerica-2 (Direct Rate Design Testimony of Paul Walker) at 15.
241 ConservAmerica Reply Br. at 3.

ConservAmerica points out SWEEP's acknowledgement that under the Settlement Agreement, a majority of customers will see a reduction in their BSCs.[242] In response to SWEEP's concerns of the impact of increases in BSCs on R-Basic and R-Basic Large customers, ConservAmerica states that the intent of the Settlement Agreement's higher BSCs for those rate plans is to encourage customers to move to time-differentiated or demand-differentiated rates and change their consumption behavior, which will benefit all customers by reducing system peak, thereby creating emissions and cost savings for everyone.[243] ConservAmerica contends that, as acknowledged by SWEEP's witness, moving from basic two-part rates to such rate plans will actually allow customers multiple opportunities to control their bill, while reducing costs.[244]

ConservAmerica states that the Settlement Agreement's R-Basic BSC of $15 is the same as that approved for UNSE, and less than the $20 BSC for the comparable rate charged by Salt River Project ("SRP").[245] ConservAmerica points out that, as acknowledged by AARP's witness, the higher BSC for the R-Basic rate plan is an incentive for customers to move to TOU and demand rate plans, as the Commission approved in the recent UNSE rate Decision.[246] In response to AARP's contention that a reduced BSC would be revenue neutral, ConservAmerica states that this is so only when considering the test year billing determinants in this case.[247] ConservAmerica states that as kWh sales continue to fall, it would not be revenue neutral, and more fixed costs would go unrecovered, necessitating a larger revenue requirement to be recovered in the next rate case.[248]

7. Vote Solar

Vote Solar contends that the seven different residential rate options in the Settlement Agreement, which would replace Vote Solar's preferred standard tiered rate, when considered with the balance of issues addressed by the Settlement Agreement, are reasonable and in the public interest.[249]

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[242] *Id.* at 4, citing to Tr. at 1151-52 (SWEEP witness Schlegel).
[243] ConservAmerica Br. at 2, citing to Tr. at 1264-65 (Staff witness Abinah); ConservAmerica Reply Br. at4.
[244] ConservAmerica Reply Br. at 4, citing to Tr. at 1151-52 (SWEEP witness Schlegel).
[245] ConservAmerica Br. at 3-4, citing to Hearing Exhibit ConservAmerica-4 (Rebuttal Testimony of Paul Walker on the Settlement Agreement) at 5-6.
[246] ConservAmerica Br. at 3, citing to Tr. at 707 (AARP witness Coffman).
[247] ConservAmerica Reply Br. at 3.
[248] *Id.* at 3-4.
[249] Vote Solar Br. at 7.

8. AURA

AURA states that it was concerned with APS's original proposals for mandatory three-part demand rates and high BSCs for residential customers, but that the Settlement Agreement resolved these concerns, with no mandatory demand rates for any residential ratepayer, and with many more rate design options for residential customers. AURA's witness testified that the "modest increases to basic service charge for customers under 600kWh/month and actual reductions to service charges for TOU and three-part-rate customers more than offset the larger (though lower than initially proposed) increases for customers using more than 600kWh/month." [250]

9. ACAA

ACAA states that the Settlement Agreement rate design provides a marked improvement over APS's initial request, in that it has no mandatory demand charges, but instead gives customers the option to enroll in a demand charge rate or not, and it has much lower BSCs for the R-XS rate than APS initially requested. ACAA notes that the BSC for R-XS is $10 under the Settlement Agreement, decreasing from $18. ACAA states that high BSCs affect low-income customers especially hard, because the average low-income customer uses less energy than the average non-low-income customer, and that the R-XS rate will allow low-income customers to better manage their bills.[251]

10. FEA

FEA believes that the spread of the revenue increase across customer classes represents a reasonable compromise on complex cost of service issues, and that the ultimate rates for retail customers proposed by the Settlement Agreement are reasonable.[252]

11. RUCO

RUCO states that while it does not dismiss the concerns raised by AARP and SWEEP on this issue, RUCO sees it from a different perspective. RUCO believes that the increase to the R-Basic rate is outweighed by the other benefits of the Settlement Agreement.[253] RUCO asserts that: 1) the focus by AARP and SWEEP on the increase to the BSC for R-Basic customers ignores the overall bill impact

[250] AURA Br. at 2-3, citing to Hearing Exhibit AURA-3 (Direct Testimony of Patrick Quinn on the Settlement Agreement) at 4-5, 6.
[251] ACAA Br. at 2-3.
[252] FEA Br. at 6.
[253] RUCO Br. at 5.

after the energy usage component is factored in; 2) the number of customers currently on rate plans equivalent to the R-Basic and R-Basic Large rate together constitutes a small percentage of APS's residential customers (approximately 18 percent) while approximately 82 percent will see either a decrease or a very small increase in their BSC;[254] 3) the Settlement Agreement BSC rate design is consistent with Commission precedent in recent rate cases for TEP and UNSE, where the Commission decided to incentivize customers to move to a TOU rate;[255] and 4) R-Basic customers who prefer a lower BSC have a variety of options from which to choose.[256]

12. Staff

Staff contends that the arguments of AARP and SWEEP in opposition to the BSCs proposed in the Settlement Agreement are not compelling.[257] Staff contends that AARP's criticism of the R-Basic BSC is without evidentiary support, other than AARP's opinion that $13 is "too high" and "higher than similar customers must pay under the most recent Arizona Commission decisions changing rates for UNS and TEP."[258] Staff points out that at the hearing, AARP's witness acknowledged that UNSE currently has a $15 BSC for most residential customers.[259] Staff also points out that AARP acknowledged that there are many components of the Settlement Agreement that would be beneficial to AARP membership in Arizona; that there are AARP members with various energy usage levels; that there are low-income AARP members who stand to benefit from the continuation and expansion of the low-income programs contained in the Settlement Agreement; and that AARP has acknowledged that several of the residential rate design provisions are appropriate, and AARP takes no issue with them.[260]

Staff states that SWEEP's position 1) overlooks the fact that the Settlement Agreement rate design continues to recover a significant portion of customer bills through volumetric charges that customers can reduce through efficiency measures; and 2) fails to address the cost recovery concerns of the utility or the necessary balancing of the wide-ranging interests accommodated by the Settlement

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[254] RUCO Br. at 5-6

[255] *Id.* at 6, citing to Decision No. 7596 at 65-66 and Decision No. 75975 at 64. RUCO points out that the $15 BSC in the UNSE case for a similar rate plan is the same as that proposed here in the Settlement Agreement.

[256] RUCO Br. at 6.

[257] Staff Br. at 21-22; Staff Reply Br. at 2-3, 6.

[258] Staff Br. at 21, citing to Hearing Exhibit AARP-1 (Rebuttal Testimony of John B. Coffman on the Settlement Agreement) at 4.

[259] Staff Br. at 21, citing to Tr. at 706-07.

[260] Staff Br. at 20.

Agreement.[261] Staff states that SWEEP attempts to justify its recommendation for lower BSCs by focusing on the percentage increases in the BSCs instead of on the overall bill impact percentage of the rate increase on customers. Staff explains that while on its face, some of the percent increases to the BSCs appear to be large, it is important to consider the overall rate increase impact of 4.54% for the average residential customer, pointing out that SWEEP does not take issue with the overall rate increase, or with the fact that APS incurs the costs included in the Settlement Agreement BSCs.[262] Staff notes that SWEEP is a nonprofit agency that advances its energy efficiency goals, and that its "narrowly focused advocacy promoting energy efficiency" drives SWEEP's proposal to put most of the rate increase into volumetric charges.[263] Staff points out that the Settlement Agreement rate design utilizes the same two methods, the Basic Customer Method and the Minimum System Method to calculate the BSCs that the Commission relied on to inform its policy decision in the recent TEP Rate Decision.[264] Staff states that while it would agree with SWEEP that BSCs should not be set based on what has been authorized for other electric utilities, a comparison to other Arizona electric utility BSCs can be an appropriate benchmark or factor to consider, among others.[265]

Staff contends that the rates as structured in the Settlement Agreement, including the BSCs, properly balance the needs of customers' continued ability to save through energy efficiency with the need for APS to better recover its authorized revenue requirement, and that the Settlement Agreement should be approved without modification.

13. Resolution

After examination of the evidence and the legal arguments on this contested issue, we find that the BSCs set forth in the Settlement Agreement reasonably and appropriately balance the interests of the ratepayers and the Company, and are in the public interest.

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[261] *Id.* at 23; Staff Reply Br. at 3.
[262] Staff Reply Br. at 2-3.
[263] Staff Br. at 23; Staff Reply Br. at 3.
[264] Staff Br. at 22-23; Staff Reply Br. at 2, citing to Decision No. 75975 at 64.
[265] Staff Reply Br. at 3.

ii. **Choice of Rate Plan / 90-Day Trial Period**

Section 19.1 of the Settlement Agreement provides as follows:

> All customers may select R-Basic, R-Basic Large, TOU-E, R-2, R-3, R-Tech or R-XS if they qualify until May 1, 2018, except to the extent grandfathered under other sections of this Settlement Agreement. Distributed Generation customers will not be eligible for R-XS, R-Basic or R-Basic Large. After May 1, 2018, R-Basic Large will no longer be available to new customers or customers who are on another rate. New customers after May 1, 2018 may choose TOU-E, R-2, R-3 or if they qualify, R-XS or R-Tech. After 90 days, new customers may opt-out of their current rate and select R-Basic if they qualify. Customers transitioning to R-Basic must stay on that rate for at least 12 months.[266]

1. <u>SWEEP</u>

SWEEP proposes that the Settlement Agreement's 90-day trial period for new customers be eliminated.[267] SWEEP believes that on their first day as an APS customer, customers should be allowed to choose their rate plan from among options for which they are eligible, without waiting 90 days.[268] SWEEP proposes that if the Commission approves the 90-day waiting period, the Commission should also require APS to notify customers of all rates available to them at the end of the 90-day period.[269]

In response to APS's assertion that a significant majority of customers will save money on the new rates, SWEEP responds "[i]f that is true, then customers will choose the rates that save them the most money."[270] SWEEP believes that with incentives for customers to move to time-of-use rates, the 90-day trial period is not justified.[271]

2. <u>AARP</u>

AARP opposes any limits on the availability of residential rate design options as proposed in Section 19.1 of the Settlement Agreement.[272] AARP requests that the Commission reject the provision in the Settlement Agreement that precludes new customers, after May 1, 2018, from choosing the R-Basic rate plan until after first taking service under a TOU plan for a period of 90 days.[273] AARP

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[266] Settlement Agreement Section 19.1 (page 20).
[267] SWEEP Br. at 5, 16; SWEEP Reply Br. at 7.
[268] SWEEP Br. at 6; SWEEP Reply Br. at 7.
[269] SWEEP Br. at 17; SWEEP Reply Br. at 8.
[270] SWEEP Reply Br. at 7.
[271] *Id.*
[272] AARP Br. at 3.
[273] *Id.* at 6, 8.

asserts that the 90-day trial period "is unnecessarily complicated and confusing, and it would prevent many customers from choosing the rate option that they believe is the best plan for them."[274] AARP argues that the 90-day trial period for new customers "would create a policy of discriminatory treatment towards new customers and would also create a high barrier for switching to a Basic rate plan later."[275] AARP contends that the 90-day trial period "would likely be confusing and frustrating for the affected customers, creating the need for considerable customer education."[276]

AARP alludes to "extreme difficulty" that a customer would face in attempting to switch to an R-Basic plan after the 90-day trial period, and states that AARP would expect most customers to be "confused about how to switch after 90 days."[277] AARP claims that "[i]t appears that the proposed 90-day provision is an attempt by APS to divert large numbers of unwitting residential customers onto a demand rate."[278]

AARP is concerned that the Settlement Agreement lacks specificity regarding how customers will be notified of their choice to change rate plans after the 90-day trial period has elapsed.[279] AARP proposes that if the 90-day trial period is adopted, APS be specifically required to provide written notification to new customers as to all of the rate options that will be available to them, including R-Basic, after the 90-day trial period has elapsed.[280] In addition, AARP proposes that APS be required to notify new customers at or about 90 days after they begin taking service on a TOU or Demand Rate plan of their eligibility to switch to an R-Basic plan.[281]

3. Mr. Gayer

Mr. Gayer contends that the Settlement Agreement's 90-day trial period for new customers is discriminatory under A.R.S. § 40-334; would violate new customers' due process rights; and would constitute a form of consumer fraud under A.R.S. § 44-1521 *et seq.*[282] Mr. Gayer believes new customers should be allowed to choose from any rate for which they qualify when they become a new

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[274] *Id.* at 8.
[275] *Id.*
[276] *Id.*
[277] AARP Br. at 7.
[278] AARP Br. at 7.
[279] *Id.*
[280] *Id.*. at 9.
[281] *Id.*
[282] Gayer Br. at 9-12.

customer and should not be required to take service for a 90-day trial period on a time-based rate.[283] Mr. Gayer proposes that if the Commission approves the 90-day trial period, APS should be required to inform new customers of their options sufficiently before the 90 days have passed so that their newly chosen rate will be effective on the date that the 90-day period expires.[284]

4. Mr. Woodward

Mr. Woodward asserts that the 90-day trial period for new customers to take service under TOU or demand rates is unjust because he believes they are unaffordable for some customers, and that it should be removed.[285] He supports the arguments of AARP and SWEEP to remove the 90-day trial period but if approved, to hold APS accountable for effective customer notification as to their options after the 90-day trial period. In addition, Mr. Woodward contends that APS should not receive $5 million to use for customer education on the new rate design proposals in the Settlement Agreement.[286]

5. APS

APS believes that AARP and SWEEP, in their opposition to the 90-day trial period provision of the Settlement Agreement, fail to consider the importance of how customer rate choices impact all customers and the system as a whole,[287] and that they fail to consider the balance that was struck in the Settlement Agreement between parties with widely divergent views.[288] APS states that the 90-day trial period in the Settlement Agreement would expose new customers to modern rates that are time- or demand-differentiated while still allowing them to move to rates that are not time- or demand-differentiated at the end of the 90-day trial period, when they will have a minimum of three rate plan choices.[289] APS states that data shows that a significant majority of APS customers will save money on time- or demand-differentiated rates, with savings occurring even before customers modify their behavior and shift usage.[290] However, customers whose average monthly usage is 600 kWh or below are less likely to benefit as much from time- or demand-differentiated rates, and the terms of the

[283] Gayer Br. at 15; Gayer Reply Br. at 9.
[284] *Id.*
[285] Woodward Br. at 41,42 citing to Hearing Exhibit Woodward-1 generally (Direct Testimony of Warren Woodward) and Hearing Exhibit Woodward-6 generally (Direct Testimony of Warren Woodward on the Settlement Agreement).
[286] Woodward Br. at 42.
[287] APS Reply Br. at 57.
[288] *Id.* at 6.
[289] APS Br. at 56, 57.
[290] *Id.*; APS Reply Br. at 5, citing to Tr. at 858-60 (APS witness Snook).

Settlement Agreement therefore exempt these low-usage, R-XS customers from the 90-day trial period.[291]

APS believes it is important to balance the benefits that accrue to all customers from time- and demand-differentiated rates with individual customer choice.[292] APS describes the benefits as follows:

> When customers react to rates that are time-differentiated, and in particular rates with demand components, they shift load to off-peak periods, taking service when there is excess supply and capacity. This not only permits short-term cost savings with lower fuel costs, but also the possibility that APS can avoid building new infrastructure to meet growing peak demand.[293]

APS states that the 90-day trial period for new customers that the Settling Parties agreed to is a compromise position designed to achieve a balance.[294] While the 90-day trial period does not adopt the outcome sought by those who are opposed to any changes to APS's rate design, neither does it adopt the outcome sought by APS that all customers take service on time-differentiated demand rates.[295] APS contends that the Settlement Agreement 90-day trial period provision establishes a more moderate path towards implementing time- and demand-differentiated rates than APS's initial proposal, and that part of the moderation involves customers being able to return to the R-Basic rate after the 90-day trial.[296]

APS takes issue with AARP's arguments that the 90-day trial period would "likely be confusing and frustrating for the affected customers,"[297] and AARP's assertion that customers would prefer a basic rate plan. APS posits that AARP's position that a TOU or demand rate could be detrimental to customers lacks evidentiary support, and likely reflects national, and not local interests. APS states that AARP does not represent the concerns of local seniors groups such as PORA in Sun City West, and SCHOA in Sun City, both of which are signatories to the Settlement Agreement. [298] And APS points to the admission by AARP's witness that AARP never gathered data from its constituents regarding

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[291] APS Br. at 57.
[292] *Id.* at 58.
[293] *Id.*, referring to Hearing Exhibit APS-7 (Rebuttal Testimony of Charles Miessner on the Settlement Agreement) at 12-13.
[294] APS Br. at 58, Reply Br. at 6.
[295] APS Br. at 58.
[296] *Id.* at 7-8, Reply Br. at 6.
[297] APS Reply Br. at 5, citing to AARP Br. at 8.
[298] APS Reply Br. at 5.

whether they would prefer lower overall bills, or a simpler bill structure.[299] APS believes that the fact that over half of its customers are already on a TOU rate demonstrates that APS customers have the ability to adapt to and manage time-differentiated rates, and that there is no basis for an assumption that future APS customers will be less sophisticated.[300]

6. AIC

AIC contends that, in contrast to the characterization by AARP of "taking away" customer choice, the Settlement Agreement provides a choice of seven residential rate options, and balances customers' individual interests and customer choice with the benefits that moving all customers toward time-differentiated and demand-differentiated rate plans would provide.[301]

7. ConservAmerica

ConservAmerica believes that the Settlement Agreement rate design, of which the 90-day trial period for new customers is an integral part, is fairer than the current rate design; is a sensible limitation, because it applies only to new customers, and only for a limited time; will promote reductions in costs and emissions; and should be approved. ConservAmerica asserts that providing new customers with experience on time-differentiated and demand-differentiated rate plans, after customer education, will benefit those customers because many will save money, while beginning to provide the benefits for all customers – lower costs, reduced emissions, and reduced inequities – that will come from having more customers taking service under the TOU or demand rate plans, and modifying their usage patterns accordingly.[302] ConservAmerica agrees with Staff that 90 days is an appropriate time period to provide customers with their usage data so that they can determine which rate plan is better for them.[303]

In response to Mr. Gayer's argument that the 90-day trial period would violate due process, ConservAmerica responds that adequate public notice was provided which more than satisfied any due process requirements.[304]

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[299] *Id.*, citing to Tr. at 724 (AARP witness Coffman).
[300] APS Reply Br. at 5-6.
[301] AIC Reply Br. at 3.
[302] ConservAmerica Br. at 4; ConservAmerica Reply Br. at 5.
[303] ConservAmerica Br. at 4, citing to Tr. at 1268 (Staff witness Abinah).
[304] ConservAmerica Reply Br. at 5. ConservAmerica asserts that there are no constitutional or statutory provisions requiring notice of setting utility rates. ConservAmerica Reply Br. at 4-6, citing to *Appeal of Office of Consumer Advocate*, 803 A.2d 1054, 1059 (N.H. 2002), and referring to *Arizona Corp. Comm'n v. Tucson Ins. & Bonding Agency*, 3 Ariz. App. 458, 463,

ConservAmerica responds to AARP's statement on brief that public comments oppose "mandatory demand charges," pointing out that the terms of the Settlement Agreement do not require any customer, including new customers in the 90-day trial period, to take service on a demand charge rate plan.[305]

8. RUCO

RUCO believes that new customers will not be disadvantaged by the 90-day trial period before they can sign up for the R-Basic rate plan because: 1) there are new rate plans available to choose from; 2) those rate plans have BSCs that are either decreasing from present BSCs or increasing only slightly; and 3) the new TOU options, with lower BSCs, will provide the new customers with more control over the variable portion of their bills than does the R-Basic rate plan. RUCO asserts that having new customers try a TOU option for 90 days will result in more customer control, energy efficiency, and will better reflect cost causation, and that customers will have the choice to go to the R-Basic plan after the 90-day trial period if they wish to do so.[306]

9. Staff

Staff states that the purpose of the 90-day trial period is to encourage the implementation of newer and updated rate designs going forward. Staff believes that inclusion of the 90-day trial period for new customers strikes an appropriate balance in that it gives customers options with respect to rate plans while also providing a reasonable means for APS to educate customers on new updated rate designs.[307]

Staff agrees with the proposals of SWEEP and AARP that APS be required to notify customers near the end of the 90-day period about their option to switch to another rate,[308] and that such notification should be accompanied with information on the estimated bill impact of switching to another rate.[309] Staff states that the Settlement Agreement already provides that APS will expend $5

415 P.2d 472, 477 (1966); *Walker v. De Concini*, 86 Ariz. 143, 148, 341 P.2d 933, 937 (1959); Arizona Administrative Code ("A.A.C.") R14-2-105(B); and A.A.C. R14-3-109(B).

305 ConservAmerica Reply Br. at 4, citing to AARP Br. at 15 and to Settlement Agreement at Section 19.1 (page 20).

306 RUCO Br. at 7.

307 Staff Reply Br. at 5.

308 Staff Reply Br. at 5, 6 citing to SWEEP Br. at 17, AARP Br. at 9-10, and Hearing Exhibit S-12 (Rebuttal Testimony of Ralph Smith on the Settlement Agreement) at 9.

309 Staff Reply Br. at 5, citing to Hearing Exhibit S-12 (Rebuttal Testimony of Ralph Smith on the Settlement Agreement) at 9.

million of over collected DSMAC funds toward ratepayer education to help them understand and manage new rates and rate options, and that Staff sees no inconsistency with the Settlement Agreement if the Commission were to order APS to develop a notice as part of its customer education program to inform new ratepayers subject to the 90-day trial period of their rate options at the conclusion of the trial period.[310]

10. Resolution

After examination of the evidence and the legal arguments on this contested issue, we find that the 90-day trial period for new customers as set forth in the Settlement Agreement is in the public interest. Notably, however, the Settlement Agreement provides at most an eight-month window for customers who are on another rate to evaluate several new rate plans. We find there is sufficient evidence in the record and it is in the public interest for existing customers to have additional time to adequately consider the R-Basic Large plan. We therefore recommend that the sunset for R-Basic Large be modified as follows: "After September 1, 2018, R-Basic Large will no longer be available to customers who are on another rate."

Educating customers about the energy efficiency effects of both time-differentiated and demand-differentiated rate plans will encourage customers to be cognizant of efficient energy use. This customer knowledge will ultimately benefit all APS customers. For new customers, a short trial period on their choice of either a time- or demand-differentiated rate is reasonable, in order to demonstrate how they can manage their usage in order to better control their bills. The 90-day trial period reasonably and appropriately balances the goal of increased energy efficiency with the customer interest of having a variety of rate plans from which to choose, so that customers can decide, based on specific facts particular to them, which rate plan works best for their individual circumstances.

Arguments have been advanced regarding the lack of specificity in the Settlement Agreement in regard to educating customers about their rate plan choices at the end of the 90-day trial period. The Settlement Agreement provides that:

> APS will make a one-time allocation of $5 million from over-collected DSMAC funds to DSM programs for education and to help customers manage new rates and rate

[310] Staff Reply Br. at 6-7.

> options including services and tools available to customers to help them manage their utility costs. APS shall file an outreach and education plan and shall provide stakeholders with an opportunity to review and comment on the draft plan prior to completing its final plan.[311]

The record does not support elimination of Section 27.1 of the Settlement Agreement. APS has indicated that it is committed to making sure that customers are aware of their options, and that it will notify customers through a variety of different channels and encourage customers to choose the rate plan that works best for them.[312] The evidentiary record supports the imposition of the following specific requirement for the Settlement Agreement's customer outreach and education plan:

> The draft plan that APS files according to Section 27 of the Settlement Agreement shall include a form of notice to inform new ratepayers subject to the 90-day trial period of their rate options at the conclusion of the trial period, accompanied by information on the estimated bill impact of switching to another rate, and shall address a suitable method for delivery of such notice so that such customers will receive the notice shortly after, or concurrently with, their second bill, in order to provide them with sufficient notice should they wish to begin taking service at that time on the R-Basic rate plan instead of a time- or demand-differentiated rate plan.

Because the Settlement Agreement does not set forth deadlines for the roll out of the customer education plans, we will require APS to file a draft Customer Education and Outreach Program ("CEOP") in Docket Control within 15 business days of a Commission Decision in this matter. The CEOP should contain at a minimum, simple, easy to understand information regarding the new rate plans, the transition plan, and the plans available after May 1, 2018. Stakeholders will have 10 days thereafter to review and comment on the draft plan. APS will have 10 additional days following the review and comment deadline to submit a final plan for Commission Staff's consideration and approval.

The Settlement Agreement makes significant changes to the existing rate plans. We find that it is in the public's interest to have adequate notice in a timely manner so customers can evaluate the available plans before the deadline. The evidentiary record supports the imposition of the following specific requirements for the Settlement Agreement's CEOP:

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[311] *See* Settlement Agreement Section 27.1 (page 24).

[312] *See* Hearing Exhibit APS-3 (Rebuttal Testimony of Barbara Lockwood on the Settlement Agreement) at 6, and Tr. at 251, 293 (APS witness Lockwood).

The draft CEOP should include a form of notice for both new customers and customers who are on another rate.

For customers who are on another rate, the final approved notice must be provided to the customers on another rate at least 3 billing cycles prior to May 1, 2018, or the date on which APS's new rate plans commence, whichever occurs later.

For both new customers and customers who are on another rate, the form of notice in the draft CEOP shall inform the customers of their rate options after May 1, 2018, accompanied by information on the estimated bill impact of switching to another rate.

iii. **Time of Use Hours**

The Settlement Agreement provides for TOU on-peak rates from 3:00 p.m. to 8:00 p.m. on weekdays, excluding holidays.[313] In addition, the Settlement Agreement provides for a Winter Super Off-peak period from 10:00 a.m. to 3:00 p.m. weekdays during the winter months.[314]

1. SWEEP

SWEEP proposes that the on-peak period for residential TOU rates be set for 4:00 p.m. to 7:00 p.m. instead.[315] SWEEP contends that "[a] five-hour (3:00 pm to 8:00 pm) on-peak period virtually mandates that Arizona families and other customers (e.g., homebound customers) will face high on-peak charges without any real flexibility to move some activities and energy use to off-peak periods."[316]

SWEEP contends that "[t]he Commission should not set the on-peak period for 2020 or future years in this rate case; that decision could be made and is more appropriately made in the next rate case with the then-current facts available for consideration."[317] SWEEP argues that APS's testimony regarding its peak load shape shows that the three summer hours with the highest peak demand are 4:00 p.m. to 7:00 p.m.[318] SWEEP asserts that if customers could shift some of their demand to hours before 4:00 p.m., they would not increase the APS system demand between 4:00 p.m. and 7:00 p.m.[319] SWEEP asserts that the shorter on-peak period it proposes would be attractive to more customers, and additional customers would move to TOU rates.[320]

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313 Settlement Agreement Section 17.8 (page 19).
314 Settlement Agreement Section 17.4 (page 18).
315 SWEEP Br. at 5, 15, SWEEP Reply Br. at 6.
316 SWEEP Br. at 15, citing to Hearing Exhibit SWEEP 4 (Rebuttal Testimony of Jeff Schlegel on the Settlement Agreement) at 12.
317 SWEEP Reply Br. at 7.
318 SWEEP Br. at 16 and Reply Br. at 6, referring to Hearing Exhibit APS-7 (Rebuttal Testimony of Charles Miessner on the Settlement Agreement) at 9, Figure 1, and to Tr. at 1137 (SWEEP witness Schlegel).
319 SWEEP Br. at 16; SWEEP Reply Br. at 7.
320 *Id.*, citing to Tr. at 1138 (SWEEP witness Schlegel).

2. AARP

AARP opposes the 3:00 to 8:00 p.m. on-peak period proposed in the Settlement Agreement.[321] AARP asserts that this late in the day peak period "will leave many seniors with less flexibility to adjust their usage to find savings."[322] AARP supports SWEEP's position.[323]

3. Districts

The Districts assert that the Settlement Agreement's proposed time of use rates would be "punishing for working families."[324]

4. APS

APS contends that the Settlement Agreement's proposed 3:00 p.m. to 8:00 p.m. on peak time period properly balances system realities with customer convenience, and that SWEEP's proposal disregards actual system conditions and the policy goal of influencing prospective usage.[325] APS states that the Settlement Agreement reduces the number of on-peak hours, and adds more off-peak holidays, compared to the present TOU tariffs, which have on-peak periods from 12:00 noon to 7:00 p.m. and 9:00 a.m. to 9:00 p.m.[326] APS asserts that the Settlement Agreement on-peak hours are part of a carefully crafted and balanced rate design agreed upon by the Settling Parties, and that failure to adopt them has the potential to disrupt the balance and the result desired by numerous parties, particularly the solar intervenors.[327]

APS asserts that the Settlement Agreement on-peak hours are aligned with APS's highest system peaks and costs,[328] and that energy use during system peak should properly align with the costs to provide that service.[329] In contrast, the current TOU on-peak hours send customers the wrong conservation message.[330] APS's witness James Wilde explains that current on-peak times encourage conservation at mid-day and early afternoon, when demand and wholesale prices are low, and energy

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[321] AARP Br. at 3.
[322] *Id.* at 3, 11.
[323] *Id.* at 11.
[324] Districts Br. at 2 -3.
[325] APS Reply Br. at 6
[326] APS Br. at 58, citing to Tr. at 341 (APS witness Miessner) and Hearing Exhibit APS-19 (Direct Testimony of James Wilde) at 12.
[327] APS Br. at 61.
[328] *Id.* at 58, citing to Tr. at 341 (APS witness Miessner).
[329] APS Br. at 61.
[330] APS Br. at 58-59, citing to Exhibit APS-19 (Direct Testimony of James Wilde) at 13-14.

abundant on the regional system, but not in the evening hours when system demand is peaking and wholesale prices are high.[331]

APS witness Charles Miessner included a graph in his prefiled testimony showing APS's System Summer Peak Hours.[332] APS states that APS has a very broad peak, and that in the summer months APS's load often remains within 5% of the peak hour for 4-5 hours, such that on-peak time periods must run later in the evening.[333] APS's witness testified that in the summer months particularly, system peak is generally expected to occur between 7:00 p.m. and 9:00 p.m.[334] APS projects that the trend for later system peak loads will continue in the future.[335]

APS argues that TOU periods should not be set looking backward, but looking forward, in order to maximize the benefits of energy conservation that occur when customers shift usage.[336] APS acknowledges SWEEP's argument that the Settlement Agreement's proposed 3:00 p.m. to 8:00 p.m. on peak time period may be inconvenient for customers, but points out that the resulting shift in usage by customers may allow APS to avoid or delay construction of new infrastructure, and the period is shorter than existing on-peak time periods.[337] APS asserts that the proposed 3:00 p.m. to 8:00 p.m. on

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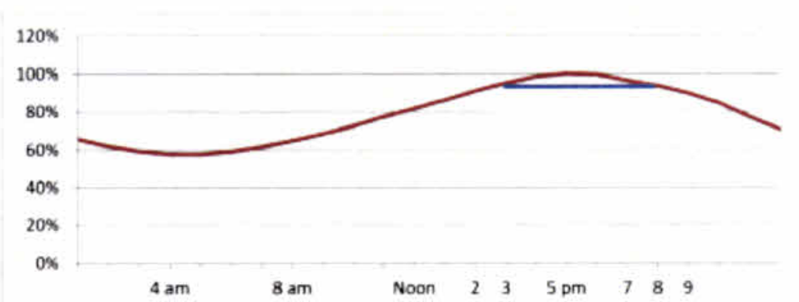
[331] APS Br. at 58-59, citing to Exhibit APS-19 (Direct Testimony of James Wilde) at 13-14.
[332] Hearing Exhibit APS-7 (Rebuttal Testimony of Charles Miessner on the Settlement Agreement) at 9, Figure 1.

Figure 1 APS Summer System Sumer Peak Hours[5]



[5] Test Year 2015 system load, top 80 hours, June through September.

[333] APS Br. at 59, citing to Hearing Exhibit APS-7 (Rebuttal Testimony of Charles Miessner on the Settlement Agreement Testimony) at 9, Figure 1.
[334] Hearing Exhibit APS-19 (Direct Testimony of James Wilde) at 14.
[335] APS Br. at 59-60, citing to Hearing Exhibit APS-7 (Miessner Rebuttal Settlement Agreement Testimony) at 12, Figure 2 (Time of Day Relative Energy & Capacity Heat Map).
[336] APS Br. at 60.
[337] *Id.* at 60-61.

peak time period was carefully crafted to maximize the efficiencies of shifting load to off-peak.[338] Without a change in the on-peak period to align it with actual system peak, system costs will not be reduced, and the entire purpose of on-peak rates would be undermined. APS believes its current TOU customers and new TOU customers can and will respond to the new shorter on-peak times in a meaningful manner, and that setting forward-looking on-peak periods would also remove the need for extensive customer re-education in future rate cases.[339]

5. AIC

Along with the other rate design changes in the Settlement Agreement, AIC supports the adjusted on-peak hours of 3:00 p.m. to 8:00 p.m. in the Settlement Agreement, noting that the majority of parties support the change.[340] AIC states that the new hours allow customers to take advantage of fewer on-peak hours, and more off-peak holidays, than they currently have, while focusing more accurately on the time of day when demand reduction is needed most, and argues that "[t]he TOU on-peak periods were carefully designed to achieve the stated revenue amount, properly align the cost of providing service during on-peak times, and preserve the economics of rooftop solar – they should remain unmodified in the Settlement."[341]

6. Vote Solar

Vote Solar asserts that "when considered with the balance of many different issues addressed by the Proposed Settlement Agreement, the 3 p.m. to 8 p.m. period peak is reasonable."[342]

7. SEIA

SEIA supports the 3:00 p.m. to 8:00 p.m. on-peak period established in the Settlement Agreement.[343]

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338 APS Reply Br. at 7.
339 APS Br. at 60-61.
340 AIC Br. at 5; AIC Reply Br. at 3.
341 AIC Reply Br. at 3, 4.
342 Vote Solar Br. at 6, citing to Hearing Exhibit Vote Solar-2 (Direct Testimony of Brianna Kobor on the Settlement Agreement) at 5.
343 SEIA Br. at 4, citing to Hearing Exhibit SEIA-2 (Direct Testimony of Sara Birmingham on the Settlement Agreement) at 5.

8. Staff

Staff characterizes SWEEP's proposed modification to the Settlement Agreement's on-peak hours, to 4:00 to 7:00 p.m., as unbalanced and one-sided, and as being based on customer convenience rather than APS's system peak.[344] Staff asserts that while SWEEP's argument that its proposal would be attractive to more customers and lead more customers to subscribe to TOU rates might seem reasonable on its face, SWEEP's advocacy is narrowly focused on its own interests, and does not strike an appropriate balance between customer needs and utility needs.[345] Staff emphasizes that the Settlement Agreement would provide customers with a shorter on-peak period than they currently have, and would add four additional off-peak holidays.[346]

Staff states that the Settlement Agreement's on-peak hours of 3:00 p.m. to 8:00 p.m. are aligned with APS's highest peaks and costs;[347] that it is undisputed that APS has a very broad peak, where loads remain very near peak until as late as 9:00 p.m.;[348] and that even though APS's peak has not yet occurred after 7:00 p.m., its loads remain very near peak until 8:00 to 9:00 p.m.[349] Staff points out that SWEEP acknowledged two factors that support approval of the on-peak period of 3:00 p.m. to 8:00 p.m. agreed to by the Settling Parties: 1) APS's system peak can shift to a later time than SWEEP's proposed 7:00 p.m. cutoff; and 2) APS's peak period has shifted over time, to later in the day.[350]

Staff contends that the Settlement Agreement's proposed changes to TOU on-peak hours balance competing interests, and move APS's rate design in the right direction by sending appropriate cost signals to encourage customers to shift load to off-peak hours.[351]

9. Resolution

We agree with Staff that the TOU on-peak period proposed in the Settlement Agreement "strikes that appropriate balance between the [TOU] customer's ability to adjust usage into off-peak

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[344] Staff Br. at 23.
[345] Staff Reply Br. at 4.
[346] Staff Br. at 23; Staff Reply Br. at 4.
[347] Staff Reply Br. at 4, citing to Tr. at 341 (APS witness Miessner).
[348] Staff Reply Br. at 4, citing to Hearing Exhibit APS-7 (Rebuttal Testimony of Charles Miessner on the Settlement Agreement) at 9.
[349] Staff Reply Br. at 4.
[350] Staff Br. at 23; Staff Reply Br. at 4, citing to Tr. at 1174, 1176-77 (SWEEP witness Schlegel).
[351] Staff Br. at 23; Staff Reply Br. at 4.

hours while recognizing that demand on APS's system can remain high after 7:00 p.m."[352] The arguments advanced by SWEEP and AARP in favor of rejecting the proposed Settlement Agreement on-peak TOU hours are not convincing on this important point. The Settlement Agreement provides customers with more off-peak hours than TOU customers currently have, and importantly, customers retain the choice to take service under the R-Basic rate plan, if they determine that the on-peak hours, which reflect system costs, are not suited to their individual energy usage patterns.

VI. ADOPTION OF THE SETTLEMENT AGREEMENT

After reviewing the Settlement Agreement in its entirety, as well as the arguments in support of and in opposition to its adoption, we believe the Settlement Agreement is in the public interest and should be adopted, as discussed herein.[353] As the Settlement proponents point out, a broad range of parties representing vastly different interests were able to craft a comprehensive agreement through negotiation and compromise. The Settlement Agreement provides a number of benefits for customers, including: a base rate increase substantially less than originally requested by APS; increased rate options for residential customers, including TOU rates with additional non-peak hours and days; a stay-out provision that precludes APS from seeking another base rate increase prior to June 1, 2019; a pilot program to incent customers to adopt technologies to manage demand and reduce system peak; increased assistance for low-income customers; continuation of a buy-through program for industrial customers; and a collaborative resolution of issues related to DG customers and net metering. When viewed in its totality, the benefits of adopting the Settlement Agreement outweigh the arguments in opposition raised by several non-signatory parties. We will therefore adopt the Settlement Agreement, for the reasons set forth above.

VII. INCENTIVIZING BATTERY STORAGE FOR E-32 L CUSTOMERS

The Settling Parties did not reach agreement on the rate design issue of ratcheted rates for APS's large commercial customers. The interested parties litigated it in this proceeding, and their arguments are set forth here.

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[352] *See* Staff Reply Br. at 4.

[353] As stated out the outset of the discussion, Section 30 of the Settlement Agreement is bifurcated from our Decision today, and will be addressed in a forthcoming Decision.

a. APS's E-32 L and E-32 L TOU Rates

APS's E-32 L and E-32 L TOU rates[354] apply to large commercial customers whose average demand is 401-3,000 kW per month, and include an 80 percent demand ratchet, declining demand blocks, and a decreased off-peak demand charge for the E-32 L TOU rate.[355] These rates were established in APS's prior rate case, where the parties agreed that instead of paying an LFCR to address unrecovered fixed costs, E-32 L and E-32 L TOU customers would take service under rates that included, among other cost-recovery protections, a ratchet.[356] APS states that as an existing approved rate structure, its E-32 L and E-32 L TOU rates are entitled to the legal presumption that they are just and reasonable, absent persuasive evidence to the contrary.[357]

APS states that the differential in the on-peak and the off-peak demand charges, which under the Settlement Agreement's proposed rates would be \$5.98/kW on-peak, but only \$2.275/kW off-peak, incentivizes customers to shift their consumption to off-peak periods.[358] The ratchet is for 80 percent of the customer's peak demand imposed on the system during APS's peak summer months, and remains in effect for the single year following that customer's summer peak.[359] APS states that ratchets are advantageous because they: (i) mitigate any cost shift; (ii) promote revenue stability; (iii) promote equitable rate design; and (iv) promote efficient use of the system.[360]

APS states that the ratchet is cost based, and poses no barriers to commercial customers to install battery storage.[361] APS asserts that ratcheted rates properly incentivize storage technologies, because reductions in energy usage result in bill savings (due to the fact that reductions in energy usage are not affected by the ratchet); because the ratchet period is a rolling 12 months, such that reductions in demand that occur after the summer peak will result in savings the following summer; and because the ratchet emphasizes the importance of reducing summer demand.[362] APS states that the ratchet

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[354] *See* Settlement Agreement Appendix I.
[355] APS Br. at 33.
[356] APS Reply Br. at 19.
[357] APS Reply Br. at 29, referring to *Tucson Elec. Power Co. v. Ariz. Corp. Comm'n*, 132 Ariz. 240, 242, 645 P.2d 231, 233 (1982); *Litchfield Park Serv. Co. v. Ariz. Corp. Comm'n*, 178 Ariz. 431, 434, 874 P.2d 988, 991 (App. 1994); and *PPL Wallingford Energy LLC v. F.E.R.C.*, 419 F.3d 1194, 1199 (D.C. Cir.2005).
[358] APS Reply Br. at 30, referring to Settlement Agreement Appendix G at 11 of 14.
[359] APS Br. at 28.
[360] *Id.* at 40, citing to Hearing Exhibit Staff-11 (Direct Testimony of Ralph Smith on the Settlement Agreement) at 22-23.
[361] APS Br. at 32-33.
[362] *Id.* at 38.

serves to promote the recovery of costs by the customers who cause them. APS believes that the fact that E-32 L customers install energy efficiency in proportion to other general service customers suggests that the current E-32 L rate structure does not impede customer efforts to reduce load.[363]

APS states that the off-peak demand charge in the E-32 L TOU rate recognizes that significant costs exist year round, during both peak and off-peak periods of the day, and the off-peak demand charge is appropriately set at less than half of the on-peak charge.[364] APS points out that the R-Tech residential rate in the Settlement Agreement also has an off-peak demand charge which serves as a safeguard to ensure that the customer who causes a cost pays that cost.[365] APS contends that off-peak usage drives costs too, and that removing the off-peak demand charge from the E-32 L TOU rate would remove an essential safeguard for cost recovery, and would be inappropriate because it currently allows sophisticated customers the opportunity to shift their load to avoid costs far beyond system savings.[366] APS states that when a technology reduces grid costs, the cost of service savings will equal the bill savings, avoiding shifting of costs to other customers.[367]

AIC supports approval of the E-32 L rates as proposed by APS.[368] AIC asserts that a demand ratchet is a common feature of commercial billing rate design and its purpose is to help ensure that a customer pays its appropriate level of grid costs when demand is billed on a monthly basis, and that for this class of customer, because grid infrastructure is commonly upgraded to serve the customer's specific requirements, the demand ratchet is important for recovering those costs.[369] AIC states that if APS invests in infrastructure to serve a customer with a specific demand requirement, and that customer's demand drops or fluctuates, there is a likelihood that APS's investment costs will be stranded.[370] AIC contends that APS's proposed E-32 L rates reflect APS's consistent advocacy for rates that provide clear and accurate price signals, regardless of the type of technology customers

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[363] APS Reply Br. at 20.
[364] APS Br. at 37, citing to Tr. at 422, 442, 473 (APS witness Miessner) and referring to Hearing Exhibit APS-6 (Direct Testimony of Charles Miessner on the Settlement Agreement) at 19; APS Reply Br. at 30.
[365] APS Br. at 38, citing to Tr. at 802, 803 (APS witness Snook).
[366] APS Br. at 38; APS Reply Br. at 30.
[367] APS Reply Br. at 21-22, citing to Tr. at 372 (APS witness Miessner).
[368] AIC Br. at 7, 11.
[369] *Id.* at 8, citing to Hearing Exhibit APS-6 (Direct Testimony of Charles Miessner on the Settlement Agreement) at 17.
[370] AIC Br. at 8-9, citing to Hearing Exhibit APS-6 (Direct Testimony of Charles Miessner on the Settlement Agreement) at 18 and Tr. at 1000 (Staff witness Ralph Smith).

choose to adopt.[371] AIC states that when costs are appropriately reflected in rates, as AIC contends they are in the E-32 rates, proper price signals are sent to incentivize customers to change behavior to take advantage of that cost-based price signal, for example, by installing energy storage to reduce its demand.[372] AIC believes that rate design should incentivize long term reduction in summertime peak demand in a predictable and sustainable manner, and that the E-32 L rate sends the appropriate price signal to do that while also providing an incentive for customers to adopt storage technology.[373]

EFCA contends that demand ratchets serve as an impediment to the adoption of storage because they act like unavoidable fixed charges and therefore send poor price signals.[374] EFCA asserts that with a demand ratchet, the absence of strong price signals to reduce load during system peak provides no economic incentive for customers to adopt storage,[375] and because of the annual reset of the ratchet, a customer installing storage must wait a full year to recognize the benefit of their storage investment.[376] EFCA states that because the ratchet is set based on a customer's usage during any 15-minute interval in the summer months, a single unexpected or unmitigated demand surge can set the ratchet for the next year, and the customer has no incentive to reduce demand in the current month.[377] EFCA contends that in addition to the ratchet, two other features of the existing rate design fail to foster peak reduction and deployment of storage solutions.[378] EFCA asserts that the first block of declining block demand charges in both existing rates is so small that it is unavoidable, thus acting as an unavoidable fixed charge,[379] and that the off-peak demand charge in the E-32 L TOU rate actually charges customers for shifting peak consumption to system off-peak.[380]

b. EFCA's Proposed Optional E-32 Rate

EFCA proposes that in addition to APS's E-32 L and E-32 L TOU rates, the Commission also adopt its proposed optional non-ratchet tariffs ("Optional E-32 Rates") which would be available to

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[371] AIC Reply Br. at 5.
[372] *Id.*
[373] *Id.*
[374] EFCA Br. at 4-6.
[375] *Id.* at 5-6.
[376] *Id.* at 7.
[377] *Id.* at 6.
[378] *Id.* at 7-9.
[379] *Id.* at 8, citing to Tr. at 1204 (EFCA witness Mark E. Garrett).
[380] EFCA Br. at 8-9, citing to Hearing Exhibit EFCA-4 (Direct Rate Design Testimony of Mark E. Garrett) at 14-15.

customers taking service under APS's E-32 L and E-32 L TOU rates. EFCA's proposed Optional E-32 Rates are shown in the following two tables reproduced from Hearing Exhibit EFCA-14 (Rebuttal Testimony of Mark E. Garrett on the Settlement Agreement) at 15-16:

Table 1: Optional LGS Storage Rates

Source: EFCA 29.1 and EFCA 31.5(c)	Rate Class: E-32-L APS Proposed Settlement kW Rates (with Ratchet)	APS Units	APS Proposed Revenue Settlement	Step 1 - Remove Ratchets EFCA Proposed No Ratchet	EFCA Units	EFCA Proposed Revenue	Step 2 - Remove Tiers Avg Rev	Avg Units	EFCA Proposed Rates
Summer Days									
kW Secondary tier 1	$ 25.37	437,397	$11,097,637	$ 26.71	415,527	$11,097,637	$ 58,489,047	2,972,860	$ 19.67
kW Secondary tier 2	17.61	2,691,929	47,391,410	18.53	2,557,333	47,391,410			
kW Primary tier 1	23.05	34,800	802,105	24.26	33,060	802,105	8,030,347	451,488	$ 17.79
kW Primary tier 2	16.41	440,451	7,228,241	17.27	418,428	7,228,241			
kW Transmission tier 1	17.62	2,600	45,822	18.55	2,470	45,822	364,199	28,205	$ 12.91
kW Transmission tier 2	11.75	27,089	318,377	12.37	25,735	318,377			
Proof Summer Demand Revenue			$66,883,593			$66,883,593	$ 66,883,593		
Winter Days									
kW Secondary tier 1	$ 25.37	441,333	$11,197,501	$ 26.71	419,266	$11,197,501	$ 54,325,948	2,746,561	$ 19.78
kW Secondary tier 2	17.61	2,449,784	43,128,447	18.53	2,327,295	43,128,447			
kW Primary tier 1	23.05	35,600	820,544	24.26	33,820	820,544	$ 7,614,387	427,102	$ 17.83
kW Primary tier 2	16.41	413,981	6,793,842	17.27	393,282	6,793,842			
kW Transmission tier 1	17.62	2,400	42,298	18.55	2,280	42,298	$ 343,433	26,621	$ 12.90
kW Transmission tier 2	11.75	25,622	301,135	12.37	24,341	301,135			
Proof Winter Demand Revenue			$62,283,768			$62,283,768	$ 62,283,768		

Table 2: Optional LGS-TOU Storage Rates

Source: EFCA 29.1 and EFCA 31.5(c)	Rate Class E-32-TOU-L APS Proposed Settlement kW Rates (with Ratchet	APS Units	APS Proposed Revenue	Step 1 - Remove Ratchets EFCA Proposed (No Ratchet)	EFCA Units	EFCA Proposed Revenue kW Rates (No Ratchet)	Step 2 - Remove Tiers and Off Peak kW Avg Rev	Avg Units	EFCA Proposed Rates
Summer Days									
kW tier 1 - secondary - on	$ 17.51	27,250	$ 477,093	$ 18.43	25,888	$ 477,093	$ 3,678,113	216,890	$ 16.96
kW tier 2 - secondary - on	11.80	201,055	2,371,444	12.42	191,002	2,371,444			
kW tier 1 - secondary - off	6.40	27,223	174,118	6.73	25,862	174,118			
kW tier 2 - secondary - off	3.37	194,498	655,458	3.55	184,773	655,458			
kW tier 1 - primary - on	16.94	5,700	96,535	17.83	5,415	96,535	$ 1,257,187	75,627	$ 16.62
kW tier 2 - primary - on	11.71	73,907	865,451	12.33	70,212	865,451			
kW tier 1 - primary - off	5.68	6,115	34,727	5.98	5,809	34,727			
kW tier 2 - primary - off	3.27	79,607	260,474	3.44	75,627	260,474			
kW tier 1 - transmission - on	15.92	573	9,120	16.75	544	9,120	$ 149,693	10,075	$ 14.86
kW tier 2 - transmission - on	10.48	10,032	105,115	11.03	9,530	105,115			
kW tier 1 - transmission - off	4.87	559	2,723	5.13	531	2,723			
kW tier 2 - transmission - off	3.14	10,435	32,735	3.30	9,913	32,735			
Proof Summer Demand Revenue			$ 5,084,993			$ 5,084,993	$5,084,993		
Winter Days									
kW tier 1 - secondary - on	$ 17.51	36,700	$ 642,544	$ 18.43	34,865	$ 642,544	$ 3,681,359	217,795	$ 16.90
kW tier 2 - secondary - on	11.80	192,558	2,271,222	12.42	182,930	2,271,222			
kW tier 1 - secondary - off	6.40	26,700	170,773	6.73	25,365	170,773			
kW tier 2 - secondary - off	3.37	177,098	596,820	3.55	168,243	596,820			
kW tier 1 - primary - on	16.94	5,280	89,422	17.83	5,016	89,422	$ 905,811	54,593	$ 16.59
kW tier 2 - primary - on	11.71	52,186	611,098	12.33	49,577	611,098			
kW tier 1 - primary - off	5.68	5,376	30,530	5.98	5,107	30,530			
kW tier 2 - primary - off	3.27	53,411	174,761	3.44	50,740	174,761			
kW tier 1 - transmission - on	15.92	576	9,168	16.75	547	9,168	$ 171,302	11,747	$ 14.58
kW tier 2 - transmission - on	10.48	11,789	123,525	11.03	11,200	123,525			
kW tier 1 - transmission - off	4.87	576	2,806	5.13	547	2,806			
kW tier 2 - transmission - off	3.04	11,789	35,803	3.20	11,200	35,803			
Proof Winter Demand Revenue			$ 4,758,472			$ 4,758,472	$4,758,472		

EFCA contends that APS's current E-32 L rate structure acts as an impediment to the adoption of energy storage technology by sending poor price signals.[381] EFCA claims that its proposed Optional E-32 Storage rate will incentivize deployment of storage technologies immediately and begin offsetting costly infrastructure investments needed to meet APS's projected 50 percent load growth over the next 15 years by shifting E-32 L customers' demand off-peak.[382] EFCA states that the Commission recently ordered UNSE to consider designing rates that match cost causation with revenue recovery and to evaluate methods of revenue recovery that do not involve ratchets,[383] and ordered TEP to file an Optional Rate tariff without a demand ratchet for its large commercial class customers who elect to adopt storage technology.[384] EFCA disagrees with APS's arguments that the UNSE and TEP rate case Decisions should not be given weight in the Commission's determinations on this disputed issue.[385]

EFCA contends that its proposed Optional E-32 Rate is cost-based, revenue neutral, and contrary to APS's claims, will not cause APS to experience stranded costs.[386] EFCA asserts that its proposed Optional E-32 Rate proposal addresses a real and pressing issue,[387] and will not cause a cost shift.[388] EFCA characterizes APS's comparison of the proposed Optional E-32 Rate to net metering as a "scare tactic" without support,[389] and contends that APS's opposition to it is motivated by its business interests, and not its customers,[390] pointing out that the E-32 customers participating in this proceeding have not opposed adoption of the proposed Optional E-32 Rate.[391]

AIC believes that it would be bad public policy to adopt EFCA's Optional E-32 Rate proposal.[392] AIC warns that removing the ratchet would not only put cost recovery at risk,[393] but if adopted, EFCA's rate proposal would cause the same cost shifting problems that net metering did, by maximizing bill savings for individual customers irrespective of the actual reduction in costs to the

[381] EFCA Br. at 4-8.
[382] *Id.* at 9-11.
[383] *Id.* at 12, citing to Decision No. 75697 at 86.
[384] EFCA Br. at 12, citing to Decision No. 75975 at 188, 193.
[385] EFCA Reply Br. at 16.
[386] EFCA Br. at 13-18.
[387] EFCA Reply Br. at 5.
[388] *Id.* at 13.
[389] EFCA Reply Br. at 4.
[390] *Id.* at 14.
[391] *Id.* at 17.
[392] AIC Br. at 10.
[393] *Id.*, citing to Tr. at 1239 (EFCA witness Mark E. Garrett), 141 (APS witness Lockwood).

utility to serve that customer, and shifting those unrecovered costs to non-storage customers.[394] AIC urges the Commission to instead approve cost-based rates that are technologically neutral, and not vote to eliminate cost-based rates in favor of rates that include an incentive for a particular technology.[395]

AIC argues that EFCA's proposal only addresses third-party interests, in contrast to APS's proposal, which is balanced and takes into account the utility and its customers.[396] AIC states that "EFCA represents 'businesses that develop, provide, and research customers' adoption of residential and commercial distributed energy resources'"[397] and asserts that "EFCA's advocacy on the E-32 demand ratchet issue is intended to directly benefit third-party businesses, not the utility's customers."[398] AIC states that approximately 960 customers take service on the E-32 L rate; they are typically a very sophisticated class of customers; a number of intervenors in this case are members of this class of customers; that none of the intervenors supports EFCA's proposal or objects to APS's proposal; and that EFCA does not represent any of the customers in the class.[399]

AIC is dismissive of EFCA's claim that demand ratchets discourage the adoption of energy storage.[400] AIC argues that a ratchet does not eliminate any potential for first year demand savings from storage, if the storage is installed at the appropriate time; that the sophisticated energy customers in this rate class don't make energy decisions based on first year savings, but over the life of the investment; and that one of the goals of a ratchet is to reduce summer month loads, and using storage to reduce summer load would not reduce demand savings on an annual basis whenever winter loads are lower than summer loads.[401]

AIC argues that although TEP was ordered to implement an optional non-ratcheted rate for its Large General Service ("LGS") customers in future rate cases, that the Commission is not bound to

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[394] AIC Br. at 10, citing to Hearing Exhibit APS-6 (Direct Testimony of Charles Miessner on the Settlement Agreement) at 16.
[395] AIC Br. at 10, citing to Tr. at 140 (APS witness Lockwood).
[396] AIC Br. at 8; AIC Reply Br. at 5.
[397] AIC Br. at 8, citing to Tr. at 1234-35 (EFCA witness Mark E. Garrett).
[398] AIC Br. at 8, citing to Tr. at 1234 (EFCA witness Mark E. Garrett); AIC Reply Br. at 5.
[399] AIC Br. at 8; AIC Reply Br. at 5.
[400] AIC Br. at 9-10.
[401] *Id.*, citing to Hearing Exhibit APS-6 (Direct Testimony of Charles Miessner on the Settlement Agreement) at 16 and Tr. at 346 (APS witness Miessner).

require APS to do so, and that because TEP's and APS's ratchets are not substantially similar, the concerns the Commission may have had in the TEP case are not present in APS's E-32 L rates.[402]

APS recommends that the existing E-32 L and E-32 L TOU rate design be adopted, and that EFCA's proposed Optional E-32 Rate be rejected. APS asserts that EFCA's proposal would "over reward load reduction in the winter months when load reduction is not generally needed."[403] APS asserts that EFCA has failed to explain how battery storage that is dispersed dependent upon sales by EFCA's members could supplant APS's need to plan for and build infrastructure based on system needs.[404] APS states that battery storage is an unproven technology that does not supplant APS's responsibility to plan for and meet peak demand, and APS must stand ready to serve the entire load during peak in the event a battery fails to discharge a customer's needed power for the entire length of its peak period. APS states that being ready to supply 100 percent of a battery customer's peak load is a standby service that requires the same amount of fixed infrastructure needed if the customer never installed battery storage.[405] APS states that the record is bereft of specific evidence regarding the capabilities of behind-the-meter battery storage such as consistent dispatch capability and longevity, when installations would occur, what size the installations would be, and how much system peak load battery customers would actually mitigate, if any.[406] APS states that for system peak to be mitigated, E-32 customers would have to discharge their batteries reliably, every day, and that whether the technology is reliable in this regard is currently unknown.[407]

In response to EFCA's statement that adoption of the Optional E-32 Storage rate will begin offsetting costly infrastructure investments needed to meet APS's projected 50 percent load growth over the next 15 years by shifting E-32 L commercial customers' demand off-peak, APS states that while its 2017 IRP forecasts a 50% increase in residential load, this forecast is a conservative planning estimate, and does not translate into actual system costs; and that EFCA's use of the entire 15 years

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[402] AIC Reply Br. at 7.
[403] APS Reply Br. at 17, citing to Tr. at 345-346 (APS witness Miessner).
[404] APS Reply Br. at 17.
[405] *Id.*
[406] APS Reply Br. at 14.
[407] *Id.* at 15.

instead of the compound annual growth rate in residential customers of 2.5 percent to support its optional commercial rate design is misleading and speculative.[408]

APS contends that EFCA's request for special rate treatment for prospective battery energy storage customers is not in the public interest, and can be granted only at the expense of other APS customers, similar to the cost shift caused by the net energy metering ("NEM") structure for existing rooftop solar customers.[409] APS states that EFCA's proposal would remove the basic safeguards from the E-32 L and E-32 L TOU rates that ensure that E-32 L customers pay their proper amount of grid costs, and that the resulting unrecovered costs would be shifted from E-32 L customers who install battery storage to E-32 L customers who have no battery storage.[410] APS points out that no member of the E-32 L customer class, several of whom are active participants in this proceeding, is requesting the change to E-32 L rates, and APS argues that it is likely due to the cost shift that would result from EFCA's proposal that this is the case.[411] APS argues that EFCA is proposing the promotion of a specific technology through rate subsidies that lacks any support from potentially affected customers, and that while it is understandable that EFCA is promoting the installation of a product by one of its members, there is no need to create new problems by disturbing a functioning rate structure that has the broad support of those taking service under it.[412]

APS contends that EFCA's witness acknowledged that EFCA's Optional E-32 Rate proposal would cause a cost shift when he testified that it might be appropriate for customers on that proposed rate to be included in the LFCR to minimize the loss of revenue, and that the LFCR would only spread to all other customers the cost shift responsibility that would rightfully be borne by large commercial customers with battery storage installed.[413] APS asserts that its E-32 L class is particularly vulnerable to cost shifts, because these customers account for 10 percent of APS's total revenues, but constitute

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[408] *Id.* at 16.
[409] APS Br. at 32-33.
[410] *Id.* at 33, 34.
[411] *Id.*
[412] APS Br. at 37.
[413] *Id.* at 35, citing to Tr. at 1249-50 (EFCA witness Mark E. Garrett). EFCA argued on brief that Mr. Garrett also testified that "there is no cost shift emanating from the ratchets." EFCA Reply Br. at 2-3, citing to Tr. at 1215 (EFCA witness Mark E. Garrett). EFCA argues that "Mr. Garrett was clear that he believes it is unnecessary to subject the Optional Rate to the LFCR but that he suggested it was an option for the Commission to consider if it was concerned about this issue in spite of the lack of evidence supporting the lost fixed cost claim." EFCA Reply Br. at 3.

less than 0.1 percent of APS customers.[414] APS states that because each individual E-32 L customer contributes a substantial amount to the grid's fixed costs, the cost shift risk for each battery storage installation is heightened, and due to the fact that there are only a small number of other E-32 L customers onto which unpaid fixed costs are shifted, the consequences of the cost shift are higher for each affected customer.[415] APS asserts that eliminating the ratchet would require that demand rates be increased by $7 million,[416] and making the ratchet optional would require an even larger increase.[417] APS states that because the off-peak demand revenue for the E-32 L class is 22 percent of the total demand revenue, its elimination could be even more significant.[418] APS states that while the cost shifts would not occur immediately, they would begin as soon as the first customer began installing storage and avoiding contributions, under EFCA's Optional E-32 Rate, to the fixed costs necessary to serve them.[419]

APS contends that the LGS ratchets discussed in the recent UNSE and TEP rate Decisions do not offer a useful comparison to the APS's E-32 L ratchets, because they do not function in the same way APS's E-32 L ratchets function.[420] Unlike APS's E-32 L ratchets, both TEP and UNSE's LGS ratchets are based on the highest demands during the preceding 11 months, which includes all the non-summer months, and also apply to non-peak hours of the day.[421] In the UNSE case, affected LGS customers with off-peak loads intervened and registered their complaints about the UNSE LGS ratchet,[422] and the Decision in that case responded to their concerns.[423] APS points out that in the TEP case, TEP sought to create a new medium general service class of service for customers with average demand of 20 kW to 300 kW per month, and to use a ratchet in the rate design for the new class,[424]

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414 APS Br. at 35.
415 *Id.*
416 APS Br. at 36, citing to Hearing Exhibit EFCA-14 (Rebuttal Testimony of Mark E. Garrett on the Settlement Agreement) at 15-16, Tables 1 and 2, referring to APS Response to Data Request EFCA 31.5 (c) in which APS provided the $7 million calculation.
417 APS Br. at 36, citing to Tr. at 465 (APS witness Miessner); APS Reply Br. at 30.
418 APS Br. at 36, referring to Hearing Exhibit EFCA-14 (Rebuttal Testimony of Mark E. Garrett on the Settlement Agreement) at 1, Table 2, showing in the APS Proposed Revenue column that the off-peak charges are designed to generate $2,171,728 of the total E-32 L TOU class revenue of $9,843,465.
419 APS Br. at 36.
420 *Id.* at 41-43.
421 *Id.* at 41, citing to Tr. at 350 (Miessner).
422 APS Br. at 41.
423 *See* Decision No. 75697 at 86.
424 APS Br. at 41, citing to Decision No. 75975 at 72-73.

whereas APS's E-32 L rates with ratchets apply to larger customers, with average demand of 401 to 3,000 kW.[425] APS contends that the TEP rate case Decision, which ordered TEP to create an optional non-ratchet rate for TEP's LGS class included no discussion of the cost-shift ramifications of removing ratchets from rate design for larger customers, and does not establish a strong policy disfavoring ratchets, but states that ratchets may "make sense for large customers which tend to have high load factors."[426]

APS argues that the modifications EFCA proposes in this proceeding to the E-32 L ratcheted rate designs, which specifically remove not only the ratchets, but also the declining block rate structure and off-peak demand rate structures, were neither proposed nor considered in the UNSE and TEP rate cases, and that the Commission's direction to TEP to propose a non-ratcheted rate design is far different from EFCA's detailed and broad-sweeping proposal in this proceeding.[427] APS states that EFCA has not explained its contention that tiered demand rates or off-peak demand charges impede adoption of storage technology.[428] APS responds to EFCA's criticisms of the first tier charge as constituting a "fixed" charge as without merit, stating that customers are billed for their usage, and that requiring customers to pay for their usage does not make a charge "fixed."[429] APS asserts that EFCA has also failed to explain how the existence of two demand tiers would impede the development of battery storage, or to prove its contention that it would.[430]

APS contends that EFCA's primary concern, regarding the lack of "first year savings" by customers installing storage is really a business model problem, which could be addressed by timing battery installations to go online prior to the summer billing period, or by structuring contract payments to better match payments with savings.[431] APS suggests that other contractual options could mitigate battery vendors' first year savings issue, such as 1) reducing or eliminating charges in the first year; 2) reducing prices in the off-season; and 3) staging installations so that the first year installation is smaller

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[425] APS Br. at 42.
[426] *Id.*, citing to Decision No. 75975 at 94.
[427] APS Br. at 43.
[428] APS Reply Br. at 28-29.
[429] *Id.* at 29.
[430] *Id.*
[431] APS Br. at 39, citing to Hearing Exhibit APS-6 (Direct Testimony of Charles Miessner on the Settlement Agreement) at 19-22 and referring to Tr. at 459-460 (APS witness Miessner); APS Reply Br. at 20.

and only reduces demand by the 20 percent ratchet amount, with the second-year installation being larger.[432]

APS asserts that it is better for E-32 L customers to understand how ratchets work in conjunction with battery storage, than for incentives that are not tied to reducible costs to be buried in rate design.[433] APS states that the issue here is not whether to incentivize battery storage, but how to do it. APS is opposed to rates that are intentionally designed to help the business model of some intervenors at the expense of APS's customers.[434] APS urges the Commission to take a balanced approach to protect the interests of all customers in the E-32 L class, and not just those who purchase battery storage from EFCA's members.[435]

APS states that customers pay for incentives, and because they will be held responsible financially through rates for any battery storage subsidy, its cost-effectiveness must be quantifiable and reviewable.[436] APS asserts that EFCA's proposal lacks any explanation of how it will achieve meaningful load reduction.[437] APS characterizes EFCA's proposal as the opposite of utility planning – "an unquantified incentive, embedded in rates, funded by customers, and designed to spur the installation of batteries without regard to (i) system location or need; (ii) cost-effectiveness; or (iii) the possibility of more-targeted alternatives."[438]

c. APS's Alternative Proposal for an Up-Front Incentive ("E-32 UFI") Pilot Program

APS contends that if the Commission wishes to incentivize customer-installed batteries beyond the current E-32 L rate design, a transparent incentive mechanism such as its proposed E-32 UFI program, as set forth in Hearing Exhibit APS-33, is a better policy alternative than EFCA's proposed Optional E-32 L Rate. Hearing Exhibit APS-33 is reproduced here for reference:

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[432] APS Br. at 39.
[433] *Id.*; APS Reply Br. at 21.
[434] APS Reply Br. at 21.
[435] *Id.*
[436] APS Reply Br. at 26.
[437] *Id.* at 24.
[438] *Id.* at 25, 26.

APS Proposed Pilot for E-32L TOU Customers Installing Storage

1. $2M annual program cap for each year for the period of 2017-2019 funded through the DSMAC adjustor.
    - Eligibility is limited to E-32L customers and must be on a TOU rate
    - Cash incentive amounts would be limited to 50% of individual system cost and would not exceed $100,000 per installation
    - Incentive payments would be paid commensurate with the duration of storage (at the rated continuous power) technology aligned with system benefits as follows:

Storage Duration	Amount of Incentive Paid
5 hours	100%
4 hours	80%
3 hours	60%
2 hours	40%
1 hour	20%

    - All kWh stored and discharged through participating systems would be credited towards APS annual DSM compliance requirements
    - Participating systems must complete all required interconnection approvals prior to operation and include all required metering and communication infrastructure
2. Participating customers are eligible for a one-time demand forgiveness once per year where a single 15-minute demand interval would be omitted. The customer must initiate the request for this adjustment within 30 days of receiving their bill.
3. Upon approval of the storage system interconnection, the existing billing basis for the ratchet value will be reset to reflect the anticipated kW demand reduction from the storage system.

APS states that its proposed E-32 UFI program would address EFCA's first-year savings concern by "(i) offering an up-front cash incentive; (ii) resetting a customer's demand that would be used to establish the ratchet when the customer installs storage based on the design criteria of the storage technology; and (iii) providing a demand forgiveness once per year to address a circumstance where the equipment does not function as intended."[439]

APS asserts that its proposed E-32 UFI program, added to the existing E-32 L and E-32 L TOU rates, would provide additional incentives for the installation of battery storage while protecting other customers from undue cost shifts, and would avoid creating the same challenges for battery storage that net metering created for rooftop solar.[440] APS states that its proposal places only $2 million at risk, while maintaining the revenue recovery safeguards built into the existing E-32 L rates, to which no E-32 L customer has objected.[441] APS states that the E-32 UFI program would "test whether battery storage technology consistently and reliably reduces peak demand," and would also "provide a means to assess the overall economics of the technology."[442] APS states that the assessments would occur under controlled circumstances, similar to the Settlement Agreement proposed R-Tech program for residential customers.[443]

APS asserts that if the Commission wishes to achieve certain policy objectives related to customer-sited technology, the best course of action is to do so in a transparent manner, which can be tapered as technology costs decline.[444] APS contends that the ability to taper incentives is critical, because without declining incentives, technologies are not forced to improve; technology tends to mature to meet marketplace needs, but the presence of incentives tends to retard the growth and maturity of a technology.[445] APS states that an advantage to incentivizing the installation of battery storage through its proposed E-32 UFI program is that the Commission retains control to increase the amount of the incentives, if $2 million each year does not result in enough battery installations to meet the Commission's policy objectives, and also to reduce the incentives as market costs decline.[446] APS contrasts this with EFCA's proposal, which lacks this flexibility,[447] and asserts that only APS's

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[439] APS Br. at 39-40, citing to Tr. at 458 (APS witness Miessner) and 814-816 (APS witness Snook).
[440] APS Br. at 33.
[441] *Id.* at 37.
[442] *Id.*, citing to Tr. at 802-803 (APS witness Snook).
[443] APS Br. at 37, citing to Tr. at 802-803 (APS witness Snook).
[444] APS Reply Br. at 22.
[445] *Id.*, citing to Tr. at 590 (APS witness Bordenkircher).
[446] APS Br. at 37; APS Reply Br. at 24.
[447] APS Reply Br. at 24.

proposal offers the Commission control over a targeted, transparent tool to protect against the risk that incentives will create a "new runaway NEM."[448]

AIC states that if the Commission wants to offer large commercial and industrial customers an option in addition to the currently structured E-32 L rate design, AIC supports APS's proposed E-32 UFI demand side management program as a compromise, where customers would be eligible for an up-front incentive of up to 50 percent of the total system costs or $100,000 depending on the storage duration, the design point, and the number of storage hours.[449] AIC contends that up-front incentives would prevent future controversy regarding the embedded subsidies in EFCA's Optional E-32 Rate proposal.[450] AIC recommends approval of the E-32 UFI program as a sound regulatory policy decision, as opposed to imbedding an incentive in rate design.[451]

EFCA argues that APS's proffered alternative to the Optional E-32 Rate proposal is inadequate, and urges the Commission not to adopt it.[452] EFCA asserts that "the preferred approach to encouraging energy efficiency development is not through incentives designed to overcome barriers, but instead to simply remove the barrier itself."[453] EFCA is critical of APS's E-32 UFI proposal because it retains the ratchet mechanism, the declining block demand charge, and the off-peak demand charge for TOU customers. EFCA characterizes the E-32 UFI proposal as retaining all the impediments to deploying storage that are inherent to the existing rates, but providing subsidies from other ratepayers to overcome those impediments.[454] EFCA asserts that APS presented no evidence to support adoption of the E-32 UFI program,[455] performed no comparative analysis of the E-32 UFI program and the Optional E-32 Rates, and did not determine if any peak reduction would result from its implementation.[456] EFCA charges that the E-32 UFI program is "not a serious attempt at proposing an alternative to a non-ratcheted rate design or addressing peak reduction and should be disregarded."[457] EFCA contends that

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[448] *Id.* at 26.
[449] AIC Br. at 11, citing to Tr. at 812-813 (APS witness Snook).
[450] AIC Br. at 10.
[451] *Id.* at 10, 11.
[452] EFCA Br. at 19-20.
[453] *Id.* at 19, citing to Tr. at 1156-57 (SWEEP witness Schlegel); EFCA Reply Br. at 7.
[454] EFCA Br. at 19.
[455] *Id.*
[456] *Id.*, citing to Tr. at 1187 (APS witness Snook).
[457] EFCA Br. at 19-20.

"even if subsidizing storage was appropriate,"[458] the proposed $2 million annual E-32 UFI subsidy would be inadequate to generate meaningful storage deployment and peak reduction.[459]

APS asserts that EFCA's criticism of the magnitude of the $2 million annual UFI proposal ignores the Commission's ability to increase incentives to achieve its desired objectives.[460] APS contends that the magnitude of the incentives embedded in EFCA's proposal aren't known, but calculates that they "far exceed $2 million annually;"[461] that eliminating the ratchet would require that demand rates be increased by $7 million;[462] and that making the ratchet optional would require an even larger increase.[463]

APS cautions that if customers install batteries as a result of the rate design incentives EFCA proposes, the Commission will never know how much of the value of the incentives has gone to third-party sellers of the technology – whether the price customers paid for the subsidy was too high for the benefit customers received from the subsidy.[464] In addition, the Commission would have no means to scale back the rate design incentive, as it would have with a direct up front incentive.[465] APS also points out that customers, along with EFCA, would very likely want to be grandfathered on the rate design incentive in the future.[466]

d. EFCA's Proposed Modifications to its Optional E-32 Rate Proposal

While asserting that there is no evidentiary support for modifying its proposed Optional E-32 Rate, EFCA asserts that it could easily be modified in order to address APS's criticisms, and EFCA is not opposed to its adoption with modifications set forth in its Initial Closing Brief and again in its Reply Closing Brief.[467] In response to criticisms that its Optional E-32 Rate proposal is too narrowly tailored to benefit only customers utilizing energy storage technology, EFCA states that it is not opposed to

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[458] *Id.* at 19.
[459] *Id.*, citing to Tr. at 1225 ((EFCA witness Mark E. Garrett).
[460] APS Reply Br. at 24.
[461] *Id.* at 23.
[462] APS Br. at 36, citing to Hearing Exhibit EFCA-14 (Rebuttal Testimony of Mark E. Garrett on the Settlement Agreement) at 15-16, Tables 1 and 2, referring to APS Response to Data Request EFCA 31.5 (c) in which APS provided the $7 million calculation.
[463] APS Br. at 36, citing to Tr. at 465 (APS witness Miessner); APS Reply Br. at 30.
[464] APS Reply Br. at 24.
[465] *Id.*
[466] APS Reply Br. at 22-23.
[467] EFCA Br. at 20-21, 23; EFCA Reply Br. at 18-19.

allowing customers adopting other energy efficiency mechanisms, and not only storage, that would meet a minimum kilowatt reduction with their technology to qualify for enrollment.[468] In response to criticisms that its Optional E-32 Rate Proposal is too broad, in that it would allow any size storage battery to qualify, EFCA states that it is not opposed to the Commission setting a minimum requirement for the size of a storage system to qualify.[469] EFCA suggests that an appropriate threshold would be for a customer's storage system to serve, at a minimum, 10 percent of the customer's prior year peak demand.[470] EFCA asserts that this sizing requirement would ensure that participating customers have invested in enough energy storage to provide a meaningful benefit to the grid, but would not "force customers to install too-large of a system that exceeds their needs and would render the investment cost-ineffective."[471] In response to criticisms that its Optional E-32 Rate Proposal would expose APS to under-recovery of its costs, EFCA contends that the only evidence presented in this proceeding demonstrates that before the ratchet was introduced, APS collected all its fixed costs from the E-32 L rate class.[472] EFCA states that in exchange for making its proposed Optional E-32 Rates available, the Commission could make customers on its proposed Optional E-32 Rates again subject to the LFCR.[473]

In its Reply Closing Brief, EFCA offered an additional modification to its proposed Optional E-32 Rates as follows:

> If the Commission wishes to proceed in a very conservative manner one other possibility exists. The Commission could modify the Optional Rates to effectively operate as a pilot program triggering an automatic review to assess its efficacy and impacts. Specifically, EFCA suggests that when and if, prior to the filing of APS' next rate case, the pilot program reaches 15% of existing E-32 L and E-32 L TOU customers by number or when the customers taking service under the Optional Rates have installed battery storage that would be capable [of] reducing peak demand in an amount equal to 15% of total peak demand for the E-32 L and E-32 L TOU classes from the last year before the Optional Rates are put in place, whichever comes first, an automatic Commission review would be triggered. Such a pilot program would give the Commission an opportunity to check in on the progress of the Optional Rate.[474]

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[468] EFCA Br. at 20.
[469] *Id.* at 21.
[470] *Id.*, citing to Tr. at 1223, 1229 (EFCA witness Mark E. Garrett).
[471] *Id.*
[472] EFCA Br. at 21, citing to Hearing Exhibit EFCA-9 (APS Response to EFCA Data Request 33).
[473] EFCA Br. at 21, citing to Tr. at 1228-29 (EFCA witness Mark E. Garrett).
[474] EFCA Reply Br. at 18-19.

The purpose of legal briefs is not to enter new evidence into the record, but to allow parties an opportunity to set forth their legal arguments on evidence presented in a proceeding. Because EFCA waited until the filing of its Reply Closing Brief to make its fourth proffered modification to EFCA's proposed Optional E-32 Rates, the parties had no opportunity to respond to it in any manner. EFCA's Reply Closing Brief proposal does not constitute evidence subject to cross-examination of a sponsoring witness, and no party has had an opportunity to advance legal arguments in response to it.

AIC responded to the three modifications that EFCA proposed to its Optional E-32 Rates as follows:

> Presented for the first time in EFCA's post-hearing brief, no party had an opportunity to cross examine EFCA or APS regarding the impact of those changes on participating and non-participating customers or on any other aspect of the modified rate design. EFCA has the burden of justifying its proposed modifications with record evidence, which – having made the proposals after the hearing in this matter had concluded – it simply cannot do.[475]

AIC also states that the modifications appear to be insufficient to address the concerns APS raised with EFCA's initial proposal.[476] AIC recommends that if the Commission determines that the public interest requires incentives for energy storage for the E-32 customer class, it should adopt APS's proposed E-32 UFI program.[477]

APS asserts that "EFCA would only suggest revisiting the (settlement in the last rate case) decision exempting E-32 L customers from paying the LFCR if lost fixed costs were on the horizon."[478] APS further asserts that applying the LFCR would not avoid a cost shift, but would socialize the lost revenues due to EFCA's proposal by shifting them on to base rates paid by other customers when they are reallocated in the next rate case.[479] APS contends that EFCA's willingness to apply the LFCR to its Optional E-32 Rate Proposal constitutes an admission that it would shift costs.[480]

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[475] AIC Reply Br. at 7. As set forth above in this section, EFCA's witness responded to questions at the hearing regarding potential modifications to its Optional E-32 Rates proposal. *See also* Tr. at 1223, 1228-29, 1246-47, 1249-51, 1256 (EFCA witness Mark Garrett).
[476] *Id.*
[477] *Id.*
[478] APS Reply Br. at 19.
[479] *Id.*
[480] APS Reply Br. at 20.

e. Resolution

While we agree with APS and AIC that the recent UNSE and TEP rate Decisions do not offer a direct comparison to APS's E-32 L ratchets, we also believe that it would be useful to create a new, optional, non-ratcheted, storage-friendly rate. This new, optional rate should eliminate the demand ratchet, off-peak demand charge, and declining block demand charge currently included in APS's E-32L and E-32L TOU rate.

The R-Tech Tariff we approve herein as part of the Settlement and TEP's recently implemented Large General Service Time-of-Use Storage Program (the TEP Tariff) set forth a number of safeguards and restrictions that should be utilized in conjunction with our approval of an optional storage-friendly rate to avoid any negative unintended consequences and ensure a smooth and meaningful implementation of an optional tariff. We find those safeguards and restrictions to be appropriate and necessary and will require that APS adopt them in connection with the new, optional tariff directed in this proceeding. Accordingly, we order that, within 120 days from the date of this order, APS file a new, optional storage-friendly tariff and order that the tariff shall include the following restrictions and safeguards similar to those in both the R-Tech and TEP Tariff:

Program Size

APS's optional Large General Service Time-of-Use Storage Program Tariff (the Optional Tariff) will be capped at a peak demand total of 35,000 kW for installed systems and active interconnection applications, on a first-come first-served basis. Allotments shall be reserved at the time of submittal of a complete interconnection application.

Stakeholder Process

Once 70% of the initial program capacity has been reached, and if such threshold has been reached prior to APS's next general rate case filing, APS will evaluate whether the costs of the program are less than the system benefits it provides. If APS determines that the costs are less than the benefits, APS shall provide notice and promptly convene a meeting of the interested parties to this Docket to discuss the future of the program. If all parties to that discussion agree on a new program size for the Optional Tariff that shall apply until the Commission determines the disposition of the Optional Tariff during APS's next general rate case, APS shall file a notice in this Docket to that effect and the program shall remain in effect up to the new agreed upon customer participation level, unless the Commission orders otherwise. However, if all parties cannot agree upon a new customer participation level, APS within 90 days of the finalization of the discussions, shall file a request with the Commission to establish the terms and conditions under which the program will continue or terminate. If APS determines that the costs are greater than the system benefits, APS will file a request with the Commission to freeze the program until changes can be made in APS's next general rate case.

Minimum Peak Demand Reduction

To qualify for the Optional Tariff, a customer must install a chemical, mechanical or thermal energy storage system that is capable of allowing the customer to offset a minimum of 20% of their measured peak demand during the On-Peak period. The determination of the measured peak demand for purposes of the calculation will be based on the customer's previous year's measured peak demand during such period prior to installation of storage facilities. If this is a new facility, the calculation of the 20% demand reduction will be determined based on APS's total estimated peak demand designed for the facility.

VAR Support

In order to qualify for the program where a power producing facility is installed, inverters must be capable of and configured to provide VAR support so that a near unity power factor of at least 95% is maintained during operation.

TOU Hours

For purposes of the APS Optional Tariff, the On-Peak period under the program will be determined as the 6 greatest average system demand hours during the previous three years by season. The Off-Peak period will be determined as the 12 lowest average system demand hours during the previous three years by season. All other hours shall be deemed as Remaining Hours.

Annual Reporting

Until such time that a final order is issued in APS's next general rate case, on July 1 of each year APS shall submit an informational filing in the docket, reporting on the status of the APS Optional Tariff. The report will include: (i) the number of customers, both in the current year and cumulatively, that are participating in the program (including the proportion of these customers relative to the entire large commercial class), (ii) the total peak demand of such customers relative to the initial program allotment of 35,000 kW, (iii) observed peak demand reductions, if any, of customers participating in the program, (iv) recommended changes, if any, to the Time-of Use periods for the program, (v) if available, information regarding the average time to process applications from customers requesting participation in the program, and (vi) current year and cumulative kWh exported to the grid by participating customers.

Rate Design

The APS Optional Tariff shall not include a demand ratchet, Off-Peak demand charge or declining block demand charge. On-Peak billing demand shall be equal to the greatest measured 15 minute interval demand read of the meter during the On-Peak Hours or the Remaining Hours during the billing period. The APS Optional Tariff may include a minimum contract demand provision. The APS Optional Tariff may also include a summer and winter Off-Peak excess demand charge for Off-Peak exceeding 150% of On-Peak billing demand. The customer service charge component of the APS Optional Tariff will be structured to maintain proper price signals to incent peak demand reduction while also ensuring appropriate cost recovery. Storage customers taking service under the APS Optional Tariff that also have distributed generation remain eligible for the EPR-6 net metering rider.

VIII. STORAGE TO BE INCLUDED IN ANALYSES OF NEW RESOURCE OPTIONS

Energy storage is a valuable tool for electric utilities to comply with the state's energy policies. Prioritizing energy storage can likewise help reduce a utility's peak demand and address load and generation challenges while also providing benefits to other parts of the system. All utilities – including APS – should explore these energy storage opportunities on a more regular and specific basis due to the potential to help utilities manage demand while also offering opportunities for new investment and consumer service options.

When acquiring new resources or considering transmission or distribution system upgrades where appropriate, utilities should perform sufficient analyses of resources and transmission and distribution system upgrades that include energy storage such that the full benefits of energy storage are being considered. Energy storage should be compared to baseload resources and non-baseload resources when a utility is considering acquiring a new resource and should be compared to alternative upgrades when a utility is considering transmission and distribution upgrades. The Commission's definition of "baseload resources" is as follows: resources that provide a continuous supply of electricity and are not used for load-following, which are traditionally operated continuously with high capacity factors. "Non-baseload resources" refer to resources that are used by the utility for load-following, grid support, load reduction, and other services.

IX. WATER ENERGY NEXUS

Water conservation is a key issue facing Arizona, particularly when existing Arizona water utilities are experiencing significant water loss levels. Efforts to reduce water loss levels can also result in benefits from reductions in electric consumption. For example, a reduction in water loss at a water utility could result in a reduction in electricity consumption due to reduced pumping operations. Utilities like APS should explore opportunities to partner with local water utilities in furtherance of reducing both electricity and water consumption.

One such opportunity exists in connection with APS's 2018 Demand Side Management Implementation Plan filing. APS should develop and propose to the Commission, for approval, a program available to water utilities within its service territory that would result in a reduction in water loss, electricity, consumption, or peak demand. APS should evaluate all available opportunities to conserve and more efficiently use water and electricity in tandem and maximize these opportunities in the program it will propose to the Commission. APS should involve the Commission's Water Committee in these efforts. The nexus between electricity consumption and water conservation is an important issue that we anticipate addressing with other electric utilities in future rate cases.

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

<u>FINDINGS OF FACT</u>

<u>Procedural History</u>

1. On January 29, 2016, APS filed a Notice of Intent to File a Rate Case Application and Request to Open Docket.

2. On February 5, 2016, Richard Gayer, Patricia Ferré and Warren Woodward each filed

a Motion to Intervene.

3. On February 17, 2016, by Procedural Order, Richard Gayer, Patricia Ferré and Warren Woodward were granted intervention.

4. On February 22 and March 7, 2016, Mr. Woodward filed comments in the docket.

5. On February 23, 2016, Mr. Gayer filed a Notice of Consent to Email Service.

6. On February 29, 2016, Mr. Woodward filed a Notice of Consent to Email Service.

7. On February 29, 2016, IO filed a Motion to Intervene.

8. On March 7, 2016, Mr. Woodward filed comments in the docket.

9. On March 21, 2016, a Procedural Order was issued granting intervention to IO and granting requests to receive service by email.

10. On April 4, 2016, Freeport and AECC jointly filed a Motion to Intervene and Consent to Email Service.

11. On April 21, 2016, a Procedural Order was issued granting intervention to Freeport and AECC and granting requests to receive service by email.

12. On May 27, 2016, SCHOA filed a Motion to Intervene and a Consent to Email Service.

13. On June 1, 2016, APS filed the Application.

14. On June 3, 2016, WRA filed a Motion for Leave to Intervene and a Consent to Email Service.

15. On June 7, 2016, AIC filed a Motion for Leave to Intervene and a Consent to Email Service.

16. On June 14, 2016, APS filed a Notice of Errata.

17. On June 14, 2016, AURA filed a Motion for Leave to Intervene and Consent to Email Service.

18. On June 14, 2016, a Procedural Order was issued granting interventions to SCHOA, WRA and AIC and granting requests to receive service by email.

19. On June 15, 2016, PORA filed an Application to Intervene and a Consent to Email Service.

20. On June 16, 2016, AriSEIA filed its Application to Intervene and a Consent to Email

Service.

21. On June 16, 2016, ASBA/AASBO jointly filed a Motion for Leave to Intervene.

22. On June 17, 2016, SCHOA filed a Clarification.

23. On June 17, 2016, Cynthia Zwick, in her individual capacity, and ACAA jointly filed a Motion for Leave to Intervene. ACAA also filed a Consent to Email Service.

24. On June 17, 2016, APS filed its Opposition to AURA's Motion for Leave to Intervene.

25. On June 22, 2016, RUCO filed a Motion for Leave to Intervene.

26. On June 22, 2016, APS docketed copies of its lead/lag study and excerpts from the Handy-Whitman Bulletin No. 182 used to calculate its proposed reconstruction cost new less depreciation ("RCND") rate base.

27. On June 22, 2016, SWEEP filed a Motion for Leave to Intervene and a Consent to Email Service.

28. On June 23, 2016, APS filed its Second Notice of Errata.

29. On June 24, 2016, AURA filed its Response in Support of Motion to Intervene.

30. On June 24, 2016, APS filed a copy of the notice it provided to parties of record of the Rate Case Technical Conferences scheduled for July 20, 2016, August 23, 2016, September 29, 2016, and October 26, 2016.

31. On June 27, 2016, Vote Solar filed a Motion for Leave to Intervene and a Consent to Email Service.

32. On June 28, 2016, APS filed its Reply in Opposition to AURA's Motion to Intervene.

33. On June 29, 2016, the ED8/McMullen jointly filed a Motion for Leave to Intervene and a Consent to Email Service.

34. On July 1, 2016, Staff issued a Letter of Sufficiency pursuant to A.A.C. R14-2-103, classifying APS as a Class A utility.

35. On July 1, 2016, AURA filed a Motion to Strike.

36. On July 5, 2016, Kroger filed a Motion for Leave to Intervene and a Consent to Email Service.

37. On July 5, 2016, John William Moore, Jr., filed with the Commission a Motion to

Associate Counsel *Pro Hac Vice* to associate Kurt J. Boehm and Jody Kyler Cohn as counsel for Kroger in this matter.

38. On July 5, 2016, APS filed its Reply in Opposition to AURA's Motion to Strike.

39. July 6, 2016, AURA filed its Response to APS's Reply in Opposition to AURA's Motion to Strike.

40. On July 7, 2016, TEP filed a Motion for Leave to Intervene and a Consent to Email Service.

41. On July 8, 2016, Pima County filed a Motion for Leave to Intervene and a Consent to Email Service.

42. On July 11, 2016, Staff filed a Request for Procedural Schedule.

43. On July 12, 2016, SEIA filed a Motion for Leave to Intervene and a Consent to Email Service.

44. On July 15, 2016, EFCA filed a Motion to Intervene.

45. On July 18, 2016 Walmart filed an Application for Leave to Intervene and a Consent to Email Service.

46. On July 19, 2016, Staff filed a Motion to Consolidate, requesting that this docket be consolidated with Docket No. E-01345A-16-0123.

47. On July 22, 2017, APS filed a copy of the presentation from its second Rate Case Technical Conference.

48. On July 22, 2016, a Rate Case Procedural Order was issued setting the procedural schedule and associated procedural deadlines for this matter, granting intervention to AURA, PORA, AriSEIA, ASBA/AASBO, Cynthia Zwick (in her personal capacity), ACAA, SWEEP, RUCO, Vote Solar, ED8/McMullen, Kroger, TEP, Pima County and SEIA, and granting several requests to receive service by email.

49. On July 28, 2016, Mr. Woodward filed a Motion for Reconsideration of the July 22, 2016 Procedural Order.

50. On July 29, 2016, the IBEW Locals filed an Application for Leave to Intervene.

51. On August 1, 2016, a Procedural Order was issued granting Staff's request to

consolidate the above-captioned dockets, correcting typographical errors in the July 22, 2016 Rate Case Procedural Order, granting interventions to EFCA and Walmart, and granting requests to receive service by email.

52. On August 1, 2016, Mr. Woodward filed comments.

53. On August 1, 2016, Noble Solutions filed an Application for Leave to Intervene.

54. On August 3, 2016, the Alliance filed an Application for Leave to Intervene.

55. On August 3, 2016, FEA filed a Motion for Leave to Intervene.

56. On August 3, 2016, Karen S. White filed with the Commission a Motion to Associate Counsel *Pro Hac Vice* to associate Thomas A. Jernigan as counsel for FEA in this matter.

57. On August 5, 2016, APS filed a Motion for Clarification and Extension of Time.

58. On August 9, 2016, a Procedural Order was issued granting APS's Motion for Clarification and Extension of Time. The Procedural Order also granted intervention to the IBEW Locals, Noble Solutions and the Alliance, and approved a consent to email service.

59. On August 11, 2016, EFCA filed a Consent to Service by Email.

60. On August 15, 2016, Staff filed a Consent to Email Service.

61. On August 17, 2016, Noble Solutions filed a Consent to Email Service.

62. On August 24, 2016, APS filed a copy of the presentation from its second Rate Case Technical Conference.

63. On August 24, 2016, the Districts jointly filed an Application for Leave to Intervene and a Consent to Email Service.

64. On August 25, 2016, Correspondence from Commissioner Bob Burns was filed in the docket.

65. On September 6, 2016, a Procedural Order was issued granting the Districts' Application for Leave to Intervene, and granting requests for service by email.

66. On September 6, 2016, CNE filed an Application for Leave to Intervene.

67. On September 6, 2016, Mr. Woodward filed two sets of comments.

68. On September 9, 2016, APS filed correspondence regarding subpoenas dated August 25, 2016.

69. On September 9, 2016, APS filed a Motion to Sever.

70. On September 9, 2016, APS filed a Motion to Quash, or in the Alternative, to Decline to Hear.

71. On September 12, 2016, APS filed correspondence regarding subpoenas dated August 25, 2016.

72. On September 13, 2016, APS filed an Affidavit of Publication and Proof of Mailing.

73. On September 13, 2016, Correspondence from Commissioner Bob Burns was filed in the docket.

74. On September 27, 2016, Karen S. White filed a Motion to Associate Counsel *Pro Hac Vic*e to associate Thomas A. Jernigan as counsel for FEA in this matter pursuant to Arizona Supreme Court Rule 38(a), to which was attached a certification of service indicating that the Motion was served on all parties.

75. On September 30, 2016, Direct Energy filed an Application for Leave to Intervene.

76. On September 30, 2016, APS filed a copy of the presentation from its third Rate Case Technical Conference.

77. On October 3, 2016, Mr. Woodward filed a Notice of Change of Address.

78. On October 3, 2016, EFCA filed a Notice of Deposition of Barbara D. Lockwood.

79. On October 6, 2016, APS filed a Motion for Procedural Conference and Interim Protective Order.

80. On October 7, 2016, Timothy M. Hogan filed Motions to Associate Counsel *Pro Hac Vic*e to associate Chinyere Ashley Osuala and David Bender as counsel for Vote Solar in this matter.

81. On October 11, 2016, counsel for Noble Solutions, CNE, and Direct Energy filed a Notice of Change of Address.

82. On October 12, 2016, AARP filed an Application to Intervene and a Motion to Associate Counsel *Pro Hac Vic*e to associate John B. Coffman as counsel for AARP in this matter.

83. On October 12, 2016, EFCA filed its Response to APS's Motion for Procedural Conference and Interim Protective Order.

84. On October 13, 2016, Mr. Woodward filed comments.

85. On October 14, 2016, Mr. Woodward filed a Response to Chairman Little's October 4, 2016 Memorandum and Call for Recusal.

86. On October 14, 2016, a Procedural Order was issued granting APS's request for an interim protective order regarding EFCA's October 3, 2016 Notice of Deposition, and setting a procedural conference to be held on October 20, 2016, for the purpose of discussing discovery issues, including but not limited to the deposition of APS witness Barbara D. Lockwood.

87. On October 17, 2016, APS filed a Consent to Email Service.

88. On October 18, 2016, APS filed its Reply in Support of Motion for Procedural Conference and Interim Protective Order.

89. On October 18, 2016, Correspondence from Commissioner Doug Little was filed in the docket.

90. On October 19, 2016, FEA and Vote Solar each filed a Consent to Email Service.

91. On October 19, 2016, AURA filed its Response in Support of the Notice of Deposition.

92. On October 20, 2016, a procedural conference was held as scheduled by the Procedural Order issued October 14, 2016. APS, EFCA, TEP, Walmart, Freeport Minerals, AECC, Noble Solutions, CNE, Direct Energy, PORA, the Alliance, RUCO, and Staff appeared through counsel or lay representative. APS, Noble Solutions, CNE, Direct Energy, EFCA, and Staff provided comments and arguments regarding discovery issues, and the matter was taken under advisement.

93. On October 21, 2016, a Procedural Order was issued granting intervention to AARP, admitting counsel for AARP *pro hac vice* in this matter, and rescheduling the date of the pre-hearing conference in this matter to March 13, 2017.

94. On October 24, 2016, Sedona filed an Application to Intervene and a Consent to Email Service.

95. On October 26, 2016, Mr. Woodward filed his Reply to Commissioner Little's October 18, 2016 Memorandum, and Call for Recusal.

96. On October 27, November 1, November 8, and November 9, 2016, AARP filed Consents to Email Service.

97. On November 2, 2016, ASDA filed an Application to Intervene and a Consent to Email

Service.

98. On November 4, 2016, EFCA filed a Supplemental Statement of Authority.

99. On November 4, 2016, APS filed a copy of the presentation from its fourth Rate Case Technical Conference.

100. On November 9, 2016, APS filed a Response to EFCA's Supplemental Statement of Authority.

101. On November 9, 2016, Sunrun Inc. filed an Application for Leave to Intervene.

102. On November 10, 2016, Coolidge filed an Application for Leave to Intervene.

103. On November 10, 2016, ConservAmerica filed an Application for Leave to Intervene and Consent to Service by Email.

104. On November 10, 2016, Granite Creek jointly filed an Application for Leave to Intervene and a Consent to Email Service.

105. On November 15, 2016, Mr. Woodward filed comments.

106. On November 15, 2016, Sunrun filed a Consent to Email Service.

107. On November 17, 2016, a Procedural Order was issued granting intervention to AARP, Sedona, and ASDA, granting requests for service by email, and setting procedural deadlines regarding the deposition of APS witness Barbara Lockwood.

108. On November 18, 2016, Granite Creek filed a Notice of Change of Address.

109. On November 18, 2016, APS docketed a letter addressed to the Commissioners to which was attached a copy of materials from the presentation from its third Rate Case Technical Conference.

110. On November 21, 2016, APS docketed a copy of the presentation from its rate case Cost of Service Model Technical Session.

111. On November 23, a Procedural Order was issued granting intervention to Sunrun, Coolidge, ConservAmerica, and Granite Creek.

112. On November 28, 2016, Ms. Ferré filed a Consent to Email Service.

113. On November 30, 2016, EFCA filed a Notice of Deposition of Barbara D. Lockwood. The Notice indicated that EFCA and APS settled upon December 15, 2016, at 9:00 a.m. as the date and time of the deposition.

114. On December 2, 2016, AARP filed a Request to Add Courtesy Email.

115. On December 5, 2016, EFCA filed its Emergency Motion to Compel Production of Barbara Lockwood Calendar in Advance of Lockwood Deposition.

116. On December 5, 2016, EFCA filed its Emergency Motion for Expedited Consideration Regarding Emergency Motion to Compel Production of Barbara Lockwood Calendar in Advance of Lockwood Deposition.

117. On December 5, 2016, EFCA filed its Personal Consultation Certificate.

118. On December 7, 2016, APS filed its Response in Opposition to EFCA's Motion to Compel.

119. On December 7, 2016, APS filed its Motion to Compel.

120. On December 7, 2016, Mr. Gayer filed his Direct Testimony.

121. On December 9, 2016, Coolidge filed a Consent to Email Service.

122. On December 12, 2016, EFCA filed its Reply in Support of Emergency Motion to Compel Production of Barbara Lockwood Calendar in Advance of Lockwood Deposition and its Emergency Motion to Compel Production of Report Regarding Rate Impact.

123. On December 13, 2016, by Procedural Order, EFCA's Motion to Compel Production of Barbara Lockwood's Calendar was denied and Energy Freedom Coalition of America was ordered to file, no later than December 16, 2016, its Response to Arizona Public Service Company's December 7, 2016 Motion to Compel.

124. On December 13, 2016, EFCA filed a Notice of Withdrawal of its Emergency Motion to Compel Production of Report Regarding Rate Impact.

125. On December 14, 2016, Sunrun filed a Notice of Withdrawal as Intervenor.

126. On December 14, 2016, Patricia Lee Refo of Snell & Wilmer LLP filed a Notice of Appearance on behalf of APS.

127. On December 16, 2016, AriSEIA filed a Notice of Consent to Email Service.

128. On December 19, 2016, EFCA filed its Response to the Motion to Compel filed by APS.

129. On December 19, 2016, Staff filed a Request for Extension of Filing Deadline.

130. On December 20, 2016, the IBEW Locals filed the Direct Testimony of G. David

Vandever.

131. On December 21, 2016, the FEA filed the Direct Testimony of its witnesses Brian C. Andrews and Michael P. Gorman.

132. On December 21, 2016, Mr. Woodward filed his Direct Testimony.

133. On December 21, 2016, a Procedural Order was issued extending the deadline for the filing of Intervenor Direct Testimony to December 28, 2016, approving the request of Sunrun, Inc. to withdraw as an intervenor, and approving SEIA's consent to email service request.

134. On December 22, 2016, ConservAmerica filed the Direct Testimony of its witness Paul Walker.

135. On December 22, 2016, RUCO filed the Direct Testimony of its witnesses John Cassidy and Frank Radigan.

136. On December 27, 2016, Mr. Woodward filed his Motion to Compel.

137. On December 27, 2016, APS filed its Reply to EFCA's Response to APS's Motion to Compel.

138. On December 27, 2016, CNE and Direct Energy each filed a Consent to Email Service.

139. On December 28, 2016, AIC filed the Direct Testimony of its witness Branko Terzik.

140. On December 28, 2016, ED8/McMullen filed the Direct Testimony of their witness James D. Downing.

141. On December 28, 2016, AECC filed the Direct Testimony of its witness Kevin Higgins.

142. On December 28, 2016, Walmart filed the Direct Testimony of its witness Gregory W. Tillman.

143. On December 28, 2016, SWEEP filed the Direct Testimony of its witness Jeff Schlegel.

144. On December 28, 2016, EFCA filed the Direct Testimony of its witness Mark E. Garrett.

145. On December 28, 2016, Staff filed the Direct Testimony of its witnesses Ralph Smith, David Parcell, Michael Lewis, and Candrea Allen.

146. On December 29, 2016, APS filed its Notice of Intent of Revenue Requirement Settlement Discussions.

147. On December 30, 2016, APS filed its Notice of Filing Supplemental Testimony, to

which was attached the Supplemental Direct Testimony of Jeffrey M. Burke, setting forth APS's proposed valuation of DG exports using the RCP Methodology.

148. On December 30, 2016, EFCA filed its Sur-Response to APS's Motion to Compel; Motion to Strike Reply Brief; and Notice of Lodging Sur-Response.

149. On December 30, 2016, EFCA filed its Notice of Deposition of Charles A. Miessner.

150. On December 30, 2016, EFCA filed its Notice of Deposition of Leland R. Snook.

151. On December 30, 2016, APS filed its Response to Mr. Woodward's Motion to Compel.

152. On January 3, 2017, Mr. Woodward filed his Reply to APS's Response to his Motion to Compel.

153. On January 4, 2017, APS filed its Response to EFCA's Motion to Strike Reply Brief and Notice of Lodging Sur-Response.

154. On January 5, 2017, APS filed a Motion for Protective Order.

155. On January 6, 2017, EFCA filed its Response to APS's Motion for Protective Order.

156. On January 6, 2017, EFCA filed its Emergency Motion for Expedited Consideration Regarding EFCA's Response to APS's Motion for Protective Order.

157. On January 6, 2017, EFCA filed its Amended Notice of Deposition of Leland R. Snook.

158. On January 6, 2017, Staff filed its Notice of Time and Location for Settlement Discussions.

159. On January 9, 2017, Vote Solar filed its Expedited Motion to Strike and for Procedural Order.

160. On January 9, 2017, a Procedural Order was issued setting a procedural conference for the dual purpose of addressing the issue of incorporating the RCP Methodology into this proceeding, as directed by Decision No. 75859; and for hearing oral argument on APS's Motion for Protective Order and responsive pleadings.

161. On January 10, 2017, Mr. Gayer docketed a supplement to his Direct Testimony.

162. On January 11, 2017, the procedural conference convened as scheduled. Appearances were entered by counsel for APS, AIC, ASDA, Vote Solar, SEIA, EFCA, IO, the Alliance, the FEA, ED8/McMullen, PORA, RUCO, and Staff.

163. On January 13, 2017, a Procedural Order was issued rescheduling the hearing date in this matter, along with associated procedural deadlines, in order to facilitate the incorporation of the RCP Methodology into this proceeding pursuant to Decision No. 75859; extending the timeclock by 33 days accordingly; denying Vote Solar's Motion to Strike; and Granting APS's Motion for Protective Order in regard to EFCA's Notices of Deposition of APS witnesses Leland R. Snook and Charles A. Miessner.

164. On January 13, 2017, EFCA filed its Amended Notice of Deposition of Charles A. Miessner.

165. On January 13, 2017, EFCA filed its second Amended Notice of Deposition of Leland R. Snook.

166. On January 18, 2017, PORA filed a request to allow Mr. Robert Miller, PORA Director and Chair of Utilities Liaison Committee, to appear and represent PORA as an alternative designee to act "with or in the stead or absence of" PORA's representatives Albert Gervenack and Rob Robbins in this proceeding.

167. On January 18, 2017, a Procedural Order was issued clarifying that public comment would be taken commencing at 10:00 a.m. on March 22, 2017, which was the publicly noticed first day of hearing in this matter; that the evidentiary portion of this proceeding would commence at 10:00 a.m. on April 24, 2017; and that parties wishing to participate in the hearing were required to attend the April 20, 2017 pre-hearing conference.

168. On January 18, 2017, EFCA filed its Motion for Reconsideration of the Approval of APS's Motion for Protective Order.

169. On January 19, 2017, Mr. Woodward filed his Motion to Compel APS to Fully Answer Woodward's Data Request 2.19.

170. On January 19, 2017, EFCA filed a Motion to Associate Counsel Pro Hac Vice.

171. On January 19, 2017, Commissioner Burns filed correspondence.

172. On January 20, 2017, APS filed its Response to Mr. Woodward's Second Motion to Compel.

173. On January 25, 2017, Mr. Woodward filed a Reply to APS's January 20, 2017

Response.

174. On January 27, 2017, Coolidge filed the Direct Testimony of its witness Rick Miller.

175. On January 27, 2017, Kroger filed the Direct Testimony of its witness Stephen J. Baron on Cost of Service and Rate Design issues.

176. On January 30, 2017, Calpine filed notice of its name change.

177. On January 31, 2017, Freeport and AECC filed a request to remove C. Webb Crockett from the service list in this matter.

178. On February 3, 2017, PORA filed the Direct Testimony of its witness Al Gervenack.

179. On February 3, 2017, the FEA filed the Direct Testimony of its witness Amanda M. Alderson.

180. On February 3, 2017, Walmart filed the Direct Testimony of its witnesses Gregory W. Tillman and Chris Hendrix.

181. On February 3, 2017, AIC filed the Direct Testimony of its witnesses Gary Yaquinto, Branko Terzik and Daniel G. Hansen.

182. On February 3, 2017, RUCO filed the Direct Testimony of its witnesses Frank Radigan and Lon Huber.

183. On February 3, 2017, Vote Solar filed the Direct Testimony of its witness Briana Kobor.

184. On February 3, 2017, ACAA filed the Direct Testimony of its witness Cynthia Zwick.

185. On February 3, 2017, SWEEP filed the Direct Testimony of its witness Jeff Schlegel.

186. On February 3, 2017, SEIA filed the Direct Testimony of its witness R. Thomas Beach.

187. On February 3, 2017, EFCA filed the Direct Testimony of its witnesses James A. Heidell and Mark E. Garrett.

188. On February 3, 2017, Freeport, AECC, Calpine, CNE, and Direct Energy filed the Direct Testimony of their witness Kevin C. Higgins.

189. On February 3, 2017, AURA filed the Direct Testimony of its witnesses Patrick J. Quinn and Scott Rubin.

190. On February 3, 2017, ConservAmerica filed the Direct Testimony of its witness Paul Walker.

191. On February 3, 2017, Staff filed the Direct Testimony of its witnesses Ralph C. Smith and Matt Connolly.

192. On February 6, 2017, a Procedural Order was issued granting Mr. Woodward's First Motion to Compel, granting PORA's Request for authorization of Robert Miller to represent PORA as an additional lay representative in this matter, and admitting Curt Ledford to appear *pro hac vice* in this matter.

193. On February 6, 2017, the IBEW Locals filed the Direct Testimony of their witness G. David Vandever (Rate Design).

194. On February 7, 2017, Walmart filed a Notice of Errata in filing the Direct Testimony of Gregory W. Tillman and Chris Hendrix (Rate Design).

195. On February 7, 2017, the IBEW Locals filed a Motion for Extension of Time and the Direct Testimony of David Vandever.

196. On February 7, 2017, Commissioner Burns filed correspondence.

197. On February 9, 2017, Mr. Woodward filed a Motion for Clarification.

198. On February 9, 2017, APS filed a Notice of Non-Objection to the IBEW Locals' Motion for Extension of Time.

199. On February 9, 2017, APS filed a Response to Mr. Woodward's Motion for Clarification.

200. On February 16, 2017, Karen White, counsel for the FEA, filed a Motion to Associate Counsel Pro Hac Vice.

201. On February 21, 2017, Commissioner Tobin filed correspondence.

202. On February 22, 2017, Chairman Forese filed correspondence.

203. On February 22, Commissioner Burns filed correspondence.

204. On February 24, 2017, APS filed a Request for Extension of Time, and requested expedited consideration.

205. On February 24, 2017, a Procedural Order was issued granting the Request for Extension of Time.

206. On February 24, 2017, Granite Creek filed its Notice of Direct Filing for a Ruling on

Unattended Matters in the Matter of Fuel and Purchased Power Procurement.

207. On February 27, 2017, Chairman Forese filed Correspondence.

208. On February 28, 2017, Mr. Woodward filed his Motion to Compel Compliance with February 6, 2017 Procedural Order.

209. On March 1, 2017, Staff filed its Notice of Filing Settlement Term Sheet. Exhibit B to the Settlement Term Sheet indicated the following parties' support of the Settlement Agreement outlined in the March 1, 2017 Settlement Term Sheet: APS, AIC, the IBEW Locals, ConservAmerica, ASDA, Vote Solar, EFCA, SEIA, AriSEIA, AURA, Direct Energy, Freeport, AECC, Calpine, CNE, the Alliance, Walmart, Kroger, Granite Creek, FEA, Coolidge, ASBA, AASBO, WRA, SCHOA, PORA, ACAA, RUCO, and Staff.

210. On March 2, 2017, Staff filed its Request for Modification of Procedural Schedule.

211. On March 2, 2017, Mr. Woodward filed his Motion for Reconsideration of February 6, 2017 Procedural Order.

212. On March 3, 2017, APS filed its Response to Mr. Woodward's Third Motion to Compel.

213. On March 3, 2016, a Procedural Order was issued Modifying Filing Deadlines.

214. On March 6, 2017, Mr. Woodward filed his Reply to APS's Response.

215. On March 7, 2017, a Procedural Order was issued regarding Public Comment in Douglas Arizona.

216. On March 10, 2017, a Procedural Order was issued denying Mr. Woodward's Motion to Compel Compliance with February 6, 2017 Procedural Order filed on February 28, 2017.

217. On March 10, 2017, APS and Pinnacle West filed a Renewed Motion to Quash.

218. On March 14, 2017, Commissioner Burns filed a Response and Objection to Motion to Quash, or, in the Alternative, to Decline to Hear.

219. On March 15, 2017, a Procedural Order was issued regarding Public Comment in Yuma, Arizona.

220. On March 21, 2017, APS filed a Certification of Publication.

221. On March 21, 2017, Staff filed Direct Testimony of its witness Dennis J. Shumaker.

222. On March 24, 2017, a Procedural Order was issued regarding Public Comment in

Clarkdale, Arizona.

223. On March 24, 2017, a Procedural Order was issued changing the deadline for Publication of the Clarkdale, Arizona Public Comment Session.

224. On March 24, 2017, Commissioner Forese filed Correspondence.

225. On March 24, 2017, Staff filed a Request for an Extension of Time to docket the Settlement Agreement.

226. On March 27, 2017, Commissioner Little filed Correspondence.

227. On March 27, 2017, Commissioner Tobin filed Correspondence.

228. On March 27, 2017, a Settlement Agreement was filed, signed by APS, AIC, the IBEW Locals, ConservAmerica, ASDA, Vote Solar, EFCA, SEIA, AriSEIA, AURA, Direct Energy, Freeport, AECC, Calpine, CNE, the Alliance, Walmart, Kroger, Granite Creek, FEA, Coolidge, ASBA, AASBO, WRA, SCHOA, PORA, ACAA, RUCO, and Staff.

229. On March 28, 2017, a Procedural Order was issued regarding Public Comment in Flagstaff, Arizona.

230. On March 29, 2017, Commissioner Burns filed Correspondence.

231. On March 29, 2017, a Procedural Order was issued changing the venue of the Flagstaff Public Comment Session.

232. On March 30, 2017, APS filed a Certification of Publication.

233. On March 30, 2017, the IBEW Locals filed Direct Testimony of G. David Vandever in Support of Settlement Agreement.

234. On March 31, 2017, Staff docketed a Notice of Filing stating that the remaining appendices to the Settlement Agreement would be filed on April 3, 2017.

235. On March 31, 2017, AURA filed the Direct Testimony of its witness Patrick J. Quinn on the Settlement Agreement.

236. On April 3, 2017, Mr. Gayer filed his Direct Testimony in Opposition to the Settlement Agreement.

237. On April 3, 2017, AIC filed the Direct Testimony of its witness Gary Yaquinto in Support of Settlement Agreement.

238. On April 3, 2017, FEA filed the Direct Testimony of its witness Amanda M. Alderson in Support of the Settlement Agreement.

239. On April 3, 2017, Patricia Ferré filed her Direct Testimony in Opposition to the Settlement Agreement.

240. On April 3, 2017, Mr. Woodward filed his Direct Testimony in Opposition to the Settlement Agreement.

241. On April 3, 2017, Mr. Woodward filed the Direct Testimony of his witness Erik S. Anderson, P.E. in Opposition to the Settlement Agreement.

242. On April 3, 2017, Mr. Woodward filed the Direct Testimony of his witness Dr. Sam Milham, MD, MPH in Opposition to the Settlement Agreement.

243. On April 3, 2017, RUCO filed the Direct Testimony of its witness David P. Tenney in Support of the Settlement Agreement.

244. On April 3, 2017, ASDA filed the Direct Testimony of its witness Sean Seitz in Support of the Settlement Agreement.

245. On April 3, 2017, Staff filed the Direct Testimony of its witnesses Ralph C. Smith and Elijah O Abinah in Support of the Settlement Agreement.

246. On April 3, 2017, SWEEP filed the Direct Testimony of its witness Jeff Schlegel in Opposition to the Settlement Agreement.

247. On April 3, 2017, ConservAmerica filed the Direct Testimony of its witness Paul Walker in Support of the Settlement Agreement.

248. On April 3, 2017, EFCA filed the Direct Testimony of its witness James A. Heidell in Support of the Settlement Agreement.

249. On April 3, 2017, EFCA filed the Direct Testimony of its witness Mark E. Garrett on Commercial and Industrial Customer Rate Design.

250. On April 3, 2017, AARP filed the Direct Testimony of its witness John B. Coffman in Opposition to the Settlement Agreement.

251. On April 3, 2017, AriSEIA filed the Direct Testimony of its witness Sara Birmingham and R. Thomas Beach in Support of the Settlement Agreement.

252. On April 3, 2017, ACAA filed the Direct Testimony of its witness Cynthia Zwick in Support of the Settlement Agreement.

253. April 3, 2017, APS filed the Direct Testimony of its witnesses Barbara Lockwood, Leland Snook and Charles Miessner in Support of the Settlement Agreement.

254. On April 3, 2017, ED8/McMullen filed the Direct Testimony of their witness James D. Downing in Opposition to Settlement Agreement.

255. On April 3, 2017, Freeport, AECC, Calpine, NewEnergy and Direct filed the Direct Testimony of their witness Kevin C. Higgins in Support of the Settlement Agreement.

256. On April 3, 2017, Vote Solar filed the Direct Testimony of its witness Briana Kobor in Support of the Settlement Agreement.

257. On April 3, 2017, Walmart filed the Direct Testimony of its witness Chris Hendrix in Support of Settlement Agreement.

258. On April 3, 2017, Staff filed a Notice of Filing Remaining Appendices to the Settlement Agreement.

259. On April 5, 2017, APS filed a Certification of Publication.

260. On April 6, 2017, a Stipulated Motion was jointly filed in this docket by Staff, RUCO, APS, and the "Solar Parties" (ASDA, AriSEIA, SEIA, Vote Solar, and EFCA), ("Moving Parties") stipulating to the entry of a Protective Order in this docket to govern the treatment of the Joint Solar Cooperation Agreement ("JSCA")[481] as requested by APS, the Solar Parties, and other entities who are not intervenors in this docket. The Moving Parties requested that a Protective Order to Govern the Treatment of the Joint Solar Cooperation Agreement ("JSCA Protective Order") be entered in the form attached to the Stipulated Motion as Exhibit A.

261. On April 7, 2017, Staff filed a Notice of Errata with a revision to the requested JSCA Protective Order.

262. On April 10, 2017, counsel for Calpine, CNE, and Direct Energy filed a Motion to Participate Telephonically in the Prehearing Conference, or in the Alternative, to be Excused from

[481] The JSCA is an agreement between APS, the Solar Parties, and certain other entities who are not intervenors in this case.

Attendance.

263. On April 11, 2017, APS filed a Certification of Publication.

264. On April 11, 2017, Commissioner Burns filed Correspondence.

265. On April 13, 2017, Vote Solar filed a Motion to Participate Telephonically in Prehearing Conference or, in the Alternative, to be Excused from Attendance.

266. On April 14, 2017, a Protective Order was issued.

267. On April 17, 2017, Mary R. O'Grady filed a Motion to Associate Counsel *Pro Hac Vice* to associate Matthew E. Price as counsel for APS and Pinnacle West.

268. On April 17, 2017, Mr. Woodward, APS, Vote Solar and the IBEW Locals filed Responses to Commissioner Burns' April 11, 2017 Correspondence Request.

269. On April 17, 2017, APS filed the Rebuttal Testimony of its witnesses Barbara Lockwood, Leland Snook, Charles Miessner and Scott Bordenkircher on the Settlement Agreement.

270. On April 17, 2017, ConservAmerica filed the Rebuttal Testimony of its witness Paul Walker in Support of the Settlement Agreement.

271. On April 17, 2017, Staff filed the Rebuttal Testimony of its witness Ralph C. Smith in Support of the Settlement Agreement.

272. On April 17, 2017, SWEEP filed the Rebuttal Testimony of its witness Jeff Schlegel in Opposition to the Settlement Agreement.

273. On April 17, 2017, Mr. Woodward filed his Rebuttal Testimony in Opposition to the Settlement Agreement.

274. On April 17, 2017, APS and Pinnacle West filed a Motion to Associate Counsel *pro hac vice.*

275. On April 17, 2017, EFCA filed a Motion for One Day Extension of Reply Testimony of Mark E. Garrett.

276. On April 18, 2017, ED8/McMullen, AriSEIA, RUCO and EFCA filed Responses to Commissioner Burns' April 11, 2017 Correspondence.

277. On April 18, 2017, a Procedural Order was issued admitting counsel *pro hac vice.*

278. On April 18, 2017, EFCA filed the Rebuttal Testimony of its witness Mark E. Garrett.

279. On April 19, 2017, Commissioner Burns filed Correspondence.

280. On April 19, 2017, Elijah Abinah, Director of the Utilities Division, filed Correspondence.

281. On April 19, 2017, APS filed a Jointly-Developed Proposed Witness and Hearing Schedule.

282. On April 19, 2017, APS filed the Testimony Summaries of Barbara Lockwood, Leland Snook, Charles Miessner and Scott Bordenkircher.

283. On April 20, 2017, the City of Sedona filed a Notice of Filing of Correspondence

284. On April 20, 2017, EFCA filed a Notice of Errata.

285. On April 21, 2017, Commissioner Burns filed Correspondence.

286. On April 21, 2017, Commissioner Burns docketed court filings from the Maricopa County Superior Court.

287. On April 21, 2017, Staff filed a Notice of Filing Supplemental Responses.

288. On April 24, 2017, Mr. Gayer filed the Summary of his Testimony.

289. On April 25, 2017, SWEEP filed the Testimony Summary of Jeff Schlegel.

290. On April 26, 2017, APS filed an Objection to Commissioner Burns' Demand for Testimony.

291. On April 26, 2017, Commissioner Burns filed his Emergency Motion for Relief (1) Confirming that the Administrative Law Judge will Facilitate Calling and Questioning of Hearing Witnesses; and (2) Approval of His Counsel Participating in Questioning (Expedited Ruling and Suspension and Continuance of Hearing Requested).

292. On April 26, 2017, ED8/McMullen filed the Testimony Summary of James D. Downing.

293. On April 26, 2017, Staff filed the Testimony Summaries of Ralph C. Smith, Elijah O. Abinah and Dennis J. Schumaker.

294. On April 26, 2017, EFCA filed the Testimony Summary for Mark E. Garrett.

295. On April 27, 2017, RUCO filed the Testimony Summary of David P. Tenney.

296. On April 27, 2017, Mr. Woodward filed the Testimony Summary of Dr. Sam Milham,

MD, MPH.

297. On April 27, 2017, Mr. Woodward filed the Testimony Summary of Erik S. Anderson, PE.

298. On April 27, 2017, Mr. Woodward filed his Testimony Summary.

299. On April 27, 2017, Commissioner Burns filed a Motion for Determination of Disqualification and for Stay of Proceedings Pending Full Investigation.

300. On May 1, 2017, Mr. Gayer filed a Motion to Suspend Proceedings Regarding the 90-Day Fair Notice Issue.

301. On May 4, 2017, APS filed the Declaration of Barbara Lockwood.

302. On May 4, 2017, SWEEP filed a Notice of Filing Corrected SWEEP Exhibit 6 and Related Corrections to SWEEP Exhibit 4.

303. On May 9, 2017, SWEEP filed its Notice of Filing Late Filed SWEEP Exhibits 8A and 8B.

304. On May 11, 2017, Mr. Woodward filed Corrections to Hearings Transcript Prepared by Coash & Coash.

305. On May 15, 2017, Mr. Gayer filed his Initial Closing Brief.

306. On May 17, 2017, APS, AIC, the IBEW Locals, ConservAmerica, ASDA, Vote Solar, EFCA, SEIA, AriSEIA, AURA, AECC, Freeport, Calpine, CNE, Direct Energy, Walmart, FEA, ED8/McMullen, the Districts, ACAA, SWEEP, AARP, Mr. Woodward, RUCO, and Staff filed their Initial Closing Briefs.

307. On May 26, 2017, a Special Open Meeting Revised Notice was docketed.

308. On May 30, 2017, Mr. Gayer filed his Reply Closing Brief.

309. On May 30, 2017, Commissioner Dunn filed Correspondence.

310. On June 1, 2017, APS, AIC, the IBEW Locals, ConservAmerica, AECC, Freeport, EFCA, SEIA, Calpine, CNE, Direct Energy, SWEEP, Mr. Woodward, and Staff filed their Reply Closing Briefs.

311. On June 1, 2017, RUCO filed notice that it would not be filing a Reply Closing Brief.

312. On June 2, 2017, Commissioner Burns filed Correspondence, an Emergency Motion to

Compel Compliance with Investigatory Subpoenas (Expedited Ruling and Suspension and Continuance of Rate Case Proceedings Requested) and an Emergency Renewed Motion for Relief Staying These Rate-Making Proceedings (Expedited Ruling Requested).

313. On June 5, 2017, Commissioner Burns filed a Notice of Errata Regarding Certificate of Service for Emergency Motion to Compel Compliance with Investigatory Subpoenas (Expedited Ruling and Suspension and Continuance of Rate Case Proceedings Requested).

314. On June 15, 2017, APS filed its Opposition to the Emergency Renewed Motion of Commissioner Robert Burns for Relief Staying these Rate-Making Proceedings and its Opposition to Emergency Motion of Commissioner Robert Burns to Compel Compliance with Investigatory Subpoenas.

315. On June 20, 2017, Commissioner Little filed Correspondence.

316. On June 20, 2017, Commissioner Dunn filed a Proposed Interlocutory Order (Discovery Motions).

317. On June 20, 2017, Commissioner Burns filed a Response to Commissioner Dunn's Proposed Interlocutory Order.

318. On June 20, 2017, Commissioner Dunn filed a Proposed Amendment to the Proposed Interlocutory Order.

319. On June 20, 2017, Chairman Forese filed a Proposed Amendment to the Proposed Interlocutory Order.

320. On June 26, 2017, Commissioner Burns filed a letter requesting the docketing of the deposition transcripts of APS witnesses Barbara Lockwood, Charles A. Miessner, and Leland R. Snook.

321. On June 27, 2017, the Commission issued Decision No. 76161.

322. On June 28, 2017, Commissioner Burns filed an Application for Rehearing of Decision No. 76161.

323. On June 29, 2017, FEA filed a Notice of Withdrawal of Attorney-of-Record Capt. Natalie A. Cepak.

324. On June 30, 2017, APS filed a response to Commissioner Burns' request for deposition

transcripts.

325. On July 14, 2017, Commissioner Tobin filed Correspondence.

326. On July 21, 2017, EFCA docketed a letter in response to Commissioner Tobin's July 14, 2107 Correspondence.

Determinations

327. The rates, terms and conditions of the Settlement Agreement are just, fair and reasonable and in the public interest, and should be adopted as set forth in the Settlement Agreement, except that the issues surrounding the Settlement Agreement Proposed AMI Opt-Out program, which were heavily litigated in this proceeding, will be bifurcated from this Decision, and will be addressed in a forthcoming Decision.

328. The fair value of APS's jurisdictional rate base for the test year ending December 31, 2015 is $9,990,561,000.

329. APS's total adjusted test year revenue is $2,888,903,000.

330. A capital structure comprised of 44.2 percent debt and 55.8 percent common equity is appropriate for establishing rates in this matter.

331. A return on common equity of 10.0 percent and an embedded cost of debt of 5.13 percent are appropriate estimates of the cost of capital for establishing rates in this matter.

332. A fair value rate of return of 5.59 percent, which includes a 0.8 percent return on the fair value increment, is appropriate for establishing rates in this matter.

333. APS should be authorized a $362.58 million base rate increase comprised of an increase in its non-fuel base rates of $148.250 million, a fuel base rate decrease of $53.63 million and a transfer of cost recovery from adjustor mechanisms to base rates of $267.95 million.

334. Under the terms of the Settlement Agreement, the average bill impact is 4.54 percent for residential customers, and 1.93 percent for general service customers.

335. A base cost of fuel and power of $0.030168 per kWh is appropriate under the terms of the Settlement Agreement.

336. The record in this matter should remain open as described in the Settlement Agreement.

337. The draft plan that APS files according to Section 27 of the Settlement Agreement

should include a form of notice for customers who are on another rate that informs the customers of their rate options after May 1, 2018, accompanied by information on the estimated bill impact of switching to another rate. For customers who are on another rate, the final approved notice must be provided to the existing customer at least 3 billing cycles prior to May 1, 2018, or the date on which APS's new rate plans commence, whichever event occurs later. It should also include a form of notice to inform new ratepayers subject to the 90-day trial period of their rate options at the conclusion of the trial period, and address a suitable method for delivery of such notice so that such customers will receive the notice shortly after, or concurrently with, their second bill, in order to provide them with sufficient notice should they wish to begin taking service at that time on the R-Basic rate plan instead of a time- or demand-differentiated rate plan.

338. APS should be required to comply with the Staff recommendations in regard to its power procurement procedures and documentation.

339. Optional rates to encourage the adoption of battery storage among APS E-32L and E-32L TOU customers should be added and approved and the tariff shall include the following restrictions and safeguards similar to those in both the R-Tech and TEP Tariff:

<u>Program Size</u>

APS's optional Large General Service Time-of-Use Storage Program Tariff (the Optional Tariff) will be capped at a peak demand total of 35,000 kW for installed systems and active interconnection applications, on a first-come first-served basis. Allotments shall be reserved at the time of submittal of a complete interconnection application.

<u>Stakeholder Process</u>

Once 70% of the initial program capacity has been reached, and if such threshold has been reached prior to APS's next general rate case filing, APS will evaluate whether the costs of the program are less than the system benefits it provides. If APS determines that the costs are less than the benefits, APS shall provide notice and promptly convene a meeting of the interested parties to this Docket to discuss the future of the program. If all parties to that discussion agree on a new program size for the Optional Tariff that shall apply until the Commission determines the disposition of the Optional Tariff during APS's next general rate case, APS shall file a notice in this Docket to that effect and the program shall remain in effect up to the new agreed upon customer participation level, unless the Commission orders otherwise. However, if all parties cannot agree upon a new customer participation level, APS within 90 days of the finalization of the discussions, shall file a request with the Commission to establish the terms and conditions under which the program will continue or terminate. If APS determines that the costs are greater than the system benefits, APS will file a request with the Commission to freeze the program until changes can be made in APS's next general rate case.

Minimum Peak Demand Reduction

To qualify for the Optional Tariff, a customer must install a chemical, mechanical or thermal energy storage system that is capable of allowing the customer to offset a minimum of 20% of their measured peak demand during the On-Peak period. The determination of the measured peak demand for purposes of the calculation will be based on the customer's previous year's measured peak demand during such period prior to installation of storage facilities. If this is a new facility, the calculation of the 20% demand reduction will be determined based on APS's total estimated peak demand designed for the facility.

VAR Support

In order to qualify for the program where a power producing facility is installed, inverters must be capable of and configured to provide VAR support so that a near unity power factor of at least 95% is maintained during operation.

TOU Hours

For purposes of the APS Optional Tariff, the On-Peak period under the program will be determined as the 6 greatest average system demand hours during the previous three years by season. The Off-Peak period will be determined as the 12 lowest average system demand hours during the previous three years by season. All other hours shall be deemed as Remaining Hours.

Annual Reporting

Until such time that a final order is issued in APS's next general rate case, on July 1 of each year APS shall submit an informational filing in the docket, reporting on the status of the APS Optional Tariff. The report will include: (i) the number of customers, both in the current year and cumulatively, that are participating in the program (including the proportion of these customers relative to the entire large commercial class), (ii) the total peak demand of such customers relative to the initial program allotment of 35,000 kW, (iii) observed peak demand reductions, if any, of customers participating in the program, (iv) recommended changes, if any, to the Time-of Use periods for the program, (v) if available, information regarding the average time to process applications from customers requesting participation in the program, and (vi) current year and cumulative kWh exported to the grid by participating customers.

Rate Design

The APS Optional Tariff shall not include a demand ratchet, Off-Peak demand charge or declining block demand charge. On-Peak billing demand shall be equal to the greatest measured 15 minute interval demand read of the meter during the On-Peak Hours or the Remaining Hours during the billing period. The APS Optional Tariff may include a minimum contract demand provision. The APS Optional Tariff may also include a summer and winter Off-Peak excess demand charge for Off-Peak exceeding 150% of On-Peak billing demand. The customer service charge component of the APS Optional Tariff will be structured to maintain proper price signals to incent peak demand reduction while also ensuring appropriate cost recovery. Storage customers taking service under the APS Optional Tariff that also have distributed generation remain eligible for the EPR-6 net metering rider.

340. Forest bioenergy has become an increasingly important energy source in Arizona, for many reasons. Forest bioenergy is a carbon-neutral, renewable energy source. It creates energy for the grid while encouraging responsible forest management and reducing the risk of wildfires. Federal agencies like the U.S. Department of Energy, the U.S. Department of Agriculture, and the Environmental Protection Agency have recently been directed to develop policies which recognize these benefits and encourage the use of forest bioenergy as an energy source. The energy community in Arizona should likewise explore the benefits of this important energy source.

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CONCLUSIONS OF LAW

1. APS is a public service corporation within the meaning of Article XV, Sections 3 and 14 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 applications.

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

4. The rate and charges produced by the Settlement Agreement are just and reasonable.

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

ORDER

IT IS THEREFORE ORDERED that the Settlement Agreement attached hereto as Exhibit A is adopted, as modified herein, except that the issues surrounding the Settlement Agreement Proposed AMI Opt-Out program, which were heavily litigated in this proceeding, will be bifurcated from this Decision, and will be addressed in a forthcoming Decision.

IT IS FURTHER ORDERED that the Settlement Agreement is hereby modified as follows: After September 1, 2018, R-Basic Large will no longer be available to customers who are on another rate.

IT IS FURTHER ORDERED that Arizona Public Service Company is hereby direct to file with the Commission on or before August 18, 2017, revised schedules of rates and charges and Plans of Administration consistent with Exhibit A and the findings herein.

IT IS FURTHER ORDERED that this rate case shall be held open to allow Arizona Public Service Company to file a request that its rates be adjusted no later than January 1, 2019 to reflect its proposed addition of Selective Catalytic Reduction equipment at the Four Corners Generating Station.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after August 19, 2017. The grandfathering date for customers submitting interconnection applications for DG systems is extended through August 31, 2017.

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.

IT IS FURTHER ORDERED that Arizona Public Service Company shall, in future rate cases, impute net revenue growth for any revenue producing plant included in post-test year plant.

IT IS FURTHER ORDERED that as set forth in the Settlement Agreement, Arizona Public Service Company shall not file its next general rate case before June 1, 2019, with a test year ending no earlier than December 31, 2018.

IT IS FURTHER ORDERED that $1.25 million of the revenue requirement increase approved in this order is dedicated to funding Arizona Public Service Company's crisis bill assistance program.

IT IS FURTHER ORDERED that Arizona Public Service Company is hereby authorized to defer, for possible later recovery through rates, all non-fuel costs (as defined herein to include all O&M, property taxes, depreciation, and a return at APS's embedded cost of debt in this proceeding) of owning, operating, and maintaining the Ocotillo Modernization Project and retiring the existing steam generation at Ocotillo. Nothing in this Ordering Paragraph shall be construed in any way to limit the Commission's authority to review the entirety of the project and to make any disallowances thereof due to imprudence, errors or inappropriate application of the requirements of this Decision. The interest component of the deferral shall be set at the embedded cost of debt established in this Decision.

IT IS FURTHER ORDERED that Arizona Public Service Company is authorized to defer for possible later recovery through rates, all non-fuel costs (as defined herein to include all O&M, property taxes, depreciation, and a return at APS's embedded cost of debt in this proceeding) of owning, operating, and maintaining the Selective Catalytic Reduction environmental controls at the Four Corners Power Plant. Nothing in this Decision shall be construed in any way to limit this Commission's authority to review the entirety of the project and to make any disallowances thereof due to imprudence, errors or inappropriate application of the requirements of this Decision.

IT IS FURTHER ORDERED that Arizona Public Service Company is hereby authorized to defer, for future recovery (or credit to customers), the Arizona property tax expense above or below the test year caused by changes to the applicable composite property tax rate, subject to the provisions set forth in the Settlement Agreement Section 11.

IT IS FURTHER ORDERED that in the event that significant Federal income tax reform legislation is enacted and becomes effective prior to the conclusion of Arizona Public Service Company's next general rate case, and such legislation materially impacts the Company's annual revenue requirements Arizona Public Service Company is hereby authorized to create a rate adjustment mechanism to enable the pass-through of income tax effects to customers, in accordance with the requirements set forth in Section 16 of the Settlement Agreement.

IT IS FURTHER ORDERED that the disposition of collected but unspent DSMAC funds as set forth in the Settlement Agreement is approved, consistent with the discussion herein.

IT IS FURTHER ORDERED that within 15 business days of a Commission Decision in this matter, APS shall file, with Docket Control, a draft Customer Education and Outreach Program ("CEOP") for the Commission Staff's review and approval. Stakeholders will have 10 calendar days to provide comment and APS will have 10 days thereafter to file a final plan. The Commission Staff shall approve a final CEOP. The draft CEOP shall include a proposed form of notice for both customers who are on another rate and new customers that informs the customers of their rate options after May 1, 2018, accompanied by information on the estimated bill impact of switching to another rate. For customers who are on another rate, the final approved notice must be provided to the existing customer at least 3 billing cycles prior to May 1, 2018, or the date on which APS's new rate plans commence, whichever occurs later.

IT IS FURTHER ORDERED that the draft plan that Arizona Public Service Company files according to Section 27 of the Settlement Agreement shall include a form of notice to inform new ratepayers subject to the 90-day trial period of their rate options at the conclusion of the trial period, accompanied by information on the estimated bill impact of switching to another rate, and shall address a suitable method for delivery of such notice so that such customers will receive the notice shortly after, or concurrently with, their second bill, in order to provide them with sufficient notice should they wish to begin taking service at that time on the R-Basic rate plan instead of a time- or demand-differentiated rate plan.

IT IS FURTHER ORDERED that Arizona Public Service Company shall implement the following Staff recommendations within the following timeframes in regard to power procurement procedures and documentation:

Staff Recommendation	Description	Initiation Timeframe
II-1	Perform a study to determine if changes can be made to the coal supply chain to yield some plant efficiencies.	0-6 months
III-1	Improve spreadsheet usage and associated references and cross references on how used.	0-12 months
III-2	Have internal or external auditors audit PSA filings, as they have yet to address PSA filing procedures.	0-18 months
III-3	Incorporate more detailed implementation steps, including sample screen prints, in Monthly PSA Filings documentation, plus risk management documentation, which should be reviewed and modified, as necessary, at least annually.	0-6 months
III-4	Develop formal written documentation for supplemental fuel charges or refunds.	0-6 months

IT IS FURTHER ORDERED that Arizona Public Service Company shall, within 120 days from the date of this order, file a new, optional storage-friendly tariff and that the tariff shall include the following restrictions and safeguards similar to those in both the R-Tech and TEP Tariff:

Program Size

APS's optional Large General Service Time-of-Use Storage Program Tariff (the Optional Tariff) will be capped at a peak demand total of 35,000 kW for installed systems and active interconnection applications, on a first-come first-served basis. Allotments shall be reserved at the time of submittal of a complete interconnection application.

Stakeholder Process

Once 70% of the initial program capacity has been reached, and if such threshold has been reached prior to APS's next general rate case filing, APS will evaluate whether the costs of the program are less than the system benefits it provides. If APS determines that the costs are less than the benefits, APS shall provide notice and promptly convene a meeting of the interested parties to this Docket to discuss the future of the program. If all parties to that discussion agree on a new program size for the Optional Tariff that shall apply until the Commission determines the disposition of the Optional Tariff during APS's next general rate case, APS shall file a notice in this Docket to that effect and the program shall remain in effect up to the new agreed upon customer participation level, unless the Commission orders otherwise. However, if all parties cannot agree upon a new customer participation level, APS within 120 days of the finalization of the discussions, shall file a request with the Commission to establish the terms and conditions under which the program will continue or terminate. If APS determines that the costs are greater than the system benefits, APS will file a request with the Commission to freeze the program until changes can be made in APS's next general rate case.

Minimum Peak Demand Reduction

To qualify for the Optional Tariff, a customer must install a chemical, mechanical or thermal energy storage system that is capable of allowing the customer to offset a minimum of 20% of their measured peak demand during the On-Peak period. The determination of the measured peak demand for purposes of the calculation will be based on the customer's previous year's measured peak demand during such period prior to installation of storage facilities. If this is a new facility, the calculation of the 20% demand reduction will be determined based on APS's total estimated peak demand designed for the facility.

VAR Support

In order to qualify for the program where a power producing facility is installed, inverters must be capable of and configured to provide VAR support so that a near unity power factor of at least 95% is maintained during operation.

TOU Hours

For purposes of the APS Optional Tariff, the On-Peak period under the program will be determined as the 6 greatest average system demand hours during the previous three years by season. The Off-Peak period will be determined as the 12 lowest average system demand hours during the previous three years by season. All other hours shall be deemed as Remaining Hours.

Annual Reporting

Until such time that a final order is issued in APS's next general rate case, on July 1 of each year APS shall submit an informational filing in the docket, reporting on the status of the APS Optional Tariff. The report will include: (i) the number of customers, both in the current year and cumulatively, that are participating in the program (including the proportion of these customers relative to the entire large commercial class), (ii) the total peak demand of such customers relative to the initial program allotment of 35,000 kW, (iii) observed peak demand reductions, if any, of customers participating in the program, (iv) recommended changes, if any, to the Time-of Use periods for the program, (v) if available, information regarding the average time to process applications from customers requesting participation in the program, and (vi) current year and cumulative kWh exported to the grid by participating customers.

Rate Design

The APS Optional Tariff shall not include a demand ratchet, Off-Peak demand charge or declining block demand charge. On-Peak billing demand shall be equal to the greatest measured 15 minute interval demand read of the meter during the On-Peak Hours or the Remaining Hours during the billing period. The APS Optional Tariff may include a minimum contract demand provision. The APS Optional Tariff may also include a summer and winter Off-Peak excess demand charge for Off-Peak exceeding 150% of On-Peak billing demand. The customer service charge component of the APS Optional Tariff will be structured to maintain proper price signals to incent peak demand reduction while also ensuring appropriate cost recovery. Storage customers taking service under the APS Optional Tariff that also have distributed generation remain eligible for the EPR-6 net metering rider.

IT IS FURTHER ORDERED that when acquiring any new resource or transmission or distribution upgrade where appropriate, APS shall demonstrate that its analysis of resource and system upgrade options include a storage alternative. In the analysis, APS must demonstrate that it has reasonably considered all of the costs and benefits of each resource or system upgrade option, allowing for comparisons to be made on similar terms and planning assumptions. Energy storage shall also be included as a resource option in any analysis of baseload resources as well as any analysis of non-baseload resources.

IT IS FURTHER ORDERED that APS shall include accurate cost data in its modeling assumptions in connection with the above Ordering Paragraph. APS shall account for the forecasted decline in energy storage costs and ensure that storage resources are modeled in such a way that the Integrated Resource Planning model captures their impact. Costs shall also be transparent by providing the cost of each technology with and without state and federal tax incentives and/or credits. APS shall also identify and analyze a reasonable, representative range of storage technologies and chemistries.

IT IS FURTHER ORDERED that as part of its 2018 Demand Side Management Implementation Plan filing, APS shall develop and propose to the Commission, for approval, a program available to water utilities within its service territory that would result in a reduction in water loss, electricity, consumption, or peak demand.

IT IS FURTHER ORDERED that APS shall report back to the Commission within 90 calendar days of the docketing of this Order, and provide at least three scenarios for forest bioenergy that examine low-, medium-, and high-use of forest bioenergy. This report shall take into consideration forest thinning activities, and evaluate the costs of said activities, any adjustments that should be made to APS's revenue requirement or power supply adjustor, environmental benefits, and any other relevant information that will help the Commission moving forward. This report shall also include the amount of forest acres affected by each case scenario, as well as projected water savings. In connection with this report, APS is expected to consult with the following parties: Salt River Project; Arizona Department of Water Resources; Arizona State Forester's Office; United States Forest Service; Four Forest Restoration Initiative; and other relevant stakeholders.

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IT IS FURTHER ORDERED that the Commission's Federal Affairs Committee shall review the APS forest bioenergy report and return to the Commission with appropriate recommendations.

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

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN FORESE	COMMISSIONER DUNN

		DISSENT
COMMISSIONER TOBIN	COMMISSIONER LITTLE	COMMISSIONER BURNS

IN WITNESS WHEREOF, I, TED VOGT, 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 18th day of August 2017.

TED VOGT
EXECUTIVE DIRECTOR

DISSENT ______________________

DISSENT ______________________

TJ/rt

DECISION NO. 76295

COMMISSIONERS
TOM FORESE – Chairman
BOB BURNS
DOUG LITTLE
ANDY TOBIN
BOYD DUNN

BOB BURNS
Commissioner

ARIZONA CORPORATION COMMISSION

August 16, 2017

RE: Dissenting Opinion in APS Rate Case
Dockets No. E-01345A-16-0036, E-01345A-16-0123

Dear Commissioners, Parties and Stakeholders:

I strongly dissent from this decision, and reiterate the positions I expressed in my earlier motions in this rate case and in my comments raised at relevant Commission Staff and Regular Open Meetings. The analysis I have raised, and the precedent, constitutional and statutory provisions I have cited, all establish that this decision is a violation of my legal rights and obligations to advance the public's interest, and in violation of this Commission's constitutional obligations to the public.

Furthermore, the evidence presented in this case did not justify the rate increase. RUCO, Commission Staff and EFCA all originally testified that the evidence supported a 0% rate increase, or even a rate decrease. This decision takes away customer choice and requires customers to be on time-of-use or demand rates regardless of their needs or desires. Making it more expensive to run air conditioners, do laundry or cook during 3:00-8:00 p.m. on our hot summer days is bad policy.

Fortunately, Arizona law allows the courts to overturn this vote, to require APS to make appropriate refunds to customers, and to eliminate any risks that pro-APS bias or partiality will affect any more rate decisions. I want to assure the Arizona citizens who depend on us daily that I will not succumb to the strategy of APS and the Commissioners, who have accepted their invitation to ignore Arizona customers. I will not allow them to safeguard the improper approval of a rate increase by simply outspending me with the massive amounts of public tax dollars and hard-earned ratepayer monies they have now committed to an army of lawyers. I will continue my struggle to enforce the constitutional rights the framers of our government intended. I will continue my fight to protect the interests of Arizona's utility customers against the unacceptable undue influence by a regulated monopoly that our State's founders expected us to resolutely resist.

The Commission's decision to proceed with a vote approving the APS rate request, especially by a final order that does not remind APS of its potential duty to refund consumer payments should my legal challenges succeed and without imposing a bond requirement to guarantee funding for immediate refunds should they be required, ignores the substantial rate impacts that will detrimentally affect Arizona customers within the next few days. It also violates fundamental constitutional obligations our framers put in place to assure that bias and disqualification issues are fully investigated, disclosed and acted on to protect consumers and parties.

As I stated at the meeting, the citizens who created this Commission and gave it unique powers through our constitution, expected we would consider fully and protect the interests of utility consumers, not our own personal interests. My colleagues' decisions to disregard consumer interests and cast votes approving this rate request fell far short of those expectations, acting outside their legal authority and creating an illegal and unenforceable order and approval.

For these reasons and for all the reasons outlined in my filings in this docket, my comments at Staff and Regular Open Meetings, including the Open Meeting where this decision was approved, I dissent.

Sincerely,

Robert L. Burns

Robert L. Burns
Commissioner

SERVICE LIST FOR: ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO.: E-01345A-16-0036 AND E-01345A-16-0123

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EXHIBIT A

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NOS. E-01345A-16-0036 and E-01345A-16-0123

SETTLEMENT AGREEMENT

MARCH 27 2017

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SETTLEMENT AGREEMENT
ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A RATE INCREASE (DOCKET NO. E-01345-A-0036) AND THE FUEL AND PURCHASED POWER PROCUREMENT AUDIT OF APS (DOCKET NO. E-01345A-16-0123)

The purpose of this Settlement Agreement ("Agreement") is to settle disputed issues related to Arizona Public Service Company's ("APS" or "Company") application to increase its rates (Docket No. E-01345A-16-0036) and the fuel and purchased power procurement audit of APS (Docket No. E-1345A-16-0123). This Agreement is entered into by the following entities:

Arizona Corporation Commission - Utilities Division Staff
Arizona Public Service Company
Residential Utility Consumer Office
Arizona Utility Ratepayer Alliance
Federal Executive Agencies
Arizona Solar Deployment Alliance
Arizona Solar Energy Industries Association
Vote Solar
Solar Energy Industries Association
Arizona School Boards Association and the Arizona Association of School Business Officials
Arizonans for Electric Choice and Competition
Western Resource Advocates
Wal-Mart Stores, Inc. and Sam's West, Inc.
Local Unions 387 and 769 of the International Brotherhood of Electrical Workers, AFL-CIO
Freeport Minerals Corporation
Arizona Community Action Association
The Kroger Co.
Arizona Investment Council
Property Owners & Residents Association, Sun City West
Sun City Home Owners Association
REP America d/b/a ConservAmerica
Constellation New Energy, LLC
Direct Energy Business, LLC
Calpine Energy Solutions, LLC
Arizona Competitive Power Alliance
Energy Freedom Coalition of America
City of Coolidge
Granite Creek Farms, LLC
Granite Creek Power & Gas, LLC

These entities shall be referred to collectively as Signing Parties; a single entity shall be referred to individually as a Signing Party.

I. RECITALS

1.1 APS filed the rate application underlying ACC Docket No. E-01345A-16-0036 on June 1, 2016. On August 6, 2016, the administrative law judge granted a motion to consolidate the Fuel and Purchased Power Procurement Audits, ACC Docket No. E-01345A-16-0123, with APS's rate case. Collectively, these dockets may be referred to herein as the Docket.

1.2 Subsequently, the Commission approved applications to intervene filed by Richard Gayer; Patricia Ferre; Warren Woodward; Arizona Solar Deployment Alliance ("ASDA"); IO Data Centers, LLC ("IO"); Freeport Minerals Corporation (Freeport) and Arizonans for Electric Choice and Competition (collectively, "AECC"); Sun City Home Owners Association ("Sun City HOA"); Western Resource Advocates ("WRA"); Arizona Investment Council ("AIC"); Arizona Utility Ratepayer Alliance ("AURA"), Property Owners and Residents Association, Sun City West ("PORA"); Arizona Solar Energy Industries Association ("AriSEIA"); Arizona School Boards Association ("ASBA") and Arizona Association of School Business Officials ("AASBO") (collectively, "ASBA/AASBO"); Cynthia Zwick, Arizona Community Action Association ("ACAA"); Southwest Energy Efficiency Project ("SWEEP"); the Residential Utility Consumer Office ("RUCO"); Vote Solar; Electrical District Number Eight and McMullen Valley Water Conservation & Drainage District (collectively, "ED8/McMullen"); The Kroger Co. ("Kroger"); Tucson Electric Power Company ("TEP"); Pima County; Solar Energy Industries Association ("SEIA"); the Energy Freedom Coalition of America ("EFCA"); Wal-Mart Stores, Inc. and Sam's West, Inc. (collectively, "Wal-Mart"); Local Unions 387 and 769 of the International Brotherhood of Electrical Workers, AFL-CIO (collectively, "the IBEW Locals"); Noble Americas Energy Solutions LLC ("Noble Solutions"); the Arizona Competitive Power Alliance ("the Alliance"); Electrical District Number Six, Pinal County, Arizona ("ED 6"); Electrical District Number Seven of the County of Maricopa, State of Arizona ("ED "7); Aguila Irrigation District ("AID"); Tonopah Irrigation District ("TID"); Harquahala Valley Power District ("HVPD"); and Maricopa County Municipal Water Conservation District Number One ("MWD") (collectively, Districts); SunRun; the Federal Executive Agencies ("FEA"); Constellation New Energy, Inc. ("CNE"); Direct Energy, Inc. ("Direct Energy"); AARP; the City of Coolidge ("Coolidge"); REP America d/b/a ConservAmerica ("ConservAmerica");

and Granite Creek Power & Gas and Granite Creek Farms LLC (collectively, "Granite Creek"). SunRun subsequently withdrew its intervention.

1.3 APS filed a notice of revenue requirement settlement discussions on December 29, 2016. Revenue requirement settlement discussions began on January 12, 2017; rate design settlement discussions began on February 6, 2017. 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.

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 reliability of the electric system, as well as the convenience, comfort and safety, and the preservation of health, of the employees and customers of APS consistent with the Commission's obligations under Arizona law; resolve the issues arising from this Docket; and avoid unnecessary litigation expense and delay.

1.5 The Signing Parties believe that this Agreement balances APS's rate increase with benefits for customers. The Signing Parties agree that some of the significant provisions of the Agreement include:

a. A $87.25 million non-fuel, non-depreciation revenue requirement increase, or a reduction of $58.96 million from APS's original application.

b. An average 4.54% bill impact for residential customers compared to an average 7.96% bill impact for residential customers in APS's original application.

c. A refund to customers through the Demand Side Management Adjustor Clause ("DSMAC"), of $15 million in collected, but unspent DSMAC funds to mitigate the first year bill impacts.

d. A rate case stay out, in which APS agrees not to file a new general rate case filing prior to June 1, 2019;

e. A program to expand access to utility owned rooftop solar for low and moderate income Arizonans, Title I Schools, and rural governments;

f. Continuation of a buy-through rate for Industrial and large General Service customers;

g. Continuation of crisis bill assistance for low income customers;

h. More off-peak hours and holidays for time-differentiated rates;

i. A moratorium on new self-build generation until January 1, 2022 and through December 31, 2027 for construction of combined-cycle generating units;

j. An experimental pilot technology rate initially available for up to 10,000 customers;

k. New updated rate designs with rate options for all customers.

l. An educational plan and concerted outreach effort by APS on its various rate plans with transitional rates in place until May 1, 2018 to allow for customer education;

m. Additional discounts for Schools and Military Customers;

n. Resolution of Solar Distributed Generation ("DG") issues for the term of the Settlement Agreement;

o. Agreement by Signing Parties to withdraw any appeals of the Commission's Value of Solar Decisions (Docket Nos. 75859 and 75932).

p. Agreement by Signing Parties to refrain from pursuing actions in any forum that are inconsistent with the provisions of the Settlement Agreement.

1.6 The Signing Parties request that the Commission find that the rates, terms and conditions of this Agreement are just, fair and reasonable and in the public interest in accordance with Article 15, Sections 3 and 14 of the Arizona Constitution and Arizona Revised Statutes Section 40-250 along with any and all other necessary findings, and to approve the Agreement and order that it and the rates contained herein become effective on July 1, 2017.

TERMS AND CONDITIONS

II. RATE CASE STABILITY PROVISION

4.2 APS will not file its next general rate case before June 1, 2019. The test year end date for the base rate increase filing contemplated in this section shall be no earlier than December 31, 2018.

III. RATE INCREASE

3.1. APS shall receive a $87.25 million non-fuel, non-depreciation revenue requirement increase. When the reduction for base fuel of $53.63 million and the increase for depreciation of $61.00 million is taken into account, the result is a net base rate increase of $94.624 million, exclusive of the adjustor transfer described below in Paragraph 3.2.

3.2 APS also requested to transfer amounts collected in adjustor mechanisms to base rates, which is revenue neutral since the adjustor balances will be reduced with the transfer to base rates. After including the transferred adjustor mechanism amount of $267.95 million, the Company's total base rate revenue requirement is $362.58 million ("revenue requirement"). This amount is comprised of: (1) a non-fuel base rate increase of $148.250 million, which includes a return on and of plant that is in service as of December 31, 2016 ("Post-Test Year Plant"), twelve (12) months beyond the test year ending December 31, 2015 (the "2015 Test Year"); (2) a base fuel rate decrease of $53.63 million; and (3) the transfer from adjustor mechanisms of $267.95 million to base rates described in Paragraph VIII herein. When these amounts are netted together, this amounts to a net base rate increase of $94.624 million.

3.3 The Company's jurisdictional fair value rate base used to establish the rates agreed to herein is $9,990,561,000. APS's total adjusted Test Year revenue is $2,888,903,000.

3.4 In future rate cases, APS will agree to impute net revenue growth for any revenue producing plant included in post-test year plant.

IV. BILL IMPACT

4.1 When new rates become effective, customers will have on average a 3.28% bill impact.

a. Residential customers will have on average a 4.54% bill impact.

b. General Service customers will have on average a 1.93% bill impact.

4.2 To mitigate the first year bill impacts, APS will refund to customers through the DSMAC $15 million in collected, but unspent DSMAC funds.

V. COST OF CAPITAL

5.1 An original cost of capital structure comprised of 44.2% debt and 55.8% common equity shall be adopted for ratemaking purposes for this Docket.

5.2 A return on common equity of 10.0% and an embedded cost of debt of 5.13% shall be adopted for ratemaking purposes for this Docket.

5.3 The Signing Parties agree to a fair value rate of return of 5.59% for this Docket, which includes a 0.8% return on the fair value increment.

5.4 The provisions set forth herein regarding the quantification of 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 APS will lower its proposed annual depreciation expense pro forma on APS's as filed SFR C-2 by $20 million per year, resulting in a $61 million increase in depreciation expense (inclusive of the Cholla 2 Regulatory Asset Amortization), by adjusting its proposed lives/net salvage rates for its distribution accounts and by accelerating the amortization of the present excess depreciation reserves for Palo Verde.

6.2 The annual depreciation expense for the Palo Verde Nuclear Generating Station will be decreased by $21 million.

6.3 The decrease in Palo Verde depreciation not needed to fund the reduction in revenue requirements described in Section 6.1 above ("Excess Amount") will be offset by a more rapid amortization of the Cholla 2 regulatory asset such that there will be no additional impact on APS's revenue requirement in this case.

6.4 Should the Cholla 2 regulatory asset become fully amortized prior to APS's next general rate case, the Excess Amount will be used to accelerate the recovery of APS's remaining investment in the Navajo Generating Station.

6.5 For purposes of settling this rate case, APS's depreciation rates will be deemed to use the straight-line method, vintage group procedure, and remaining life technique.

6.6 In APS's next rate case, APS will file a depreciation rate study that includes alternative calculations for cost of removal and dismantlement (negative net salvage) using the "FAS 143" discounted net present value method, computed using a discount rate to be agreed upon.

6.7 A copy of APS's agreed upon depreciation rates is attached as Appendix A.

6.8 APS's annual nuclear decommissioning expense proposal will be adopted. A copy of the decommissioning contribution schedule is attached as Appendix B.

6.9 Subject to the discussion herein of Cholla 2, the Company shall use its proposed amortization rates for regulatory assets and liabilities as well as for other intangibles.

VII. FUEL AND POWER SUPPLY ADJUSTMENT PROVISIONS

7.1 The base fuel rate shall be lowered from \$0.032071 per kWh as set in the Decision No. 73183 to \$0.030168 per kWh. This change shall take effect on the effective date of the new rates contained in this Agreement, in accordance with the Plan of Administration for the Power Supply Adjustor ("PSA") to be approved in this case.

7.2 APS shall be permitted to include chemical costs for lime, ammonia and sulfur that are incurred in the generation process in the PSA.

7.3 APS shall be permitted to include third-party storage expenses in the PSA provided that APS files for approval to include any third-party storage contract with the Commission 90 days before it becomes effective.

7.4 The September 30 Preliminary Annual PSA Rate filing and the December 31 Final Annual PSA Rate calculation filing will be consolidated into one annual reset filing that will occur annually on or before November 30. Unless the Commission otherwise acts on the APS calculation by

February 1, the PSA rate proposed by APS will go into effect with the first billing cycle in February.

7.5 The PSA Plan of Administration shall be amended as necessary to reflect the terms of this Agreement and shall be approved concurrent with the approval of this Agreement. The revised PSA Plan of Administration is attached as Appendix C.

VIII. TRANSFER OF ITEMS FROM ADJUSTMENT MECHANISMS TO BASE RATES

8.1 The Signing Parties agree that certain revenue requirements collected through the Renewable Energy Adjustor Clause ("REAC"), DSMAC Lost Fixed Cost Recovery ("LFCR"), Transmission Cost Adjustor ("TCA"), Environmental Impact Surcharge ("EIS"), Four Corners Rate Rider ("FCRR"), and the System Benefits Charge ("SBC") adjustment mechanisms shall be transferred to base rates and those adjustor rates will be zeroed out or reduced, as proposed by APS herein.

8.2 Adjustor transfers agreed to herein shall include the portion of transmission revenue requirements that was collected in the test year for the TCA, the portion of the lost fixed costs that was collected in the test year for the LFCR; the portion of environmental compliance revenue requirements that was collected in the test year for the EIS; an increase in the portion of energy efficiency expense to be collected in base rates from the DSMAC; the revenue requirement of Arizona Sun related renewable generation, the Schools and Governments Program and the Community Power Project will be transferred from the REAC into base rates; the portion of APS's acquisition of Southern California Edison's share of Four Corners currently collected in the Four Corners Rate Rider; and the portion of the System Benefits reduction that went into effect January 1, 2016 to reflect Palo Verde Unit 2 having been fully funded in the nuclear decommissioning trust. The specific amounts in each adjustor to be transferred to base rates pursuant to this Section are identified in Appendix D. The amounts transferred will be calculated using Staff's revenue conversion factor.

8.3 On the effective date of the new rates contained in this Agreement, the REAC, DSMAC, LFCR, TCA, EIS, FCRR and SBC rates shall be reduced to reflect the removal of the amounts identified in Appendix D.

IX. RATE TREATMENT RELATED TO THE INSTALLATION OF SELECTIVE CATALYTIC REDUCTIONS AT FOUR CORNERS UNITS 4 AND 5

9.1 The parties agree that this Docket shall remain open for the sole purpose of allowing APS to file a request that its rates be adjusted no later than January 1, 2019 to reflect the proposed addition of Selective Catalytic Reduction ("SCR") equipment at Four Corners, as requested in APS's application in this Docket.

9.2 APS shall be authorized by the Commission to defer for possible later recovery through rates, all non-fuel costs (as defined herein to include all O&M, property taxes, depreciation, and a return at APS's embedded cost of debt in this proceeding) of owning, operating and maintaining the Selective Catalytic Reduction environmental controls at the Four Corners Power Plant from the date such controls go into service until the inclusion of such costs into rates. Nothing in this paragraph shall be construed in any way to limit this Commission's authority to review the entirety of the project and to make any disallowances thereof due to imprudence, errors or inappropriate application of the requirements of this Decision. The interest component of the SCR deferral will be set at APS's embedded cost of debt established in this Agreement.

9.3 Any filing seeking a rate adjustment pursuant to Section 9.1 shall include 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 adjusted rate base schedule; and (6) a typical bill analysis under present and filed rates. The Signing Parties agree to use good faith efforts to process this rate adjustment request such that any resulting rate adjustment becomes effective no later than January 1, 2019, pursuant to Section 9.1.

9.4 The Signing Parties shall not present any issues in the rate adjustment proceeding other than those specifically described in this Section.

9.5 Section 9 is agreed to without prejudice to any position taken by a Signing Party in any other pending proceeding, including ASBA/AASBO v. ACC, 1 CA-CC-15-0001.

X. COST DEFERRAL RELATED TO THE OCOTILLO MODERNIZATION PROJECT

10.1 APS will be authorized to defer for possible later recovery through rates, all non-fuel costs (as defined herein to include all O&M, property taxes, depreciation, and a return at APS's embedded cost of debt in this proceeding) of owning, operating, and maintaining the Ocotillo Modernization Project ("OMP") and retiring the existing steam generation at Ocotillo. Nothing in this paragraph shall be construed in any way to limit the Commission's authority to review the entirety of the project and to make any disallowances thereof due to imprudence, errors or inappropriate application of the requirements of this Decision. The interest component of the Ocotillo deferral will be set at APS's embedded cost of debt established in this Agreement.

10.2 The entire OMP will be in service before the rate effective date of APS's next general rate case, and the entire OMP investment will be addressed and resolved in that proceeding.

10.3 This agreement does not address the prudence of the OMP, and a deferral of the OMP costs does not guarantee recovery of those costs. Consideration of OMP in APS's next general rate case does not create any precedent, guarantee, or certainty regarding the consideration or treatment of post-test year plant.

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

11.1 APS shall be allowed to defer for future recovery (or credit to customers) the Arizona property tax expense above or below the test year caused by changes to the applicable Arizona composite property tax rate.

11.2 The property tax deferral will not accrue interest during the deferral period, unless it is negative, in which case, it will accrue interest in favor of APS's customers at APS's short term debt rate.

11.3 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, with a return at APS's short term debt rate, also with a return on any unrefunded negative balance at the same short term debt rate.

11.4 The Signing Parties reserve the right to review APS's property tax deferrals in APS's next general rate case for reasonableness and prudence.

11.5 Prior to the next APS general rate case, APS will meet and confer with Staff, RUCO and other stakeholders regarding the appropriate ratemaking treatment for the two year lag on payment of property taxes for post-test year plant.

XII. COST OF SERVICE STUDY

12.1 APS agrees in its next rate case to make available to parties its cost of service study in an Excel spreadsheet with inputs linked to outputs so that parties can change the inputs as necessary to reflect their position in the case. APS will meet and confer with stakeholders prior to filing to discuss the cost of service format.

12.2 In its next general rate case, APS agrees to perform the Average and Excess methodology to allocate production demand costs to residential and general service classes and then reallocate production demand within the residential sub-classes based on 4CP. This does not preclude APS or other stakeholders from proposing alternative allocation methods.

XIII. NAVAJO GENERATING STATION

13.1 APS will address any potential impacts of the closure of the Navajo Generating Station prior to the filing of APS's next rate case in Docket No. E-00000C-17-0039. To the extent it deems appropriate, APS may request that a separate Docket specific to APS be opened to address any issues pertaining to APS's interest in the Navajo Generating Station.

XIV. ANNUAL WORKFORCE PLANNING REPORT

14.1 APS shall file a workforce planning report with the Commission containing the following information: (i) the identification of each of the specific challenges or issues APS faces regarding workforce planning; (ii) the specific action(s) APS is taking to address each challenge or issue; and (iii) an update of the progress APS has made toward resolving each challenge or issue. The workforce planning report shall be filed on an annual basis, in this Docket, on or before May 31st, until the conclusion of the next APS general rate case, and 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: (i) the number of employees then currently holding these positions; (ii) the present mean and median ages of APS's workforce with respect to these job classifications; (iii) the share of retirement-eligible employees, both as a percentage and in absolute terms, in each of these job classifications; and (iv) the anticipated hiring level and attrition level for each of these job classifications.

14.2 The obligation contained in this Section XIV for APS to file a workforce planning report supersedes any prior workforce planning reporting requirement including the requirement in Decision No. 73183.

XV. SELF-BUILD MORATORIUM

15.1 APS will not pursue any new self-build generation option having an in-service date prior to January 1, 2022 unless expressly authorized by the Commission. Such restriction shall extend to December 31, 2027 with regard to the construction of combined-cycle generating units.

15.2 This self-build moratorium does not include any of the following: (1) the OMP; (2) the acquisition of a generating unit or an interest in a generating unit from a non-affiliated merchant or utility generator; (3) the acquisition of generation needed for system reliability when under the circumstances the seeking of prior Commission approval is impossible or impractical; (4) distributed generation or storage of less than 50 MW per location; (5) microgrids irrespective of size; (6) renewable generation; or (7) uprates or repowering of existing APS-owned generation.

15.3 As part of any APS request for Commission authorization to self-build generation, APS will address:

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

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

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

d. The extent to which the request to self-build generation is consistent with any applicable Company resource plans and competitive resource acquisition rules.

e. The anticipated cost of the proposed self-build option in comparison with suitable alternatives available from the competitive market for the relevant analysis period.

15.4 Nothing in this section shall be construed as relieving APS of its obligation to prudently acquire generating resources, including, but not limited to, seeking the above authorization to self-build a generating resource or resources.

15.5 The issuance of any RFP or the conduct of any other competitive solicitation in the future shall not, in and of itself, preclude APS from negotiating bilateral agreements with non-affiliated parties.

XVI. TAX EXPENSE ADJUSTOR MECHANISM

16.1 In the event that significant Federal income tax reform legislation is enacted and becomes effective prior to the conclusion of APS's next general rate case, and such legislation materially impacts the Company's annual revenue requirements, APS will create a rate adjustment mechanism to enable the pass-through of income tax effects to customers.

16.2 This adjustor mechanism has the following elements:

a. The change in revenue requirements due to Federal tax reform will be measured as the change in:

i. The Federal Income Tax Rate (currently 35%) applied to the Company's Adjusted 2015 Test Year;

ii. The annual amortization of any resulting excess deferred income tax regulatory account compared to the Company's Adjusted 2015 Test Year, and;

iii. Permanent income tax adjustments (such as interest expense and/or property tax expense deductibility) compared to those taken in the Company's Adjusted 2015 Test Year.

b. The Company will change retail rates through the Tax Expense Adjustor Mechanism (TEAM).

i. The rate will be computed on a prospective basis each year based on the jurisdictional retail income tax change as compared to the income tax expense used to set rates in this proceeding combined with the Company's projection of jurisdictional retail sales for the coming year. The rate will be filed on December 1st and will become effective with the first billing cycle in March of each year.

ii. The adjustment will be assessed to each customer as an equal per kWh charge.

iii. The adjustor mechanism will include a balancing account such that any under- or over-collected balance will be recovered or refunded in the following year.

iv. Each year's under- or over-collected balance will accrue interest at the Company's applicable cost of short-term debt.

16.3 The TEAM will terminate with the effective date of APS's next general rate case.

16.4 The Plan of Administration for the TEAM is attached as Appendix E.

XVII. RESIDENTIAL RATE DESIGN

17.1 R-XS: Rate Schedule "R-XS" is available to customers without distributed generation using 600 or less kWh per month on average. The Basic Service Charge for R-XS is $10 for the average billing month, calculated at a daily rate of $0.329.

17.2 R-Basic: Rate Schedule "R-Basic" is available to customers without distributed generation using more than 600 kWh but less than 1,000 kWh per month on average. The Basic Service Charge for R-Basic is $15.00 for the average billing month, calculated at a daily rate of $0.493.

17.3 R-Basic Large: Rate Schedule "R-Basic Large" is available to customers without distributed generation using 1,000 kWh per month or more on average. The Basic Service Charge for R-Basic Large is $20.00 for the average billing month, calculated at a daily rate of $0.658.

17.4 TOU-E: Rate Schedule "TOU-E" is available to all customers. The Basic Service Charge for "TOU-E" is $13 for the average billing month, calculated at a daily rate of $0.427. Winter Super Off-peak hours are from 10:00am - 3:00pm. Customers currently on a Time Advantage rate plan will transition to this rate unless they select to voluntarily move to another rate for which they are eligible. For DG customers, the average off-set rate shall be inclusive of the Grid Access Charge described in Section 18.1.

17.5 R-2: Rate Schedule "R-2" is a three-part rate available to all customers. The Basic Service Charge for R-2 is $13 for the average billing month; calculated at a daily rate of $0.427.

17.6 R-3: Rate Schedule R-3 is a three-part rate available to all customers. The Basic Service Charge for R-3 is $13 for the average billing month; calculated at a daily rate of $0.427. Customers currently on the Combined Advantage rate plan will transition to this rate unless they select to voluntarily move to another rate for which they are eligible.

17.7 R-Tech: An Optional R-Tech Pilot Rate Program shall be created that will initially serve up to 10,000 customers. It is a three-part rate that is available to residential customers when the following criteria are met: (1) two or more qualifying primary on-site technologies were purchased within 90 days of the customer enrolling in the rate; or (2) one qualifying primary on-site technology was purchased within 90 days of the customer enrolling in the rate and two or more qualifying secondary on-site technologies. Qualifying technologies are set forth in Rate Schedule R-Tech attached hereto as Appendix F. The Basic Service Charge for R-Tech is $15 for the average billing month, calculated at a daily rate of $0.493.

a. Once 6,000 customers have signed up to take service under this program, and if such threshold has been reached prior to the Company's next general rate case filing, the Company shall provide notice and promptly convene a meeting of the interested parties to this Docket to discuss the future of the Pilot Program. If each of the parties to that discussion agree on a new customer participation level for the R-Tech Pilot Program that shall apply until the Commission determines the disposition of the R-Tech Pilot Program during the Company's next general rate case the Company shall file a notice in this Docket to that effect and the program shall continue to be offered up to the new agreed upon customer participation level.

b. However, if all parties cannot agree to a new customer participation level, then APS shall file a report on the R-Tech Pilot Program and request that the Commission determine whether to continue, expand, or terminate the program in the Docket within 90 days of the date that 7,000 customers have begun taking service under this program. The Commission will then promptly review the program and determine if it should continue, terminate, or be adjusted.

c. The Signatories have agreed to a rate design for the R-Tech Pilot Rate Program as set forth in Appendix F.

17.8 The on-peak period will be 3:00 pm – 8:00 pm weekdays for TOU-E, R-2, R-3, and R-Tech, excluding holidays specified in Appendix F.

17.9 Attached as Appendix G is the Residential and Commercial rate summary.

XVIII. RESIDENTIAL RATE DESIGN FOR DISTRIBUTED GENERATION CUSTOMERS

18.1 DG customers are eligible for four different rate schedules including all proposed TOU and Demand rates. DG customers that select TOU-E will be subject to a Grid Access Charge as reflected in Appendix F.

18.2 The self-consumption offset rate for TOU-E will be \$0.105/kWh, which is inclusive of the Grid Access Charge, but exclusive of taxes and adjustors. This is an approximately \$0.120/kWh offset rate after these adjustments. The offset rate is based on the load profile and production profile of APS customers with DG during the test year. Individual customer offset will vary based on individual usage patterns and DG system size, orientation, and production.

18.3 The Resource Comparison Proxy Rate ("RCP") for exported energy established in Decision No. 75859, as amended by Decision No. 75932, will be \$0.129/kWh in year one, which is inclusive of undifferentiated transmission, distribution, and loss components. This export rate was calculated using a 2015 base year with an adjustment to achieve the final export rate. Attached as Appendix H is the RCP Rate Rider, POA and EPR-6 Legacy Rate Rider.

18.4 This first year export rate is the product of settlement negotiations and does not create any precedent, imply any change to the structure of or detail in the Resource Comparison Proxy, or otherwise change any aspect of Decision No. 75859.

18.5 DG customers that file a completed interconnection application before the rate effective date adopted in the Decision in this case shall be grandfathered consistent with Section 18.6 for a period of twenty years, with the twenty year period beginning from the date the system is interconnected with APS.

18.6 As contemplated in Decision No. 75859, grandfathered DG customers will continue to take service under full retail rate net metering and will continue to take service on their current tariff schedule for the length of the grandfathering period, which for APS are rate schedules E-12, ET-1, ET-2, ECT-1, or ECT-2. In its next rate case, APS will propose that the rates on each of these legacy tariffs will be updated with an equal percent increase applied to every rate component equal to the residential average base rate increase approved. In addition, grandfathered DG customers currently served on E-3 or E-4 will continue on the current E-3 or E-4 Rate Riders for as long as they meet the eligibility criteria and/or discontinue participation in the program.

XIX. RESIDENTIAL RATE AVAILABILITY

19.1 All customers may select R-Basic, R-Basic Large, TOU-E, R-2, R-3, R-Tech or R-XS if they qualify until May 1, 2018, except to the extent grandfathered under other sections of this Settlement Agreement. Distributed Generation customers will not be eligible for R-XS, R-Basic or R-Basic Large. After May 1, 2018, R-Basic Large will no longer be available to new customers or customers who are on another rate. New customers after May 1, 2018 may choose TOU-E, R-2, R-3 or if they qualify, R-XS or R-Tech. After 90 days, new customers may opt-out of their current rate and select R-Basic if they qualify. Customers transitioning to R-Basic must stay on that rate for at least 12 months.

XX. COMMERCIAL AND INDUSTRIAL RATE DESIGN

20.1 APS's General Service XS non-demand rate is adopted and attached as Appendix G.

20.2 APS's Aggregation feature and Extra High Load Factor Rate are as proposed by the Company. Copies of these Schedules are attached as Appendix I.

20.3 Economic Development Service Schedule 9 is approved as modified by Staff and is attached as Appendix J.

20.4 There will be no change to the current net metering structure for non-residential solar customers until addressed in a future Value of Solar or other proceeding.

20.5 The Signing Parties agree that issues related to the non-ratchet rate design alternative for C&I remain unresolved by this Agreement, and the Signing Parties agree they may present their respective positions in the hearing scheduled in this proceeding.

20.6 The on-peak period will be 3:00 pm – 8:00 pm weekdays for XS through E32-L, but will remain unchanged for E-35.

XXI. E-32L RATE DESIGN

21.1 APS agrees to redesign E-32 L in a revenue neutral manner to recover an additional amount of $1.36 per kW in the unbundled generation charges.

XXII. SCHOOLS DISCOUNT RATE RIDER

22.1 All public schools and public school districts will be eligible for a new rate rider. If they apply for service under this rate rider they receive a discount of $0.0024/kWh.

XXIII. AG-X

23.1 The capacity reserve charge applicable to AG-X customers will be equal to $5.5398 per kW-month (60% of current FERC demand charge of $9.233 per kW), applied to 100% of the customer's billing demand.

23.2 This charge and other parameters will be re-evaluated in APS's next rate case, including whether AG-X should be evaluated as a separate customer class in the cost of service study.

23.3 AG-X customers must provide 1-year notice to return to APS's cost-of-service rates. At APS's option, customers seeking to return with less notice must pay market-based rates until the 1-year notice period is attained.

23.4 The Administrative Management Fee for the program will be increased to $1.80 per MWh.

23.5 A retail energy imbalance protocol specifically designed to measure how well an AG-X Generation Service Provider ("GSP") is matching its retail buy-through customer load on an hourly basis will replace the FERC energy imbalance protocol. Energy Imbalance will be determined based on each GSP's aggregated hourly customer load.

a. Within the range of +/- 15% each hour or +/- 2 MW, whichever is greater, GSPs would pay based on Schedule 4 of APS's OATT, which now reflects the terms of the CAISO imbalance charges.

b. Greater than 15% each hour or +/- 2 MW, whichever is greater, in addition to the charges in a.above, GSPs would pay a penalty of $3 per MWh.

c. In addition to the imbalance provisions described above, GSPs with 20% of hourly deviations greater than 20% of the scheduled amount occurring in a calendar month will receive a notice of intent to terminate the GSP's eligibility in the program unless remedied. Imbalances of this magnitude and frequency will be deemed "Excessive." Should Excessive imbalances occur again in a subsequent month, within 12 months from the date of the notice, the GSP's eligibility may be terminated. To avoid termination, a GSP must demonstrate to APS that it is operating in good faith to match its resources to its load. In the event of GSP termination, the customer will be required to secure a replacement GSP within 60 days.

23.6 The PSA mitigation will remain in place. However the mitigation is modified such that the resale of capacity and energy displaced by AG-X is established at a flat $1,250,000 per month of off-system sales margins and excluded from the PSA rather than using a pro-rata share of such margins.

23.7 AG-X will remain at 200 MW but the prior restrictions as to 100 MW from each of the E-32L and E-34/35 rate schedules is eliminated; however, 100 MW would be allocated to 20 MW single-site customers with load factors above 70% unless not fully subscribed during the solicitation process.

23.8 Line losses for scheduling AG-X load will be modified to reflect transmission voltage service when applicable.

23.9 The 10 MW minimum aggregation level will be retained. Current provisions on the size of single site loads eligible for aggregation also will remain in place.

23.10 There will be a new lottery if the service is oversubscribed – otherwise, first come, first served. After the initial re-lottery, if necessary, customers who enter the program will not be required to participate in a subsequent lottery to remain in the program.

23.11 The AG-1 deferral will be recovered over 5 years from all non-residential customer classes, except the street and area lighting customer classes. The amount will be allocated to each class based on adjusted Test Year kWh. APS will not propose a deferral of unmitigated costs resulting from AG-X, if any, nor propose the collection of unmitigated costs resulting from AG-X, if any, before or in its next rate case. Attached as Appendix K is the AG-X rate schedule.

XXIV. MILITARY CUSTOMERS

24.1 The unbundled delivery charge for service at military-primary voltage under rates E-34 and E-35 will be reduced to a level that results in any applicable military customer getting a net impact bill increase equal to the average for all retail customers.

XXV. REVENUE SPREAD

25.1 For the revised revenue requirement, APS will keep the same revenue spread between Residential and General Service classes. However, within General Service, because GS extra small and small customers originally had a near zero net bill impact, the reduction will be spread to all other GS customers proportionally to the original revenue spread. Attached as Appendix L is the revenue spread/targets summary.

XXVI. EFFECTIVE DATE OF RATE PLANS AND TRANSITION PLAN

26.1 The rate increase will go into effect on the effective date of the Commission's Decision in this case using transition rates which for purposes of this Agreement are defined as existing Residential and extra small General Service rate schedules with updated revenue requirements. Customers will have the opportunity to select any rate which they qualify for, and APS will provide them information on options that would minimize their bill. Customers that do not select a different rate will transition to the updated rate plan most like their existing rate on or before May 1, 2018. At least 90 days before transitioning customers who have not selected a rate, APS will provide a report to the ACC indicating the total number of customers who have not made a selection.

XXVII. FIVE MILLION DSMAC ALLOCATION

27.1 APS will make a one-time allocation of $5 million from over-collected DSMAC funds to DSM programs for education and to help customers manage new rates and rate options including services and tools available to customers to help them manage their utility costs. APS shall file an outreach and education plan and shall provide stakeholders with an opportunity for review and comment on the draft plan prior to completing its final plan.

XXVIII. AZ SUN II

28.1 APS will implement a new program for utility-owned solar distributed generation. The purpose of this program is to expand access to rooftop solar for low and moderate income Arizonans. For this program, distributed generation will be defined as photovoltaic solar generation connected to the distribution system. APS will use third-party solar contractors to install the solar systems. The third-party solar contractors will be competitively selected through an RFP process. APS will own all the generation, renewable energy credits and other attributes from this program.

28.2 All reasonable and prudent costs incurred by APS pursuant to this program will be recoverable through the Renewable Energy Adjustment Clause until the next rate case.

a. Expenses eligible for recovery through the Renewable Energy Adjustment Clause include all O&M expenses, property taxes, marketing and advertising expenses, and the capital carrying costs of any capital investment by APS through this program (depreciation expenses at rates established by the Commission, and return on both debt and equity at the pre-tax weighted average cost of capital).

b. APS may request that the capital costs of the solar systems installed under this program be included in rate base in its next rate case.

c. APS's expenses under this program may be reviewed for prudence in each annual REST docket. Further, if APS includes any of these solar systems in rate base in the next rate case, those systems will be subject to a prudence review in that case.

d. APS will propose a program not less than $10 million per year, and not more than $15 million per year, in direct capital costs for the program. At least 65% of annual program will be dedicated to residential installations as defined in subsection 28.4.b. At the end of nine months of each program year, any unspent funds dedicated to low income residential installations can be used for other eligible customers.

e. Relation to annual REST docket. The program is approved in this Docket, and APS does not need to seek further approval in the REST Docket for the program or the spending authorized herein. However, APS shall report the number of installations, capital costs, and expenses in each annual REST docket. Further, recovery of the expenses through the Renewable Energy Adjustment Clause will be reviewed in the annual REST dockets as described herein.

28.3 This program will be available throughout APS's service area, including in rural Arizona.

28.4 This program is limited to low and moderate income residential APS customers as defined below, as well as non-profits that serve low or moderate income APS residential customers, Title I schools, and rural government customers. Rural government is defined as any state, local or tribal government entity in or serving a rural municipality. Rural Municipality means Arizona incorporated cities and towns with populations of less than 150,000 (based on U.S. Census Bureau 2010 population data) not contiguous with or situated within a Metro Area. Metro Area means a city with a population of 750,000 or more and its contiguous and surrounding communities.

a. Moderate income is defined as a household earning less than 100% of the median Arizona household income. APS will verify the income of each program participant.

b. Low income is defined as a household with income at or below 200% of the federal poverty level. APS will verify the income of each program participant.

28.5 APS may include any multi-family housing (such as apartment buildings) in the program.

28.6 Each residential APS customer participating in the program, upon installation of the solar system, will receive a bill credit of $10-50 per month applied to their APS bill. APS will work with stakeholders to discuss and determine the reasonable level of bill credit dependent upon type of installation. All other terms and conditions of the customer's rate option will continue to apply.

28.7 This program is approved for a period of three years from and after the date APS files a notice of program commencement in this Docket. APS will file the notice no later than three months after the effective date of the Commission's decision in this Docket. APS agrees to not implement any additional utility-owned residential solar distribution generation programs prior to APS's next general rate case beyond AZ Sun II, as outlined above.

28.8 APS will file a report with the Commission on the status of the program every quarter during the term of the program. The reporting will list the number of installs in each eligible category until the next APS rate case.

XXIX. LIMITED INCOME PROGRAMS

29.1 The E-3 Energy Support Program for limited income customers will be revised to provide eligible customers with a flat 25% bill discount.

29.2 The E-4 Medical Support Program for limited income customers who have life sustaining medical equipment will be revised to provide eligible customers with a flat 35% bill discount.

29.3 APS agrees to fund $1.25 million annually the crisis bill program to assist customers whose incomes are less than or equal to 200% of the Federal Poverty Income Guidelines.

XXX. AMI OPT-OUT/SCHEDULE 1

30.1 The AMI Opt-Out program will be approved as proposed by APS except the fees will be changed to reflect an upfront fee of $50 to change out a standard meter for a non-standard meter and monthly fee of $5. See Service Schedule 1, attached as Appendix M.

30.2 Changes to Schedule 1 are attached in Appendix M.

XXXI. SCHEDULE 3

31.1 APS will create a new classification in Schedule 3: "Rural Municipal Business Developments" which means a tract of land that has (1) been divided into contiguous lots, (2) is owned and developed by a Rural Municipality and, (3) where the Rural Municipality will be the lease-holder for future, permanent lessee applicants.

31.2 Extension Facilities will be installed to Rural Municipal Business Developments on the basis of an Economic Feasibility analysis in advance of an application for service by permanent lessee applicants.

31.3 The refund eligibility period will be seven years (Rather than 5 years that applies to other classifications).

31.4 Advance payment of one-half of the project costs is due before the start of Company construction. The balance of the project cost will be required 7 years from the Execution Date of the agreement if the project has not become economically feasible by the end of the refundable period. Any unrefunded advance balance paid at the start of the project plus the balance of project costs due at the end of the refund period will become a non-refundable contribution in aid of construction 7 years from the Execution Date of the agreement. (Rather than full advance required before start of construction). Changes to Schedule 3 are attached as Appendix N.

XXXII. LOST FIXED COST RECOVERY MECHANISM

32.1 The LFCR opt-out rate option approved in Decision 73183 will be removed.

32.2 The adjustment will no longer be applied to customer's bills as an equal percentage surcharge, but rather as a capacity (demand) charge per kW for customers with a demand rate and as a kWh charge for customers with a two-part rate without demand.

32.3 APS shall submit its LFCR compliance filings on February 15th of each year. New LFCR rates shall take effect, upon Commission approval, with the first billing cycle in May of each year. The LFCR Plan of Administration is attached as Appendix O.

XXXIII. MODIFICATION TO ENVIRONMENTAL IMPROVEMENT SURCHARGE

33.1 APS shall be permitted to increase the cumulative per kWh cap rate for the Environmental Improvement Surcharge ("EIS") from the current \$0.00016 to a new rate of \$0.00050 and include a balancing account.

33.2 A copy of the revised EIS Plan of Administration is attached as Appendix P.

XXXIV. TRANSMISSION COST ADJUSTMENT MECHANISM

34.1 APS shall be permitted to add a balancing account to the TCA.

34.2 Consistent with the Commission's directive in Decision No. 72430, the annual TCA adjustment will become effective June 1 of each year without the need for affirmative Commission approval, consistent with the process approved by the Commission in Decision No. 72430.

34.3 A copy of the proposed TCA Plan of Administration is attached as Appendix Q.

XXXV. CHALLENGES TO DECISION NOS. 75859 AND 75932

35.1 Upon final approval of the Settlement Agreement by way of a final non-appealable Commission Order that includes no material changes to the terms of the Settlement Agreement, all Signing Parties will promptly take all necessary actions to (i) withdraw any challenge to Decision Nos. 75859 and 75932 they have filed. and (ii) refrain from pursuing any legal challenge to Decision Nos. 75859 and 75932 in any forum.

35.2 Prior to the issuance of a non-appealable Commission Order in this rate case, the Signing Parties agree to work together to secure a stay of any and all appeals that will suspend the filing of all pleadings, motions, briefings, or other court documents, until after the Commission issues its final Order in this case.

XXXVI. POWER SUPPLY ADJUSTOR AUDIT

36.1 Staff will docket the final audit report of APS's Power Supply Adjustor ("PSA") and the Signing Parties agree that any issues relating to the PSA audit report will be addressed in the hearing on this matter.

XXXVII. COMPLIANCE MATTERS

37.1 Staff's Recommendation for elimination or waiver of certain compliance requirements will be adopted. A list of the items to be eliminated or waived is attached as Appendix R.

37.2 Within ten days after the Commission issues an 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.

XXXVIII. FORCE MAJEURE PROVISION

38.1 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 any party, including any Signing Party 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.

XXXIX. COMMISSION EVALUATION OF PROPOSED SETTLEMENT

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

39.2 The Signing Parties 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.

39.3 This Agreement shall serve as a procedural device by which the Signing Parties will submit their proposed settlement of APS's pending rate case, Docket No. E-01345A-16-0036 consolidated with Docket No. E-01345A-16-0123, to the Commission.

39.4 The Signing Parties 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 Signing Parties shall abide by the terms as approved by the Commission.

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

XL. MISCELLANEOUS PROVISIONS

40.1 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 with the broad public interest. The acceptance by any Signing Party of a specific element of this Agreement shall not be considered as precedent for acceptance of that element in any other context.

40.2 No Signing Party is bound by any position asserted in negotiations, except as expressly stated in this Agreement. No Signing Party 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, and no statement, communication or position of any party, their representatives, attorneys, or witnesses in the course of negotiations or in support of this Agreement shall be considered an admission or support for any position taken in any other forum or action.

40.3 Neither this Agreement nor any of the positions taken in this Agreement by any of the Signing Parties 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.

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

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

40.6 The Signing Parties shall make reasonable and good faith efforts necessary to obtain a Commission order approving this Agreement. The Signing Parties shall support and defend this Agreement before the Commission. Subject to subsection 40.5, if the Commission adopts an order approving all material terms of the Agreement, the Signing Parties will support and defend the Commission's order before any court or regulatory agency in which it may be at issue.

40.7 This Agreement may be executed in any number of counterparts and by each Signing Party 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 Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123

SIGNATURE PAGE

ARIZONA CORPORATION COMMISSION

By: ______________________

Name: Elijah Abinah

Title: Acting Director, Utilities Division

Date: March 24, 2017

Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123

SIGNATURE PAGE

Arizona Public Service Company

By: Barbara Lockwood

Name: Barbara Lockwood

Title: Vice President, Regulation

Date: March 24, 2017

Arizona Public Service Company
Proposed Settlement Agreement
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SIGNATURE PAGE

Residential Utility Consumer Office

By: David Tenney

Name: David Tenney

Title: Director

Date: 3/24/17

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[Arizona Utility Ratepayer Alliance]

By: ____________________

Name: Patrick J Quinn

Title: Managing Partner

Date: March 24, 2017

Arizona Public Service Company
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FEDERAL EXECUTIVE AGENCIES

By:

Name: Lanny L. Zieman, Captain, USAF

Title: Utilities Litigation Attorney

Date: 24 March 2017

Arizona Public Service Company
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ARIZONA SOLAR DEPLOYMENT ALLIANCE

By: ______________________

Name: SEAN M. SEITZ

Title: PRESIDENT

Date: MARCH 24, 2017

Arizona Public Service Company
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[INSERT PARTY NAME/COMPANY]

By: Thomas A. Harris

Name: Tom Harris

Title: Treasurer, AriSEIA

Date: Mar. 24, 2017

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Vote Solar
[INSERT PARTY NAME/COMPANY]

By: ______________________

Name: Adam Browning

Title: Executive Director

Date: 3/24/17

Arizona Public Service Company
Proposed Settlement Agreement
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Solar Energy Industries Association

By: ______________________

Name: Sean Gallagher

Title: Vice-President State Affairs

Date: 3/24/17

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ENERGY FREEDOM COALITION OF AMERICA

By: ____________________

Name: Court S. Rich

Title: Attorney for Energy Freedom Coalition of America, LLC

Date: 3/27/17

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Proposed Settlement Agreement
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Arizona School Boards Association and the Arizona Association of School Business Officials

By: ______________________

Name: Timothy M. Hogan

Title: Attorney

Date:3/23/17

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ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION

By:

Name: Stan Barnes

Title: President

Date: March 24, 2017

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WESTERN RESOURCE ADVOCATES

By: John Nielsen

Name: John Nielsen

Title: Clean Energy Program Director

Date: 3/24/2017

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Wal-Mart Stores, Inc. and Sam's West, Inc.

By: Scott Wakefield

Name: Scott Wakefield

Title: Attorney

Date: March 24, 2017

Arizona Public Service Company
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LUBIN & ENOCH, P.C.

By: ______________________

Name: Nicholas J. Enoch, Esq.

Title: Attorney for Intervenors

IBEW Locals 387 & 769

Date: March 24, 2017

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FREEPORT MINERALS CORPORATION

By: Michael McElrath

Name: Michael McElrath

Title: Director Energy

Date: March 24, 2017

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[INSERT PARTY NAME/COMPANY]

By: ______________________

Name: Cynthia Zwick

Title: Executive Director,
Arizona Community Action Assoc.

Date: March 24, 2017

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[INSERT PARTY NAME/COMPANY]

By: K Boehm

Name: KURT Boehm

Title: ATTORNEY, the Kroger Co.

Date: 3/24/2017

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ARIZONA INVESTMENT COUNCIL

By: ______________________

Name: GaryYaquinto

Title: President& CEO

Date: 3/24/2017

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Property Owners & Residents Association
(PORA) Sun City West

By: Al Gervenack

Name: Al Gervenack

Title: Director, Board of Directors

Date: March 24, 2017

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[SUN CITY HOME OWNERS ASSOCIATION (SCHOA)]

By: Greg Eisert

Name: GREG EISERT

Title: Director, Chairman of Government Affairs

Date: 24 March 2017

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REP America d/b/a ConservAmerica

By: Timmy J Sabo

Name: Timothy J Sabo

Title: Attorney For ConservAmerica

Date: 3/24/17

Arizona Public Service Company
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Constellation New Energy, LLC

By: Lawrence V. Robertson, Jr.

Name: Lawrence V. Robertson, Jr.

Title: Attorney

Date: March 24, 2017

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Direct Energy Business, LLC

By: Lawrence V. Robertson, Jr.

Name: Lawrence V. Robertson, Jr.

Title: Attorney

Date: March 24, 2017

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Calpine Energy Solutions, LLC

By: Lawrence V. Robertson, Jr.

Name: Lawrence V. Robertson, Jr.

Title: Attorney

Date: March 24, 2017

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[Arizona Competitive Power Alliance]

By: ______________________

Name: Greg Patterson

Title: AzCPA Director

Date: March 24, 2017

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CITY OF COOLIDGE

By: D. M. Fitzgibbons

Name: Denis M. Fitzgibbons

Title: City of Attorney

Date: March 24, 2017

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Granite Creek Farms LLC
Granite Creek Power & Gas LLC

By: ____________________

Name: Thomas E Stewart____________

Title: General Manager______________

Date:3/26/2017____________________

Settlement Agreement Appendix Index

Appendix A

ARIZONA PUBLIC SERVICE COMPANY
Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement A

Account Description	Current (at 12/31/2015) Investment	Current Net Salvage	Current Total	Proposed (at 12/31/2015) Investment	Proposed Net Salvage	Proposed Total
A	B	C	D=B+C	E	F	G=E+F
STEAM PRODUCTION						
311.00 Structures and Improvements	2.52%	0.30%	2.82%	5.01%	0.42%	5.43%
312.00 Boiler Plant Equipment	2.17%	0.32%	2.49%	3.78%	0.39%	4.17%
314.00 Turbogenerator Units	2.51%	0.33%	2.84%	4.45%	0.50%	4.95%
315.00 Accessory Electric Equipment	2.27%	0.34%	2.61%	4.50%	0.47%	4.97%
316.00 Miscellaneous Power Plant Equipment	2.46%	0.33%	2.79%	4.77%	0.59%	5.36%
Total Steam Production Plant	2.27%	0.32%	2.59%	4.08%	0.42%	4.50%
NUCLEAR PRODUCTION						
321.00 Structures and Improvements	1.34%	0.01%	1.35%	0.96%	0.02%	0.98%
322.00 Reactor Plant Equipment	1.50%	0.05%	1.55%	0.77%	0.06%	0.83%
323.00 Turbogenerator Units	1.45%	0.02%	1.47%	0.89%	0.03%	0.92%
324.00 Accessory Electric Equipment	1.19%	0.01%	1.20%	0.39%	0.01%	0.40%
325.00 Miscellaneous Power Plant Equipment	1.51%	0.04%	1.55%	1.30%	0.05%	1.35%
Total Nuclear Production Plant	1.42%	0.03%	1.45%	0.84%	0.03%	0.87%
OTHER PRODUCTION						
341.00 Structures and Improvements	3.04%	-0.09%	2.95%	3.60%	0.26%	3.86%
342.00 Fuel Holders, Products and Accessories	3.14%	-0.15%	2.99%	3.62%	0.19%	3.81%
343.00 Prime Movers	2.40%	-0.10%	2.30%	3.28%	0.15%	3.43%
344.00 Generators and Devices	3.30%	-0.32%	2.98%	3.86%	0.12%	3.98%
345.00 Accessory Electric Equipment	3.11%	-0.06%	3.05%	3.71%	0.24%	3.95%
346.00 Miscellaneous Power Plant Equipment	3.35%	-0.15%	3.20%	4.08%	0.21%	4.29%
Total Other Production Plant	3.02%	-0.22%	2.80%	3.67%	0.15%	3.82%
TRANSMISSION PLANT						
352.02 Structures and Improvements	2.67%		2.67%	2.51%		2.51%
353.00 Station Equipment	2.31%	0.11%	2.42%	1.91%	0.09%	2.00%
354.00 Towers and Fixtures	1.84%		1.84%	1.78%		1.78%
355.00 Poles and Fixtures	1.86%	0.37%	2.23%	1.85%	0.37%	2.22%
356.00 Overhead Conductors and Devices	1.75%	0.33%	2.08%	1.74%	0.33%	2.07%
Total Transmission Plant	2.29%	0.11%	2.40%	1.91%	0.09%	2.00%
DISTRIBUTION PLANT						
361.00 Structures and Improvements	1.57%	0.07%	1.64%	1.58%	0.08%	1.66%
362.00 Station Equipment	2.19%	-0.20%	1.99%	2.20%	0.08%	2.28%
363.00 Storage Battery Equipment	6.67%		6.67%	8.79%		8.79%
364.01 Poles, Towers and Fixtures - Wood	2.29%	-0.02%	2.27%	2.10%	0.19%	2.29%
364.02 Poles, Towers and Fixtures - Steel	2.55%	0.26%	2.81%	1.95%	0.19%	2.14%
365.00 Overhead Conductors and Devices	1.98%	-0.08%	1.90%	1.92%	0.20%	2.12%
366.00 Underground Conduit	1.57%	0.08%	1.65%	1.57%	0.17%	1.74%
367.00 Underground Conductors and Devices	2.63%	0.09%	2.72%	2.34%	0.20%	2.54%
368.00 Line Transformers	1.68%	0.07%	1.75%	1.70%	0.06%	1.76%
369.00 Services	2.20%	0.10%	2.30%	1.68%	0.33%	2.01%
370.01 Meters - Electronic	3.68%		3.68%	5.52%	-0.03%	5.49%
370.03 Meters - AMI	3.82%		3.82%	4.84%		4.84%
371.00 Installations on Customers' Premises	2.34%	0.34%	2.68%	2.11%	0.31%	2.42%
373.00 Street Lighting and Signal Systems	1.72%	0.13%	1.85%	1.72%	0.18%	1.90%
Total Distribution Plant	2.25%	0.05%	2.30%	2.14%	0.16%	2.30%
GENERAL PLANT						
Depreciable						
390.00 Structures and Improvements	2.19%	0.13%	2.32%	2.52%	0.17%	2.69%
391.CM Office Furn. and Equip. - Computer	12.08%	0.02%	12.10%	12.86%	0.02%	12.88%
397.00 Communication Equipment	5.35%		5.35%	4.83%		4.83%
Total Depreciable	6.30%	0.04%	6.34%	6.40%	0.06%	6.46%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2015)			Proposed (at 12/31/2015)		
	Investment	Net Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Amortizable						
391.FE Office Furn. and Equip. - Furniture	← 20 Year Amortization →			← 20 Year Amortization →		
393.00 Stores Equipment	← 20 Year Amortization →			← 20 Year Amortization →		
394.00 Tools, Shop and Garage Equipment	← 20 Year Amortization →			← 20 Year Amortization →		
395.00 Laboratory Equipment	← 20 Year Amortization →			← 20 Year Amortization →		
398.00 Miscellaneous Equipment	← 24 Year Amortization →			← 24 Year Amortization →		
Total Amortizable	4.86%		4.86%	4.86%		4.86%
Total General Plant	6.07%	0.04%	6.11%	6.15%	0.05%	6.20%
TOTAL UTILITY	2.42%	0.03%	2.45%	2.61%	0.16%	2.77%
STEAM PRODUCTION (by Unit)						
Cholla						
311.00 Structures and Improvements	2.85%	0.14%	2.99%	7.05%	0.50%	7.55%
312.00 Boiler Plant Equipment	3.56%	0.25%	3.81%	7.02%	0.57%	7.59%
314.00 Turbogenerator Units	3.53%	0.18%	3.71%	6.64%	0.46%	7.10%
315.00 Accessory Electric Equipment	2.55%	0.14%	2.69%	6.10%	0.43%	6.53%
316.00 Miscellaneous Power Plant Equipment	3.00%	0.20%	3.20%	7.37%	0.55%	7.92%
Total Cholla	3.36%	0.22%	3.58%	6.90%	0.54%	7.44%
Cholla Unit 1						
311.00 Structures and Improvements	3.60%	0.17%	3.77%	5.36%	0.44%	5.80%
312.00 Boiler Plant Equipment	4.22%	0.26%	4.48%	6.04%	0.65%	6.69%
314.00 Turbogenerator Units	4.59%	0.24%	4.83%	6.37%	0.58%	6.95%
315.00 Accessory Electric Equipment	3.65%	0.19%	3.84%	5.48%	0.48%	5.96%
316.00 Miscellaneous Power Plant Equipment	3.45%	0.19%	3.64%	5.15%	0.45%	5.60%
Total Cholla Unit 1	4.22%	0.25%	4.47%	6.02%	0.61%	6.63%
Cholla Unit 3						
311.00 Structures and Improvements	2.19%	0.10%	2.29%	7.02%	0.46%	7.48%
312.00 Boiler Plant Equipment	3.40%	0.25%	3.65%	7.28%	0.55%	7.83%
314.00 Turbogenerator Units	3.04%	0.15%	3.19%	6.72%	0.39%	7.11%
315.00 Accessory Electric Equipment	2.16%	0.12%	2.28%	5.99%	0.42%	6.41%
316.00 Miscellaneous Power Plant Equipment	2.48%	0.15%	2.63%	7.24%	0.52%	7.76%
Total Cholla Unit 3	3.15%	0.21%	3.36%	7.05%	0.51%	7.56%
Cholla Common						
311.00 Structures and Improvements	2.94%	0.15%	3.09%	7.19%	0.52%	7.71%
312.00 Boiler Plant Equipment	3.32%	0.25%	3.57%	7.27%	0.60%	7.87%
314.00 Turbogenerator Units	2.67%	0.13%	2.80%	8.50%	0.63%	9.13%
315.00 Accessory Electric Equipment	2.96%	0.18%	3.14%	7.29%	0.47%	7.76%
316.00 Miscellaneous Power Plant Equipment	3.16%	0.22%	3.38%	7.89%	0.59%	8.48%
Total Cholla Common	3.12%	0.20%	3.32%	7.31%	0.56%	7.87%
Four Corners						
311.00 Structures and Improvements	1.35%	0.51%	1.86%	2.36%	0.26%	2.62%
312.00 Boiler Plant Equipment	0.85%	0.37%	1.22%	1.52%	0.26%	1.78%
314.00 Turbogenerator Units	0.95%	0.42%	1.37%	1.60%	0.30%	1.90%
315.00 Accessory Electric Equipment	1.40%	0.56%	1.96%	2.59%	0.39%	2.98%
316.00 Miscellaneous Power Plant Equipment	1.09%	0.29%	1.38%	2.30%	0.39%	2.69%
Total Four Corners	0.94%	0.39%	1.33%	1.69%	0.28%	1.97%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2015) Investment	Net Salvage	Total	Proposed (at 12/31/2015) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Four Corners Units 4-5						
311.00 Structures and Improvements	0.98%	0.52%	1.50%	1.75%	0.31%	2.06%
312.00 Boiler Plant Equipment	0.77%	0.36%	1.13%	1.40%	0.24%	1.64%
314.00 Turbogenerator Units	0.92%	0.43%	1.35%	1.55%	0.30%	1.85%
315.00 Accessory Electric Equipment	1.06%	0.57%	1.63%	2.12%	0.41%	2.53%
316.00 Miscellaneous Power Plant Equipment	0.54%	0.18%	0.72%	2.02%	0.40%	2.42%
Total Four Corners Units 4-5	0.80%	0.38%	1.18%	1.50%	0.26%	1.76%
Four Corners Common						
311.00 Structures and Improvements	2.23%	0.48%	2.71%	3.81%	0.16%	3.97%
312.00 Boiler Plant Equipment	2.09%	0.49%	2.58%	3.44%	0.44%	3.88%
314.00 Turbogenerator Units	1.65%	0.28%	1.93%	2.87%	0.27%	3.14%
315.00 Accessory Electric Equipment	2.39%	0.53%	2.92%	3.93%	0.36%	4.29%
316.00 Miscellaneous Power Plant Equipment	2.50%	0.58%	3.08%	3.03%	0.34%	3.37%
Total Four Corners Common	2.21%	0.50%	2.71%	3.50%	0.35%	3.85%
Navajo Units 1-3						
311.00 Structures and Improvements	3.34%	0.24%	3.58%	3.78%	0.20%	3.98%
312.00 Boiler Plant Equipment	3.42%	0.28%	3.70%	3.52%	0.19%	3.71%
314.00 Turbogenerator Units	2.71%	0.20%	2.91%	2.72%	0.15%	2.87%
315.00 Accessory Electric Equipment	2.93%	0.21%	3.14%	3.06%	0.17%	3.23%
316.00 Miscellaneous Power Plant Equipment	3.75%	0.29%	4.04%	4.19%	0.29%	4.48%
Total Navajo Units 1-3	3.33%	0.26%	3.59%	3.49%	0.19%	3.68%
Ocotillo Units 1-2						
311.00 Structures and Improvements	4.91%	0.88%	5.79%	10.65%	2.28%	12.93%
312.00 Boiler Plant Equipment	3.41%	0.65%	4.06%	8.89%	1.97%	10.86%
314.00 Turbogenerator Units	4.74%	0.88%	5.62%	9.88%	2.25%	12.13%
315.00 Accessory Electric Equipment	4.55%	0.84%	5.39%	12.68%	2.76%	15.44%
316.00 Miscellaneous Power Plant Equipment	5.80%	1.10%	6.90%	13.34%	2.76%	16.10%
Total Ocotillo Units 1-2	4.30%	0.80%	5.10%	10.17%	2.23%	12.40%
NUCLEAR PRODUCTION (by Unit)						
Palo Verde						
321.00 Structures and Improvements	1.34%	0.01%	1.35%	0.96%	0.02%	0.98%
322.00 Reactor Plant Equipment	1.50%	0.05%	1.55%	0.77%	0.06%	0.83%
323.00 Turbogenerator Units	1.45%	0.02%	1.47%	0.89%	0.03%	0.92%
324.00 Accessory Electric Equipment	1.19%	0.01%	1.20%	0.39%	0.01%	0.40%
325.00 Miscellaneous Power Plant Equipment	1.51%	0.04%	1.55%	1.30%	0.05%	1.35%
Total Palo Verde	1.42%	0.03%	1.45%	0.84%	0.03%	0.87%
Palo Verde Unit 1						
321.00 Structures and Improvements	1.13%		1.13%	0.18%	0.00%	0.19%
322.00 Reactor Plant Equipment	1.45%	0.04%	1.49%	0.60%	0.01%	0.62%
323.00 Turbogenerator Units	1.41%	0.02%	1.43%	0.79%	0.05%	0.83%
324.00 Accessory Electric Equipment	1.11%	0.01%	1.12%	0.19%	0.00%	0.20%
325.00 Miscellaneous Power Plant Equipment	1.29%	0.02%	1.31%	0.40%	0.04%	0.43%
Total Palo Verde Unit 1	1.34%	0.03%	1.37%	0.50%	0.01%	0.51%
Palo Verde Unit 2						
321.00 Structures and Improvements	1.20%	0.01%	1.21%	0.37%	0.00%	0.37%
322.00 Reactor Plant Equipment	1.52%	0.08%	1.60%	0.96%	0.06%	1.02%
323.00 Turbogenerator Units	1.41%	0.01%	1.42%	1.11%	0.03%	1.14%
324.00 Accessory Electric Equipment	1.25%	0.01%	1.26%	0.47%	0.01%	0.48%
325.00 Miscellaneous Power Plant Equipment	1.45%	0.02%	1.47%	0.69%	0.03%	0.72%
Total Palo Verde Unit 2	1.41%	0.05%	1.46%	0.82%	0.03%	0.85%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2015) Investment	Net Salvage	Total	Proposed (at 12/31/2015) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Palo Verde Unit 3						
321.00 Structures and Improvements	1.22%		1.22%	0.29%	0.00%	0.29%
322.00 Reactor Plant Equipment	1.56%	0.05%	1.61%	0.81%	0.09%	0.90%
323.00 Turbogenerator Units	1.48%	0.02%	1.50%	0.81%	0.01%	0.83%
324.00 Accessory Electric Equipment	1.24%	0.01%	1.25%	0.39%	0.01%	0.41%
325.00 Miscellaneous Power Plant Equipment	1.36%	0.02%	1.38%	0.55%	0.04%	0.59%
Total Palo Verde Unit 3	1.44%	0.03%	1.47%	0.66%	0.05%	0.71%
Palo Verde Water Reclamation						
321.00 Structures and Improvements	1.69%	0.02%	1.71%	2.05%	0.03%	2.08%
322.00 Reactor Plant Equipment	2.01%	0.03%	2.04%	2.92%	0.04%	2.96%
323.00 Turbogenerator Units	1.45%	0.01%	1.46%	1.43%	0.17%	1.60%
324.00 Accessory Electric Equipment						
325.00 Miscellaneous Power Plant Equipment	1.43%	0.05%	1.48%	2.19%	0.01%	2.20%
Total Palo Verde Water Reclamation	1.69%	0.02%	1.71%	2.05%	0.04%	2.09%
Palo Verde Common						
321.00 Structures and Improvements	1.30%	0.02%	1.32%	1.31%	0.02%	1.34%
322.00 Reactor Plant Equipment	1.22%	0.06%	1.28%	0.98%	0.42%	1.40%
323.00 Turbogenerator Units	2.15%	0.04%	2.19%	2.31%	0.24%	2.54%
324.00 Accessory Electric Equipment	1.21%	0.01%	1.22%	1.08%	0.01%	1.09%
325.00 Miscellaneous Power Plant Equipment	1.64%	0.06%	1.70%	1.94%	0.06%	2.00%
Total Palo Verde Common	1.40%	0.04%	1.44%	1.46%	0.08%	1.54%
OTHER PRODUCTION (by Unit)						
Douglas CT						
341.00 Structures and Improvements	5.13%	-0.26%	4.87%	16.13%	0.81%	16.94%
342.00 Fuel Holders, Products and Accessories	0.90%	-0.01%	0.89%	24.09%	1.08%	25.17%
343.00 Prime Movers	-0.25%	0.02%	-0.23%	11.37%	-9.17%	2.20%
344.00 Generators and Devices	-0.28%	0.01%	-0.27%	18.97%	0.95%	19.92%
345.00 Accessory Electric Equipment	0.02%	0.02%	0.04%	23.54%	1.09%	24.63%
346.00 Miscellaneous Power Plant Equipment	0.70%	-0.03%	0.67%	24.08%	1.28%	25.36%
Total Douglas CT	-0.10%	0.01%	-0.09%	14.16%	-6.05%	8.11%
Ocotillo CT Units 1-2						
341.00 Structures and Improvements	4.19%	-0.20%	3.99%	5.50%	0.48%	5.98%
342.00 Fuel Holders, Products and Accessories	2.07%	-0.10%	1.97%	3.72%	0.19%	3.91%
343.00 Prime Movers	0.73%	-0.03%	0.70%	5.41%	0.70%	6.11%
344.00 Generators and Devices	3.44%	-0.61%	2.83%	4.73%	0.25%	4.98%
345.00 Accessory Electric Equipment	1.60%	-0.06%	1.54%	4.84%	0.27%	5.11%
346.00 Miscellaneous Power Plant Equipment	2.14%	-0.09%	2.05%	4.18%	0.20%	4.38%
Total Octillo CT Units 1-2	1.91%	-0.23%	1.68%	5.07%	0.48%	5.55%
Redhawk CC Units 1-2						
341.00 Structures and Improvements	3.13%	-0.12%	3.01%	4.00%	0.20%	4.20%
342.00 Fuel Holders, Products and Accessories	3.63%	-0.18%	3.45%	4.37%	0.23%	4.60%
343.00 Prime Movers	3.11%	-0.08%	3.03%	3.97%	0.26%	4.23%
344.00 Generators and Devices	3.33%	-0.83%	2.50%	4.33%	-0.11%	4.22%
345.00 Accessory Electric Equipment	3.11%	-0.10%	3.01%	3.97%	0.19%	4.16%
346.00 Miscellaneous Power Plant Equipment	3.60%	-0.18%	3.42%	4.41%	0.20%	4.61%
Total Redhawk CC Units 1-2	3.27%	-0.56%	2.71%	4.21%	0.02%	4.23%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2015) Investment	Net Salvage	Total	Proposed (at 12/31/2015) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Saguaro						
341.00 Structures and Improvements	4.60%	-0.22%	4.38%	4.20%	0.41%	4.61%
342.00 Fuel Holders, Products and Accessories	1.27%	-0.03%	1.24%	2.16%	0.13%	2.29%
343.00 Prime Movers	0.71%	-0.03%	0.68%	4.09%	0.47%	4.56%
344.00 Generators and Devices	2.92%	-0.19%	2.73%	2.97%	0.15%	3.12%
345.00 Accessory Electric Equipment	0.55%	-0.01%	0.54%	4.08%	0.25%	4.33%
346.00 Miscellaneous Power Plant Equipment	2.57%	-0.12%	2.45%	2.25%	0.11%	2.36%
Total Saguaro	2.16%	-0.13%	2.03%	3.40%	0.27%	3.67%
Saguaro CT Units 1-2						
341.00 Structures and Improvements	4.60%	-0.22%	4.38%	4.20%	0.41%	4.61%
342.00 Fuel Holders, Products and Accessories	1.27%	-0.03%	1.24%	2.16%	0.13%	2.29%
343.00 Prime Movers	0.45%	-0.02%	0.43%	4.10%	0.50%	4.60%
344.00 Generators and Devices	3.36%	-0.52%	2.84%	2.72%	0.15%	2.87%
345.00 Accessory Electric Equipment	0.46%	-0.01%	0.45%	4.12%	0.25%	4.37%
346.00 Miscellaneous Power Plant Equipment	2.57%	-0.12%	2.45%	2.25%	0.11%	2.36%
Total Saguaro CT Units 1-2	1.46%	-0.12%	1.34%	3.73%	0.38%	4.11%
Saguaro CT Unit 3						
341.00 Structures and Improvements						
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers	2.85%	-0.14%	2.71%	3.99%	0.20%	4.19%
344.00 Generators and Devices	2.85%	-0.14%	2.71%	3.01%	0.15%	3.16%
345.00 Accessory Electric Equipment	2.85%	-0.14%	2.71%	3.00%	0.16%	3.16%
346.00 Miscellaneous Power Plant Equipment						
Total Saguaro CT Unit 3	2.85%	-0.14%	2.71%	3.07%	0.16%	3.23%
Solar Units						
341.00 Structures and Improvements						
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices						
345.00 Accessory Electric Equipment						
346.00 Miscellaneous Power Plant Equipment						
Total Solar Units	3.36%	-0.01%	3.35%	3.58%	0.28%	3.86%
Chino Valley						
341.05 Structures and Improvements	3.33%		3.33%	3.53%	0.26%	3.79%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.53%	0.26%	3.79%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.53%	0.26%	3.79%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.53%	0.26%	3.79%
Total Chino Valley	3.33%		3.33%	3.53%	0.26%	3.79%
Cotton Center						
341.05 Structures and Improvements	3.33%		3.33%	3.52%	0.24%	3.76%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.52%	0.24%	3.76%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.52%	0.24%	3.76%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.52%	0.24%	3.76%
Total Cotton Center	3.33%		3.33%	3.52%	0.24%	3.76%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2015) Investment	Net Salvage	Total	Proposed (at 12/31/2015) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Desert Star						
341.05 Structures and Improvements	3.33%		3.33%	4.51%	0.52%	5.03%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	4.51%	0.52%	5.03%
345.05 Accessory Electric Equipment	3.33%		3.33%	4.51%	0.52%	5.03%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	4.51%	0.52%	5.03%
Total Desert Star	3.33%		3.33%	4.51%	0.52%	5.03%
Foothills Units 1-2						
341.05 Structures and Improvements	3.33%		3.33%	3.48%	0.30%	3.78%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.48%	0.30%	3.78%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.48%	0.30%	3.78%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.48%	0.30%	3.78%
Total Foothills Units 1-2	3.33%		3.33%	3.48%	0.30%	3.78%
Gila Bend						
341.05 Structures and Improvements	3.33%		3.33%	3.46%	0.36%	3.82%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.46%	0.36%	3.82%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.46%	0.36%	3.82%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.46%	0.36%	3.82%
Total Gila Bend	3.33%		3.33%	3.46%	0.36%	3.82%
Hyder Units 1-2						
341.05 Structures and Improvements	3.33%		3.33%	3.51%	0.16%	3.67%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.50%	0.16%	3.66%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.48%	0.16%	3.64%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.42%	0.15%	3.57%
Total Hyder Units 1-2	3.33%		3.33%	3.50%	0.16%	3.66%
Legacy Units						
341.00 Structures and Improvements	-3.55%	0.20%	-3.35%	1.31%	0.03%	1.34%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices	3.93%	-0.86%	3.07%	3.44%	0.08%	3.52%
345.00 Accessory Electric Equipment	7.41%	-0.37%	7.04%	4.23%	0.22%	4.45%
346.00 Miscellaneous Power Plant Equipment						
Total Legacy Units	4.65%	-0.71%	3.94%	3.59%	0.12%	3.71%
Luke AFB						
341.05 Structures and Improvements	3.33%		3.33%	4.51%	0.54%	5.05%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	4.51%	0.54%	5.05%
345.05 Accessory Electric Equipment	3.33%		3.33%	4.51%	0.54%	5.05%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	4.51%	0.54%	5.05%
Total Luke AFB	3.33%		3.33%	4.51%	0.54%	5.05%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2015) Investment	Net Salvage	Total	Proposed (at 12/31/2015) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Roof Tops						
341.05 Structures and Improvements	3.33%		3.33%	3.53%	0.18%	3.71%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.55%	0.18%	3.73%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.54%	0.18%	3.72%
346.05 Miscellaneous Power Plant Equipment						
Total Roof Tops	3.33%		3.33%	3.55%	0.18%	3.73%
Paloma						
341.05 Structures and Improvements	3.33%		3.33%	3.52%	0.30%	3.82%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.52%	0.30%	3.82%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.52%	0.30%	3.82%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.52%	0.30%	3.82%
Total Paloma	3.33%		3.33%	3.52%	0.30%	3.82%
Sundance						
341.00 Structures and Improvements	2.06%	-0.10%	1.96%	2.49%	0.23%	2.72%
342.00 Fuel Holders, Products and Accessories	2.05%	-0.10%	1.95%	2.45%	0.12%	2.57%
343.00 Prime Movers	2.04%	-0.11%	1.93%	2.34%	0.12%	2.46%
344.00 Generators and Devices	2.51%	-0.13%	2.38%	4.45%	0.22%	4.67%
345.00 Accessory Electric Equipment	2.05%	-0.10%	1.95%	2.41%	0.13%	2.54%
346.00 Miscellaneous Power Plant Equipment	2.49%	-0.12%	2.37%	2.85%	0.15%	3.00%
Total Sun Dance	2.06%	-0.11%	1.95%	2.44%	0.13%	2.57%
West Phoenix						
341.00 Structures and Improvements	3.04%	-0.15%	2.89%	3.39%	0.23%	3.62%
342.00 Fuel Holders, Products and Accessories	3.67%	-0.17%	3.50%	3.81%	0.19%	4.00%
343.00 Prime Movers	2.73%	-0.09%	2.64%	3.64%	0.19%	3.83%
344.00 Generators and Devices	3.33%	-0.36%	2.97%	3.88%	0.03%	3.91%
345.00 Accessory Electric Equipment	3.51%	-0.15%	3.36%	4.53%	0.29%	4.82%
346.00 Miscellaneous Power Plant Equipment	3.80%	-0.17%	3.63%	4.45%	0.23%	4.68%
Total West Phoenix	3.18%	-0.24%	2.94%	3.84%	0.11%	3.95%
West Phoenix CC Units 1-3						
341.00 Structures and Improvements	5.00%	-0.24%	4.76%	4.03%	0.19%	4.22%
342.00 Fuel Holders, Products and Accessories	4.02%	-0.18%	3.84%	3.94%	0.20%	4.14%
343.00 Prime Movers						
344.00 Generators and Devices	4.08%	-0.65%	3.43%	4.00%	0.14%	4.14%
345.00 Accessory Electric Equipment	4.01%	-0.15%	3.86%	5.21%	0.35%	5.56%
346.00 Miscellaneous Power Plant Equipment	4.17%	-0.18%	3.99%	4.82%	0.23%	5.05%
Total West Phoenix CC Units 1-3	4.07%	-0.48%	3.59%	4.21%	0.19%	4.40%
West Phoenix CC Unit 4						
341.00 Structures and Improvements	3.05%	-0.15%	2.90%	3.30%	0.17%	3.47%
342.00 Fuel Holders, Products and Accessories	2.98%	-0.15%	2.83%	3.21%	0.16%	3.37%
343.00 Prime Movers	2.98%	-0.15%	2.83%	3.21%	0.02%	3.23%
344.00 Generators and Devices	3.07%	-0.30%	2.77%	3.80%	0.18%	3.98%
345.00 Accessory Electric Equipment	3.57%	-0.18%	3.39%	4.00%	0.20%	4.20%
346.00 Miscellaneous Power Plant Equipment	3.72%	-0.17%	3.55%	4.50%	0.22%	4.72%
Total West Phoenix CC Unit 4	3.02%	-0.19%	2.83%	3.40%	0.08%	3.48%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2015) Investment	Net Salvage	Total	Proposed (at 12/31/2015) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
West Phoenix CC Unit 5						
341.00 Structures and Improvements	2.92%	-0.15%	2.77%	3.48%	0.18%	3.66%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers	3.01%	-0.08%	2.93%	3.53%	0.20%	3.73%
344.00 Generators and Devices	2.97%	-0.19%	2.78%	3.76%	-0.09%	3.67%
345.00 Accessory Electric Equipment	2.91%	-0.15%	2.76%	3.52%	0.19%	3.71%
346.00 Miscellaneous Power Plant Equipment	3.40%	-0.17%	3.23%	4.12%	0.22%	4.34%
Total West Phoenix CC Unit 5	2.98%	-0.15%	2.83%	3.67%	0.03%	3.70%
West Phoenix CT Units 1-2						
341.00 Structures and Improvements	3.80%	-0.19%	3.61%	6.05%	0.46%	6.51%
342.00 Fuel Holders, Products and Accessories	0.61%	-0.03%	0.58%	3.36%	0.17%	3.53%
343.00 Prime Movers	1.00%	-0.03%	0.97%	5.03%	0.49%	5.52%
344.00 Generators and Devices	2.25%	-0.21%	2.04%	4.80%	0.29%	5.09%
345.00 Accessory Electric Equipment	0.95%	-0.04%	0.91%	2.61%	0.13%	2.74%
346.00 Miscellaneous Power Plant Equipment	3.25%	-0.16%	3.09%	3.52%	0.26%	3.78%
Total West Phoenix CT Units 1-2	1.62%	-0.10%	1.52%	4.86%	0.40%	5.26%
West Phoenix Common						
341.00 Structures and Improvements	2.76%	-0.12%	2.64%	2.44%	0.24%	2.68%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices						
345.00 Accessory Electric Equipment						
346.00 Miscellaneous Power Plant Equipment						
Total West Phoenix Common	2.76%	-0.12%	2.64%	2.44%	0.24%	2.68%
Yucca						
341.00 Structures and Improvements	2.41%	-0.09%	2.32%	4.70%	0.29%	4.99%
342.00 Fuel Holders, Products and Accessories	0.90%	-0.04%	0.86%	1.86%	0.10%	1.96%
343.00 Prime Movers	2.54%	-0.13%	2.41%	2.98%	0.19%	3.17%
344.00 Generators and Devices	1.29%	-0.24%	1.05%	3.36%	0.21%	3.57%
345.00 Accessory Electric Equipment	1.15%	-0.05%	1.10%	2.94%	0.27%	3.21%
346.00 Miscellaneous Power Plant Equipment	1.82%	-0.09%	1.73%	2.88%	0.15%	3.03%
Total Yucca	2.26%	-0.13%	2.13%	3.06%	0.19%	3.25%
Yucca CT Units 1-4						
341.00 Structures and Improvements	2.29%	-0.08%	2.21%	4.99%	0.31%	5.30%
342.00 Fuel Holders, Products and Accessories	0.11%		0.11%	1.42%	0.08%	1.50%
343.00 Prime Movers	-0.09%		-0.09%	2.80%	0.44%	3.24%
344.00 Generators and Devices	1.27%	-0.24%	1.03%	3.36%	0.21%	3.57%
345.00 Accessory Electric Equipment	0.75%	-0.03%	0.72%	2.84%	0.27%	3.11%
346.00 Miscellaneous Power Plant Equipment	1.11%	-0.06%	1.05%	2.38%	0.12%	2.50%
Total Yucca CT Units 1-4	0.80%	-0.09%	0.71%	3.12%	0.28%	3.40%
Yucca CT Units 5-6						
341.00 Structures and Improvements	2.97%	-0.15%	2.82%	3.29%	0.17%	3.46%
342.00 Fuel Holders, Products and Accessories	2.97%	-0.15%	2.82%	3.01%	0.15%	3.16%
343.00 Prime Movers	2.97%	-0.15%	2.82%	3.01%	0.15%	3.16%
344.00 Generators and Devices	2.97%	-0.15%	2.82%	3.14%	0.16%	3.30%
345.00 Accessory Electric Equipment	2.97%	-0.15%	2.82%	3.41%	0.23%	3.64%
346.00 Miscellaneous Power Plant Equipment	2.97%	-0.15%	2.82%	3.70%	0.19%	3.89%
Total Yucca CT Units 5-6	2.97%	-0.15%	2.82%	3.03%	0.15%	3.18%

Appendix B

Palo Verde Decommissioning Trust Amounts
Test Year Ended 12/31/2015
(Dollars in Thousands)

YEAR	6/1/2045 UNIT 1	4/24/2046 UNIT 2	11/25/2047 UNIT 3	TOTAL[2]	ACC Jurisdictional Amount[1]
2016	449	-	1,832	2,281	$ 2,265
2017	377	868	1,036	2,281	2,265
2018	377	868	1,036	2,281	2,265
2019	377	868	1,036	2,281	2,265
2020	377	868	1,036	2,281	2,265
2021	377	868	1,036	2,281	2,265
2022	377	868	1,036	2,281	2,265
2023	377	868	1,036	2,281	2,265
2024	377	868	1,036	2,281	2,265
2025	377	868	1,036	2,281	2,265
2026	377	868	1,036	2,281	2,265
2027	377	868	1,036	2,281	2,265
2028	377	868	1,036	2,281	2,265
2029	377	868	1,036	2,281	2,265
2030	377	868	1,036	2,281	2,265
2031	377	868	1,036	2,281	2,265
2032	377	868	1,036	2,281	2,265
2033	377	868	1,036	2,281	2,265
2034	377	868	1,036	2,281	2,265
2035	377	868	1,036	2,281	2,265
2036	377	868	1,036	2,281	2,265
2037	377	868	1,036	2,281	2,265
2038	377	868	1,036	2,281	2,265
2039	377	868	1,036	2,281	2,265
2040	377	868	1,036	2,281	2,265
2041	377	868	1,036	2,281	2,265
2042	377	868	1,036	2,281	2,265
2043	377	868	1,036	2,281	2,265
2044	377	868	1,036	2,281	2,265
2045	189	868	1,036	2,092	2,078
2046	-	217	1,036	1,253	1,244
2047	-	-	1,036	1,036	1,028
	$ 11,207	$ 25,389	$ 33,933	$ 70,528	$ 70,049

1. ACC Jurisdictional share is approximately 99.32%.
2. Arizona Public Service Company ("APS") is proposing to keep the level of Decommissioning Trust funding constant. Therefore, APS is not proposing any additional funding even though APS anticipates higher amounts than what are reflected in this Schedule.

Appendix C

Power Supply Adjustment
Plan of Administration

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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 subsequently amended by the Commission in Decision Nos. 71448 (December 30, 2009), 73183 (May 24, 2012), and XXXXX (XXX XX, 201X). The PSA provides for the recovery of fuel and purchased power costs and other production-related variable costs to the extent that those costs deviate from the amount recovered through APS's Base PSA Cost ($0.030667 per kWh) authorized in Decision No. XXXXX, from XXX XX, 201X.

Non-fuel production costs included in the PSA relate to environmental chemical expenses which vary directly with power plant production. The production-related environmental chemical costs are limited to expenses for lime, sulfur and ammonia used at fossil fuel generation sites. The PSA allows for the refund or recovery of said costs that deviate from the base cost amount of $0.000500 per kWh[1].

In addition, the PSA allows for the refund or recovery of the net margins from sales of emission allowances, to the extent the actual sales margins deviate from the base cost amount of ($0.000001) per kWh[2] and for recovery of mandated carbon emission costs when it is economical to incur those costs as discussed below.

APS shall not incur mandatory carbon emission allowance costs unless it passes those costs on to the California entities that are purchasing energy from APS. In no event shall APS incur California's carbon emission allowance costs when doing so is not an economical choice for APS's Arizona ratepayers.

[1] $0.000500 per kWh is the result of the following: (2015 chemical costs of $13,527,111 / 2015 test year native load sales of 27,030,686 MWh) / 1000.

[2] ($0.000001) per kWh is the result of the following: (2015 net gains from sales of SO_2 allowances of $25,181 / 2015 test year native load sales of 27,030,686 MWh) / 1000.

The PSA described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs and environmental chemical costs for fossil fuel production, 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 by either the Commission or the Company (only if overcollection) 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, prudently incurred PSA Costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PSA Year's[3] PSA Costs and those embedded in base rates.
2. The Historical Component, which tracks the differences between the PSA Year's actual PSA Costs (fuel, purchased power and other allowable costs) and the recovery of those same cost elements through the combination of base rates and the Forward Component, and which provides for their recovery or refund 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 and other allowable 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 or if the Company requests to make such refund of an overcollection.
    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 November 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.

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

[3] Each February 1 through January 31 period shall constitute a PSA Year

1 and ends on the ensuing January 31. APS will submit, on or before November 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's 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 November 30 APS filing will include an accumulation of Forward Component Tracking Account balances and Historical Component Tracking Account balances for the preceding February through October and an estimate of the balances for November through January (the remaining three months of the current PSA Year). The APS filing shall use these balances to calculate the Historical Component for the coming PSA Year[4].

The November 30 filing's use of estimated balances for November 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 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

[4] For example, the November 30, 2008 filing would include actual balances for February through October of 2008 and estimated balances for November 2008 through January 2009.

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 approved mid-year changes to the PSA rate. APS or Staff may 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. 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 be deemed approved and 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 November 30 of each year an accumulation of Transition Component Tracking Account balances for the preceding February through October and an estimate of the balances for November through January (the remaining three months of the prior PSA Year). Those balances will form the basis for setting the preliminary Transition Component for the coming PSA Year.

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 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's retail electric rate schedules (with the exception of E-36 XL, AG-X, 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. November 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 November 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.[5]

b. 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.

c. Review Process

The Commission Staff and interested parties shall have an opportunity to review the November 30 forecast, balances, and supporting data on which the calculations of the three PSA components have been based. Any objections to the November 30 calculations shall be filed within 60 days of the APS filing. Before Storage Product Costs may be calculated in the PSA, APS will first seek approval. APS will request this approval by filing the third party storage contract with the Commission at least 90 days before the contract becomes effective. 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. Verification and Audit

[5] 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.

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 and other allowable 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 Chemical Costs - An amount generally expressed as a rate per kWh, which reflects the non-fuel production costs embedded in the base rates as approved by the Commission in APS's most recent rate case. The production-related environmental chemical costs are limited to expenses for lime, sulfur and ammonia used at fossil fuel generation sites. The Base Chemical Costs are set at $0.000500 per kWh effective on XXX XX, 201X.

Base Cost of Fuel and Purchased Power - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power costs 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 $0.030168 per kWh effective on XXX XX, 201X.

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 XXX XX, 201X.

Base PSA Costs - A rate equal to the sum of Base Cost of Fuel and Purchased Power as defined above, the Base Chemical Costs, 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 at year end. 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.

Mandated Carbon Emission Allowance Costs – The costs incurred in purchasing allowances to meet legal requirements, beginning in 2013, that electricity from resources which emit carbon must be accompanied by carbon emission allowances equal to the amount of carbon emitted in generating the electricity (recorded in FERC Account 509 – Allowances).

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 refers to the energy for both customer load in the balancing authority area for which APS has a generation service obligation plus 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.

PSA Costs - The combination of System Book Fuel and Purchased Power Costs net of the System Book Off-System Sales Revenues plus costs for environmental chemicals used in power production at fossil and nuclear production sites, approved storage product costs, and the Net Margins on the Sales of Emission Allowances.

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

Rate Schedule AG-X -Alternative Generation Rate Schedule approved by the Commission in Decision No. XXXXX. Resale of capacity and energy displaced by Rate Schedule AG-X shall be excluded from the PSA at a flat amount of $1,250,000 a month. The portion of capacity and energy sales margins that is not the result of displacement from Rate Schedule AG-X will continue to be a credit to the PSA.

Storage Product Costs - All costs associated with third-party storage facilities, including rent, capacity, and lease payments for electricity storage facilities (e.g. batteries) that APS utilizes in the dispatch of generated or purchased electricity.

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 XL, AG-X, RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs and broker fees are included up to the level in the Base Cost of Fuel and Purchased Power authorized in Decision No. 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'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 and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Principal Officer, as listed in APS'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. Environmental chemical costs for fossil generation.
    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 factor, 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 or per MCF, 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, costs for specified environmental chemicals that vary with power generated at fossil power plants, storage product costs, and the net margins on the sale of emission allowances and Mandated Carbon Emission Allowance Costs 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)
- 509 Allowances[6]

Additionally, broker fees recorded in FERC account 557 up to the amount included in the Base Fuel Cost, costs for environmental chemicals used in power production in FERC accounts 502 and 549, and the FERC account where applicable Storage Product Costs will be recorded are allowable accounts.

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-X 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.

[6] Or any successor FERC account used to record the costs of purchasing carbon emission allowances.

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, L16)	$ -	$ -	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 November 30 filing 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 Fossil Chemical Costs	-	-	N/A	N/A
6	Projected Net Margins on the Sale of Emission Allowances	-	-	N/A	N/A
7	Projected Billed Native Load Sales, excluding E-36XL and AG-X (MWh) [3]	##,###,###	-	N/A	N/A
8	Projected Average Net Fuel Cost $/kWh (L4 / L7)	#.######	$ -	N/A	N/A
9	Average Fossil Chemical Costs $/kWh (L5 / L7)	#.######	-	N/A	N/A
10	Projected Average Margin on Emission Allowances $/kWh (L6 / L7)	$ -	$ -	N/A	N/A
11	Total Projected Average PSA Cost $/kWh (L8+L9+L10)	#.######	$ -	N/A	N/A
12	Authorized Base Cost of Fuel and Purchased Power Rate $/kWh [4]	$ #.######	$ -	N/A	N/A
13	Authorized Base Chemical Cost Rate $/kWh [4]	#.######	-	N/A	N/A
14	Authorized Base Net Margins on the Sale of Emission Allowances Rate $/kWh [4]	$ #.######	$ -	N/A	N/A
15	Total Authorized Base Cost $/kWh	#.######	$ -	N/A	N/A
16	Forward Component Rate $/kWh (L11 - L15)	#.######	$ -	N/A	N/A

Notes:

[1] Proposed levels are provided in the November 30 filing each year.

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

[3] The Projected Billed Native Load Sales of X,XXX,XXX MWh for the Current Rate represent forecast sales for XXXX as of November 30th, XXXX. They exclude sales made under the City of Williams wholesale contract through December 2017.

[4] Base Cost of Fuel and Purchased Power, Chemicals, and Net Margins on the Sale of Emission Allowances established in Decision No. XXXXX.

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/kW

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 L27													
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 and AG-X Sales (MWh) [3]														
PSA Costs														
7 Fuel and Purchased Power Costs [4,5]														
8 Off System Revenue (Credit) [6]														
9 Off System Margin Displaced by AG-X (Debit)														
10 Fossil Chemical Costs														
11 Net Margins on Sale of Emission Allowances														
12 Net PSA Costs	sum(L7 to L11)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Retail PSA Costs														
13 Fuel and Purchased Power Costs	L5 * L7													
14 Off System Revenue (Credit)	L5 * L8													
15 Off System Margin Displaced by AG-X (Debit)	L5 * L9													
16 Fossil Chemical Costs	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 Fuel and Purchased Power Recovery	L29 * L2													
20 Fossil Chemical Cost Recovery	L30 * L2													
21 Net Margins on Sale of Emission Allowances Recovery	L31 * L2													
(Over) Under Recovery From Base Rate														
22 Fuel and Purchased Power (Over) Under Recovery	(L13 + L14 + L15) - L19													
23 Fossil Chemical Costs (Over) Under Recovery	L16 - L20													
24 Net Margins on Sale of Emission Allowances (Over) Under Recovery	L17 - L21													
25 Total (Over) Under Recovery	sum(L22 to L24)	-	-	-	-	-	-	-	-	-	-	-	-	
26 Forward Component Collections [7]	- L32 * L6													
27 Tracking Account Balance	L1 + L25 + L26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
28 Annual Interest (Calculated only in January)													$ -	

29 Total Base Fuel Rate - ¢ per kWh	#.####
30 Base Chemical Rate - ¢ per kWh	#.####
31 Base Net Margin on the Sale of Emission Allowances - ¢ per kWh	#.####
32 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 schedules E-36XL and AG-X are excluded from the PSA Calculations.

[2] Includes traditional sales for resale, PacifiCorp supplemental sales, and other non-ACC jurisdictional sales. City of Williams energy sales through December 2017 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 may 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 REAC rate schedule.

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

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

[7] Generally, Line 32 * Line 6 = Line 26; however, differences may occur due to billing adjustments.

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, L27 + L28)	#,###	$ -	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 and AG-X (MWh)	##,###,###	-	N/A	N/A
5	Applicable Historical Component Rate (L3 / L4)	#.######	$ -	N/A	N/A

Notes:
[1] Proposed levels are provided in the November 30 filing 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 Nov. 30, XXXX													
2	Projected FC Tracking Account Balance at Nov. 30, XXXX													
3	True-up from November - 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 and AG-X 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 November, December and January since the actual amount was not available at the time of the projected PSA rate 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	Proposed February 1, XXXX	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 and AG-X (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.								20XX Data						20XX
		January	February	March	April	May	June	July	August	September	October	November	December	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 and AG-X 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.		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	Transfers to XXXX Transition Component Tracking Account													
4	(Over)/Under Collection													
5	Less Revenue from Applicable Forward Component Rate													
6	Annual Interest (Calculated only in January)													
7	Ending Balance (Line 1 + Line 2 + Line 3 + Line 4 - Line 5 + Line 6)													
	XXXX Historical Component Tracking Account													
8	Beginning Balance													
9	Transfers from XXXX Forward Component Tracking Account													
10	Less Revenue from Applicable Historical Component Rate													
11	Annual Interest (Calculated only in January)													
12	Ending Balance (Line 8 + Line 9 - Line 10 + Line 11)													
	XXXX Transition Component Tracking Account													
13	Beginning Balance													
14	Transfers from XXXX Forward Component Tracking Account													
15	Less Revenue from Applicable Historical Component Rate													
16	Annual Interest (Calculated only in January)													
17	Ending Balance (Line 13 + Line 14 - Line 15 + Line 16)													
18	**Combined Balance ([Line 7 + Line 12 + Line 17])**[1]													
19	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.

[1] Interest is applied on the PSA balance annually 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 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 existing short term borrowing rate, whichever is less, and will be recovered from customers over the following 12 months.

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-X 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-X 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-X 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, 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.

Appendix D

Transfer of Adjustors into Base Rates

$ in Millions

		$	%
Transmission Cost Adjustor Transfer	$	128.785	4.46%
Lost Fixed Cost Recovery Adjustor Transfer		46.054	1.59%
Environmental Improvement Surcharge Transfer		2.459	0.09%
Demand Side Management Adjustment Clause Transfer		9.993	0.35%
Renewable Energy Adjustment Clause Transfer		37.596	1.30%
Four Corners Rate Rider Transfer		57.670	2.00%
System Benefits Charge Transfer		(14.604)	-0.51%
Total Surcharge Transfer	$	267.953	9.28%

Appendix E

Tax Expense Adjustor Mechanism
Plan of Administration

Table of Contents

1. General Description

This document describes the plan for administering the Federal Income Tax Expense Adjustor Mechanism (TEAM) approved for Arizona Public Service Company (APS or Company) by the Arizona Corporation Commission (ACC or Commission) on [insert date] in Decision No. XXXXX. In the event that significant Federal income tax reform legislation is enacted and effective prior to the conclusion of APS's next General Rate Case (GRC), and such legislation materially impacts [1] the Company's annual revenue requirements; the TEAM enables the pass-through of these income tax effects to customers. The TEAM will be calculated upon the effective date of legislation, and annually on a prospective basis, and will terminate upon the conclusion of APS's next GRC.

2. Definitions

Annual Tax Expense Adjustment – The Annual Tax Expense Adjustment represents the amount to be passed through to jurisdictional retail customers in the subsequent twelve month period and is applied to customer bills via a $ per kWh adjustment.

Base Revenue Requirements Change – The change in the Company's Base Revenue Requirements as a result of any Federal income tax reform legislation will be measured as the change in:

a. The Federal Income Tax Rate-Test Year as compared to the Federal Income Tax Rate-Revised as applied to the Company's Adjusted 2015 Test Year,
b. Annual amortization of any resulting excess deferred income tax regulatory account compared to the Company's Adjusted 2015 Test Year, and;
c. Permanent income tax adjustments (such as interest expense and/or property tax expense deductibility) compared to those taken in the Company's Adjusted 2015 Test Year.

[1] "Material impacts" is defined as changing APS's revenue requirement by more than $5 million.

Federal Income Tax Rate-Revised – The Federal income tax rate that is revised as a result of any Federal income tax reform legislation enacted and effective subsequent to Decision No. XXXXX and prior to the conclusion of APS's next GRC.

Federal Income Tax Rate-Test Year – The Federal income tax rate of 35% in effect and utilized in the 2015 Test Year as approved by the Commission in Decision No. XXXXX.

Forecasted Retail kWh Sales – The forecasted calendar year energy (kWh) sales served under applicable ACC jurisdictional retail electric rate schedules. A true-up reconciliation of the forecasted data will be completed in the following year through the Balancing Account.

3. Calculation of TEAM

The Annual Tax Expense Adjustment is calculated annually and represents the amount to be passed through to jurisdictional retail customers. The adjustment is calculated based on the Company's Base Revenue Requirements Change resulting from any Federal income tax reform legislation enacted and effective subsequent to that used to set rates as approved in Decision No. XXXXX, and prior to the conclusion of APS's next GRC, as defined above.

The Annual Tax Expense Adjustment will be applied to applicable customers' total bill via a $ per kWh adjustment over the twelve month period beginning March 1 of the year following the rate filing described in Section 5 below. The TEAM $ per kWh rate is calculated by dividing the Annual Tax Expense Adjustment by the Forecasted Retail kWh Sales as determined in Schedule 1 of the filing.

4. TEAM Balancing Account

APS will maintain accounting records that accumulate the difference between the calculated Annual Tax Expense Adjustment as compared to the actual amounts applied to customers' total bills through the TEAM $ per kWh adjustment during the pass-through period (March through February). Additionally, as a result of utilizing Forecasted Retail kWh Sales, the balancing account will contain a true-up component in which estimated balances will be replaced with actual balances for the prior year filing.

The difference will be recorded to the TEAM Balancing Account each month and will accrue interest at the Company's applicable cost of short-term debt. In the event that the Annual Tax Expense Adjustment is more or less than the amount passed through to customers as of the last billing cycle of February, the over or under collection, plus interest, will be subtracted from or added to the TEAM calculation in the subsequent period.

5. Filing and Procedural Deadlines

APS will file the Annual Tax Expense Adjustment, including all Compliance Reports, with the Commission for the upcoming year by December 1st, terminating at the conclusion of APS's next GRC.

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

6. Compliance Reports

APS will provide an annual report to Staff and the Residential Utility Consumer Office detailing all calculations related to the TEAM $ per kWh adjustment. The reports will include the following Schedules 1 through 3 as attached to this document:

Schedule 1:	Current Year Annual Tax Expense Adjustment and TEAM $ per kWh Credit
Schedule 2:	Current Year TEAM Balancing Account
Schedule 3:	Adjusted 2015 Test Year SFR Schedules (as follows):

Schedule 3-A1:	Computation of Increase in Gross Revenue Requirements
Schedule 3-B1(1):	Summary of Original Cost Rate Base Elements
Schedule 3-B1(2):	Summary of RCND Rate Base Elements
Schedule 3-B2:	Original Cost Rate Base Pro Forma Adjustments
Schedule 3-B3:	RCND Rate Base Pro Forma Adjustments
Schedule 3-C1(1):	Total Company Adjusted Test Year Income Statement
Schedule 3-C1(2):	ACC Jurisdiction Adjusted Test Year Income Statement
Schedule 3-C2:	Income Statement Pro Forma Adjustments
Schedule 3-C3:	Computation of Gross Revenue Conversion Factor
Schedule 3-C2 Detail:	Detail of Pro Forma Adjustments as Shown on Schedule 3-C2

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY

Schedule 1 - TEAM

ANNUAL TAX ADJUSTMENT AND TEAM $ PER KWH CREDIT FOR [YEAR]
CURRENT YEAR ENDED 12/31/XXXX
(Thousands of Dollars)

	(A)	(B)	(C)
Line No.	Annual Tax Adjustment and TEAM $ per kWh Credit for [Year]	Reference	$
1.	Annual Tax Adjustment for [Year]	Schedule 3, A-1, Line 10	
2.	Total TEAM Balancing Account	Schedule 2, Line 4	
3.	Total Annual Tax Adjustment for [Year]	Line 1 + Line 2	
4.	Forecasted Retail Sales (kWh)	Company Records	
5.	Annual TEAM $/kWh Credit	Line 3 / Line 4	

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2 - TEAM
TEAM BALANCING ACCOUNT
CURRENT YEAR ENDED 12/31/XXXX
(Thousands of Dollars)

	(A)	(B)	(C)
Line No.	Current Year TEAM Balancing Account	Reference	$
1.	Prior Period Annual Tax Adjustment	Previous Filing Schedule 1, Line 3	
2.	True-up from January-December Estimate (a)	Update Previous Filing	
3.	Amount Applied to Customer's Bills in Prior Period (b)	Company Records	
4.	TEAM Balancing Account	Line 1 + Line 2 - Line 3	

(a) Represents any difference between estimated prior period annual tax adjustment filed December 1, 20XX and actual annual tax adjustment based on final December 31, 20XX data.

(b) Represents the amount applied to customers for the twelve (12) calendar months of 20XX. True-up is the result of utilizing forecasted jurisdictional retail sales for the period January through December since the actual sales were not available at the time of prior period filing.

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-A1 - TEAM
COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENTS
ACC JURISDICTION
ADJUSTED TEST YEAR ENDED 12/31/2015
(Thousands of Dollars)

Line No.	Description	Electric Original Cost (A)	RCND (B)	Fair Value (C)	Line No.
1.	Adjusted Rate Base				1.
2.	Adjusted Operating Income				2.
3.	Current Rate of Return				3.
4.	Required Operating Income				4.
5.	Required Rate of Return on OCRB				5.
6.	Adjusted Operating Income Deficiency on OCRB				6.
7.	Gross Revenue Conversion Factor				7.
8.	Increse/(Decrease) in Base Revenue Requirements Based on OCRB				8.
9.	After Tax Return on Fair Value Increment				9.
10.	Requested Increse/(Decrease) in Base Revenue Requirements				10.

(A) Source: Schedule 3-B1 (1) (F)
(B) Source: Schedule 3-B1 (2) (F)
(C) Calculation

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-B1 (1) - TEAM
SUMMARY OF ORIGINAL COST RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

		Original Cost						
		Total Company			ACC			
Line No.	Description	Settlement (A)	TEAM Pro Formas (B)	Adjusted Settlement (C)=(A)+(B)	Settlement (D)	TEAM Pro Formas (E)	Adjusted Settlement (F)=(D)+(E)	Line No.
1.	Gross utility plant in service							1.
2.	Less: Accumulated depreciation & amortization							2.
3.	Net utility plant in service							3.
	Deductions:							
4.	Deferred income taxes							4.
5.	Investment tax credits							5.
6.	Customer advances for construction							6.
7.	Customer deposits							7.
8.	Pension liabilities							8.
9.	Liability for asset retirements							9.
10.	Other deferred credits							10.
11.	Coal mine reclamation							11.
12.	Unrecognized tax benefits							12.
13.	Regulatory liabilities							13.
14.	Total deductions							14.
	Additions:							
15.	Regulatory assets							15.
16.	Other deferred debits							16.
17.	Decommissioning trust accounts							17.
18	OPEB assets							18
19.	Allowance for working capital							19.
20.	Total additions							20.
21.	Total rate base						(e)	21.

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-B1 (2) - TEAM
SUMMARY OF RCND RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

		RCND							
		Total Company			ACC				
Line No.	Description	Settlement (A)	TEAM Pro Formas (B)	Adjusted Settlement (C)=(A)+(B)	Settlement (D)	TEAM Pro Formas (E)	Adjusted Settlement (F)=(D)+(E)		Line No.
1.	Gross utility plant in service								1.
2.	Less: Accumulated depreciation & amortization								2.
3.	Net utility plant in service								3.
	Deductions:								
4.	Deferred income taxes								4.
5.	Investment tax credits								5.
6.	Customer advances for construction								6.
7.	Customer deposits								7.
8.	Pension liabilities								8.
9.	Liability for asset retirements								9.
10.	Other deferred credits								10.
11.	Coal mine reclamation								11.
12.	Unrecognized tax benefits								12.
13.	Regulatory liabilities								13.
14.	Total deductions								14.
	Additions:								
15.	Regulatory assets								15.
16.	Other deferred debits								16.
17.	Decommissioning trust accounts								17.
18	OPEB assets								18
19.	Allowance for working capital								19.
20.	Total additions								20.
21.	Total rate base							(e)	21.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-B2 - TEAM
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

Line No.	Description	Settlement Test Year 12/31/2015 Total Co. (A)	ACC (B)	TEAM ADIT & Regulatory Account Impact Total Co. (C)	ACC (D)	Adjusted Settlement at End of Test Year 12/31/2015 Total Co. (E)=(A)+(C)	ACC (F)=(B)+(D)
1.	Gross Utility Plant in Service						
2.	Less: Accumulated Depreciation & Amort.						
3	Net Utility Plant in Service						
4.	Less: Total Deductions						
5.	Total Additions						
6.	Total Rate Base						

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-B3 - TEAM
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

		Settlement Test Year 12/31/2015		TEAM ADIT & Regulatory Account Impact		Adjusted Settlement at End of Test Year 12/31/2015	
Line No.	Description	Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)=(A)+(C)	ACC (F)=(B)+(D)
1.	Gross Utility Plant in Service						
2.	Less: Accumulated Depreciation & Amort.						
3	Net Utility Plant in Service						
4.	Less: Total Deductions						
5.	Total Additions						
6.	Total Rate Base						

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-C1 (1) - TEAM
TOTAL COMPANY
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

		Total Company			
Line No.	Description	Settlement Test Year Ended 12/31/2015 (A)	TEAM Proforma Adjustments (B)	Settlement Results After Proforma Adjustments (C)=(A)+(B)	Line No.
	Electric Operating Revenues				
1.	Revenues from Base Rates	[illegible]	[illegible]	[illegible]	1.
2.	Revenues from Surcharges	[illegible]	[illegible]	[illegible]	2.
3.	Other Electric Revenues	[illegible]	[illegible]	[illegible]	3.
4.	Total	[illegible]	[illegible]	[illegible]	4.
	Operating expenses:				
5.	Electric fuel and purchased power	[illegible]	[illegible]	[illegible]	5.
6.	Operations and maintenance excluding fuel expenses	[illegible]	[illegible]	[illegible]	6.
7.	Depreciation and amortization	[illegible]	[illegible]	[illegible]	7.
8.	Income taxes	[illegible]	[illegible]	[illegible]	8.
9.	Other taxes	[illegible]	[illegible]	[illegible]	9.
10.	Total	[illegible]	[illegible]	[illegible]	10.
11.	Operating income	[illegible]	[illegible]	[illegible]	11.
	Other income (deductions):				
12.	Income taxes	[illegible]	[illegible]	[illegible]	12.
13.	Allowance for equity funds used during construction	[illegible]	[illegible]	[illegible]	13.
14.	Other income	[illegible]	[illegible]	[illegible]	14.
15.	Other expense	[illegible]	[illegible]	[illegible]	15.
16.	Total	[illegible]	[illegible]	[illegible]	16.
17.	Income before interest deductions	[illegible]	[illegible]	[illegible]	17.
	Interest deductions:				
18.	Interest on long-term debt	[illegible]	[illegible]	[illegible]	18.
19.	Interest on short-term borrowings	[illegible]	[illegible]	[illegible]	19.
20.	Debt discount, premium and expense	[illegible]	[illegible]	[illegible]	20.
21.	Allowance for borrowed funds used during construction	[illegible]	[illegible]	[illegible]	21.
22.	Total	[illegible]	[illegible]	[illegible]	22.
23.	Net income	[illegible]	[illegible]	[illegible]	23.

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-C1 (2) - TEAM
ACC JURISDICTION
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

		ACC Jurisdiction			
Line No.	Description	Settlement Test Year Ended 12/31/2015 (A)	TEAM Proforma Adjustments (B)	Settlement Results After Proforma Adjustments (C)=(A)+(B)	Line No.
	Electric Operating Revenues				
1.	Revenues from Base Rates				1.
2.	Revenues from Surcharges				2.
3.	Other Electric Revenues				3.
4.	Total				4.
	Operating expenses:				
5.	Electric fuel and purchased power				5.
6.	Operations and maintenance excluding fuel expenses				6.
7.	Depreciation and amortization				7.
8.	Income taxes				8.
9.	Other taxes				9.
10.	Total				10.
11.	Operating income				11.
	Other income (deductions):				
12.	Income taxes				12.
13.	Allowance for equity funds used during construction				13.
14.	Other income				14.
15.	Other expense				15.
16.	Total				16.
17.	Income before interest deductions				17.
	Interest deductions:				
18.	Interest on long-term debt				18.
19.	Interest on short-term borrowings				19.
20.	Debt discount, premium and expense				20.
21.	Allowance for borrowed funds used during construction				21.
22.	Total				22.
23.	Net income				23.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-C2 - TEAM
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

		Normalize Income Tax Expense/Interest Synchronization		Interest Expense on Rate Base Impact		Total Income Tax Income Statement Adjustments	
Line No.	Description	Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)=(A)+(C)	ACC (F)=(B)+(D)
	Electric Operating Revenues						
1.	Revenues from Base Rates						
2.	Revenues from Surcharges						
3.	Other Electric Revenues						
4.	Total Electric Operating Revenues						
5.	Electric Fuel and Purchased Power Costs						
6.	Oper Rev Less Fuel & Purch Pwr Costs						
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense						
8.	Maintenance						
9.	Subtotal						
10.	Depreciation and Amortization						
11.	Amortization of Gain						
12.	Administrative and General						
13.	Other Taxes						
14.	Total Other Operating Expense						
15.	Operating Income Before Income Tax						
16.	Interest Expense						
17.	Taxable Income						
18.	Current Income Tax Rate -						
19.	Operating Income (line 15 minus line 18)						

(A) Source: Schedule 3-C2 Workpaper Detail

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-C3 - TEAM
COMPUTATION OF GROSS REVENUE CONVERSION FACTOR
TEST YEAR ENDED 12/31/2015

Line No.	Description	Settlement Percentage of Incremental Gross Revenues (A)	TEAM Pro Forma Percentage of Incremental Gross Revenues (B)	Line No.
1	Gross Revenue			1
2	Less uncollectible revenue			2
3	Taxable revenue as a percent			3
4	Federal Income Taxes			4
5	State Income Taxes Net of Federal Tax Benefit			5
6	Total Tax Percentage			6
7	Taxable Revenue - Tax Percentage			7
8	1/Operating Income % = Gross Revenue Conversion Factor			8

'Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-C2 Workpaper Detail - TEAM
TOTAL COMPANY
DETAIL OF PRO FORMA ADJUSTMENTS AS SHOWN ON SCHEDULE 3-C2
TEST YEAR ENDED 12/31/15
(Thousands of Dollars)

Line No.	Description	TEAM Pro Forma (A)	Settlement Test Year (B)
1.	**Pre-Tax Operating Income (SFR Schedule C-1, line 11 + line 8)**		
2.	**Allocated Interest Expense (unadjusted rate base SFR B-1 line 21 * cost of debt SFR D-1 line 1)**		
3.	**Adjusted Operating Income**		
4.	**Gross Income Tax at 38.10% (Settlement Test Year) and XX.XX% (TEAM Pro Forma)**		
5.	**Tax Effected Permanent Items**		
6.	Meals and Entertainment		
7.	Non-Deductible Compensation		
8.	Research & Development Credit		
9.	Amortization of OPEB Subsidy PPACA		
10.	Other Federal Tax Credits (Net)		
11.	Amortization of FAS109 Liability		
12.	Arizona Tax Credits		
13.	Depreciation on AFUDC		
14.	Amortization of Permanent Plant Basis Differences		
15a.	New Permanent Income Tax Adjustment [1]		
15b.	New Permanent Income Tax Adjustment [2]		
15c.	Other New Permanent Income Tax Adjustment (Add row as necessary)		
16.	Out of Period Adjustments		
	Rounding		
17.	**Net On-Going Tax Expense**	-	-
18.	**Settlement Test Year Tax Expense (SFR Schedule C-1, line 8)**	-	
19.	**TEAM Pro Forma Adjustment**	$ -	

(A) Source: 2015 Test Year Normalize Income Tax Expense/Interest Synchronization pro forma, adjusted for tax reform impacts

Appendix F

aps

RATE SCHEDULE R-XS
EXTRA SMALL RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available to full requirements residential Customers with an average monthly energy usage of 600 kilowatt-hours (kWh) or less who do not have an on-site distributed generation system. For new customers, initial annual average monthly energy usage will be based on historical energy consumption at the Customer's site. Annual reassignment will begin with January 2019 bills.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. Energy charges are based on how much energy (kWh) is used during the month. This rate does not have time-of-use charges, seasonal charges, or a demand charge.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	$0.329	per day
Energy Charge	$0.11672	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$0.072	per day
Metering Charge	$0.104	per day
Meter Reading Charge	$0.072	per day
Billing Charge	$0.081	per day

Energy Charge Components

System Benefits Charge:	$0.00276	per kWh
Transmission Charge	$0.01097	per kWh
Delivery Charge	$0.03112	per kWh
Generation Charge	$0.07187	per kWh

aps

RATE SCHEDULE R-XS
EXTRA SMALL RESIDENTIAL SERVICE

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedules EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
8. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown below.

RATE SCHEDULE R-BASIC
SMALL RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available to residential Customers with an annual average monthly energy usage of more than 600 but less than 1,000 kilowatt-hours (kWh) who do not have an on-site distributed generation system. For new customers, initial annual average monthly energy usage will be based on historical energy consumption at the Customer's site. Annual reassignment will begin with January 2019 bills.

Starting May 1, 2018, first-time Customers are not eligible for this rate for a period of ninety (90) days from the date service begins. After this initial 90-day period, qualifying Customers may move to this rate at any time but must remain on this R-Basic rate schedule for at least twelve (12) consecutive months before moving to another residential rate schedule for which the Customer may qualify.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. Energy charges are based on how much energy (kWh) is used during the month. This rate does not vary by time-of-use, season, or demand (how much energy is used at one time).

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	$0.493	per day
Energy Charge	$0.12393	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$0.125	per day
Metering Charge	$0.215	per day
Meter Reading Charge	$0.072	per day
Billing Charge	$0.081	per day

RATE SCHEDULE R-BASIC
SMALL RESIDENTIAL SERVICE

Energy Charge Components

System Benefits Charge	$0.00276	per kWh
Transmission Charge	$0.01097	per kWh
Delivery Charge	$0.03112	per kWh
Generation Charge	$0.07908	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
8. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

RATE SCHEDULE R-BASIC
SMALL RESIDENTIAL SERVICE

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

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RATE SCHEDULE R-BASIC L
LARGE RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available to residential Customers with an annual average monthly energy usage of 1,000 kilowatt-hours (kWh) or more who do not have an on-site distributed generation system. For new customers, initial annual average monthly energy usage will be based on historical energy consumption at the Customer's site.

Eligibility for this rate schedule will be frozen on May 1, 2018. After this date, Customers may not elect to take service under this rate, whether they are new or moving from a different rate. Charges on this schedule may change.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. Energy charges are based on how much energy (kWh) is used during the month. This rate does not vary by time-of-use, season, or demand (how much energy is used at one time).

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	$0.658	per day
Energy Charge	$0.13412	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$0.290	per day
Metering Charge	$0.215	per day
Meter Reading Charge	$0.072	per day
Billing Charge	$0.081	per day

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RATE SCHEDULE R-BASIC L
LARGE RESIDENTIAL SERVICE

Energy Charge Components

System Benefits Charge	$0.00276	per kWh
Transmission Charge	$0.01097	per kWh
Delivery Charge	$0.03112	per kWh
Generation Charge	$0.08927	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
8. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

aps

RATE SCHEDULE R-BASIC L
LARGE RESIDENTIAL SERVICE

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

aps

RATE SCHEDULE TOU-E
RESIDENTIAL TIME-OF-USE SERVICE

AVAILABILITY

This rate schedule is available to all residential Customers, including Partial Requirements Customers with an on-site distributed generation system.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). This rate does not include a demand charge.

TIME PERIODS

The On-Peak time period for residential rate schedules is 3 p.m. to 8 p.m. Monday through Friday year round. This rate also has a Super Off-Peak period, which is 10 a.m. to 3 p.m. Monday through Friday during the winter billing cycles of November through April. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Independence Day - July 4*
- Labor Day - First Monday in September
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Day - December 25*

*If these holidays fall on a Saturday, the preceding Friday will be Off-peak. If they fall on a Sunday, the following Monday will be Off-Peak.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	$0.427	per day

aps

RATE SCHEDULE TOU-E
RESIDENTIAL TIME-OF-USE SERVICE

Bundled Charges continued:

	Summer	Winter	
On-Peak Energy Charge	$0.24314	$0.23068	per kWh
Off-Peak Energy Charge	$0.10873	$0.10873	per kWh
Super Off-Peak Energy Charge		$0.03200	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$0.073	per day
Metering Charge	$0.201	per day
Meter Reading Charge	$0.072	per day
Billing Charge	$0.081	per day

Energy Charge Components

System Benefits Charge	$0.00276	per kWh
Transmission Charge	$0.01097	per kWh

	Summer	Winter	
Delivery Charge	$0.03112	$0.01105	per kWh
Generation On-Peak Charge	$0.19829	$0.18583	per kWh
Generation Off-Peak Charge	$0.06388	$0.06388	per kWh
Generation Super Off-Peak Charge		$0.00722	per kWh

CHARGE FOR ON-SITE DISTRIBUTED GENERATION CUSTOMERS

The monthly bill for Customers on this rate schedule who have an on-site distributed generation system will also include a Grid Access Charge. This charge will apply to the nameplate kW-dc power rating of the Customer's distributed generation facility:

Grid Access Charge	$0.93	per kW-dc of generation

RATE SCHEDULE TOU-E
RESIDENTIAL TIME-OF-USE SERVICE

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
8. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP (RES)	Critical Peak Pricing (Residential)
EPR-2	Partial Requirements
EPR-6	Partial Requirements – Net Metering (Residential Non-Solar)
RCP	Resource Comparison Proxy
E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

aps

RATE SCHEDULE TOU-E
RESIDENTIAL TIME-OF-USE SERVICE

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric servies from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Acounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing servies are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

aps

RATE SCHEDULE R-2
RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available to all residential Customers, including Partial Requirements Customers with an on-site distributed generation system.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a one hour On-Peak period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). The demand charge will not vary by season.

TIME PERIODS

The On-Peak time period for residential rate schedules is 3 p.m. to 8 p.m. Monday through Friday year round. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Independence Day - July 4*
- Labor Day - First Monday in September
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Day - December 25*

*If these holidays fall on a Saturday, the preceding Friday will be Off-peak. If they fall on a Sunday, the following Monday will be Off-Peak.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

CHARGES

This monthly bill will consist of the following charges, plus adjustments:

aps

RATE SCHEDULE R-2
RESIDENTIAL SERVICE

Bundled Charges

Basic Service Charge:	$0.427	per day

	Summer	Winter	
On-Peak Demand Charge:	$8.40	$8.40	per kW
On-Peak Energy Charge:	$0.13160	$0.11017	per kWh
Off-Peak Energy Charge:	$0.07798	$0.07798	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge:	$0.073	per day
Metering Charge	$0.201	per day
Meter Reading Charge	$0.072	per day
Billing Charge	$0.081	per day

Demand Charge Components

Delivery On-Peak kW Charge	$4.000	per kW
Generation On-Peak kW Charge	$4.400	per kW

Energy Charge Components

System Benefits Charge:	$0.00276	per kWh
Transmission Charge:	$0.01097	per kWh

	Summer	Winter	
Delivery Charge for all kWh:	$0.01105	$0.01105	per kWh
Generation On-Peak kWh Charge:	$0.10682	$0.08539	per kWh
Generation Off-Peak kWh Charge:	$0.05320	$0.05320	per kWh

RATE SCHEDULE R-2
RESIDENTIAL SERVICE

The kW used to determine the demand charge above will be the Customer's highest amount of demand (kW) averaged in a one-hour On-Peak period for the billing month.

For full requirements Customers, billing demands are limited to a kW no higher than that which would result in a 15% load factor, based on the Customer's kWh usage during the month. This limitation is not available to partial requirements Customers.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
8. Direct Access customers returning to Standard Offer service may be subject to Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-RES	Critical Peak Pricing (Residential)
E-3	Limited income discount
E-4	Limited income medical discount
EPR-2	Partial Requirements
EPR-6	Partial Requirements - Net Metering (Residential Non-Solar)
RCP	Resource Comparison Proxy
GPS-1, GPS-2, GPS-3	Green Power

aps

RATE SCHEDULE R-2
RESIDENTIAL SERVICE

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

5. Load factor is a relationship between how much energy (kWh) a Customer uses over a period of time and how much demand (kW) is used at one time during that same period, expressed in percentage. The Company will calculate the Customer's load factor for purposes of the billing demand limitation described earlier using the following formula:

   Monthly Load Factor = Billed kWh/(Billed kW * Billing Days * 24 hours)

aps

RATE SCHEDULE R-3
RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available to all residential Customers, including Partial Requirements Customers with an on-site distributed generation system.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a one hour On-Peak period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). The demand charge also varies by season.

TIME PERIODS

The On-Peak time period for residential rate schedules is 3 p.m. to 8 p.m. Monday through Friday. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Independence Day - July 4*
- Labor Day - First Monday in September
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Day - December 25*

*If these holidays fall on a Saturday, the preceding Friday will be Off-peak. If they fall on a Sunday, the following Monday will be Off-Peak.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

CHARGES

This monthly bill will consist of the following charges, plus adjustments:

aps

RATE SCHEDULE R-3
RESIDENTIAL SERVICE

Bundled Charges

Basic Service Charge:	$0.427	per day

	Summer	Winter	
On-Peak Demand Charge:	$17.438	$12.239	per kW
On-Peak Energy Charge:	$0.08683	$0.06376	per kWh
Off-Peak Energy Charge:	$0.05230	$0.05230	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge:	$0.073	per day
Metering Charge	$0.201	per day
Meter Reading Charge	$0.072	per day
Billing Charge	$0.081	per day

Demand Charge Components

	Summer	Winter	
Delivery On-Peak kW Charge	$4.000	$4.000	per kW
Generation On-Peak kW Charge	$13.438	$8.239	per kW

Energy Charge Components

System Benefits Charge:	$0.00276	per kWh
Transmission Charge:	$0.01097	per kWh

	Summer	Winter	
Delivery Charge for all kWh:	$0.01105	$0.01105	per kWh
Generation On-Peak kWh Charge:	$0.06205	$0.03898	per kWh
Generation Off-Peak kWh Charge:	$0.02752	$0.02752	per kWh

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RATE SCHEDULE R-3
RESIDENTIAL SERVICE

The kW used to determine the demand charge above will be the Customer's highest amount of demand (kW) averaged in a one-hour On-Peak period for the billing month..

For full requirements Customers, billing demands are limited to a kW no higher than that which would result in a 15% load factor, based on the Customer's kWh usage during the month. This limitation is not available to partial requirements Customers.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Charge TEAM.
8. Direct Access customers returning to Standard Offer service may be subject to Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CCP- RES	Critical Peak Pricing (Residential)
EPR-2	Partial requirements
EPR-6	Partial Requirements - Net Metering (Residential Non-Solar)
RCP	Resource Comparison Proxy
E-3	Limited income discount
E-4	Limited income medical discount

RATE SCHEDULE R-3
RESIDENTIAL SERVICE

GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the Partial Requirements Service rate riders.

2. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

3. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

4. Electric service is supplied at a single point of delivery and measured through a single meter.

5. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

6. Load factor is a relationship between how much energy (kWh) a Customer uses over a period of time and how much demand (kW) is used at one time during that same period, expressed in percentage. The Company will calculate the Customer's load factor for purposes of the billing demand limitation described earlier using the following formula:

   Monthly Load Factor = Billed kWh/(Billed kW * Billing Days * 24 hours)

RATE SCHEDULE R-TECH
RESIDENTIAL SERVICE
PILOT TECHNOLOGY RATE

AVAILABILITY

This rate schedule is available to residential Customers with the following:

1. Two or more qualifying primary on-site technologies were purchased within 90 days of the customer enrolling in the rate; or
2. One qualifying primary on-site technology was purchased within 90 days of the customer enrolling in the rate and two or more qualifying secondary on-site technologies.

This is a pilot rate schedule. This means this rate is associated with a specific program approved by the Arizona Corporation Commission, and is available only to those customers eligible to participate in the program. The R-Tech pilot program will test the ability and desire of participating residential customers to reduce On-Peak energy and demand usage through multiple behind-the-meter technologies.

Qualifying technologies for the R-Tech pilot program are as follows:

1. Primary technologies:
   a. A rooftop solar photovoltaic system. The size of the system cannot be smaller than 2 kW-dc. For systems over 10 kW-dc, the facility's nameplate capacity cannot be larger than 150% of the customer's maximum one-hour peak demand measured in AC over the prior twelve (12) months. (For example, if the customer's peak is 8kW-ac, the maximum system size that could be installed would be 12kW-dc).
   b. A chemical storage system. The size of the system cannot be smaller than 4 kWh. There is no maximum limitation for this technology.
   c. An electric vehicle. There are no limitations for this technology.

2. Secondary technologies:
   a. A device with a variable speed motor (such as a variable speed pool pump or a variable speed Heating, Ventilating, and Air Conditioning (HVAC) system).
   b. A grid-interactive water heating system.
   c. A smart thermostat.
   d. An automated load controller.

This rate schedule is initially limited to a maximum of 10,000 residential customers as outlined in Decision No. xxxxx.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the amount of demand (kW) averaged in a one hour period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). The demand charge will also vary by season (summer or winter) and time of day (On-Peak or Off-Peak).

TIME PERIODS

The On-Peak time period for residential rate schedules is 3 p.m. to 8 p.m. Monday through Friday. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Independence Day - July 4*
- Labor Day - First Monday in September
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Day - December 25*

*If these holidays fall on a Saturday, the preceding Friday will be Off-peak. If they fall on a Sunday, the following Monday will be Off-Peak.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

CHARGES

This monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	$0.493	per day

		Summer	Winter	
On-Peak Demand Charge		$20.25	$14.25	per kW
Off-Peak Demand Charge	First 5 kW	$0.00	$0.00	per kW
	All remaining kW	$6.50	$6.50	

aps

RATE SCHEDULE R-TECH
RESIDENTIAL SERVICE
PILOT TECHNOLOGY RATE

On-Peak Energy Charge	$0.05750	$0.04750	per kWh
Off-Peak Energy Charge	$0.04750	$0.04750	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$0.125	per day
Metering Charge	$0.215	per day
Meter Reading Charge	$0.072	per day
Billing Charge	$0.081	per day

Demand Charge Components

		Summer	Winter	
On-Peak Generation Charge		$13.750	$7.750	per kW
Off-Peak Generation Charge	First 5 kW	$0.000	$0.000	per kW
	All remaining kW	$1.000	$1.000	per kW
On-Peak Delivery Charge		$6.500	$6.500	per kW
Off-Peak Delivery Charge	First 5 kW	$0.000	$0.000	per kW
	All remaining kW	$5.500	$5.500	

Energy Charge Components

System Benefits Charge	$0.00276	per kWh
Transmission Charge	$0.01097	per kWh
Delivery Charge for all kWh	$0.00210	per kWh

	Summer	Winter	
Generation On-Peak kWh Charge	$0.04167	$0.03167	per kWh
Generation Off-Peak kWh Charge	$0.03167	$0.03167	per kWh

The kW used to determine the On-Peak demand charge above will be the Customer's highest amount of demand (kW) averaged in a one hour On-Peak period for the month.

aps

RATE SCHEDULE R-TECH
RESIDENTIAL SERVICE
PILOT TECHNOLOGY RATE

The kW used to determine the Off-Peak demand charge above will be the Customer's highest amount of demand (kW) averaged in a one hour Off-Peak period during the weekday (Monday through Friday), excluding holidays that may fall on a weekday.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
8. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

RCP	Resource Comparison Proxy
EPR-2	Partial Requirements
EPR-6	Partial Requirements – Net Metering (Residential Non-Solar)
E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. This pilot rate schedule requires the Customer to have a standard AMI meter in place.

RATE SCHEDULE R-TECH
RESIDENTIAL SERVICE
PILOT TECHNOLOGY RATE

2. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the Partial Requirements Service rate riders.

3. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

4. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

5. Electric service is supplied at a single point of delivery and measured through a single meter.

6. Direct Access customers are not eligible for this rate schedule.

Appendix G

Settlement Rate Summary for Residential Rates

	TOU-E	R-2	R-3
Bundled Rates			
Summer			
BSC $/day	0.427	0.427	0.427
On kW		8.400	17.438
On-peak kWh	0.24314	0.13160	0.08683
Off-peak kWh	0.10873	0.07798	0.05230
Winter			
BSC $/day	0.427	0.427	0.427
On kW		8.400	12.239
On-peak kWh	0.23068	0.11017	0.06376
Off-peak kWh	0.10873	0.07798	0.05230
Super Off-peak kWh	0.03200		
Unbundled Rates			
Generation - Summer			
kWh - on	0.19829	0.10682	0.06205
kWh - off	0.06388	0.05320	0.02752
kW - on		4.400	13.438
Generation - Winter			
kWh - on	0.18583	0.08539	0.03898
kWh - off	0.06388	0.05320	0.02752
kWh - super off	0.00722		
kW - on		4.400	8.239
Transmission - kWh	0.01097	0.01097	0.01097
Delivery - Summer			
kWh	0.03112	0.01105	0.01105
kW		4.000	4.000
Delivery - Winter			
kWh	0.01105	0.01105	0.01105
kW		4.000	4.000
System Benefits - kWh	0.00276	0.00276	0.00276
BSC $/day			
Customer accounts	0.073	0.073	0.073
Metering	0.201	0.201	0.201
Billing	0.081	0.081	0.081
Meter reading	0.072	0.072	0.072

	R-TECH
Bundled Rates	
Summer	
BSC $/day	0.493
On kW	20.250
Off kW	6.500
On-peak kWh	0.05750
Off-peak kWh	0.04750
Winter	
BSC $/day	0.493
On kW	14.250
Off kW	6.500
On-peak kWh	0.04750
Off-peak kWh	0.04750
Super Off-peak kWh	
Unbundled Rates	
Generation - Summer	
kWh - on	0.04167
kWh - off	0.03167
kW - on	13.750
kW - off	1.000
Generation - Winter	
kWh - on	0.03167
kWh - off	0.03167
kW - on	7.750
kW - off	1.000
Transmission - kWh	0.01097
Delivery	
kWh	0.00210
kW - on	6.500
kW - off	5.500
System Benefits - kWh	0.00276
BCS $-Day	
Customer accounts	0.125
Metering	0.215
Billing	0.081
Meter reading	0.072

Settlement Rate Summary for Residential Rates

	R-XS	R-BASIC	R-BASIC L
Bundled Rates			
Summer & Winter			
BSC $/day	0.329	0.493	0.658
kWh	0.11672	0.12393	0.13412
Unbundled Rates			
Generation kWh	0.07187	0.07908	0.08927
Transmission - kWh	0.01097	0.01097	0.01097
Delivery kWh	0.03112	0.03112	0.03112
System Benefits - kWh	0.00276	0.00276	0.00276
BSC $/day			
Customer accounts	0.072	0.125	0.290
Metering	0.104	0.215	0.215
Billing	0.081	0.081	0.081
Meter reading	0.072	0.072	0.072

Transition E-12 Bundled Rates	
Summer	
BSC $/day	0.330
0-400 kWh	0.11161
401-800 kWh	0.15920
801-3000 kWh	0.18627
< 3000 kWh	0.19863
Winter	
BSC $/day	0.330
All kWh	0.10851
Unbundled Rates	
Generation - Summer	
1st 400 kWh	0.06676
Next 400 kWh	0.11435
Next 2200 kWh	0.14142
All other kWh	0.15378
Generation Winter - kWh	0.06366
Transmission - kWh	0.01097
Delivery kWh	0.03112
System Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.073
Metering	0.104
Billing	0.081
Meter reading	0.072

Settlement Rate Summary for Residential Rates

Transition TOU-E Bundled Rates	ET-1	ET-2
Summer		
BSC $/day	0.643	0.643
On-Peak kWh	0.20697	0.28205
Off-Peak kWh	0.06697	0.07105
Winter		
BSC $/day	0.643	0.643
On-Peak kWh	0.16794	0.22900
Off-Peak kWh	0.06397	0.07005
Unbundled Rates		
Generation - Summer		
On-Peak kWh	0.16211	0.23715
Off-Peak kWh	0.02211	0.02615
Generation - Winter		
On-Peak kWh	0.12308	0.18410
Off-Peak kWh	0.01911	0.02515
Transmission - kWh	0.01097	0.01097
Delivery kWh	0.03113	0.03117
System Benefits - kWh	0.00276	0.00276
BSC $/day		
Customer accounts	0.27500	0.27500
Metering	0.21500	0.21500
Billing	0.08100	0.08100
Meter reading	0.07200	0.07200

Transition TOU-D Bundled Rates	ECT-1R	ECT-2
Summer		
BSC $/day	0.643	0.643
kW	15.69	15.61
On-Peak kWh	0.08490	0.10256
Off-Peak kWh	0.04730	0.05109
Winter		
BSC $/day	0.643	0.643
kW	10.89	10.76
On-Peak kWh	0.06470	0.06647
Off-Peak kWh	0.04594	0.04750
Unbundled Rates		
Generation - Summer		
On-Peak kWh	0.05332	0.07264
Off-Peak kWh	0.01572	0.02117
kW	11.17500	10.40900
Generation - Winter		
On-Peak kWh	0.03128	0.03435
Off-Peak kWh	0.01252	0.01538
kW	8.22200	7.98000
Transmission - kWh	0.01097	0.01097
Delivery		
Summer kWh	0.01785	0.01619
Summer kW	4.51600	5.20500
Winter kWh	0.01969	0.01839
Winter kW	2.66300	2.77600
System Benefits - kWh	0.00276	0.00276
BSC $/day		
Customer accounts	0.27500	0.27500
Metering	0.21500	0.21500
Billing	0.08100	0.08100
Meter reading	0.07200	0.07200
Total Non-timed kWh		
Summer kWh	0.03156	0.02992
Winter kWh	0.03342	0.03212

Settlement Rate Summary for Residential Rates

Solar Legacy E-12 Bundled Rates	
Summer	
BSC $/day	0.330
0-400 kWh	0.11161
401-800 kWh	0.15920
801-3000 kWh	0.18627
< 3000 kWh	0.19863
Winter	
BSC $/day	0.330
All kWh	0.10851
Unbundled Rates	
Generation - Summer	
1st 400 kWh	0.06676
Next 400 kWh	0.11435
Next 2200 kWh	0.14142
All other kWh	0.15378
Generation Winter - kWh	0.06366
Transmission - kWh	0.01097
Delivery kWh	0.03112
System Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.07300
Metering	0.10400
Billing	0.08100
Meter reading	0.07200

Solar Legacy TOU-E Bundled Rates	ET-1	ET-2
Summer		
BSC $/day	0.643	0.643
On-Peak kWh	0.20697	0.28205
Off-Peak kWh	0.06697	0.07105
Winter		
BSC $/day	0.643	0.643
On-Peak kWh	0.16794	0.22900
Off-Peak kWh	0.06397	0.07005
Unbundled Rates		
Generation - Summer		
On-Peak kWh	0.16211	0.23715
Off-Peak kWh	0.02211	0.02615
Generation - Winter		
On-Peak kWh	0.12308	0.18410
Off-Peak kWh	0.01911	0.02515
Transmission - kWh	0.01097	0.01097
Delivery kWh	0.03113	0.03117
System Benefits - kWh	0.00276	0.00276
BSC $/day		
Customer accounts	0.27500	0.27500
Metering	0.21500	0.21500
Billing	0.08100	0.08100
Meter reading	0.07200	0.07200
Total untimed kWh	0.04486	0.04490

Settlement Rate Summary for Residential Rates

Solar Legacy TOU-D Bundled Rates	ECT-1R	ECT-2
Summer		
BSC $/day	0.643	0.643
kW	15.69	15.61
On-Peak kWh	0.08490	0.10256
Off-Peak kWh	0.04730	0.05109
Winter		
BSC $/day	0.643	0.643
kW	10.89	10.76
On-Peak kWh	0.06470	0.06647
Off-Peak kWh	0.04594	0.04750
Unbundled Rates		
Generation - Summer		
On-Peak kWh	0.05332	0.07264
Off-Peak kWh	0.01572	0.02117
kW	11.17500	10.40900
Generation - Winter		
On-Peak kWh	0.03128	0.03435
Off-Peak kWh	0.01252	0.01538
kW	8.22200	7.98000
Transmission - kWh	0.01097	0.01097
Delivery		
Summer kWh	0.01785	0.01619
Summer kW	4.51600	5.20500
Winter kWh	0.01969	0.01839
Winter kW	2.66300	2.77600
System Benefits - kWh	0.00276	0.00276
BSC $/day		
Customer accounts	0.27500	0.27500
Metering	0.21500	0.21500
Billing	0.08100	0.08100
Meter reading	0.07200	0.07200
Total Non-timed kWh		
Summer kWh	0.03156	0.02992
Winter kWh	0.03342	0.03212

Settlement Rate Summary for General Service Rates

E-20 House of Worship
Bundled Rates

Summer	
BSC $/day	2.020
kW on-peak	3.800
kW excess	2.400
On-peak kWh	0.15458
Off-peak kWh	0.07519
Winter	
BSC $/day	2.020
kW on-peak	3.800
kW excess	2.400
On-peak kWh	0.13626
Off-peak kWh	0.06748
Minimum	
BSC(Days)	2.020
KW	3.101
Unbundled Rates	
Generation	
kWh summer - on	0.11390
kWh summer - off	0.03451
kWh winter - on	0.09558
kWh winter - off	0.02680
Delivery kW - on	0.930
Delivery kW - excess	2.400
Delivery kWh	0.03792
Transmission - kW - on	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	
Metering - instrument rated	1.477
Metering - primary	
Metering - Transmission	

E-30 Non-Metered
Bundled Rates

Summer	
BSC $/day	0.405
kWh	0.13791
Winter	
BSC $/day	0.405
kWh	0.12443
Unbundled Rates	
Generation - Summer	
kWh	0.07972
Generation - Winter	
kWh	0.06624
Transmission	0.00794
Delivery	0.04749
Systems Benefits	0.00276
BSC $/day	
Customer accounts	0.375
Billing	0.030

E-32 XS D
Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Summer	
kW Secondary	6.900
kW Primary	4.300
kWh secondary	0.10549
kWh- primary	0.09951
Winter	
kW Secondary	6.90
kW Primary	4.30
kWh secondary	0.08631
kWh- primary	0.08051
Unbundled Rates	
Generation	
Summer kWh	0.08081
Winter kWh	0.06181
Delivery - Summer	
kWh secondary	0.01398
kWh- primary	0.00800
kW secondary	6.900
kW primary	4.300
Delivery - Winter	
kWh secondary	0.01380
kWh- primary	0.00800
kW secondary	6.900
kW primary	4.300
Transmission - kWh	0.00794
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
kWh Schools discount	-0.0024

Settlement Rate Summary for General Service Rates

E-32 XS
Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Summer	
kWh secondary tier 1	0.13514
kWh secondary tier 2	0.07612
kWh primary tier 1	0.13195
kWh primary tier 2	0.07264
Winter	
kWh secondary tier 1	0.11797
kWh secondary tier 2	0.05864
kWh primary tier 1	0.11476
kWh primary tier 2	0.05545
Unbundled Rates	
Generation - Summer	
kWh tier 1	0.08390
kWh tier 2	0.05240
Generation - Winter	
kWh tier 1	0.06680
kWh tier 2	0.03529
Delivery - Summer	
kWh tier 1 - secondary	0.04054
kWh tier 2 - secondary	0.01302
kWh tier 1 - primary	0.03735
kWh tier 2 - primary	0.00954
Delivery - Winter	
kWh tier 1 - secondary	0.04047
kWh tier 2 - secondary	0.01265
kWh tier 1 - primary	0.03726
kWh tier 2 - primary	0.00946
Transmission - kWh	0.00794
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404

Solar billing determinants
E-32 XS
Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Summer	
kWh secondary tier 1	0.13514
kWh secondary tier 2	0.10762
kWh primary tier 1	0.13195
kWh primary tier 2	0.10414
Winter	
kWh secondary tier 1	0.11797
kWh secondary tier 2	0.09015
kWh primary tier 1	0.11476
kWh primary tier 2	0.08696
Unbundled Rates	
Generation - Summer	
kWh tier 1	0.08390
kWh tier 2	0.08390
Generation - Winter	
kWh tier 1	0.06680
kWh tier 2	0.06680
Delivery - Summer	
kWh tier 1 - secondary	0.04054
kWh tier 2 - secondary	0.01302
kWh tier 1 - primary	0.03735
kWh tier 2 - primary	0.00954
Delivery - Winter	
kWh tier 1 - secondary	0.04047
kWh tier 2 - secondary	0.01265
kWh tier 1 - primary	0.03726
kWh tier 2 - primary	0.00946
Transmission - kWh	0.00794
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404

E-32 S
Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Demand	
kW tier 1 - secondary	11.360
kW tier 2 - secondary	6.608
kW tier 1 - primary	10.627
kW tier 2 - primary	5.875
Summer	
kWh secondary tier 1	0.10828
kWh secondary tier 2	0.06535
Winter	
kWh secondary tier 1	0.09126
kWh secondary tier 2	0.04836
Unbundled Rates	
Generation - Summer	
kWh tier 1	0.09658
kWh tier 2	0.05365
Generation - Winter	
kWh tier 1	0.07956
kWh tier 2	0.03666
Delivery	
kW tier 1 - secondary	8.490
kW tier 2 - secondary	3.738
kW tier 1 - primary	7.757
kW tier 2 - primary	3.005
kWh	0.00894
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
kWh Schools discount	-0.0024

Settlement Rate Summary for General Service Rates

E-32 M
Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Transmission meter	36.795
Demand	
kW tier 1 - secondary	12.124
kW tier 2 - secondary	6.935
kW tier 1 - primary	11.226
kW tier 2 - primary	6.197
kW tier 1 - transmission	9.056
kW tier 2 - transmission	3.869
Summer	
kWh secondary tier 1	0.10532
kWh secondary tier 2	0.06475
Winter	
kWh secondary tier 1	0.08921
kWh secondary tier 2	0.04863

Unbundled Rates

Generation - Summer	
kWh tier 1	0.09101
kWh tier 2	0.05044
Generation - Winter	
kWh tier 1	0.07490
kWh tier 2	0.03432
Delivery	
kW tier 1 - secondary	9.25400
kW tier 2 - secondary	4.06500
kW tier 1 - primary	8.35600
kW tier 2 - primary	3.32700
kW tier 1 - transmission	6.18600
kW tier 2 - transmission	0.99900
kWh	0.01155
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Metering - Transmission	36.252
kWh Schools discount	-0.0024

E-32 L
Bundled Rates

BSC $/day	
Self contained meter	3.060
Instrument rated meter	3.920
Primary meter	6.847
Transmission meter	38.695
Demand	
kW tier 1 - secondary	25.372
kW tier 2 - secondary	17.605
kW tier 1 - primary	23.049
kW tier 2 - primary	16.411
kW tier 1 - transmission	17.624
kW tier 2 - transmission	11.753
Summer	
kWh	0.05540
Winter	
kWh	0.03712

Unbundled Rates

Generation - Summer	
kWh	0.05264
Generation - Winter	
kWh	0.03436
Generation - kW	5.49600
Delivery	1.36
kW tier 1 - secondary	17.00600
kW tier 2 - secondary	9.23900
kW tier 1 - primary	14.68300
kW tier 2 - primary	8.04500
kW tier 1 - transmission	9.25800
kW tier 2 - transmission	3.38700
kWh	-
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	2.404
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Metering - Transmission	36.252
kWh aggregation discount	-0.0024
kWh Schools discount	-0.0024

E-34
Bundled Rates

BSC $/day	
Self contained meter	4.262
Instrument rated meter	5.122
Primary meter	8.049
Transmission meter	39.897
Demand	
Secondary	22.009
Primary	20.675
Transmission	14.088
Military	15.051
kWh	0.03972

Unbundled Rates

Generation	
kWh	0.03696
kW	10.464
Delivery - kW	
Secondary	8.309
Primary	6.975
Transmission	0.388
Military	1.351
Transmission - kW	3.236
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	3.606
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Metering - Transmission	36.252

Settlement Rate Summary for General Service Rates

E-35
Bundled Rates

BSC $/day	
Self contained meter	4.262
Instrument rated meter	5.122
Primary meter	8.049
Transmission meter	39.897
Demand	
Secondary on peak	19.229
off peak	2.975
Primary on peak	17.947
off peak	2.847
Transmission on peak	11.323
off peak	2.183
Military on peak	13.103
off peak	2.361
kWh on peak	0.04483
kWh off peak	0.03550
Unbundled Rates	
Generation	
kWh on peak	0.04207
kWh off peak	0.03274
kW on peak	7.49800
kW off peak	2.12600
Delivery - kW	
Secondary on peak	8.49500
off peak	0.84900
Primary on peak	7.21300
off peak	0.72100
Transmission on peak	0.58900
off peak	0.05700
Military on peak	2.36900
off peak	0.23500
Transmission - kW	3.236
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	3.606
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Metering - Transmission	36.252

E-221
Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Demand	
kW secondary	4.754
kWh	
Tier 1	0.10640
Tier 2	0.07336
Unbundled Rates	
Generation	
kWh - Tier 1	0.07675
kWh - Tier 2	0.06115
kW	0.99600
Delivery	
kW Secondary	0.88800
kWh Secondary Tier 1	0.02689
kWh Secondary Tier 2	0.00945
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404

E-221 8 T
Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Demand	
kW secondary on-peak	6.617
kW secondary off-peak	4.410
kWh	
on-peak	0.08967
off-peak	0.04808
Unbundled Rates	
Generation	
kWh - on-peak	0.08517
kWh - off-peak	0.04358
kW - on-peak	2.20714
kW - off-peak	-
Delivery	
kW Secondary On and Off peak	1.54000
kWh	0.00174
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404

Settlement Rate Summary for General Service Rates

E-32 TOU XS
Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Summer	
kWh - secondary - on	0.13800
kWh - secondary - off	0.10321
kWh - primary - on	0.13600
kWh - primary - off	0.09700
kW - secondary - on	4.546
kW - secondary - off	2.599
kW - primary - on	3.951
kW - primary - off	1.565
Winter	
kWh - secondary - on	0.10800
kWh - secondary - off	0.08021
kWh - primary - on	0.10600
kWh - primary - off	0.07400
kW - secondary - on	4.546
kW - secondary - off	2.599
kW - primary - on	3.951
kW - primary - off	1.565

Unbundled Rates

Generation - Summer	
kWh - on	0.08100
kWh - off	0.06700
kW - on	2.95100
kW - off	1.51500
Generation - Winter	
kWh - on	0.05100
kWh - off	0.04400
kW - on	2.951
kW - off	1.515
Delivery	
kWh - secondary - on	0.05700
kWh - secondary - off	0.03621
kWh - primary - on	0.05500
kWh - primary - off	0.03000
kW - secondary - on	1.595
kW - secondary - off	1.084
kW - primary - on	1.000
kW - primary - off	0.050
Transmission - kWh	0.00794
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
kWh Schools discount	-0.0024

E-32 TOU S
Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Demand	
kW tier 1 - secondary - on	19.977
kW tier 2 - secondary - on	10.225
kW tier 1 - secondary - off	7.879
kW tier 2 - secondary - off	2.715
kW tier 1 - primary - on	19.004
kW tier 2 - primary - on	10.081
kW tier 1 - primary - off	6.657
kW tier 2 - primary - off	2.548
Summer	
kWh - on	0.07161
kWh - off	0.05436
Winter	
kWh - on	0.05601
kWh - off	0.04121

Unbundled Rates

Generation - Summer	
kWh - on	0.06885
kWh - off	0.05160
Generation - Winter	
kWh - on	0.05325
kWh - off	0.03845
Generation - kW	
kW - on	4.83700
kW - off	1.84000
Delivery	
kW tier 1 - secondary - on	12.27000
kW tier 2 - secondary - on	2.51800
kW tier 1 - secondary - off	6.03900
kW tier 2 - secondary - off	0.87500
kW tier 1 - primary - on	11.29700
kW tier 2 - primary - on	2.37400
kW tier 1 - primary - off	4.81700
kW tier 2 - primary - off	0.70800
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
kWh Schools discount	-0.0024

E-32 TOU M
Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Transmission meter	36.795
Demand	
kW tier 1 - secondary - on	18.190
kW tier 2 - secondary - on	11.744
kW tier 1 - secondary - off	6.742
kW tier 2 - secondary - off	3.327
kW tier 1 - primary - on	17.546
kW tier 2 - primary - on	11.647
kW tier 1 - primary - off	5.934
kW tier 2 - primary - off	3.216
kW tier 1 - transmission - on	16.394
kW tier 2 - transmission - on	11.250
kW tier 1 - transmission - off	5.022
kW tier 2 - transmission - off	3.066
Summer	
kWh - on	0.07170
kWh - off	0.05952
Winter	
kWh - on	0.05783
kWh - off	0.04566

Unbundled Rates

Generation - Summer	
kWh - on	0.05756
kWh - off	0.04538
Generation - Winter	
kWh - on	0.04369
kWh - off	0.03152
Generation - kW	
kW - on	4.91300
kW - off	1.87000
Delivery	
kW tier 1 - secondary - on	10.40700
kW tier 2 - secondary - on	3.96100
kW tier 1 - secondary - off	4.87200
kW tier 2 - secondary - off	1.45700
kW tier 1 - primary - on	9.76300
kW tier 2 - primary - on	3.86400
kW tier 1 - primary - off	4.06400
kW tier 2 - primary - off	1.34600
kW tier 1 - transmission - on	8.61100
kW tier 2 - transmission - on	3.46700
kW tier 1 - transmission - off	3.15200
kW tier 2 - transmission - off	1.19600
kWh	0.01138
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Metering - transmission	36.252
kWh Schools discount	-0.0024

Settlement Rate Summary for General Service Rates

E-32 TOU L — Bundled Rates

BSC $/day	
Self contained meter	3.060
Instrument rated meter	3.920
Primary meter	6.847
Transmission meter	38.695
Demand	
kW tier 1 - secondary - on	17.508
kW tier 2 - secondary - on	11.795
kW tier 1 - secondary - off	6.396
kW tier 2 - secondary - off	3.370
kW tier 1 - primary - on	16.936
kW tier 2 - primary - on	11.710
kW tier 1 - primary - off	5.679
kW tier 2 - primary - off	3.272
kW tier 1 - transmission - on	15.916
kW tier 2 - transmission - on	10.478
kW tier 1 - transmission - off	4.871
kW tier 2 - transmission - off	3.137
Summer	
kWh - on	0.07018
kWh - off	0.05730
Winter	
kWh - on	0.05552
kWh - off	0.04264

E-32 TOU L — Unbundled Rates

Generation - Summer	
kWh - on	0.05534
kWh - off	0.04246
Generation - Winter	
kWh - on	0.04068
kWh - off	0.02780
Generation - kW	
kW - on	5.98000
kW - off	2.27500
Delivery	
kW tier 1 - secondary - on	8.658
kW tier 2 - secondary - on	2.945
kW tier 1 - secondary - off	4.121
kW tier 2 - secondary - off	1.095
kW tier 1 - primary - on	8.086
kW tier 2 - primary - on	2.860
kW tier 1 - primary - off	3.404
kW tier 2 - primary - off	0.997
kW tier 1 - transmission - on	7.066
kW tier 2 - transmission - on	1.628
kW tier 1 - transmission - off	2.596
kW tier 2 - transmission - off	0.862
kWh	0.01208
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	2.404
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Metering - transmission	36.252
kWh aggregation discount	-0.0024
kWh Schools discount	-0.0024

GS-Schools M — Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Transmission meter	36.795
Demand	
kW tier 1 - secondary	11.816
kW tier 2 - secondary	6.802
kW tier 1 - primary	11.044
kW tier 2 - primary	6.028
kW tier 1 - transmission	8.853
kW tier 2 - transmission	3.839
Summer - Peak	
kWh - on	0.18571
kWh - shoulder	0.13746
kWh - off	0.06920
Summer - Shoulder	
kWh - on	0.16032
kWh - shoulder	0.11865
kWh - off	0.05952
Winter	
kWh - on	0.12415
kWh - shoulder	0.09186
kWh - off	0.04617

GS-Schools M — Unbundled Rates

Generation - Summer Peak	
kWh - on	0.16003
kWh - shoulder	0.11178
kWh - off	0.04352
Generation - Summer Shoulder	
kWh - on	0.13464
kWh - shoulder	0.09297
kWh - off	0.03384
Generation - Winter	
kWh - on	0.09847
kWh - shoulder	0.06618
kWh - off	0.02049
Generation - kW	-
kW	-
Delivery	
kW tier 1 - secondary	8.946
kW tier 2 - secondary	3.932
kW tier 1 - primary	8.174
kW tier 2 - primary	3.158
kW tier 1 - transmission	5.983
kW tier 2 - transmission	0.969
kWh	0.02292
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Metering - transmission	36.252
kWh Schools discount	-0.0024

GS-Schools L — Bundled Rates

BSC $/day	
Self contained meter	3.060
Instrument rated meter	3.920
Primary meter	6.847
Transmission meter	38.695
Demand	
kW tier 1 - secondary	11.564
kW tier 2 - secondary	6.661
kW tier 1 - primary	10.804
kW tier 2 - primary	5.905
kW tier 1 - transmission	8.666
kW tier 2 - transmission	3.761
Summer - Peak	
kWh - on	0.16704
kWh - shoulder	0.12360
kWh - off	0.06809
Summer - Shoulder	
kWh - on	0.14419
kWh - shoulder	0.10667
kWh - off	0.05163
Winter	
kWh - on	0.11163
kWh - shoulder	0.08257
kWh - off	0.04541

GS-Schools L — Unbundled Rates

Generation - Summer Peak	
kWh - on	0.14913
kWh - shoulder	0.10569
kWh - off	0.05018
Generation - Summer Shoulder	
kWh - on	0.12628
kWh - shoulder	0.08876
kWh - off	0.03372
Generation - Winter	
kWh - on	0.09372
kWh - shoulder	0.06466
kWh - off	0.02750
Generation - kW	
kW	-
Delivery	
kW tier 1 - secondary	8.694
kW tier 2 - secondary	3.791
kW tier 1 - primary	7.934
kW tier 2 - primary	3.035
kW tier 1 - transmission	5.796
kW tier 2 - transmission	0.891
kWh	0.01515
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	2.404
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Metering - transmission	36.252
kWh Schools discount	-0.0024

Settlement Rate Summary for General Service Rates

E-59 Bundled Rates		SL Contract Bundled Rates		E-67 Bundled Rates	
lamp	3.00	Delivery Point	17.73	kWh	0.05594
kWh	0.06563	kWh	0.09142		

Settlement Rate Summary for General Service Rates

XHLF Rate
Bundled Rates

BSC $/day	
Instrument rated met	5.122
Primary meter	8.049
Transmission meter	39.897
Demand (kW)	
Secondary	17.950
Primary	16.609
Transmission	12.917
kWh	0.037610
Unbundled Rates	
Generation - kWh	
kW	9.27400
kWh	0.03485
Delivery - kW (primary)	
Secondary	5.44000
Primary	4.09900
Transmission	0.40700
Transmission - kW	3.236
Systems Benefits - kV	0.00276
BSC (day)	
Customer accounts	3.606
Billing	0.030
Meter reading	0.009
Metering - instrumen	1.477
Metering - primary	4.404
Metering - Transmissi	36.252

E-36 XL
Bundled Rates

Basic Service Charge	7,436
T&D Capacity Charge:	
Secondary	5.584
Primary	5.388
Transmission	1.743
Hourly Proxy	
Power Supply kWh	0.00061

E-36 M (Rider)
Bundled Rates

BSC $/day	
E32-XS option	
Self contained meter	3.764
Instrument rated meter	4.602
Primary meter	13.037
E32-L option	
Self contained meter	3.764
Instrument rated meter	4.602
Primary meter	13.037
Transmision meter	44.885
Unbundled Rates	
BSC (day)	
E32-XS option	
Customer accounts:	
Self contained meter	3.14700
Instrument rated meter	3.12500
Primary meter	8.63300
Metering:	
Self contained meter	0.61700
Instrument rated meter	1.47700
Primary meter	4.40400
Meter Reading	0.00900
Billing	0.03000
kWh rate - summer	0.13514
kWh rate - winter	0.11797
E32-L option	
Customer accounts:	
Self contained meter	3.14700
Instrument rated meter	3.12500
Primary meter	8.63300
Metering:	
Self contained meter	0.61700
Instrument rated meter	1.47700
Primary meter	4.40400
Transmision meter	36.25200
Meter Reading	0.00900
Billing	0.03000

Settlement Rate Summary for General Service Rates

E-56 Back-up Power Charges		Rider PPR	
Rate Schedule E-34	0.647	Extra Large	0.05142
Rate Schedule E-32	0.131	Large - summer	0.06080
Excess power charge		Large - winter	0.04480
secondary	0.54802	Medium - summer	0.06623
primary	0.52019	Medium - winter	0.05220
transmission	0.38187		

Appendix H

Resource Comparison Proxy
Plan of Administration

Table of Contents

1. General Description

This document describes the plan for administering the Resource Comparison Proxy purchase rate (RCP) approved for Arizona Public Service Company (APS or Company) in Arizona Corporation Commission (Commission) Decision No. 75859 (January 3, 2017), as modified by Decision No. 75932 (January 13, 2017) and implemented in Decision No. xxxxx (xxx x, 2017). The RCP is the price at which the Company purchases Exported Energy from residential Customers with qualified on-site solar distributed generation facilities. This price is provided in Rate Rider RCP.

The RCP is a proxy for the avoided cost of providing electrical service that results when a distributed generator exports power to the grid. The RCP is calculated using: (i) a rolling historical five-year weighted average cost of grid-scale solar photovoltaic facilities that the Company owns or has rights to through a solar photovoltaic Purchased Power Agreement (PPA); and (ii) applicable Avoided Transmission Capacity Cost, Avoided Distribution Capacity Cost, and Line Losses.

2. Customer Billing

The Company will provide the Customer a monthly bill credit for the Export Energy based on the applicable RCP.

Any bill credit in excess of the Customer's otherwise applicable monthly bill will be credited on the next monthly bill, or subsequent bills if necessary. After the Customer's December bill, a Customer may request a check for any outstanding credits from the prior year; if the outstanding credits exceed $25 a check will automatically be issued; otherwise the bill credits will carry forward to the following year.

3. Resource Comparison Proxy Purchase Rate

The RCP will be determined as follows:

- An RCP will be determined for each tranche of new DG Customers, effective July 1 each year without proration. The RCP may not be reduced by more than 10% each year.

- Each Customer's bill credit will initially be based on the RCP in effect at the time they submit an interconnection application for their system before July 1 provided that they subsequently complete the installation and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application unless, through no fault of the Customer or the Customer's installer, the interconnection is delayed by a third party or APS. In that circumstance, the Customer will have 270 days to complete their interconnection.

- Each Customer's initial RCP will be applicable for 10 years from the time of their interconnection.

- After each Customer's initial 10-year period the bill credit will be based on the purchase rate in effect at that time, and will change from year to year.

4. Definitions

Avoided Cost. In the context of this Plan of Administration, the additional cost APS would incur to acquire electric energy to serve its customers if electricity was not available from on-site distributed generation sources.

Avoided Distribution Capacity Cost. In the context of this Plan of Administration, the net cost of distribution grid equipment and facilities necessary to distribute electricity to APS customers if electricity from on-site distributed generation sources was not available.

Avoided Transmission Capacity Cost. In the context of this Plan of Administration, the additional cost of transmission grid equipment and facilities necessary to transmit electricity to APS customers if electricity from on-site distributed generation sources was not available.

Base Year. For the initial RCP calculation (effective July 1, 2017), the Company's most recent test year, calendar year ending December 31, 2015. Each subsequent annual calculation will use the immediately preceding calendar year as the Base Year. As an example, the RCP that will become effective with the first billing cycle of July 2018 will be calculated with the calendar year ending December 31, 2017 as the Base Year.

Customer(s). For purposes of this Plan of Administration, an APS Customer taking service under a Residential rate schedule.

Export(ed) Energy. Energy generated by an on-site interconnected solar photovoltaic distributed generation source that is greater than the Customer's electric load at any single point in time and flows into the Company's distribution grid.

Levelized Cost. For purposes of this Plan of Administration, the net present value of the overall cost of building and operating a grid-scale solar photovoltaic generating plant, or the net present value of the overall cost to APS of an executed solar photovoltaic PPA, over the economic life of the asset and converted to equal annual amounts.

Line Losses. Electric energy lost as it is transmitted from a supply source (i.e., an electric generation plant) to a delivery point (i.e., the Customer's residence or place of business).

Partial Requirements Service. Electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is configured so that the energy generated first supplies its own electric requirements, and any excess generation (over and above its own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).

Production Tax Credit. The income tax credit available in the State of Arizona for taxpayers that own a qualified renewable energy generator as defined in A.R.S. §43-1083.02 and §43-1164.03 that produces energy after December 31, 2010 and before January 1, 2021. The amount of Production Tax Credit available is limited by facility and by calendar year.

Revenue Requirement. For purposes of this Plan of Administration, the amount of revenue calculated to be recovered in rates for the APS-owned grid-scale solar facilities included in the RCP calculation. Revenue Requirement expenses include depreciation expense, income taxes, property taxes, deferred taxes and tax credits where appropriate, associated operation and maintenance expense, and an approved debt and equity return.

5. System Eligibility

A distributed generation facility must meet all of the following qualifications to be eligible for the RCP:

- Electricity must be generated using solar photovoltaic panels;
- The facility must be interconnected to the Company's distribution grid;
- The generator must be on-site, installed behind the billing meter, and must serve the Customer's load;
- The facility's nameplate capacity cannot be larger than the following electrical service limits:
  a. For 200 Amp service, a maximum of 15 kW-dc,
  b. For 400 Amp service, a maximum of 30 kW-dc,
  c. For 600 Amp service, a maximum of 45 kW-dc,
  d. For 800 Amp service and above, a maximum of 60 kW-dc; and

- For systems over 10 kW-dc, the facility's nameplate capacity cannot be larger than 150% of the customer's maximum one-hour peak demand measured in AC over the prior twelve (12) months. (For example, if the customer's peak is 8kW-ac, the maximum system size that could be installed would be 12kW-dc).

SPECIAL CASES

Switching from a grandfathered legacy solar rate. A Customer may switch from a grandfathered solar Legacy rate and net metering rider to a new retail rate and the RCP rider. However, they will lose their grandfathering status and may not subsequently switch back to the grandfathered rate or net metering program. In addition, the Customer will not be eligible for an initial 10-year lock in the purchase rate; rather their bill credits will be based on the annual RCP rate as it changes from year to year.

Increasing Capacity. If a Customer modifies their generation system to include a material increase in capacity they will no longer be eligible for the initial RCP purchase rate they locked in for ten years; rather their bill credits will be based on the current RCP rate locked in for a period of ten years minus the number of years they received service under a prior RCP rate. For purposes of this Plan of Administration, a material increase in capacity means increasing the capacity by 10% or 1 kW, whichever is greater. Over the term of the Customer's ten year RCP lock, they may only increase their system's capacity by a total of 10% or 1 kW, whichever is greater.

Transferring Service. If a Customer moves to a site that is currently being served under rate rider RCP they will continue service under the rider with the same rate tranche. If a Customer moves their solar system to another site they will no longer be eligible for the initial 10-year lock in the RCP purchase rate; rather their bill credits will be based on the annual RCP rate as it changes from year to year.

6. Calculation of Resource Comparison Proxy Purchase Rate

The RCP is calculated by developing a historical rolling five-year weighted average cost per kWh for all grid-scale renewable solar photovoltaic generating systems used by APS to serve its customers, both APS-owned facilities and facilities from which APS purchases power through an executed PPA. The calculation methodology is as follows:

The first RCP effective on July 1, 2017 is $0.12900/kWh, using 2015 as the Base Year inclusive of adjustments as provided for in Decision No. xxxxx. Subsequent RCPs derived from following the calculations in Steps 1 through 8 below will then be compared to the RCP in effect. If the calculated RCP results in a reduction in the purchase rate from the previous RCP, any such reduction will be no greater than 10% of the previous RCP.

1. Determine appropriate five-year period. The RCP will be calculated using the 5-year period with the Base Year as the final year of the five. Only those grid-scale solar facilities with an in-service date within this 5-year period will be included in the annual RCP calculation.

If there are no grid-scale solar photovoltaic projects in any particular year of the rolling five-year period described above, the rolling 5 year average will be calculated without a project for that particular year. Calculating the RCP without a project for a particular year (i) is the product of the settlement approved in Decision No. xxxx; (ii) is the product of compromise; (iii) does not establish a precedent for how the RCP should be calculated; and (iv) will be revisited in APS's next general rate case.

2. Develop/update annual Revenue Requirement for each APS-owned facility. The Company will calculate revenue requirements for each grid-scale solar photovoltaic generation facility owned by the Company that qualifies for inclusion in the RCP calculation as determined in Step 1. The annual designed output of the facility, including degradation, will be used for this calculation. This step provides an annual revenue requirement cost in dollars for each year of the facility's depreciable life.

3. Incorporate applicable Production Tax Credit. All expected available annual Production Tax Credit tax savings (in dollars) for the above APS facilities will be calculated based on expected annual energy production and subtracted from the annual facility cost derived in Step 2 above for each year.

4. Develop/update annual cost of power from each PPA facility. The Company will calculate an annual cost of purchased power for each facility from which APS purchases power under an executed agreement that qualifies for inclusion in the RCP calculation as determined in Step 1. The annual cost for each of these facilities will be calculated separately for the contract life of each PPA using the contract price and the designed output, including degradation, of the facilities, including contractual escalation factors, as appropriate.

5. Calculate individual facility Levelized Cost. The Levelized Cost for each of the facilities will then be calculated using the data derived in Steps 2 through 4 above. The net present value discount rate used in the Levelized Cost calculations will be calculated using the approved after-tax weighted average cost of capital as determined in the Company's most recent rate case. The result of this calculation step will be a Levelized Cost per MWh for each of the facilities.

6. Calculate weighted Levelized Cost for each facility. The weighted Levelized Cost is calculated by multiplying the cost per MWh derived for each facility in Step 5 by the actual Base year energy production in MWh for each Step 5 facility. The result of this step is an annual weighted cost in dollars for each included facility.

7. Calculate weighted average Levelized Cost for all facilities. The annual weighted average Levelized Cost is determined by dividing the total annual weighted costs for all included facilities by the total Base year energy production MWh. The result of this step is the rolling historical five-year weighted average Levelized Cost per MWh for grid-scale solar photovoltaic facilities on the APS system before any applicable adjustments.

8. Adjustments. An adjustment is then applied to the annual weighted average Levelized Cost per MWh for avoided transmission capacity cost, avoided distribution capacity cost, and line

losses as required in Decision No. 75859. For purposes of this Plan of Administration, and subject to future Commission proceedings, the combined adjustment for these three values is set at \$0.02/kWh as provided for in Decision No. xxxxx. This amount is negotiated, does not reflect an actual calculation of system conditions, and establishes no precedent for any future RCP or avoided cost calculations. While future Commission proceedings may establish methodologies for calculation of the adjustments, no changes will be made to this value until the conclusion of the next APS general rate case.

7. Procedural Timeline

The Company will provide Commission Staff and other intervening parties with its annual RCP calculation no later than March 1 each year. Interested parties will file comments to the Company's RCP calculation by April 1. Commission Staff will file its Report by May 15 and request that Staff's Report be considered in the June Open Meeting and be approved so that the new RCP calculation is effective on July 1.

8. Confidential Data

Portions of the data used to calculate APS's annual RCP are competitively/highly confidential and cannot be released to the public. Competitively/highly confidential information will be made reasonably accessible to parties so that they may determine that such data supports the RCP calculation and that the RCP calculation complies with Commission orders. Competitively/highly confidential information includes cost and production data for facilities from which APS purchases energy under a PPA agreement.

9. Schedules

Templates of the spreadsheet used to calculate the RCP are attached:

Schedule 1: Annual Resource Comparison Proxy Calculation Summary
Schedule 2: Solar Photovoltaic Grid-Scale Plant Data and Levelized Cost
Schedule 3: Individual Plant Annual Cost (\$/MWh)
Schedule 4: Individual Plant Energy Production (MWh)
Schedule 5: Individual Plant Revenue Requirement/PPA Annual Cost (\$000)
Schedule 6: Individual Plant Revenue Requirement/PPA Annual Cost including Production Tax Credits (\$000)

Each of these schedules contains competitively/highly confidential PPA data as indicated.

Arizona Public Service Company
Schedule 1: Annual Resource Comparison Proxy Calculation Summary

Competitively/Highly Confidential
Page 1 of 6

= Competitively/Highly Confidential

			Competitively/Highly Confidential				Competitively/Highly Confidential
Year	Project #	Projects	Cost per MWh	1st Year Energy	Weight	Weighted Energy	Weighted Cost (1,000's)
	1						
	2						
	3						
	4						
	5						
	1						
	2						
	3						
	4						
	5						
	1						
	2						
	3						
	4						
	5						
	1						
	2						
	3						
	4						
	5						
	1						
	2						
	3						
	4						
	5						

Weighted Cost	
Energy	
Average Cost per MWh	
Grid Scale Adjustment	
Cost per MWh after Grid-Scale Adjustment	
Trans, Dist, and Losses Adjustment	
Final Resource Comparison Proxy (RCP)	

Arizona Public Service Company
Schedule 2: Solar Photovoltaic Grid-Scale Plant Data and Levelized Cost

Competitively/Highly Confidential
Page 2 of 6

Project	RFP Year	Start Date	Start Year	Levelized Cost (Base Year)	GWH (1st Year)
= Competitively/Highly Confidential					

Arizona Public Service Company
Schedule 3: Individual Plant Annual Cost ($/MWh)

Competitively/Highly Confidential
Page 3 of 6

Project	Levelized Cost per MWh	BY YEAR: 2011 through 2046
		= Competitively/Highly Confidential

Arizona Public Service Company
Schedule 4: Individual Plant Energy Production (MWh)

Discount Rate		
Project	Levelized Energy	= Competitively/Highly Confidential BY YEAR: 2011 through 2046

Arizona Public Service Company
Schedule 5: Individual Plant Revenue Requirement/PPA Annual Cost ($000)

Competitively/Highly Confidential
Page 5 of 6

Discount Rate		
Project	Levelized Cost	= Competitively/Highly Confidential BY YEAR: 2011 through 2046

Arizona Public Service Company

Schedule 6: Individual Plant Revenue Requirement/PPA Annual Cost including Production Tax Credits ($000)

Competitively/Highly Confidential

Discount Rate		
Project	Levelized Cost	= Competitively/Highly Confidential BY YEAR: 2011 through 2046

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RATE RIDER RCP
PARTIAL REQUIREMENTS SERVICE FOR NEW ON-SITE SOLAR DISTRIBUTED GENERATION RESOURCE COMPARISON PROXY EXPORT RATE

AVAILABILITY

This rate rider is available to partial requirements customers with qualified on-site solar generation, served under an applicable residential rate. This rate rider may not be used in conjunction with a grandfathered residential Legacy rate schedule or Legacy rate rider.

DESCRIPTION

A Customer with solar generation exports power to the grid from time to time when their generation exceeds the load in their home. The Company will meter this export power on an instantaneous basis and provide a monthly bill credit based on the purchase rate in this schedule.

The purchase rates will be determined as follows:

a. An RCP rate will be determined for each annual tranche of new DG Customers, effective July 1 each year without proration. The RCP rate may not be reduced by more than 10% each year.

b. Each Customer's bill credit will initially be based on the RCP in effect at the time they submit an interconnection application for their system before July 1 provided that they subsequently complete the installation and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application unless, through no fault of the Customer or the Customer's installer, the interconnection is delayed by a third party or APS. In that circumstance, the Customer will have 270 days to complete their interconnection.

c. Each Customer's initial RCP rate will be applicable for 10 years from the time of their interconnection.

d. After each Customer's initial 10 year period the bill credit will be based on the purchase rate in effect at that time, and may change from year to year.

Further details are provided in the Resource Comparison Proxy Plan of Administration and Arizona Corporation Commission Decisions No. 75859 and xxxxx.

aps

RATE RIDER RCP
PARTIAL REQUIREMENTS SERVICE FOR
NEW ON-SITE SOLAR DISTRIBUTED GENERATION
RESOURCE COMPARISON PROXY EXPORT RATE

PURCHASE RATES

The Company will provide a bill credit for the exported energy based on the following purchase rates:

Tranche 2017	July 1, 2017 through June 30, 2018	\$0.1290	per kWh
Tranche 2018	July 1, 2018 through June 30, 2019	TBD	per kWh

Any bill credit in excess of the Customer's otherwise applicable monthly bill will be credited on the next monthly bill, or subsequent bills if necessary. After the Customer's December bill, a Customer may request a check for any outstanding credits from the prior year; however, if the outstanding credits exceed \$25, the Company will automatically issue a check to the Customer. Otherwise, the bill credits will carry forward to the following year.

GENERATOR REQUIREMENTS

Distributed generators must meet all of the following qualifications:

1. Electricity must be generated using solar photovoltaic panels;
2. The generator must be interconnected to the Company's distribution grid;
3. The generator must be on-site, installed behind the billing meter, and must serve the Customer's load;
4. The facility's nameplate capacity cannot be larger than the following electrical service limits:
    a. For 200 Amp service, a maximum of 15 kW-dc.
    b. For 400 Amp service, a maximum of 30 kW-dc.
    c. For 600 Amp service, a maximum of 45 kW-dc.
    d. For 800 Amp service and above, a maximum of 60 kW-dc; and
5. For systems over 10 kW-dc, the facility's nameplate capacity cannot be larger than 150% of the customer's maximum one-hour peak demand measured in AC over the prior twelve (12) months. (For example, if the customer's peak is 8kW-ac, the maximum system size that could be installed would be 12kW-dc).

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RATE RIDER RCP
PARTIAL REQUIREMENTS SERVICE FOR NEW ON-SITE SOLAR DISTRIBUTED GENERATION RESOURCE COMPARISON PROXY EXPORT RATE

SPECIAL CASES

1. Switching from a grandfathered legacy solar rate. A Customer may switch from a grandfathered solar Legacy rate and net metering rider to a new retail rate and the RCP rider. However, they will lose their grandfathering status and may not subsequently switch back to the grandfathered rate or net metering program. In addition, the Customer will not be eligible for an initial 10-year lock in the purchase rate; rather their bill credits will be based on the annual RCP rate as it changes from year to year.

2. Increasing Capacity. If a Customer modifies their generation system to include a material increase in capacity they will no longer be eligible for the initial RCP purchase rate they locked in for ten years; rather their bill credits will be based on the current RCP rate locked in for a period of ten years minus the number of years they received service under a prior RCP rate. For purposes of this rate rider, a material increase in capacity means increasing the capacity by 10% or 1 kW, whichever is greater. Over the term of the Customer's ten year RCP lock, they may only increase their system's capacity by a total of 10% or 1 kW, whichever is greater.

3. Transferring Service. If a Customer moves to a site that is currently being served under rate rider RCP they will continue service under the rider with the same rate tranche. If a Customer moves their solar system to another site they will no longer be eligible for the initial 10-year lock in the RCP purchase rate; rather their bill credits will be based on the annual RCP rate as it changes from year to year.

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule continue to apply.

2. The Customer must have a standard Advanced Metering Infrastructure (AMI) meter installed to measure the production from their solar generation system as well as an AMI meter for electrical service.

3. The Company provides service under this rider in accordance with its Interconnection Requirements Manual. Service terms an conditions may be included in a Customer's interconnection agreement.

4. Partial Requirements Service is electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is configured so that the energy generated first supplies its own electric requirements, and any excess generation (over and above its own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).

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RATE RIDER EPR-6
PARTIAL REQUIREMENTS SERVICE FOR
ON-SITE RENEWABLE DISTRIBUTED GENERATION
NET METERING

AVAILABILITY

This rate rider is available to qualifying residential and non-residential partial requirements Customers with an on-site renewable distributed generation system. Residential Customers with an interconnected on-site solar photovoltaic system are not eligible for this rate rider.

DESCRIPTION

This rate rider describes how the Company will bill a Customer who participates in the Company's net metering program and exports energy through the Company's distribution grid. Export energy occurs when the Customer's generation is greater than their electrical load in any instant and this excess energy flows back to the Company's grid.

Under this rider, export energy (kWh) will be netted against kWh supplied by the Company during the billing month, or banked and netted on a subsequent bill if necessary.

If a Customer is served under a time-of-use rate, the export energy will be netted according to the on-peak and off-peak periods. On-peak export energy will be netted against on-peak energy from the Company and off-peak export energy will be netted against off-peak energy, for all unbundled components of the rate that have time-of-use charges.

PURCHASE RATES

After the December bill, any export energy that has not already been netted on a bill will be acquired by the Company in exchange for a monetary bill credit based on the following purchase rate:

\$0.02895	per kWh

The purchase rate is based on the Company's near-term avoided costs and is revised from time to time.

BILLING DETAILS

1. All terms and charges in the customer's rate schedule continue to apply to electric service provided under this rider.

2. If the Customer terminates electric service, the Company will issue a check for any remaining export energy at the purchase price.

RATE RIDER EPR-6
PARTIAL REQUIREMENTS SERVICE FOR
ON-SITE RENEWABLE DISTRIBUTED GENERATION
NET METERING

GENERATOR REQUIREMENTS

Distributed generators must meet all of the following qualifications:

1. The generator must be interconnected to the Company's distribution grid;

2. The generator must be on-site, installed behind the billing meter, and must serve the Customer's load;

3. For qualifying residential facilities, the nameplate capacity cannot be larger than the following electrical service limits:
   a. For 200 Amp service, a maximum of 15 kW-dc.
   b. For 400 Amp service, a maximum of 30 kW-dc.
   c. For 600 Amp service, a maximum of 45 kW-dc.
   d. For 800 Amp service and above, a maximum of 60 kW-dc; and

4. For all qualifying residential and non-residential facilities over 10 kW-dc, the facility's nameplate capacity cannot be larger than 150% of the customer's maximum one-hour peak demand measured in AC over the prior twelve (12) months. (For example, if the customer's peak is 8kW-ac, the maximum system size that could be installed would be 12kW-dc).

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule continue to apply.

2. The Customer must have an Advanced Metering Infrastructure (AMI) meter, or equivalent, installed to measure the production from their solar generation system as well as an AMI meter for electrical service.

3. The Company provides service under this rider in accordance with its Interconnection Requirements Manual. Service terms and conditions may be included in a customer interconnection agreement.

4. A Net Metering Facility is an on-site distributed generation system that:

   a. Provides part of the Customer's energy requirements at the site where the system is installed;

   b. Uses renewable resources, as defined by the Arizona Corporation Commission, including a fuel cell with the chemical reaction derived from renewable resources

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RATE RIDER EPR-6
PARTIAL REQUIREMENTS SERVICE FOR
ON-SITE RENEWABLE DISTRIBUTED GENERATION
NET METERING

or a combined heat and power (CHP) facility as defined by A.A.C. R14-2-2302, to generate energy; and

c. Is interconnected to and can operate in parallel and in phase with the Company's existing distribution system.

5. Partial Requirements Service is electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is configured so that the energy generated first supplies its own electric requirements, and any excess generation (over and above its own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).

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RATE RIDER LEGACY EPR-6 PARTIAL REQUIREMENTS SERVICE FOR ON-SITE RENEWABLE DISTRIBUTED GENERATION NET METERING

AVAILABILITY

This rate rider is available to Customers that qualify for the residential solar grandfathering program. It may be used in conjunction with the residential Legacy rate schedules for distributed generation systems.

This rate rider is frozen effective July 1, 2017. This means a residential Customer that is already taking service under this rate rider by that date may continue service under the terms of the grandfathering program. Other residential Customers must meet the qualification requirements of the grandfathering program to take service under this schedule.

A residential Customer may remain on this rate rider for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the residential Customer will not be eligible for a grandfathered solar Legacy rate or this rate rider. Instead, the residential Customer will be served under an applicable retail rate of their choice and Rate Rider RCP, or a subsequent replacement rider.

DESCRIPTION

This rate rider describes how the Company will bill a Customer who participates in the Company's net metering program. A partial requirements Customer has on-site generation that serves some of their electrical requirements and relies on the Company for additional electrical services. Export energy occurs when the Customer's generation is greater than their electrical load in any instant and this excess energy flows back to the Company's grid.

Under this rider, export energy (kWh) will be netted against kWh supplied by the Company during the billing month, or banked and netted on a subsequent bill if necessary.

If a Customer is served under a time-of-use rate, the export energy will be netted according to the on-peak and off-peak periods, i.e. on-peak export energy will be netted against on-peak energy from the Company and vice-versa, for all unbundled components of the rate that have time-of-use charges.

PURCHASE RATES

After the December billing cycle, any export energy that has not already been netted on a bill will be acquired by the Company in exchange for a monetary bill credit based on the following purchase rate:

$0.02895	per kWh

The purchase rate is based on the Company's near-term avoided costs and is revised from time to time.

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RATE RIDER LEGACY EPR-6
PARTIAL REQUIREMENTS SERVICE FOR ON-SITE RENEWABLE DISTRIBUTED GENERATION NET METERING

BILLING DETAILS

1. All terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

2. If the Customer terminates electric service, the Company will issue a check for the remaining export energy at the purchase price.

RESIDENTIAL GRANDFATHERING PROGRAM

The terms and conditions for the solar grandfathering program for residential Customers are as follows:

1. Existing solar customers with systems interconnected to the Company's distribution grid prior to July 1, 2017 and otherwise qualify for this rate rider may continue service under the grandfathering program.

2. Customers who (i) submit a complete application for interconnection to the Company by July 1, 2017; (ii) include in their interconnection application a fully executed sales or lease contract for their rooftop solar system; and (iii) install their rooftop solar system and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application, and otherwise qualify for this rate rider may take service under the grandfathering program. If the interconnection is delayed by a third party or APS through no fault of the Customer or the Customer's installer, the Customer will have 270 days to complete their interconnection.

3. The grandfathering period will be 20 years from the customer's initial interconnection date and applies to the site where the system is located.

4. Over the term of the grandfathering period, a Customer may not increase the capacity of their grandfathered solar generation unit by more than a total of 10% or 1 kW, whichever is greater.

5. Customers may not move their solar generation unit to another site.

6. The grandfathering may be transferred to a new customer purchasing the home.

7. The Customer may remain on their current Legacy rate schedule but may not move between alternate grandfathered Legacy rate schedules.

8. The Customer will be subject to changes in annual adjustor rates including the rate structure and level.

RATE RIDER LEGACY EPR-6
PARTIAL REQUIREMENTS SERVICE FOR ON-SITE RENEWABLE DISTRIBUTED GENERATION NET METERING

9. Frozen Rate Rider Legacy LFCR-DG will continue to apply.

10. A Customer may leave the grandfathering program and be served under a non-Legacy rate schedule. However, the Customer may not subsequently return to the grandfathering program at a later date.

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule continue to apply.

2. The Customer must have an Advanced Metering Infrastructure (AMI) meter, or equivalent, installed to measure the production from their solar generation system as well as an AMI meter for electrical service.

3. The Company provides service under this rider in accordance with its Interconnection Requirements Manual. Service terms and conditions may be included in a customer interconnection or purchase agreement.

4. A Net Metering Facility is an on-site distributed generation system that:

    a. Provides part of the Customer's energy requirements at the site where the system is installed;

    b. Uses renewable resources, as defined by the Arizona Corporation Commission, to generate energy; and

    c. Is interconnected to and can operate in parallel and in phase with the Company's existing distribution system.

Appendix I

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RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

AVAILABILITY

This rate schedule is available to non-residential Customers with monthly loads of 401 kW and greater that do not qualify for Rate Schedules E-34 or E-35.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a 15-minute period for the month, and an energy charge for the energy (kWh) used during the month. The energy charge will vary by season (summer or winter).

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charges (only one applies)		
For service through Self-Contained Meters	$3.060	per day
For service through Instrument-Rated Meters	$3.920	per day
For service at Primary Voltage	$6.847	per day
For service at Transmission Voltage	$38.695	per day

Demand Charges (only one set applies)			
Secondary	First 100 kW	$25.372	per kW
	All additional kW	$17.605	per kW
Primary	First 100 kW	$23.049	per kW
	All additional kW	$16.411	per kW
Transmission	First 100 kW	$17.624	per kW
	All additional kW	$11.753	per kW

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RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

	Summer	Winter	
Energy Charge	$0.05540	$0.03712	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$2.404	per day
Meter Reading	$0.009	per day
Billing	$0.030	per day
Metering* (only one applies)		
Self Contained Meters	$0.617	per day
Instrument-Rated Meters	$1.477	per day
Primary	$4.404	per day
Transmission	$36.252	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission		$2.870	per kW
Generation		$5.496	per kW
Delivery - Secondary	First 100 kW	$17.006	per kW
	All additional kW	$9.239	per kW
Delivery - Primary	First 100 kW	$14.683	per kW
	All additional kW	$8.045	per kW
Delivery - Transmission	First 100 kW	$9.258	per kW
	All additional kW	$3.387	per kW

Energy Charge Components

System Benefits	$0.00276	per kWh
Delivery	$0.00000	per kWh

	Summer	Winter	
Generation	$0.05264	$0.03436	per kWh

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RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

For billing purposes, the kW used in this rate schedule will be the greater of the following:

1. The average kW supplied during the 15-minute period (or other period as specified by an individual customer contract) of maximum use during the month, as determined from readings of the Company's meter or in accordance with the Company's Service Schedule 8.

2. 80% of the highest kW measured during the six (6) summer billing months (May-October) of the twelve (12) months ending with the current month.

3. The minimum kW specified in the agreement for service or individual contract.

The monthly bill for service under this rate schedule will not be less than the Bundled Basic Service Charge plus the Bundled Demand Charge for each kW.

AGGREGATION OPTION

Customers with multiple accounts served under Rate Schedule E-32 L or E-32TOU L that together have a combined load of at least 5 MW are eligible for a discount of $0.0024 per kWh for the unbundled Generation charge in this rate schedule. All other charges of this schedule apply as shown. Customers must execute a contract with the Company specifying eligible accounts prior to receiving this discount. Customer accounts served under Rate Rider PPR, Rate Rider E-56, or Rate Rider E-56R or have on-site generation greater than 100 kW-AC are not eligible for this option.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.

5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.

6. The Tax Expense Adjustment Charge, Adjustment Schedule TEAM.

7. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

8. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

PPR	Preference Power
CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Solar Net Metering
E-56	Partial Requirements Service
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its customers, and they have provisions and charges that may affect the customer's bill (for example, service connection charges).

RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

2. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the customer at the charges shown above.

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RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE

AVAILABILITY

This rate schedule is available to non-residential Customers with monthly loads of 401 kW and greater that do not qualify for Rate Schedule E-35.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a 15-minute period for the month, and an energy charge for the energy (kWh) used during the month. The energy charge will vary by season (summer or winter) and time of day (On-Peak and Off-Peak).

The Company will place the Customer on the applicable Rate Schedule Time-of-Use E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

On-Peak hours:	3:00 pm - 8:00 pm Monday through Friday
Off-Peak hours:	All remaining hours
Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge (only one applies)		
For service through Self-Contained Meters	\$3.060	per day
For service through Instrument-Rated Meters	\$3.920	per day
For service at Primary Voltage	\$6.847	per day
For service at Transmission Voltage	\$38.695	per day

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RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE

Demand Charges (only one set applies)			
Secondary	First 100 On-Peak kW	508	per kW
	All additional On-Peak kW	$11.795	per kW
	First 100 Off-Peak kW	$6.396	per kW
	All additional Off-Peak kW	$3.370	per kW
Primary	First 100 On-Peak kW	$16.936	per kW
	All additional On-Peak kW	$11.710	per kW
	First 100 Off-Peak kW	$5.679	per kW
	All additional Off-Peak kW	$3.272	per kW
Transmission	First 100 On-Peak kW	$15.916	per kW
	All additional On-Peak kW	$10.478	per kW
	First 100 Off-Peak kW	$4.871	per kW
	All additional Off-Peak kW	$3.137	per kW

Energy Charges			
	Summer	Winter	
On-Peak	$0.07018	$0.05552	per kWh
Off-Peak	$0.05730	$0.04264	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$2.404	per day
Meter Reading	$0.009	per day
Billing	$0.030	per day

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RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE

Metering* (only one applies)		
Self Contained Meters	$0.617	per day
Instrument-Rated Meters	$1.477	per day
Primary	$4.404	per day
Transmission	$36.252	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission		$2.870	per kW
Generation On-Peak		$5.980	per kW
Generation Off-Peak		$2.275	per kW
Delivery - Secondary	First 100 On-Peak kW	$8.658	per kW
	All additional On-Peak kW	$2.945	per kW
	First 100 Off-Peak kW	$4.121	per kW
	All additional Off-Peak kW	$1.095	per kW
Delivery - Primary	First 100 On-Peak kW	$8.086	per kW
	All additional On-Peak kW	$2.860	per kW
	First 100 Off-Peak kW	$3.404	per kW
	All additional Off-Peak kW	$0.997	per kW
Delivery - Transmission	First 100 On-Peak kW	$7.066	per kW
	All additional On-Peak kW	$1.628	per kW
	First 100 Off-Peak kW	$2.596	per kW
	All additional Off-Peak kW	$0.862	per kW

Energy Charge Components

System Benefits Charge:	$0.00276	per kWh
Delivery Charge	$0.01208	Per kWh

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RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE

	Summer	Winter	
Generation On-Peak	\$0.05534	\$0.04068	per kWh
Generation Off-Peak	\$0.04246	\$0.02780	per kWh

For billing purposes, the On-Peak kW used in this rate schedule will be the greater of the following:

1. The average kW supplied during the 15-minute period of maximum use during the On-Peak period during the billing period, as determined from readings of the Company's meter or in accordance with the Company's Service Schedule 8.

2. 80% of the highest On-Peak kW measured during the six summer billing months (May-October) of the twelve (12) months ending with the current month.

3. The minimum kW specified in the agreement for service or individual contract.

Off-peak kW will be based on the average kW supplied during the 15-minute period of maximum use during the Off-peak hours of the billing period, as determined from readings of the Company's meter.

The monthly bill for service under this rate schedule will not be less than the Bundled Basic Service Charge plus the Bundled Demand Charge for each kW.

AGGREGATION OPTION

Customers with multiple accounts served under Rate Schedule E-32 L or E-32TOU L that together have a combined load of at least 5 MW are eligible for a discount of \$0.0024 per kWh for the unbundled Generation charge in this rate schedule. All other charges of this schedule apply as shown. Customers must execute a contract with the Company specifying eligible accounts prior to receiving this discount. Customer accounts served under Rate Rider PPR, Rate Rider E-56, or Rate Rider E-56R or have on-site generation greater than 100 kW-AC are not eligible for this option.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.

5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.

6. The Tax Expense Adjustment Charge, Adjustment Schedule TEAM.

7. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

8. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

PPR	Preference Power
CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Solar Net Metering
E-56	Partial Requirements
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

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RATE SCHEDULE XHLF
GENERAL SERVICE
EXTRA HIGH LOAD FACTOR

AVAILABILITY

This rate schedule is available to Customers whose monthly maximum demand is 5,000 kW or more with a load factor of 92% or more for a minimum of nine months of the prior 12 month period.

Customers will be required to execute a service agreement or contract that specifies certain provisions of their electric service, such as a contract length, minimum and maximum monthly loads, special charges, and other service details.

Qualifying Customers with monthly demands of 15,000 kW and greater may choose to be served with transmission level service by providing the Company with a contribution in aid of construction (CIAC) in lieu of purchasing transmission level facilities. The Customer will be required to execute a maintenance contract and share in the cost of replacement facilities. Under this option, the Company may also finance the CIAC at the Company's weighted average cost of capital established in its most recent rate case. This financing period will not exceed 10 years.

DESCRIPTION

This rate has three parts: a basic service charge, a demand (kW) charge consisting of the average kW supplied during the 15-minute period of maximum use during the billing period, and an energy (kWh) charge for the energy used for the entire month.

Monthly load factor will be established using the formula:

Monthly Load Factor = Billed kWh/(billed kW * Billing Days * 24 hours)

CHARGES

The monthly bill will be calculated at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Service

Customers Served at Secondary Voltage		
Basic Service Charge	$5.122	per day
Demand Charge	$17.950	per kW
Energy Charge	$0.03761	per kWh

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RATE SCHEDULE XHLF
GENERAL SERVICE
EXTRA HIGH LOAD FACTOR

Customers Served at Primary Voltage		
Basic Service Charge	$8.049	per day
Demand Charge	$16.609	per kW
Energy Charge	$0.03761	per kWh

Customers Served at Transmission Voltage		
Basic Service Charge	$39.897	per day
Demand Charge	$12.917	per kW
Energy Charge	$0.03761	per kWh

<u>Unbundled Standard Offer Service</u>

Bundled Charges consists of the Components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts	$3.606	per day
Meter Reading	$0.009	per day
Billing	$0.030	per day
Meter (only one applies)		
Instrument-Rated Meter	$1.477	per day
Primary Meter	$4.404	per day
Transmission Meter	$36.252	per day
Demand Charge Components		
Transmission Charge	$3.236	per kW
Generation - Capacity	$9.274	per kW
Delivery (only one applies)		
Secondary Service	$5.440	per kW
Primary Service	$4.099	per kW
Transmission Service	$0.407	per kW
Energy Charge Components		
Generation - Fuel	$0.03485	per kWh
System Benefits	$0.00276	per kWh

The kW for billing will be the greater of:

a. The average kW supplied during the 15-minute period of maximum use during the monthly billing period; or

b. The minimum kW specified in a service agreement.

MINIMUM BILL

The bill will not be less than the minimum amount specified in the Customer's service agreement or contract.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.

5. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

6. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.

7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.

8. Any applicable taxes and governmental fees that are assessed on APS's revenue, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

GPS-1, GPS-2, GPS-3	Green Power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

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RATE SCHEDULE XHLF
GENERAL SERVICE
EXTRA HIGH LOAD FACTOR

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. The type of service provided under this schedule will be three phase, 60 Hertz, at the Company's standard voltages that are available within the vicinity of the Customer site.

2. Daily metering charges apply to typical installations. Customers requiring specialized Equipment may incur additional metering charges that reflect the additional cost.

3. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the partial requirement rate riders.

4. Electrical service must be supplied at one point of delivery and measured through one meter unless otherwise specified in a service agreement.

5. This schedule is not applicable to breakdown, standby, supplemental, residential or reseale service.

6. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by the Company and billed to the Customer at the charges shown above.

7. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

Appendix J

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SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE INDUSTRIAL DEVELOPMENT PLAN

General Description

This Service Schedule provides the Terms and Conditions under which Arizona Public Service Company (APS or Company) may offer financial incentives to potential new commercial or industrial Customers or to existing commercial and industrial Customers who are adding significant new load.

Availability of this schedule is limited to the lesser of 100 MW of new and additional load or 50 new Customers.

The Customer must provide all requested information to the Company in order to demonstrate eligibility. The Company will evaluate all relevant information and will determine whether to offer the Customer an incentive.

Consistent with the Schedule, when the Company determines that it is appropriate to offer an incentive to an eligible Customer, an agreement will be executed with the Customer. The agreement will specify the incentive and other terms where different from the Company's other Service Schedules.

APS will file each agreement, along with a complete Customer Characteristics Report with Arizona Corporation Commission (Commission) Staff as a compliance filing. Each agreement filed with the Commission Staff will become effective 30 days after filing.

Any Customer information that the Company provides to Commission Staff on a confidential basis will be returned to the Company no later than 60 days after an application under this Schedule is filed.

1. Eligibility Criteria

The Company will evaluate the following Customer characteristics prior to offering service under this Schedule to determine if the Customer is eligible for a financial incentive:

1.1 Availability of Alternative Locations

(A) Incentives are available only to Customers who have not located or expanded in the Company's service area before the Commission's review of the application and who would not locate or expand in the Company's service area without this Schedule's incentive.

(B) The Customer must provide the Company with evidence that additional locations, outside the Company's service area, have been considered for location or expansion. This evidence must consist of written documentation including, but not limited to, detailed quantitative analyses performed by the Customer or consultants regarding the suitability of alternative locations.

(C) Based on the information provided, the Company will determine whether the Customer would reasonably locate elsewhere in the absence of the incentive. If so, the Customer will be deemed to have met this requirement.

1.2 Effects on Competitors

(A) Incentives will be available to the Customer only when existing Customers in the same line of business and market are not adversely impacted by the discounted rates.

(B) The Customer must provide a detailed description of goods and services produced, the technology employed, and the market(s) the Customer serves.

(C) Based on the provided information, along with knowledge of its customer base, the Company must reasonably verify that this requirement is satisfied for the Customer to be eligible for an incentive.

1.3 Customer Load Requirements

(A) To qualify for this Schedule, electric requirements for a new Customer must be at least 2 MW and existing Customers must add at least 1 MW of load. To determine Customer load, APS will consider both energy purchased from the Company and any energy generated by the Customer using cogeneration or small power production facilities.

(B) The Customer's monthly average load factor must be 55% or greater. This load factor criteria may be waived if one of the following apply:

1. The Customer's daily off-peak energy usage in kWh is greater than 50% of total monthly energy usage in kWh (off-peak hours will be defined using the applicable General Service Rate Schedule); or
2. The Customer's new or added load is interruptible and the Customer's peak load is at least 3 MW.

(C) Loads that do not operate in the summer months of June through September will be given special consideration when determining an applicable incentive.

(D) APS will assist the Customer to consider and employ state-of-the-art, cost-effective energy conservation and demand response measures at its facility. These measures may include efficiency motors, motor control systems, and other general measures such as efficient lighting, space heating and cooling, and insulation.

SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE INDUSTRIAL DEVELOPMENT PLAN

1.4 Economic Requirements

(A) The load must be economic, as calculated under the Company's current extension policy using standard rates.

(B) To be eligible for incentives under this schedule, a potential load must bring a significant number of jobs or ancillary business into Arizona. In conjunction with this criterion, capital investment by the Customer may also be considered.

(C) The Company will give particular consideration to Customers whose electric bills exceed 5% of their operating expenses.

2. Conflict of Interest.

2.1 In order to limit any potential conflict of interest, APS is required to submit an affidavit to Commission Staff for each Customer under consideration for service under this Service Schedule. This affidavit will include:

(A) A statement that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries, or one who has filled such role within the three-years prior to the effective date of the Customer's agreement, has or had any interest, direct or indirect, with any entity which has provided substantial services, including real estate broker services, to the Customer in connection with a proposed agreement under this Schedule; and

(B) A statement that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries or affiliates has or had any direct or indirect interest in any property owned in whole or in part by the Customer.

2.2 If the affidavit provided by APS is shown to be inaccurate, the Commission will, in future APS rate cases, impute as revenue the difference between the discounted rate and the tariffed rate which would otherwise apply to the Customer for the period during which the discount was in effect.

3. Rate Provisions

3.1 A Customer satisfying the requirements above may receive an incentive to locate in the Company's service territory. The incentive will be a discount from the Customer's otherwise applicable base electric bill (excluding taxes and adjustments).

3.2 The discounted charges will not be below the Company's marginal cost.

SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE INDUSTRIAL DEVELOPMENT PLAN

3.3 The discount may vary over the term of the Customer agreement.

3.4 The discount will not be larger than 25% of the Customer's total energy bill from the Company.

3.5 No discount will be provided from the minimum bill as computed under the Customer's otherwise applicable rate.

3.6 For current Customers adding load, the discount will apply only to the added load.

3.7 Any incentive available under this schedule will be limited to a specific period of six years or less.

3.8 The specific discount and the period over which the discount is applied will be determined after full evaluation of the Customer information as determined by the Company.

4. Customer Characteristic Report

Each agreement must be accompanied by a Customer Characteristic Report. The following information will be included in the Customer Characteristics Report:

4.1 **General Information**
- (A) Customer name
- (B) Customer contact name and address
- (C) Dates of Customer application and Company decision
- (D) New or existing Customer
- (E) Proposed effective date of agreement

4.2 **Location Decision**
- (A) Customer location
- (B) Description of other locations considered
- (C) Other locations of Customer's operations
- (D) An affidavit from Customer demonstrating that the Customer would not locate or expand in Arizona absent the discounts
- (E) Within ninety (90) days of the effective date of any agreement under this Schedule, the Customer must supply written documentation and analyses substantiating the affidavit provided under 4.2 (D)
- (F) If the requirements of 4.2 (E) are not met within ninety (90) days of approval of the agreement, the agreement will be void

(G) Proportion of Customer's production and distribution expenses accounted for by electricity, by natural gas and by other energy sources (specify)

4.3 **Effects on Competitors**

(A) Nature of business, description and North American Industry Classification System (NAICS) code
(B) Number of other Customers in same business
(C) Market area served by Customer
(D) Description of effects on other Customers

4.4 **Load Characteristics**

(A) Size of load
(B) Annual load factor
(C) Off-peak operation
(D) Description of daily load shape
(E) Seasonality
(F) Interruptibility
(G) Permanency of load
(H) Estimated impact on system peak demand from the new load

4.5 **Energy Service Mix**

(A) Use of natural gas and other energy sources
(B) Description of energy efficiency measures including building design, processing and other
(C) Feasibility of cogeneration

4.6 **Rates**

(A) Applicable rate schedule
(B) Years discount will be in effect
(C) Percentage discount by year
(D) Estimated annual revenues
(E) Estimated annual incremental electricity production costs
(F) Support that the agreement meets the terms described in Rate Provisions Section 3.2 and 3.4

4.7 **Special Agreement Provisions**

(A) List of special provisions
(B) Reasons for special provisions

Appendix K

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RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION

AVAILABILITY

This 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-X, except as modified herein. Total program participation will be limited to 200 MW of customer load, 100 MW of which will be initially reserved for Customers with single-site peak demands of 20 MW or greater and with monthly average load factors above 70% unless not fully subscribed during the solicitation process.

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-X.

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.

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RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION

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 aggregated actual hourly metered load 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.

CUSTOMER ENROLLMENT

The Company will 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 will 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. Otherwise, customers may enroll on a first come first serve basis. After the initial lottery, if necessary, customers who enter the program will not be required to participate in a subsequent lottery to remain in the program.

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 must apply for service under this rate rider schedule.

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

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

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

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**RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION**

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

The Company will 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.

APS will not propose a deferral of unmitigated costs resulting from AG-X, if any, and APS will not request recovery of any unmitigated costs resulting from AG-X, if any, in its next rate case.

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 will serve as the scheduling coordinator. The Generation Service Provider must 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 will be either scheduled or financially settled. Line losses will be modified to reflect transmission voltage service when applicable.

IMBALANCE SERVICE

The Company will provide Imbalance Service according to the terms and provisions below:

RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION

i. Within the range of +/- 15% each hour or +/- 2 MW, whichever is greater, GSPs would pay based on Schedule 4 of APS's OATT which now reflects the terms of the CAISO imbalance charges.

ii. Greater than 15 % each hour or +/- 2 MW, whichever is greater, in addition to the charges in ii) GSPs would pay a penalty of $3 per MWh.

iii. In addition to the imbalance provisions described above, GSPs with 20% of hourly deviations greater than 20% of the scheduled amount occurring in a calendar month will receive a notice of intent to terminate the GSP's eligibility in the program unless remedied. Imbalances of this magnitude and frequency will be deemed "Excessive." Should Excessive imbalances occur again in a subsequent month, within 12 months from the date of the notice, the GSP's eligibility may be terminated. To avoid termination, a GSP must demonstrate to APS that it is operating in good faith to match its resources to its load. In the event of GSP termination, the Customer will be required to secure a replacement GSP within 60 days, and will be subject to the terms listed in "Default of the third party generation provider".

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 will provide the required power to the customer, which will be charged at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus $10 per MWh not to be less than $0 per MWh or at the applicable retail rate at the company's option. 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 if: (1) they provide one or more years notice to the Company; or (2) if the Commission terminates the program. Absent one of these conditions, the Company will provide generation service to the Customers under the following conditions. The Company may elect to provide the customer with generation service at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus $10 per MWh for a period of time for the Customer to attain 1 year notice, at which time the Customer returns to the Company's Standard Generation Service under their

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applicable retail rate schedule. The returning customer must remain with the Company's Standard Generation Service for at least 1 year.

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-1 will not apply;
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 will be applied to the customer's bill.

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

1. A monthly administrative management fee of $0.00180 per kWh applied to the customer's billed kWh;
2. A monthly reserve capacity charge of $5.540 per kW applied to 100% of the customer's billed kW (on-peak for Rate Schedules E-35 and E-32 TOU L);
3. Returning Customer charge, where applicable, as described herein;
4. Generation Service Provider Default charge, where applicable, as described herein.

These charges and other parameters will be re-evaluated in APS's next rate case, including whether AG-X should be evaluated as a separate customer class in the cost of service study.

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

1. Generation Service charges will 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.

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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 will 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 charges for transmission and distribution will 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, while Capacity Reservation Charge, the Management Fee, and Imbalance Service charges will 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 will 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.

CONTRACT TERM AND REQUIREMENTS

The term of the contract with the Generation Service Provider must be for not less than one year and must include termination provisions to comply with Section IV under imbalance services, as well as general termination provisions should the program be discontinued at some point in the future.

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.

Appendix L

Targets by Class
Settlement

	Target	Percent
Settlement revenue increase	94,624,000	3.28%
Application revenue increase	165,883,743	5.74%
ratio	57.0424%	
adjustor transfer	267,953,000	9.28%
Increase base rates (with adjustor transfer)	362,577,000	12.55%
GS - XS,S decrease to spread to non-res	123,826	0.014%
Schools discount	1,206,688	0.086%

Class	Base Rates ATY Revenue	Present % COS	Application Requested Increase	Step 1 Settlement Requested Increase	Step 2 Spread GS - XS,S hold	Step 3a Recover Schools Discount	Step 3b Receive Schools Discount	**Net Impact** Increase	Adjustor Transfers	Target **Increase Base Rates**	Actual **Increase Base Rates**
Residential	1,486,577,640	85.9%	7.959%	4.54%	0.00%	0.00%	0.00%	4.54%	11.36%	**15.90%**	15.90%
GS - XS,S	515,621,307	123.7%	0.042%	0.04%	0.00%	0.09%	-0.04%	0.09%	8.59%	**8.68%**	8.66%
GS - M	316,428,191	111.9%	4.042%	2.31%	-0.01%	0.09%	-0.17%	2.21%	7.66%	**9.86%**	9.87%
GS - L	293,386,250	100.5%	6.042%	3.45%	-0.01%	0.09%	-0.07%	3.45%	5.10%	**8.55%**	8.55%
GS - XL	203,076,401	87.0%	6.142%	3.50%	-0.01%	0.09%	0.00%	3.58%	4.71%	**8.28%**	8.28%
GS - schools	11,344,975	91.1%	6.042%	3.45%	-0.01%	0.09%	-2.33%	1.19%	9.35%	**10.54%**	10.54%
GS - worship	4,069,264	62.3%	9.042%	5.16%	-0.01%	0.09%	0.00%	5.23%	11.34%	**16.57%**	16.77%
Irrigation	28,739,440	93.7%	5.742%	3.28%	-0.01%	0.09%	0.00%	3.35%	11.30%	**14.65%**	14.66%
Lighting	29,660,294	94.6%	5.742%	3.28%	-0.01%	0.09%	0.00%	3.35%	4.37%	**7.71%**	7.71%
Total	2,888,903,762	95.0%	5.742%	3.28%				3.28%	9.28%	**12.55%**	**12.55%**

		Increase	Increase
residential	1,486,577,640	7.96%	4.54%
Non-res	1,402,326,122	3.40%	1.93%

Appendix M

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SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR STANDARD OFFER AND DIRECT ACCESS SERVICES

Terms and Conditions

The following Terms and Conditions and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (APS or Company). These Terms and Conditions are considered a part of all rate schedules, except where specifically excluded or changed by a written agreement. For a Customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required. If there is a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule apply.

1. **Application for Service**
   Before supplying service APS will verify the identity of Applicant. Applicants may be required to appear at Company's place of business to produce proof of identity, sign an application, or execute a contract for service before APS supplies service. If there is no signed application or contract for service, APS's standard contract terms apply and the supplying of Standard Offer or Direct Access services and Customer's acceptance of service forms a service agreement between APS and the Customer for delivery, acceptance, and payment for services.

   1.1 Grounds for Refusal of Service - APS may refuse service if any of the following conditions exist:

   (A) The Applicant has an outstanding amount due with APS for the same class of service and is unwilling to make payment arrangements that are acceptable to Company.

   (B) A condition exists that in Company's judgment is unsafe or hazardous.

   (C) The Applicant has failed to meet APS's security-deposit requirements outlined in Section 3.

   (D) The Applicant is known to be in violation of a Company Tariff.

   (E) The Applicant fails to furnish the funds, service, equipment, rights-of-way or Easements required to serve the Applicant and that have been specified by APS as a condition for providing service.

   (F) The Applicant falsifies his or her identity for the purpose of obtaining service.

   (G) Service is already being provided at the address for which the Applicant is requesting service.

   (H) Service is requested by an Applicant, and a prior Customer, who will reside at, or benefit from service at the premises, owes APS a delinquent bill for the same class of service, from the same or a prior service address.

   (I) The Applicant has failed to obtain any required permit or inspection indicating that the Applicant's facilities comply with current local construction and safety codes.

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2. **Service-Establishment Charges**
A Service-Establishment Charge of $8.00 for residential or $33.00 non-residential plus applicable adjustments will be assessed each time APS is asked to establish or re-establish electric service, or to make a special read without a disconnect and calculate a bill for a partial month.

2.1 Multiple Connects - If multiple connects are performed during the same site visit, in the same Applicant name, at the same address, and for the same class of service, APS will assess the Service-Establishment Charge once for every two Delivery Points.

2.2 After-hours Charge -The Customer must also pay an after-hours charge plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203.D.3, be established or re-established after 5:00 p.m. on a day other than the day of request. The after-hours charge will be $8.00 for residential with standard metering, $137.00 plus applicable adjustments for residential with non-standard metering or $164.00 plus applicable adjustments for non-residential.

2.3 Same-Day Connect Charge - The Customer must also pay a same-day connect charge of $87.00 plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203.D.3, be established or re-established on the same business day the request is being made, and APS agrees to work the request on the same day of the request. This will be charged regardless of the time the order may be worked by APS on that day. APS may, where no additional costs are incurred by Company, waive the same-day fee.

2.4 Non-Standard Service Request Charge -The Customer must also pay $164.00 plus applicable adjustments per crew-person per hour when Customer requests services that do not meet the definition of Service-Establishment as defined in A.A.C. R14-2-203.D.3 and that require the availability of Company representatives after-hours, on a weekend day, or on a Company holiday. Examples of non-standard service requests are Customer-requested outages for maintenance and metering-equipment installations that include instrument transformers. The number of representatives used by APS to fulfill a request is in the Company's sole discretion. Customers will be given notice of estimated charges before the work is performed.

2.5 Waiving of Service Establishment Charge - Company may waive the Service-Establishment Charge if:

(A) The establishment of service is effective with the last Meter read date billed and a field trip is not required because Applicant accepts responsibility for energy billed and not yet paid.

(B) Applicant has an active Landlord Automatic Transfer of Service Agreement on file with Company.

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3. **Establishing Credit, Security Deposits and other forms of Credit Assurance**
When credit cannot be established as provided for in Section 3.1 and 3.2 or when it is determined that the Applicant left an unpaid final bill owed to another utility company, the Applicant will be required to place a security deposit to secure payment of bills for service.
   - **3.1 Residential Establishment of Credit** - APS will not require a security deposit from a new Applicant for service at a primary or secondary residence if the Applicant can meet any of the following requirements:
     - **(A)** The Applicant has had service of a comparable nature with APS within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months or been disconnected for nonpayment.
     - **(B)** Company receives an acceptable credit rating, as determined by Company, for the Applicant from a credit-rating agency used by Company.
     - **(C)** The Applicant can produce a letter regarding verification of credit from an electric utility where service of a comparable nature was last received within six months of the current date, and the utility states that the Applicant had a timely payment history for the prior 12 consecutive months.
     - **(D)**If in lieu of a security deposit, Company receives an acceptable deposit-guarantee notification from a social or governmental agency or a surety bond in a sum equal to the required deposit.
   - **3.2 Nonresidential Establishment of Credit** - All nonresidential Applicants will be required to place a cash deposit to secure payment of bills for service, unless:
     - **(A)** The Applicant had service of a comparable nature with Company within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months and was not disconnected for nonpayment.
     - **(B)** The Applicant provides a noncash security deposit in the form of a surety bond, irrevocable letter of credit, or assignment of monies in an amount equal to the required security deposit.
   - **3.3 General Deposits Guidelines** - If a security deposit is required, a separate deposit may be required for each service location.
     - **(A)** Customer's security deposits will not preclude Company from terminating an agreement for service or suspending service if Customer fails to meet service-agreement obligations.
     - **(B)** Company may choose to accept less than the full deposit required at time of service establishment based on Customer's financial condition.
     - **(C)** A security deposit may increase or decrease if the Customer's average consumption increases or decreases by more than 10% for residential accounts

or 5% for nonresidential accounts within 12 consecutive months and credit has not been established.

(D) Where three or more additional residential services are requested, Company may require Customer to establish or reestablish a security deposit.

3.4 Residential Security Deposits - Residential security deposits will not exceed two times the Customer's average monthly bill as estimated by Company. APS may require a residential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within a 12 consecutive month period or has been disconnected for non-payment during the last 12 months.

3.5 Nonresidential Security Deposits - Nonresidential security deposits will not exceed two and one-half times the Customer's maximum monthly billing as estimated by Company. APS may require a nonresidential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within 12 consecutive months or if the Customer has been disconnected for nonpayment during the last 12 months, or when the Customer's financial condition may jeopardize the payment of the bill, as determined by Company based on the results of using a credit-scoring worksheet. Company will inform all Customers of the Arizona Corporation Commission's complaint process should the Customer dispute the deposit based on the financial data.

3.6 Deposit Interest - Cash deposits held by APS six months (183 days or longer) earn interest from the date the deposit was collected at the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website.

3.7 Deposit Refunds - If the Customer terminates all service with Company, their security deposit may be credited to any remaining final bills. Any remaining credit balance will be refunded to the Customer of record within 30 days.

3.8 Residential security deposits or other instruments of credit will automatically expire or be credited or returned to the Customer's account after 12 consecutive months of service, if the Customer has not been delinquent in payments more than twice and the Customer has not filed bankruptcy in the last 12 months.

(A) Nonresidential security deposits and noncash deposits on file with Company will be reviewed after 24 months of service and will be returned if:

(1) The Customer has not been delinquent in payments more than twice, has not been disconnected for non-payment, and has not filed for bankruptcy during the previous 12 consecutive months; and

(2) Customer's financial condition does not warrant an extension of the security deposit.

4. Rates

The Customer's service characteristics and service requirements determine the selection of the applicable rate schedule.

4.1 Rate Selection - APS will use reasonable care in initially establishing service to the Customer under the most advantageous rate schedule applicable to the Customer. Because of varying Customer usage patterns and other reasons beyond APS's reasonable knowledge or control, Company cannot guarantee that the most economic applicable rate will be applied. APS will not make any refunds in any instance where it is determined that the Customer would have paid less for service had the Customer been billed on an alternate rate or provision of that rate.

4.2 Rate Information - APS will provide, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to the Customer for the requested type of service. In addition, APS will notify its Customers of any changes in Company Tariff affecting those Customers.

4.3 Optional Rates – Optional rate schedules are available for certain classes of service. After establishing service a Customer may choose an alternate rate schedule effective from the next regularly scheduled Meter reading, after the appropriate metering equipment is reprogramed or installed. No further rate schedule changes may be made within the succeeding 12 month period. If the rate schedule or contract under which the Customer is provided service specifies a term, the Customer may not exercise its option to select an alternate rate schedule until expiration of that term.

5. Billing

Billing Periods for service normally consist of approximately 30 days unless otherwise designated under rate schedules, through contractual agreement, or at Company option.

5.1 Payment of Bills - The Customer is responsible for paying bills until service is ordered discontinued and Company has had reasonable time to secure a final Meter reading for those services involving energy usage, or, if nonmetered services are involved, until Company has had reasonable time to process the disconnect request.

5.2 Failure to Receive Bills or Notices (including notices of disconnection) which have been properly placed in the United States mail or sent through alternative billing forms, such as electronic mail, will not prevent such bills from becoming delinquent or prevent the notices from being effective, or relieve the customer of their obligations.

5.3 Incentive for Electronic Payments - A monthly incentive of $0.48 per Customer will be given to Customers who elect to pay their bills using the Company's electronically transmitted payment options AutoPay, SurePay or similar programs.

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5.4 Billing Errors - When an error is found in the billing sent to the Customer, APS will correct the error to recover or refund the difference between the original billing and the correct billing. Adjusted billings will not be sent for periods beyond the applicable statute of limitations from the date the error is discovered.

5.5 Corrected Charges for Overbilling - Refunds or credits to Customers resulting from overbillings will be made promptly upon discovery by Company.

5.6 Corrected Charges for Underbilling - Except as specified below, corrected charges for underbillings will be limited to three months for residential accounts and six months for nonresidential accounts. Customers will be given an equal length of time, such as the number of months underbilled, to pay the backbill without late-payment penalties. Where the account is billed on a special contract or nonmetered rate, corrected charges for underbillings will be billed in accordance with the contract or rate-schedule requirements and is not limited to three or six months as applicable.

(A) Where service has been established but no bills have been rendered, corrected charges for underbillings will go back to the date service was established.

(B) Where there is evidence of Meter Tampering or energy diversions, corrected charges for underbillings will go back to the date Meter Tampering or energy diversions began, as determined by Company, and APS is not required to give an equal length of time, such as the number of months underbilled, to pay the backbill. APS will work with Customer to establish a payment plan that is acceptable to Company.

(C) Where lack of access to the Meter (caused by the Customer) has resulted in estimated bills, corrected charges for underbillings will go back to the Billing Month of the last Company-obtained Meter-read date.

(D) Where actual Customer usage can be determined without estimating reads, corrected charges for underbillings are not limited to three or six months, as applicable. In no event may such rebilling exceed the applicable statute of limitations.

5.7 Company may forgo correcting a billing error if the amount over or under billed is de minimis and the cost of rebilling does not justify the cost and time required to rebill.

6. Collection Policy

The following collection policies apply to all Customer accounts:

6.1 Delinquent Bills - All bills rendered by Company are due and payable no later than 15 calendar days from the billing date. Any payment not received within this time frame are delinquent. All delinquent accounts, for which payment has not been received, are subject to the provisions of Company's termination procedure.

Company may suspend or terminate a Customer's service for nonpayment of any Arizona Corporation Commission approved charges.

6.2 Late Charges - All delinquent charges, including past due security deposits, are subject to a late charge at the rate of 18% per annum (1.5% per month) plus applicable adjustments.

6.3 Transfer of Outstanding Bills - If a Customer has two or more services with APS and one or more services are terminated for any reason leaving an outstanding bill, and the Customer is unwilling to make payment arrangements that are acceptable to Company, Company may transfer the balance due on the terminated service to any other active account of the Customer for the same class of service. The Customer's failure to pay the active account will result in the suspension or termination of service. If service is requested by two or more individuals, Company has the right to collect the full amount owed from any one of the Customers.

6.4 Dishonored Payments - If Company is notified by the Customer's financial institution that it will not honor a payment tendered by the Customer for payment of any bill, Company may require the Customer to make payment in cash, or by money order, certified or cashier's check, or other means that guarantee the Customer's payment to Company.

(A) The Customer will be charged a fee of $15.00 plus applicable adjustments for each instance where the Customer's payment is not honored by the Customer's financial institution.

(B) The tender of a dishonored payment in no way relieves the Customer of the obligation to pay Company under the original terms of the bill, or defers the Company's right to terminate service for nonpayment of bills.

(C) Where the Customer has tendered two or more dishonored payments in the past 12 consecutive months, Company may require the Customer to make payment in cash, or money order or cashier's check for the next 12 consecutive months.

6.5 Collection Agency Referrals - All unpaid delinquent final bills may be referred to a collection agency for collection. If collection-agency referral is warranted, Customer may be responsible for the associated collection-agency fees incurred.

7. Termination of Service

7.1 To avoid termination of service, the Customer will make payment in full, including any necessary deposit as outlined in Section 3, or make payment arrangements that are satisfactory to Company.

7.2 If service is terminated, APS will not restore service until the conditions which resulted in the termination have been corrected to the satisfaction of Company.

APS may also require payment of Same-Day and After-Hours charges prior to restoring service

7.3 **Termination of Service With Notice** - APS may, without liability for injury or damage, and without making a personal visit to the site, disconnect service to any Customer for any of the reasons stated below, if Company has met the notice requirements established by the Arizona Corporation Commission:

- **(A)** Customer's violation of any applicable rules of the Arizona Corporation Commission or Company Tariff.
- **(B)** A Customer's failure to pay a Delinquent Bill for services provided by Company.
- **(C)** The Customer's breach of a written contract for service.
- **(D)** The Customer's failure to comply with Company's deposit requirements.
- **(E)** The Customer's failure to provide Company with satisfactory and unassisted access to Company's equipment.
- **(F)** When necessary to comply with an order of any governmental agency having jurisdiction.
- **(G)** A prior Customer's failure to pay a Delinquent Bill for utility services where the prior Customer continues to reside on the premises.
- **(H)** Failure to provide or retain rights-of-way or Easements necessary to serve the Customer.
- **(I)** Company learns of the existence of any condition in Section 1.1 - Grounds For Refusal of Service.

7.4 **Termination of Service Without Notice** - Company may, without liability for injury or damage, disconnect service to any Customer without advance notice under any of the following conditions:

- **(A)** If Company observes, or has evidence of, a hazard to the health or safety of persons or property;
- **(B)** If Company has evidence of Meter Tampering or fraud.
- **(C)** If Company has evidence of unauthorized resale or use of electric service.
- **(D)** The Customer fails to comply with the curtailment procedures imposed by Company during a supply shortage.

7.5 **Termination of Service for Dishonored Payment** - Before reconnecting service, payment of funds resulting from a dishonored payment and all other delinquent amounts will be required in cash, money order, or certified funds. If Customer has already received a notice of disconnection at the time the bill became past due, APS may, without liability for injury or damage, disconnect service without additional notice under any of the following conditions:

- **(A)** When Customer makes payments to avoid or stop disconnection with a dishonored payment and has already received a notice at the time the bill became past due.

(B) When Customer pays to reconnect service with a dishonored payment and has already received a notice at the time the bill became past due.

7.6 Termination Process Charges - Company will require payment of a Field Call Charge of $10.00 plus applicable adjustments when an authorized Company representative travels to the Customer's site to accept payment on a delinquent account, notify of service termination, make payment arrangements, or terminate the service. This charge only applies for field calls resulting from the termination process.

(A) If a termination is required at the pole the reconnection charge will be $89.00 plus applicable adjustments.

(B) If a termination is in underground equipment the reconnection charge will be $135.00 plus applicable adjustments.

8. Metering & Metering Equipment

8.1 Standard Metering - The Company's standard method of measuring energy usage is through the use of Automated Metering Infrastructure (AMI) metering equipment. All customers will be served using the Company's standard metering equipment unless:

(A) the customer is in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used; or

(B) the customer meets all eligibility requirements for non-standard metering and voluntarily requests non-standard metering.

8.2 Non-Standard Metering - The Company's non-standard billing meter is the digital meter. A digital meter records energy electronically and displays the usage measurements. This meter does not employ any communications technology and must be read manually each month. Certain optional rates may not be available to customers who select a non-standard meter.

8.3 Non-Standard Metering Eligibility - Only residential customers, in whose name service is being provided, may request non-standard metering. Customers who have an existing, purchased or leased rooftop solar distributed generation (DG) system, or customers with newly installed rooftop solar, are not eligible for non-standard metering.

8.4 Non-Standard Metering Charges –The following charges will apply when a customer voluntarily requests, and is granted, non-standard metering as described in Section 8.1(B):

(A) Monthly Meter Reading Charge: $5.00

(B) Non-Standard Metering Set-up Fee: A $50.00 one-time charge for customerswith existing AMI meter.

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(C) Customers in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used [see 8.1(A)] will not be billed a non-standard meter reading charge.

8.5 Discontinuation of Non-Standard Metering - The Company may replace a non-standard meter with a standard meter, without notifying the customer prior to replacement, under any of the following conditions:

(A) Company employees observe or have evidence of a safety hazard to employees, customers, or Company or customer property.

(B) Company employees observe or have evidence of meter tampering, energy diversion, or fraud.

(C) Company has evidence of unauthorized resale of electricity.

(D) Company employees have received verbal or physical threats, including, but not limited to, verbal threats while installing meters or performing maintenance to Company equipment, and physical threats such as weapons or dogs.

(E) All terms and conditions in Section 7, regarding termination of service, will also apply.

8.6 Measuring Customer Service - All energy sold to the Customer by Company will be measured by commercially acceptable measuring devices. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by Company. The readings of the Meter will be conclusive as to the amount of electric power supplied to the Customer unless there is evidence of Meter Tampering or energy diversion or unless a test reveals the Meter is in error by more than 3%, either fast or slow.

8.7 Meter Rereads – When requested by Customer, APS will reread the customer's Meter within 10 working days after the request. The cost of each reread is $14.00 plus applicable adjustments if the original reading was not in error.

8.8 Meter Testing - APS tests its Meters regularly in accordance with a Meter testing and maintenance program approved by the Arizona Corporation Commission. APS will individually test a Company owned and maintained Meter upon Customer request.

If after testing, a Meter is found to be more than 3% in error, either fast or slow, correction will be made of previous readings and adjusted bills will be rendered.

8.9 Meter Test Charge - If the Meter is found to be within the plus or minus 3% limit, Company may charge the Customer $44.00 plus applicable adjustments for Meter test if the Meter is removed from the site and tested in the meter shop, or $93.00 plus applicable adjustments if the Meter remains on site and is tested in the field.

8.10 Meter Tampering - If there is evidence of Meter Tampering or energy diversion, the Customer, person, or entity demonstrated to have tampered with the Meter, or benefited from the tampering or diversion will be billed for the estimated energy and, if applicable, Demand, for the period in which the energy diversion took place. Additionally, where there is evidence of Meter Tampering, energy diversion, or by-passing the Meter, the Customer, person or entity demonstrated to have tampered with the Meter or diverted energy will also be charged the cost of the investigation as determined by Company.

9. **Service Installations & Metering -** The Customer's service installation will normally be arranged to accept only one type of service at one Point of Delivery to enable service measurement through one Meter. If the Customer requires more than one type of service, or total service cannot be measured through one Meter according to Company's regular practice, separate Meters will be used and separate billing rendered for the service measured by each Meter.

9.1 Customer Equipment - The Customer must install and maintain all wiring and equipment beyond the Point of Delivery except for Company's Meters and special equipment. The Customer's entire installation must conform to all applicable construction standards and safety codes, and the Customer must furnish an inspection or permit if required by law or by Company. In circumstances where a clearance is not required by law, Company may require Customer to execute a Letter In-Lieu of Electrical Clearance. The Customer must also provide, in accordance with APS's current service standards and Electric Service Requirements Manual, at no expense to Company, and close to the Point of Delivery, a space that is, in the Company's opinion, both suitable and sufficient for installing, accessing and maintaining Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line on the Company's website.

9.2 Special Meter-Reading Device - Where a Customer requests, and Company approves, a special Meter-reading device or communications services or devices to accommodate the Customer's needs, the cost for the additional equipment and usage fees are the Customer's responsibility.

9.3 Totalized Metering and Billing - Company normally meters and bills each site separately. But, at Customer's request, adjacent and contiguous sites (not separated by private or public property or right of way), operated as one integral unit under the same name and as a part of the same business, may at Company's option, be considered a single site as specified in Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

9.4 Service Connections - Company is not required to install or maintain any lines and equipment on the Customer's side of the Point of Delivery except its Meter.

(A) For overhead service, the Point of Delivery is where Company's service conductors terminate at the Customer's weatherhead or bus rider.

(B) For underground service, the Point of Delivery is where Company's service conductors terminate in the Customer's or development's service equipment. The Customer must furnish, install, and maintain any risers, raceways, or termination cabinet necessary for installing Company's underground service conductors.

(C) For special Applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, the designated Point of Delivery must be mutually agreed on by the parties.

(D) For the mutual protection of the Customer and Company, only authorized employees or agents of Company or the Load Serving ESP are permitted to make and energize the connection between Company's service wires and the Customer's service entrance conductors. APS employees must carry Company-issued identification that they will show on request.

10. Customer Obligations

10.1 Load Characteristics – The Customer must exercise reasonable care to ensure that the electrical characteristics of its load, such as deviation from sine-wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in Demand, do not impair service to other Customers or interfere with operating any telephone, television, or other communication facilities. Customer must meet power factor requirements as specified in the applicable rate schedules.

10.2 Easements - All suitable Easements or rights-of-way required by Company for any portion of an extension to serve a Customer, which is either on sites owned, leased, or otherwise controlled by the Customer or developer, or other property required for the extension, will be furnished 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 granted to, or obtained on behalf of Company will contain terms and conditions that are acceptable to Company. When Company discovers that the Customer or the Customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow, adjacent to or within an Easement or right-of-way or Company-owned equipment, and the work, construction, vegetation, or facility poses a hazard, or violates federal, state, or local laws, ordinances, statutes, rules, or regulations, or significantly interferes with Company's safe use, operation, or maintenance of, or access to, equipment, or facilities, Company will notify the Customer or the Customer's agent and take whatever actions are necessary to eliminate the hazard, obstruction, interference, or violation at the Customer's expense. Company will notify the Customer in writing of the violations.

10.3 Access for Repair, Maintenance and Service Restoration - Company's authorized agents must have satisfactory unassisted 24 hour a day, seven days a week access to Company's equipment located on Customer's sites for the purpose of repair, maintenance, and service-restoration work that Company may need to perform.

10.4 Access for Install, Inspect, Read, or Remove - Company's authorized agents must have satisfactory unassisted access to the Customer's sites at all reasonable hours to install, inspect, read, or remove its Meters or to install, operate, or maintain other Company property, to verify that Customer is in compliance with its obligations, or to inspect and determine the connected electrical load.

10.5 Trip Charge - A trip charge of $22.00 for residential or $26.00 for non-residential, plus applicable adjustments will be assessed each time an authorized Company representative travels to a site and is unable to complete a Customer's service request because of lack of access to the Point of Delivery.

10.6 Six Months No Access - If Company, in its opinion, does not have satisfactory unassisted access to the Meter after six months (not necessarily consecutive) of good-faith efforts to work with the Customer, then Company has sufficient cause to terminate service or deny any rate options where, in Company's opinion, access is required.

10.7 Remedies - The remedy for unassisted access will be at APS's discretion and may include the installation by Company of a specialized Meter. If a specialized Meter is installed, the Customer will be billed the difference between the otherwise applicable Meter for Customer's rate and the specialized Meter plus the cost incurred to install the specialized Meter as a one-time charge and any reoccurring incremental costs. If service is terminated as a result of failure to provide unassisted access, APS verification of unassisted access will be required before service is restored. Written termination notice is required before disconnecting service under this section.

11. Company Obligations

11.1 Customer-Specific Information - Customer-specific information will not be released without Customer's specific prior written authorization unless the information is requested by a law-enforcement or other public agency, or is requested by the Arizona Corporation Commission or its staff, or is reasonably required for legitimate account-collection activities, or is necessary to provide efficient, effective, safe, or reliable service to the Customer. Customer-specific information may be provided to suppliers of goods or services under contract with Company if the goods or services will help Company to provide efficient, effective, safe, or reliable service; and the contract includes a requirement that the information be kept confidential and be used only to fulfill the supplier's obligations to Company.

11.2 Service Voltage –Company will deliver electric service to the designated Point of Delivery, as specified in Section 9.4 of this Schedule, at the standard voltages specified in the Company's Electric Service Requirements Manual and as specified in A.A.C. R14-2-208.F. Company may deliver service for special applications at higher voltages, with prior approval from Company's Engineering Department and in accordance with Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services approved by the Arizona Corporation Commission.

12. **Limitations on Liability of Company**

12.1 Service Interruptions - Company is not liable to the Customer for any damages caused by Load Serving Electric Service Provider's equipment or failure to perform, fluctuations, interruptions, or curtailment of electric service, except where caused by Company's willful misconduct or gross negligence.

(A) Company may, without incurring any liability, suspend the Customer's electric service for periods reasonably required to permit Company to accomplish repairs to, or changes in, any Company's facilities.

(B) The Customer is responsible for protecting Customer's own sensitive equipment from harm caused by variations or interruptions in power supply.

(C) If a national emergency or local disaster results in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other Customers to provide necessary service to civil-defense or other emergency-service agencies on a temporary basis until normal service to these agencies can be restored.

12.2 Use of Service or Apparatus - The Customer will save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by Company or their use on the Customer's side of the Point of Delivery. Company has the right to suspend or terminate service if Company learns of service use by the Customer under hazardous conditions.

(A) The Customer will exercise all reasonable care to prevent loss or damage to Company property installed on the Customer's site for the purpose of supplying service to the Customer. The Customer is responsible for payment for loss or damage to Company property on the Customer's site arising from neglect, carelessness, or misuse, and will reimburse Company for the cost of necessary repairs or replacements.

(B) The Customer is responsible for payment of any equipment damage or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by-passing the Meter.

(C) The Customer is responsible for notifying APS of any failure in Company's equipment.

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12.3 Removal of Facilities - Upon termination of service, Company may, without liability for injury or damage, dismantle and remove its facilities, installed for the purpose of supplying service to the Customer, and Company will have no further obligation to serve the Customer.

13. Successors and Assigns - Agreements for Service are binding on and for the benefit of the successors and assigns of the Customer and Company, but no assignments by the Customer are effective until the Customer's assignee agrees in writing to be bound and until the assignment is accepted in writing by Company.

14. Warranty – There are no understanding, agreements, representations, or warranties , expressed or implied (including warranties regarding merchantability or fitness for a particular purpose), not specified here or in the applicable rules of the Arizona Corporation Commission concerning the sale and delivery of services by Company to the Customer. These Terms and Conditions and the applicable rules of the Arizona Corporation Commission state the entire obligation of Company in connection with sales and deliveries.

15. Direct Access Service – *NOTE: Retail Electric Competition is currently on hold in APS Service Territory.*

15.1 Direct Access Service Request (DASR) - A Direct Access Service Request charge of $10.00 plus any applicable adjustments will be assessed to the Electric Service Provider (ESP) submitting the DASR each time Company processes a Request (RQ) type DASR as specified in Company's Schedule 10, Terms and Conditions for Direct Access.

15.2 Direct Access Service - Direct Access Service will be effective upon the next Meter read date if DASR is processed 15 calendar days before that read date and the appropriate metering equipment is in place. If a DASR is made less than 15 calendar days before the next regular read date, the effective date will be at the next Meter read date. The above timeframes are applicable for Customers changing their selection of ESP or for Customers returning to Standard Offer service.

(A) Any Customer that selects Direct Access service may return to Standard Offer service in accordance with the rules, regulations, and orders of the Arizona Corporation Commission. The Customer will not be eligible for Direct Access service for the succeeding 12 months.

(B) If a Customer returning to Standard Offer, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will apply only if the Customer fails to select another ESP within 60 days of returning to Standard Offer service.

(C) Unpaid charges incurred before the Customer selects Direct Access will not delay the Customer's request for Direct Access. These charges remain the responsibility of the Customer to pay. Normal collection activity, including discontinuing service, may result from failure to pay.

(D) Where the ESP is the MSP or MRSP, and the ESP or its' agent fails to provide the Meter data to Company under Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, Company may, at its option, obtain the data or estimate the billing determinants.

(E) Where Company is the MRSP, Company will, at the request of the Customer or the ESP, reread or test the Customer's Meter within 10 working days after the request. The cost of each reread or test may be applied to the Customer or ESP when applicable.

(F) All energy sold to the Customer by MRSP will be measured by commercially acceptable measuring devices and under the terms and conditions of Company's Schedule 10 - Terms and Conditions for Direct Access.

15.3 Direct Access Deposits - If the Customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount that reflects the portion of the Customer's service being provided by a Load Serving ESP. If the Load Serving ESP is providing ESP Consolidated Billing under Company's Schedule 10 Section 7, the entire deposit will be credited to the Customer's account; or, if the Customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount under Section 3.3 which reflects that Company is providing bundled electric service.

15.4 Direct Access and Company Equipment

(A) Meters - A Meter Service Provider (MSP) or its authorized agents may remove Company's metering equipment under Company's Schedule 10 Terms and Conditions for Direct Access. Meters not returned to Company or returned damaged will result in charge to the MSP of the replacement costs, plus an administration fee of 15%, less five year's depreciation.

(B) Lock-rings - Company will lease lock-ring keys to MSP's or their agents who are authorized to remove Company Meters under the terms and conditions of Company's Schedule 10 at a refundable charge of $70.00 plus applicable adjustments per key. The charge will not be refunded if a key is lost, stolen, or damaged. If Company must replace 10% of the issued keys within any 12 month period because of loss by the MSP's agent, Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint

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meeting. All lock-ring keys must be returned to Company within five working days if the MSP or its authorized agents are:

No longer permitted to remove Company Meters under the conditions of Company's Schedule 10;

(1)No longer authorized by the Arizona Corporation Commission to provide services; or

(2)The ESP Agreement has been terminated.

(C) **Site Meetings -** If the MSP, the Customer, or the Customer's agent requests a joint site meeting for removal of Company metering and associated equipment or lock ring, a base charge of $62.00 plus applicable adjustments per site will be assessed. Company may assess an additional charge of $53.00 plus applicable adjustments per hour for joint site meetings that exceed 30 minutes. If Company must temporarily replace the MSP's Meter or associated metering equipment during emergency situations or to restore power to a Customer, the above charges may apply.

DEFINITIONS

Applicant means a person requesting the utility to supply electric service. [A.A.C. R14-2-201-(2)]

Application means a request to the utility for electric service, as distinguished from an inquiry as to the availability or charges for such service. [A.A.C. R14-2-201-(3)]

Billing Month means the period between any two regular readings of the utility's Meters at approximately 30 day intervals. [A.A.C. R14-2-201-(5)]

Billing Period means the time interval between two consecutive Meter readings that are taken for billing purposes. [A.A.C. R14-2-201-(6)]

Company holidays (as referred to in section 2.4) are New Year's Day, Martin Luther King Jr. Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, the day after Thanksgiving, and Christmas Day.

Customer means the person or entity in whose name service is rendered, as evidenced by the signature on the Application or contract for that service, or by the receipt and/or payment of bills regularly issued in his name regardless of the identity of the actual user of the service. [A.A.C. R14-2-201-(9)]

Delinquent Bill means a bill in which current electric charges are considered past due (15 *calendar* days after the statement date).

Demand means the rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units. [A.A.C. R14-2-201-(12)]

Distribution Lines means the utility lines operated at distribution voltages which are constructed along public roadways or other bona fide rights-of-way, including Easements on Customer's property. [A.A.C. R-14-2-201-(13)]

Easement means a property owner ("Grantor") grants the right to use the owner's land to another party. An easement gives Company the right to have Company lines on property not owned by the Company. This allows Company to build, replace, repair, operate and maintain electrical equipment for the safe transmission and distribution of electricity. The Grantor may continue to use the land along the easement within certain limitations.

Landlord Automatic Transfer of Service Agreement is a legal contract established between the customer ("Landlord") and Company, that provides continuous and uninterrupted service to the Landlord during intervals when a Landlord has no tenants. A Service Establishment Charge will not apply and service will automatically be transferred into the Landlord's name. Landlord Automatic Transfer of Service Agreements are available to property owners that have established credit with Company.

Master meter means a meter used for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage. [A.A.C. R14-2-201(23)]

Meter means the instrument used for measuring and indicating or recording the flow of electricity that has passed through it. [A.A.C. R14-2-201(25)]

Meter tampering means a situation where a meter has been altered or bypassed without prior written authorization from Company. Common examples are meter bypassing, use of magnets to slow the meter recording, and broken meter seals. [A.A.C. R14-2-201(26)]

Minimum charge means the amount the customer must pay for the availability of electric service, including an amount of usage, as specified in the utility's tariffs. [A.A.C. R14-2-201(27)]

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Point of delivery or delivery point means the point where facilities owned, leased, or under license by a customer connects to the utility's facilities. [A.A.C. R14-2-201(31)]

Tariffs mean the documents filed with the Arizona Corporation Commission which list the services and products offered by the utility and which set forth the terms and conditions and a schedule of the rates and charges, for those services and products. [A.A.C. R14-2-201(42)]

Statement of Charges		
Description	**Charge**	**Reference**
Residential Service Establishment Charge	$8.00	2
Nonresidential Service Establishment Charge	$33.00	2
After hours Charge –Residential Standard Metering	$8.00	2.2
After hours Charge –Residential Non-Standard Metering	$137.00	2.2
After hours Charge –Nonresidential	$164.00	2.2
Same Day Connect Charge	$87.00	2.3
Non-Standard Service Request Charge (per crew person, per hour)	$164.00	2.4
Electronically Transmitted Payment Discount	-$0.48	5.3
Dishonored Payment Fee	$15.00	6.4
Field Call Charge	$10.00	7.6
Overhead Reconnection Charge	$89.00	7.6
Underground Reconnection Charge	$135.00	7.6
Non-Standard Metering- Monthly Meter Reading	$5.00	8.4
Non-Standard Metering Set-up fee for customer with existing AMI meter	$50.00	8.4
Meter Reread	$14.00	8.7
Meter test in shop	$44.00	8.9
Meter test at site	$93.00	8.9

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Trip Charge - Residential	\$22.00	10.5
Trip Charge - Nonresidential	\$26.00	10.5

Appendix N

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

General Description

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

All facility installations and upgrades will 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.

The following provisions govern the installation of overhead and underground electric distribution facilities to applicants whose requirements are deemed by Company to be usual and reasonable in nature.

1. Definitions

1.1 **APS Approved Electrical Distribution Contractor** means an electrical contractor who is licensed in the State of Arizona and properly qualified to install electric distribution facilities in accordance with Company standards and good utility construction practices as determined by Company.

1.2 **Backbone Infrastructure** means the electrical distribution facilities typically consisting of main three-phase feeder lines and/or cables, conduit, duct banks, manholes, switching cabinets and capacitor banks.

1.3 **Conduit Only Design** means the conduit layout design for the installation of underground Extension Facilities that will be required when the Extension Facilities are to be installed at a later date.

1.4 **Conversion** means converting overhead distribution facilities to underground facilities.

1.5 **Corporate Business and Industrial Park 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 or industrial use.

1.6 **Doubtful Permanency means** a customer who in the opinion of the Company is neither Permanent nor Temporary. Service which, in the opinion of the Company, is for operations of a speculative character is considered Doubtfully Permanent.

1.7 **Economic Feasibility** means a determination by Company that the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the applicant.

1.8 **Execution Date** means the date Company signs the agreement after the applicant has signed the agreement and money has been collected by company.

1.9 **Extension Facilities** means the electrical facilities, including conductors, cables, transformers, and related equipment installed solely to serve an individual applicant, or groups of applicants. For example, the Extension Facilities to serve a Residential Subdivision would consist of the line extension required to connect the subdivision to Company's existing system, as well as Company's electrical facilities constructed within the subdivision which would include primary and service lines, and transformers.

1.10 **High Rise Development** means a building built with four or more floors (usually using elevators for accessing floors) that may consist of residential or non-residential use, or a combination of both residential and non-residential uses.

1.11 **Irrigation** means water pumping service.

1.12 **Line Extension Agreement** means the contractual agreement between Company and applicant that defines applicant payment requirements, terms of refund, scope of project, estimated costs, and construction responsibilities for Company and the applicant. Line Extension Agreements may be assigned to applicants successors in interest with Company approval, which approval will not be unreasonably withheld.

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

1.14 **Master Meter** means a meter for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage.

1.15 **Metro Area** means a city with a population of 750,000 or more and its contiguous and surrounding communities.

1.16 **Mixed-Use Development** means a development that consists of both residential and non-residential uses, such as a building with three stories or less, where the first level is for commercial purposes and the upper floors are for residential units, or a development that includes an apartment complex and a commercial center, or a development that includes a subdivision and a water treatment plant.

1.17 **Permanent** means a customer who is a tenant or owner of a service location who applies for and receives electric service, which, in the opinion of the Company, is of a permanent and established character. The use of electricity may be continuous, intermittent, or seasonal in nature. Permanency at the service location may be established by such things as city/county/state permits, a permanent water system, an approved sewer/septic system, or other permanent structures.

1.18 **Project-Specific Cost Estimate** means cost estimates that are developed recognizing the unique characteristics of large or special projects to which the Schedule of Charges is not applicable. A Project-Specific Cost Estimate provided to an applicant is valid for a period of up to six months from the date the estimate is provided to the applicant.

1.19 **Relocation** means moving a distribution line or facilities from its current location to a new location.

1.20 **Residential "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 and the costs to provide service, which may include backbone, transformer and service.

1.21 **Residential Multi-Family Development** means a development consisting of apartments, condominiums, or townhouses with less than four floors.

1.22 **Residential Single Family** means a house, or a manufactured or mobile home Permanently affixed to a lot or site.

1.23 **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 costs to provide service, including backbone, transformers and services for the residential homes or permanent manufactured or mobile home sites.

1.24 **Residual Value** means the remaining un-depreciated original cost of the existing facilities to be removed

1.25 **Rural Arizona Municipality** means Arizona incorporated cities and towns with populations of less than 150,000 (based on U.S. Census Bureau 2010 population data) not contiguous with or situated within a Metro Area.

1.26 **Rural Municipal Business Development** means a tract of land which has been divided into contiguous lots, is owned and developed by an Rural Arizona Municipality, and where the Rural Arizona Municipality will be the lease-holder for future permanent applicants.

1.27 **Schedule of Charges** means the list of charges that is used to determine the applicant's cost responsibility for the Extension Facilities.

1.28 **Service Entrance Upgrade** means the replacement of the customer's electric panel to one with larger load capacity. This includes panels that are upgraded to a larger amperage rating, greater voltage or additional phases (1 phase to 3 phase).

1.29 **Temporary** means premises or enterprises which are temporary in character, or where it is known in advance that the Extension Facilities will be of limited duration.

2. General Provisions for Service

2.1 **Applicant Classification** - For the purposes of this Service Schedule 3, applications for Extension Facilities will be classified as "Residential" or "General Service" as listed below, and further described in the referenced sections.

(A) Residential classifications are: "Residential Single Family Home" (Section 3), "Residential Subdivision Developments" (Section 4), "Residential "Lot Sale" Developments (Section 5), "Master Planned Community Developments" (Section 6) or "Residential Multi-Family Developments" (Section 7).

(B) General Service classifications are: "Basic General Service" (Section 9), "High Rise Developments" (Section 10), Mixed-Use Developments (Section 11), "Corporate Business & Industrial Park Developments" (Section 12), "Temporary Applicants" (Section 13), and "Doubtful Permanency Customers" (Section 14).

2.2 **Schedule of Charges** -An applicant requesting an extension will be provided a sketch showing the Extension Facilities and an itemized cost quote based on the Schedule of Charges or other applicable details. The Schedule of Charges is attached to this Service Schedule as Attachment 1. When the Schedule of Charges is not applicable, charges for Extension Facilities will be determined by the Company based on Project-Specific Cost Estimates. The Schedule of Charges is not applicable for the following:

(A) Extension Facilities requiring modifications, removal, relocations or conversions of existing facilities in conjunction with a new extension or existing customer requested upgrade. The removal, replacement, conversion, and new Extension Facilities charges will be determined by a combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project and may include residual value costs as computed in accordance with the method described in A.R.S 40-347.

(B) Extension Facilities required for modifications, relocations or conversions of existing facilities not in conjunction with a new extension or existing customer upgrade.

(C) Extension Facilities for General Service applicants with estimated demand loads of three megawatts or greater, or that require in aggregate 3,000 kVA of transformer capacity or greater.

(D) Extension Facilities that require three-phase transformer installations greater than the sizes noted in the Schedule of Charges.

(E) Extension Facilities required for High Rise Developments, Mixed-Use Developments, Master Planned Developments or Temporary service.

(F) Extension Facilities involving spot networks, vault installations, primary metering, or specialized or additional equipment for enhanced reliability.

(G) Special studies, leases or permits required by the city, county, state or federal governmental agency for installing electric facilities on private, government or public lands.

2.3 **General Underground Construction Policy** - With respect to all underground installations under a Line Extension Agreement, Company will install underground facilities only if all of the following conditions are met:

(A) The Extension Facilities meet all requirements as specified in "Residential" or "General Service" Sections 2.1 (A) & (B) of this Service Schedule 3.

(B) The applicant signs a trench agreement and provides all earth-work including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications.

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

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

2.4 **Refunds** - The following general refund conditions will apply:

(A) No refund will be made to any applicant for an amount more than the unrefunded balance of the applicant's refundable advance.

(B) Company reserves the right to withhold refunds to any applicant who is delinquent on any account, agreement, or invoice, including the payment of electric service, and may apply these refund amounts to past due bills.

(C) The refund eligibility period for Basic General Service and High Rise Development will be five years from the date Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.

(D) The refund eligibility period for Residential Subdivisions and Multi-Family Developments will be five years and will start three months from the date Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.

(E) Refunds will be mailed to the applicant of record noted on the executed agreement no later than 60-days from the annual review date.

2.5 **Interest** - All refundable advances made by the applicant to the Company will be non-interest bearing.

2.6 **Ownership** - Except for applicant owned facilities, all Extension Facilities installed in accordance with this Service Schedule 3 will be owned, operated, and maintained by Company.

RESIDENTIAL

3. Residential Single Family Homes

3.1 Extension Facilities will be installed to new Permanent residential applicants or groups of new Permanent residential applicants on a free footage basis under the following conditions:

(A) A Line Extension Agreement signed by the applicant and construction costs in excess of the allowances, as described in 3.1(C) and 3.2 will be paid by the applicant before the Company begins installing facilities. Payment is due at the time the Line

Extension Agreement is signed by the applicant.

(B) The site plan has been approved and recorded in the county having jurisdiction.

(C) The total footage of the Extension Facilities (primary, secondary, service) does not exceed 750 feet per applicant or $10,000; or

(D) The total cost of the Extension Facilities, as determined by Company, is less than $10,000 per applicant.

3.2 All additional construction costs over $10,000 per applicant will be paid by applicant as a non-refundable contribution in aid of construction.

3.3 Applicants who combine to form a group may also combine their allowance as specified in Sections 3.1(C) and 3.2.

3.4 The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project which will exclude the cost of one single-phase transformer.

3.5 The footage allowance of 750 feet and the cap of $10,000 will be reviewed from time to time with the Arizona Corporation Commission.

3.6 Examples of the application of Section 3.1 can be found in Attachment 2 – Free Footage Illustrative Example.

4. Residential Subdivision Developments

4.1 Extension Facilities will be installed to Residential Subdivision Developments of four or more homes in advance of application for service by Permanent customers under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of construction by the Company. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The subdivision development plat has been approved and recorded in the county having jurisdiction. Applicant is responsible for providing Company an approved subdivision plat prior to project design. If final approved plat is different from what was originally submitted to Company it may cause delays and additional cost for redesign.

4.2 The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

4.3 A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per lot" allowance provisions of Section 4.6 and in accordance with Section 2.4.

4.4 In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond based on the financial condition, or organizational structure of developer.

4.5 That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as street lights.

4.6 The refundable advance will be eligible for refund based on a "per lot" allowance of $3,500 for each Permanently connected residential customer over a five year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date Company executes the Line Extension Agreement with the applicant. A review of the project will be conducted annually to determine subdivision buildout, and if the qualifications have been met for any refunds.

4.7 Examples of the application of Section 4 can be found in Attachment 3 – Residential Subdivision Illustrative Example.

5. Residential "Lot Sale" Developments

5.1 Extension Facilities will be installed to Residential "Lot Sale" Developments in advance of application for service by Permanent applicants under the following conditions:
(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
(B) The development plat has been approved and recorded in the county having jurisdiction.

5.2 The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

5.3 The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for street lights and other non-standard construction charges.

5.4 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. Future extensions in the development will be required to follow the original design plan.

5.5 Extension Facilities will be installed to individual applicants in accordance with provisions listed in Section 3.

6. Master Planned Community Developments

6.1 Extension Facilities will be installed to Master Planned Community Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county having jurisdiction.

6.2 The cost of extending service to applicant will be determined by a Project-Specific Cost Estimate based on the scope of the project.

6.3 The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for street lights and other non-standard construction charges.

6.4 Extension Facilities will be installed to each subdivided tract within the planned development in accordance with the applicable sections of this Service Schedule 3.

7. Residential Multi-Family Developments

7.1 Extension Facilities will be installed to Residential Multi-Family Developments in advance of application for service by Permanent customers under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county having jurisdiction.

7.2 The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost estimate depending on the scope of the project.

7.3 A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per unit" refundable allowance provisions of Section 7.6 and in accordance with Section 2.4.

7.4 In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond based on the financial condition, or organizational structure of applicant.

7.5 That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as street lights etc.

7.6 The refundable advance will be eligible for refund based on a "per unit" allowance of $1,000 for each new meter, installed for a permanent residential structure, over a five year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date Company executes the Line Extension Agreement. A review of the project will be conducted annually to determine buildout and if the qualifications have been met for any refunds.

<u>GENERAL SERVICE</u>

8 General Service Provisions

8.1 Extension Facilities that do not meet the requirements under Residential Sections 3, 4, 5, 6, or 7 will be considered General Service and will be installed to all applicants who meet the qualifications under Sections 9, 10, 11, 12, 13, or 14 of this Service Schedule 3.

9 Basic General Service

9.1 Extension Facilities will be installed to Basic General Service in advance of application for service by Permanent applicants under the following conditions:
(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
(B) The site development plan for the project for which the Line Extension has been requested has been approved and recorded in the county having jurisdiction.

9.2 The project costs for Basic General Service installations will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or a combination of Schedule of Charges and Project-Specific Cost Estimate depending on the scope of the project.

9.3 The cost for Extension Facilities installed for applicants with estimated demand loads of less than three megawatts or less than 3,000 kVA of transformer capacity, will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

9.4 The cost for Extension Facilities installed for applicants with projected loads of three megawatts or greater, requiring transformer capacity of 3,000 kVA and greater, special requests involving primary metering, or specialized/additional equipment for enhanced reliability will be determined by the Company based on Project-Specific Cost Estimates.

9.5 Economic Feasibility Analysis for Basic General Service Applicants - Applicants who's Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Project Cost $25,000 or less - Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is $25,000 or less will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments) multiplied by six is equal to or greater than the cost of the applicant's Extension Facilities.

(B) Project Cost greater than $25,000 - Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(C) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(D) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(E) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10 High Rise Developments

10.1 Extension Facilities will be installed to High Rise Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

(C) The residential units are individually metered or master metered in accordance with Section 21.

(D) Extension Facilities will be installed to designated points of delivery in accordance with APS's Electric Service Requirements Manual (ESRM). It is the applicant's responsibility to provide and maintain the electrical facilities within the building.

10.2 The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate, and will be paid by the applicant before Company installing facilities.

10.3 Economic Feasibility Analysis for High Rise Developments - Applicants who's Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10.4 Before Company orders specialized materials or equipment required to provide service, applicant will be required to make an advance payment to the Company for the estimated cost of the material or equipment in accordance with Section 27.2.

11 Mixed-Use Developments

11.1 Extension Facilities will be installed to Mixed-Use Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

(C) The residential units are individually metered or master metered in accordance with Section 21.

11.2 The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate, and will be paid by the applicant before Company installing facilities.

11.3 Economic Feasibility Analysis for Mixed-Use Developments - Applicants who's Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

11.4 Before Company orders specialized materials or equipment required to provide service applicant will be required to make an advance payment to the Company for the estimated cost of the material or equipment in accordance with Section 27.2.

12 Corporate Business & Industrial Park Developments

12.1 Extension Facilities will be made to Corporate Business and Industrial Park Developments in advance of application for service by Permanent customer under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

12.2 The cost of installing Extension Facilities will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a project-specific cost estimate depending on the scope of the project.

12.3 The cost for Extension Facilities installed for applicants with estimated demand loads of less than three megawatts or less than 3,000 kVA of transformer capacity, will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

12.4 The cost for Extension Facilities installed for applicants with projected loads of three megawatts or greater, requiring transformer capacity of 3,000 kVA and greater, special requests involving primary metering, or specialized/additional equipment for enhanced reliability will be determined by the Company based on Project-Specific Cost Estimates.

12.5 The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for street lights and other non-standard construction charges.

12.6 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. Future extensions in the development will be required to follow the original design plan.

12.7 Extension Facilities will be installed to individual lots (at the request of an applicant) within the Corporate Business and Industrial Park Development in accordance with the applicable sections of this Service Schedule 3.

13 Temporary Applicants

13.1 Where Temporary Extension Facilities are required to provide service to the applicant, the applicant will make a non-refundable payment in advance of installation or construction equal to the cost of installing and removing of the facilities required in providing Temporary service, less the salvage value of such facilities. Charges will be determined by Company based on a Project-Specific Cost Estimate.

13.2 A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

13.3 When use of the Temporary service is discontinued or service is terminated, Company may dismantle and remove its facilities and the materials and equipment provided by Company will remain Company property.

14 Doubtful Permanency Customers

14.1 When, in the opinion of Company, Permanency of the applicant's residence or operation is doubtful, the applicant will be required to pay the total cost of the Extension Facilities. The cost of extending service to applicant will be determined in accordance with the

Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for street lights and other non-standard construction charges.

14.2 A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

OTHER CONDITIONS

15 Municipalities and Other Governmental Agencies

15.1 Extension Facility installations, relocations, or conversions of existing facilities required to serve loads of municipalities or other governmental agencies may be constructed before the receipt of a signed Line Extension Agreement. However, this does not relieve the municipality or governmental agency of the responsibility for payment of the Extension Facilities costs in accordance with the applicable sections of this Service Schedule 3.

15.2 The effective date for projects enacted under this provision for purposes of refunds (Section 2.4) will be the date the municipality or agency provided written approval to the Company to proceed with construction.

16 Change in Applicant's Service Requirements

16.1 Company will rebuild, modify, or upgrade its existing facilities to meet the applicant's added load, service entrance upgrade, or change in service requirements on the basis specified in Sections 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, or 14. Charges for such changes will be in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a Project-Specific Cost Estimate determined by the Company based on project-specific requirements.

17 Relocations, Conversions and Upgrades of Company Facilities

17.1 **Relocations** - Company will relocate its facilities at the applicant's request. The cost of relocations not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.

(A) When the relocation of Company facilities involves "prior rights" conditions, the applicant will be required to make payment equal to the estimated cost of relocation as a non-refundable contribution in aid of construction. In addition, applicant will be required to provide similar "rights" for the relocated facilities.

(B) Payment of all project costs is required prior to the start of Company construction.

Payment is due at the time the Line Extension Agreement is signed by applicant.

17.2 **Conversions** - Company will convert from overhead to underground its facilities at applicant request. The cost of conversions not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate and may include residual value costs as computed in accordance with the method described in A.R.S. Section 40-347.

(A) The applicant will be required to make a payment equal to the estimated cost of conversion as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

17.3 **Upgrades** - Company will upgrade its facilities at applicant request. The cost of Company facility upgrades not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.

(A) The applicant will be required to make a payment equal to the estimated cost of the upgrade as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

18 Additional Primary Feed or Specialized Equipment

18.1 When specifically requested by an applicant to provide an alternate primary feed or specialized equipment (excluding transformation), Company will perform a special study to determine the feasibility of the request. The applicant will be required to pay for the cost of the additional feed requested as a non-refundable contribution in aid of construction. Installation cost will be based on a Project-Specific Cost Estimate. Payment for the installation of Extension Facilities is due at the time the Line Extension Agreement is signed by the applicant.

19 Unusual Circumstances

19.1 In unusual circumstances as determined by Company, when the application and provisions of this Service Schedule 3 appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when applicant's estimated demand load will exceed 3,000 kW, Company may 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 the Company's Service Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

20 Abnormal Loads

20.1 Company, at its option, may install Extension Facilities 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 applicant will be included in the payment described in previous sections of this Service Schedule 3.

21 Master Metering

21.1 **Mobile Home Parks** - Company will refuse service to all new construction or expansion of existing Permanent residential mobile home parks unless the construction or expansion are individually metered by Company.

21.2 **Residential Apartment Complexes, Condominiums** - Company will 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 Arizona Administrative Code and the requirements discussed in 21.3 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.

21.3 **Multi-Unit High Rise Residential Developments** - Company will allow master metering for high rise residential units under the following conditions:

(A) The building will be served by a centralized heating, ventilation or air conditioning system

(B) Each residential unit will be individually sub-metered and responsible for energy consumption of that unit.

(C) Sub-metering will be provided and maintained by the builder or homeowners association.

(D) Responsibility and methodology for determining each unit's energy billing will be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company before Company installing Extension Facilities.

21.4 **Conversion from Master Meter to Individually Metered System** - Company will convert its facilities from a master metered system to a Permanent individually metered system at the applicant's request provided the applicant makes a non-refundable contribution in aid of construction 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 in accordance with the applicable sections of this Service Schedule 3. Applicant is responsible for all costs related to the installation of new service entrance equipment.

22 Voltage

22.1 All Extension Facility installations will be designed and constructed for operation at standard voltages used by Company in the area in which the Extension Facilities are located. At the request of applicant, Company may, at its option, deliver service for special applications of non-standard or higher voltages with prior approval from Company's Engineering Department. Applicant will be required to pay the costs of any required studies as a non-refundable payment.

22.2 Extension Facilities installed at higher voltages will be limited to serving an applicant operating as one integral unit under the same name and as part of the same business on adjacent and contiguous sites not separated by private property owned by another party or separated by public property or public right–of- way.

23 Point of Delivery

23.1 For overhead service, the point of delivery will be where Company's service conductors terminate at the applicant's weatherhead or bus riser.

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

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

24 Easements

24.1 Before Company begins construction of Extension Facilities, all suitable easements and rights-of-way required for any portion of the extension, will be obtained by applicant and provided to Company in Company's name without cost to, or condemnation by Company. All easements and rights-of-way obtained on behalf of Company will be on Company's standard easement form which contains the terms and conditions that are acceptable to Company.

25 Grade Modifications

25.1 If after construction of Extension Facilities, the final grade of the property established by the applicant is changed in such a way as to require relocation of Company facilities, or the applicant's actions or those of his contractor results in damage to such facilities, the cost of replacement, relocation, or any resulting repairs will be borne by applicant as a non-refundable contribution in aid of construction.

26 Measurement and Location

26.1 Measurement must be along the proposed route of construction.

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

26.3 Extension Facilities must be a branch from, the continuation of, or an addition to, Company's existing distribution facilities.

27 Agreements

27.1 **Study and Design Agreements** -Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost estimates will be required to make a payment to Company in an amount equal to the estimated cost of preparation. When the applicant authorizes Company to proceed with construction of the Extension Facilities, the payment will be credited to the cost of the Extension Facilities otherwise the payment will be non-refundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the applicant upon request.

27.2 **Material Order Agreements** - Any applicant requesting Company to enter into a Line Extension Agreement, or relocation agreement which requires either large quantities of material or material and equipment which the Company does not keep in stock will be required to make a payment to Company before the material being ordered in an amount equal to the material/equipment's estimated cost. When the applicant authorizes Company to proceed with construction of the extension, the payment will be credited to the cost of the extension; otherwise the payment will be non-refundable.

27.3 **Line Extension Agreements** - All facility installations or equipment upgrades requiring payment by an applicant will be in writing and signed by both the applicant and Company.

28 Applicant Construction of Company Distribution Facilities

28.1 Applicant may provide construction related labor only services associated with the installation of new distribution line facilities (21 kV and below) to serve the applicant's new or added load provided the applicant receives written approval from Company before performing any such services and uses electrical contractors who are qualified and licensed in the State of Arizona to construct such facilities and designated as an APS Approved Electrical Distribution Contractor.

28.2 This option is not available for the following:
(A) Replacement, modifications, upgrades, relocation, or conversions of existing systems.
(B) Where all or a portion of the distribution line facilities are to be constructed on or installed on existing distribution line or transmission lines.

28.3 All construction services provided by the applicant will be subject to inspection by a duly authorized Company representative and will comply with Company designs, construction standards, and other requirements which may be in effect at the time of construction. Any work found to be substandard in the sole opinion of the Company must be corrected by applicant before energization by Company.

28.4 Applicant will reimburse Company for all inspection and project coordination costs as a non-refundable contribution in aid of construction. Estimated costs for inspection and project coordination will be identified in the construction agreement executed by Company and applicant.

28.5 Costs for Extension Facilities for applicants who provide construction of Company distribution facilities will be based on a Project-Specific Cost Estimate.

28.6 A signed agreement and payment of all project costs minus labor are required before the start of applicant construction. Payment is due at the time the agreement is signed by the applicant.

28.7 For applicants that are not served by the terms in General Service Sections of this document, Company will provide a Project-Specific Cost Estimate. Applicants may submit an invoice detailing costs of Extension Facilities and apply any allowance provided in Residential Sections 3, 4, or 7 to these costs. At no point will these costs exceed the Company's Project-Specific Cost Estimate.

28.8 Applicants served by the terms in General Service Sections 9, 10, 11, 12, 13, or 14 of this document will be subject to the rules set forth in the respective section and Refund Section 2.4.

29 Settlement of Disputes

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

30 Policy Exceptions

30.1 This Schedule 3 is applicable to all applicants unless specific exceptions are approved by the Arizona Corporation Commission. The following exceptions have been approved for Rural Municipality applicants:

(A) Extension Facilities will be installed to Rural Municipal Business Developments on the basis of an Economic Feasibility analysis in advance of application for service by Permanent applicants.

(B) The cost of installing Extension Facilities to Rural Municipal Business Developments will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

(C) The refund eligibility period for Rural Municipal Business Developments will be seven years from the date the Company executes the Line Extension Agreement with the Rural Municipality applicant.

(D) Rural Municipal Business Development applicants will be required to advance payment of one-half of the project costs at the time the Line Extension Agreement is signed and before the start of Company construction. The balance of the project cost will be required seven years from the Execution Date of the agreement if the project has not become economically feasible by the end of the seven year refundable period. Any unrefunded advance balance paid at the start of the project, plus the balance of project costs due at the end of refund period, will become a non-refundable contribution in aid of construction seven years from the Execution Date of the agreement.

(E) Company may require a Surety Bond, Irrevocable Letter of Credit or Assignment of Monies in amount equal to any Advance not collected at the start of construction.

(F) The Economic Feasibility analysis for the Rural Municipal Business Development's Extension Facilities will be reviewed at the end of the third, fifth and seventh year of the Line Extension Agreement based on the average monthly demand within the Rural Municipal Business Development for the preceding year and to the degree that the average monthly demand supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance.

(G) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

aps

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

Attachment 1
Schedule of Charges – Single Phase

APS Schedule 3 Rev 13, Line Extension Schedule of Charges

Single Phase	OH Primary	UG Primary				OH Secondary	UG Secondary	
	Cost per Circuit Foot	Cost per Circuit Foot	Pull Box	Pad Mount Junction Cabinet	OH/UG Transition	Secondary Pole	OH/UG Secondary Transition	J Box
	$16.67	$5.64	$898	$3,889	$1,346	$2,259	$892.22	$105.55
	Each Installation							
Pole Interset	$10,251.54							
OVERHEAD Single Phase	SES Size	Transformer Size, 120/240V		Service wire/Linear Ft				
	200 Amp	25kVA	$3,853	$6.15				
	200 Amp	50kVA	$4,178	$7.90				
	400 Amp	50kVA	$4,178	$7.90				
	600 Amp	75kVA	$5,249	$13.06				
	800 Amp	100kVA	$6,057	$18.23				
UNDERGROUND Single Phase	SES Size	Transformer Size, 120/240V		Service wire/Linear Ft				
	200 Amp	25kVA	$4,266	$5.22				
	200 Amp	50kVA	$4,657	$6.66				
	400 Amp	50kVA	$4,657	$6.66				
	600 Amp	75kVA	$5,229	$13.46				
	800 Amp	100kVA	$5,984	$14.91				

1) Extension Facilities that do not qualify for the Schedule of Charges will be determined by a project specific cost estimate.
2) Cost per foot charges will be determined from termination at the source to the next device in the circuit. Linear footage for each circuit will be summed to determine charges.
3) Pad Mount Junction Cabinet is a single phase termination cabinet.
4) Primary OH cost per foot is for one phase and a neutral or two phases and no neutral; includes poles, framing, 2R conductor.
5) Charges for services are based on linear footage from Transformer to SES regardless of the number of sets. J Boxes not included in footage cost.
6) All footages to be calculated by linear footages.
7) Transition is from the OH line to the UG line: includes wire down pole and accessories. Pole NOT included.

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

Attachment 1
Schedule of Charges - Three Phase

APS Schedule 3 Rev 13, Line Extension Schedule of Charges

	Overhead	Underground								
FEEDER Three Phase	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	Cost per Circuit Foot 1100A Cable (3-1100)	Cost per Circuit Foot 1100A Cable (6-1100)
	$29.31	$24.36	$4,694	$13,345	$48.08	$8,435	$19,144	$17,981	$27.63	$54.63
		Each Installation			Each Installation				Each Installation	Each Installation
OH/UG Transition		$6,566			$7,947				$6,603	$8,021
	Each Installation									
Pole Interset	$10,425.96									
	Overhead	Underground								
PRIMARY Three Phase	Cost per Circuit Foot	Cost per Circuit Foot (3-1/0T)	Cost per Circuit Foot (3-4/0T)	Pull Box	Pad Mount Switch Gear					
	$22.18	$16.80	$19.91	$1,647	$17,981					
		Each Installation	Each Installation							
OH/UG Transition		$3,004	$3,100							
	Each Installation									
Pole Interset	$10,425.96									
	Overhead									
OVERHEAD Three Phase	SES Size	Transformer Size 120/208 Volts		Service wire/Linear Ft		SES Size	Transformer Size 277/480 Volts		Service wire/Linear Ft	
	200 Amp	3-25kVA	$9,047	$6.29		200 Amp	3-50kVA	$12,069	$6.29	
	200 Amp	3-50kVA	$10,422	$6.29						
	400 Amp	3-50kVA	$10,422	$8.19		400 Amp	3-75kVA	$14,064	$8.19	
	600 Amp	3-50kVA	$10,422	$10.42		600 Amp	3-100kVA	$15,939	$10.42	
	800/1000 Amp	3-75kVA	$13,619	$19.69		600 Amp	3-167kVA	$18,181	$10.42	
	Underground Pad mount									Transition
UNDERGROUND Three Phase	SES Size	Transformer Size 120/208 Volts		Service wire/Linear Ft		SES Size	Transformer Size 277/480 Volts		Service wire/Linear Ft	OH/UG Secondary Transition
	200 Amp	112.5kVA	$8,337	$7.12		200 Amp	112.5kVA	$11,080	$7.12	
						400 Amp	150kVA	$12,434	$12.71	
	400 Amp	112.5kVA	$8,337	$12.73		400 Amp	225kVA	$13,445	$12.71	$927.66
	600 Amp	150kVA	$12,495	$18.08		600 Amp	300kVA	$15,042	$22.86	
	800 Amp	225kVA	$13,907	$36.16		800 Amp	500kVA	$17,145	$36.09	
	1000 Amp	225kVA	$13,907	$36.16		1000 Amp	500kVA	$17,145	$36.09	
	1200 Amp	300kVA	$15,181	$36.16		1200 Amp	750kVA	$21,376	$54.01	
	1600 Amp	500kVA	$19,433	$72.04		1600 Amp	1000kVA	$24,378	$72.04	
	2000 Amp	500kVA	$19,438	$72.04		2000 Amp	1000kVA	$24,383	$72.04	
	2500 Amp	750kVA	$25,603	$126.10		2500 Amp	1500kVA	$34,903	$108.09	
	3000 Amp	750kVA	$25,613	$126.10		3000 Amp	1500KVA	$34,913	$108.09	
	3000 Amp	1000kVA	$30,638	$162.05		3000 Amp	2000kVA	$42,539	$162.05	

1) Extension Facilities that do not qualify for the Schedule of Charges will be determined by a project specific cost estimate.
2) Cost per foot charges will be determined from termination at the source to the next device in the circuit. Linear footage for each circuit will be summed to determine charges.
3) 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 total of each SES size in amps, rounded up to the nearest SES size, limited to a combined maximum of 3,000 amps.
4) Overhead feeder cost per foot is for 3/0 and above, including 477 & 795 conductors.
5) UG Primary circuit footage is 3 cables making up 3 phase; 2 circuits is parallel conductors.
6) Charges for services are based on linear footage from transformer to SES regardless for the number of sets.
7) Transition is from the OH line to the UG line: includes wire down pole and accessories. Pole NOT included.

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

Attachment 2
Examples to Section 3* - Free Footage Illustrative Example

	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 1	**500**	**$15.00**	**50**	**$ 4.89**	**550**	**$ 7,744.50**	**$ -**

APS $7,744.50** | Total 550' | Customer Payment $0

	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 2	**620**	**$ 15.00**	**135**	**$ 4.89**	**755**	**$ 9,960.15**	**$ -**

APS $9,960.15** | Total 755' | Customer Payment $0

	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 3	**675**	**$ 15.00**	**50**	**$ 4.89**	**725**	**$ 10,369.50**	**$ 369.50**

APS $10,000.00** | Total 725' | Customer Payment $369.50

	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 4	**660**	**$ 15.00**	**90**	**$ 4.89**	**750**	**$ 10,340.10**	**$ 340.10**

APS $10,000.00** | Total 750' | Customer Payment $340.10

	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 5	**700**	**$ 15.00**	**100**	**$ 4.89**	**800**	**$ 10,989.00**	**$ 989.00**

APS $10,000.00** | Total 800' | Customer Payment $989.00

*Scenarios do not reflect all components required for a complete project. **APS portion does not include cost of transformer.

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

Attachment 3
Residential Subdivision Illustrative Example

Scenario 1	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 2	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 3	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

Scenario 4	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

Appendix O

Lost Fixed Cost Recovery
Plan of Administration

Effective Date: XXXX

Table of Contents

1. General Description

This document describes the plan of administration for the Lost Fixed Cost Recovery (LFCR) mechanism approved for Arizona Public Service Company (APS or Company) by the Arizona Corporation Commission (ACC or Commission) on XX/XX/XXX in Decision No. XXXXX. The LFCR mechanism provides for the recovery of lost fixed costs authorized by the Commission, as measured by revenue, associated with the amount of energy efficiency (EE) savings and distributed generation (DG) determined to have occurred. Costs to be recovered through the LFCR include the portion of distribution costs included in base rates, less what is already recovered by 50% of demand revenues associated with distribution.

2. Definitions

Applicable Company Revenues - The amount of revenue generated by sales to retail customers, for all applicable rate schedules.

Current Period - The most recent adjustment year.

DG Savings - The amount of MWh sales reduced by DG. APS will use meter data to calculate DG system savings where available. Each year, APS will use actual data from January through September and forecast data for the remainder of the calendar year (October through December) to calculate the savings. The calculation of DG Savings will consist of the following by class:

a. 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.

b. Excluded MWh Production: The reduction of recoverable DG Savings calculated for commercial and industrial customers, by subtracting the amount of DG produced by customers on Excluded Rate Schedules.

c. 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.

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

EE Savings - The amount of MWh sales reduced by EE as demonstrated by the Measurement, Evaluation, and Research (MER) conducted for EE Programs. The calculation of EE Savings will consist of the following by class:

a. 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.

b. Current Period: The annual EE related sales reductions (MWh). Each year, APS will use actual pre-MER verified data through November and forecast data for December to calculate annual savings.

c. Excluded MWh reduction: The reduction of recoverable EE Savings calculated for commercial and industrial customers, by subtracting the amount of EE Savings actually achieved by customers on Excluded Rate Schedules.

d. True-Up Prior Period: The reconciliation of APS's forecast data of annual EE sales reductions for the Prior Period to the MER verified EE sales reductions in the Prior Period.

Excluded Delivery Revenue - 50% of any delivery demand (kW) revenue as determined in Decision No. XXXXX and calculated on Schedules 6 and 7.

Excluded Rate Schedules - The LFCR mechanism will not apply to large general service customers taking service under rate schedules E-32 L, E-32 L TOU, E-34, E-35, XHLF and E-36 XL, or to unmetered General Service customers under E-30 and lighting schedules, Contract 12.

LFCR Adjustment - Total Lost Fixed Cost Revenue as calculated on Schedule 2, divided by forecast retail kWh sales for the proposed adjustor period. For customers on a demand rate the adjustment will be applied as a kW charge. For customers on an energy only rate the adjustment will be applied as kWh charge. This adjustment will be applied to all customer bills, with the exception of those customers on Excluded Rate Schedules, or if the customer's current rate has alternate provisions.

Lost Fixed Cost Rate - A rate determined at the conclusion of APS's most recent general rate case by taking the sum of allowed Distribution Revenue for each General Service & Residential 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 calendar year. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable MWh Savings, by rate class.

Prior Period - The 12 months preceding the Current Period.

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

Transition Balance - The Lost Fixed Cost Revenue balance as calculated in compliance with the LFCR Plan of Administration applicable during that time period per Decision No. 73183 and modified in Decision No. 74202.

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 Treasury Constant Maturities, effective on the first business day each year, as published on the Federal Reserve website or its successor publication will be applied annually to any deferred balance.

4. Historical Transition

Upon implementation of the revised LFCR Plan of Administration in Decision No. XXXXX, the Transition balance will be calculated on Schedule 4 (LFCR Historical Transition) and reported on Schedule 2 (LFCR Annual Incremental Cap Calculation).

5. Filing and Procedural Deadlines

APS will file the calculated LFCR Adjustment, including all Compliance Reports, with the Commission for the previous year by February 15th. The new LFCR Adjustment will not go into effect until approved by the Commission. If approved, the new rate will take effect with the first billing cycle in May, unless otherwise specified by the Commission.

6. 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
- Schedule 2: LFCR Annual Incremental Cap Calculation
- Schedule 3: LFCR Calculation
- Schedule 4: LFCR Historical Transition
- Schedule 5: LFCR Test Year Rate Calculation
- Schedule 6: Distribution Revenue Calculation - General Service
- Schedule 7: Distribution Revenue Calculation - Residential
- Schedule 8: Annual DG Installation Report

Schedules 1 through 8, attached hereto, will be submitted with APS's annual compliance filing.

Line No.	(A) **Annual Percentage Adjustment**	(B) **Reference**		(C) **Total**
1.	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 15	$	-
2.	Applicable Company MWh			-
3.	$/kWh	Line 1 / Line 2	$	-
4.	Applicable Company MWh for customer billed demand			-
5.	$ for Customers Billed Demand	Line 3 * Line 4	$	-
6.	Applicable Company MW for customer billed demand			-
7.	$/kW	Line 5 / Line 6	$	-

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 33, Column C	$	-
4a	Historical Transition	Schedule 4, Line 33, Column C	$	-
5.	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 13, 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 4a + Line 5 + Line 7)	$	-
9.	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 15, Column C	$	-
10a	Lost Fixed Cost Revenue - Billed[1]		$	-
10b	Rate Rider LFCR DG - Billed[1,2]		$	-
10c	Grid Access - Billed[1,2]		$	-
11.	LFCR Balancing Account	(Line 9 - Line 10)	$	-
12.	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9 + Line 11)	$	-
13.	Amount in Excess of Cap to Defer	(Line 12 - Line 3)	$	-
14.	Incremental Period Adjustment as %	[(Line 12 - Line 13) / Line 1]		0.00%
15.	Total Lost Fixed Cost Revenue for Current Period	(Line 8 + Line 11 - Line 13)	$	-

[1] Amount billed to customers for the 12 calendar months of 20XX.

[2] Excludes amount billed to customers with DG installations prior to 2016.

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

Line No.	(A) Lost Fixed Cost Revenue Calculation	(B) Reference	(C) Totals	(D) Units
	Residential			
	Energy Efficiency Savings			
1.	Current Period		-	MWh
2.	Prior Period		-	MWh
3.	Verified - Prior Period		-	MWh
4.	True-Up Prior Period	(Line 3 - Line 2)	-	MWh
5.	Cumulative Verified		-	MWh
6.	Total Recoverable EE Savings	(Line 1 + Line 4 + Line 5)	-	MWh
	Distributed Generation Savings			
7.	Current Period		-	MWh
8.	Prior Period		-	MWh
9.	Verified - Prior Period		-	MWh
10.	True-Up Prior Period	(Line 9 - Line 8)	-	MWh
11.	Total Recoverable DG Savings	(Line 7 + Line 10)	-	MWh
12.	Total Recoverable MWh Savings	(Line 6 + Line 11)	-	MWh
13.	Residential - Lost Fixed Cost Rate	Decision No. 73183	$ 0.031111	$/kWh
14.	Residential - Lost Fixed Cost Revenue	(Line 12 * Line 13)	$ -	
	C&I			
	Energy Efficiency Savings			
15.	Current Period		-	MWh
16.	Excluded MWh reduction		-	MWh
17.	Net - Current Period	(Line 15 - Line 16)	-	MWh
18.	Prior Period		-	MWh
19.	Verified - Prior Period		-	MWh
20.	True-Up Prior Period	(Line 19 - Line 18)	-	MWh
21.	Cumulative Verified		-	MWh
22.	Total Recoverable EE Savings	(Line 17 + Line 20 + Line 21)	-	MWh
	Distributed Generation Savings			
23.	Current Period		-	MWh
24.	MWh DG Savings from Rate Schedules Excluded from LFCR		-	MWh
25.	Net - Current Period	(Line 23 - Line 24)	-	MWh
26.	Prior Period		-	MWh
27.	Verified - Prior Period		-	MWh
28.	True-Up Prior Period	(Line 27 - Line 26)	-	MWh
29.	Total Recoverable DG Savings	(Line 25 + Line 28)	-	MWh
30.	Total Recoverable MWh Savings	(Line 22 + Line 29)	-	MWh
31.	C&I - Lost Fixed Cost Rate	Decision No. 73183	$ 0.023190	$/kWh
32.	C&I - Lost Fixed Cost Revenue	(Line 30 * Line 31)	$ -	
33.	**Total Lost Fixed Cost Revenue**	**(Line 14 + Line 32)**	$ -	

Line No.	(A) Lost Fixed Cost Rate Calculation	(B) Reference	(C) Total
	Residential Customers		
1.	Residential Fixed Revenue	Schedule 7, Line 18, Column G	$ -
2.	MWh Billed	Schedule 7, Line 17, Column B / 1,000	-
3.	Lost Fixed Cost Rate	(Line 1 / Line 2)	$ -
	C & I Customers		
4.	Total Fixed Revenue	Schedule 6, Line 18, Column G	$ -
5.	MWh Billed	Schedule 6, Line 17, Column B / 1,000	-
6.	Lost Fixed Cost Rate	(Line 8 / Line 9)	$ -

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

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

Annual DG Statistics

	20XX	Cummulative beginning 2016
Total Number of Installation		
<5kW		
5kW to 6.5kW		
6.5kW to 10kW		
> 10kW		
Total Installed kW		

Appendix P

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 Arizona Public Service Company (APS or Company) 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

Annual EIS Adjustment - The Annual EIS Adjustment represents the EIS Capital Carrying Costs on the Qualified Net Plant to be recovered in the subsequent twelve month period and is assessed to customer bills via the EIS $/kWh rate.

EIS Capital Carrying Costs - EIS Capital Carrying Costs consists of (1) Return on the Qualified Net Plant calculated based on the Company's Weighted Average Cost of Capital (WACC) approved by the Commission in Decision No. XXXXX plus a return on the fair value increment (if any) for the Qualified Net Plant; (2) depreciation expense; (3) income taxes; (4) property taxes and (5) associated operations and maintenance expenses (O&M).

EIS Qualified Investments - Investments in Qualified Environmental Improvement Projects. Each EIS Qualified Investment 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 and (2) be tracked by a specific project number.

Fair Value Increment - For purposes of the EIS, the difference between the Fair Value of the EIS Qualified Investments and Qualified Net Plant shall be deemed to be zero.

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.

Qualified Net Plant - The Qualified Net Plant consists of the EIS Qualified Investments and their associated accumulated depreciation, accumulated deferred income taxes, tax credits and in the event of federal corporate tax reform any related unamortized excess deferred taxes, where applicable.

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 and AG-X 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 Annual EIS Adjustment

The Annual EIS Adjustment is calculated utilizing the accumulation of Qualified Net Plant and calculated EIS Capital Carrying Costs, as defined above and is applied to applicable customers' total bill via a $/kWh rate over the twelve month period beginning in April of the year following the filing described in Section 6. below. The EIS $/kWh rate is calculated by dividing the

Annual EIS Adjustment by Total kWh Sales as determined in Schedule 3 of the filing. The EIS rate will not exceed $0.00050 per kWh.

5. EIS Balancing Account

APS will maintain accounting records that accumulate the difference between the actual allowable Annual EIS Adjustment as compared to the actual revenues received by the Company through the EIS surcharge during the recovery period (April through March). The difference will be recorded to the EIS Balancing Account each month and will be provided annually in Schedule 3 of the filing. In the event that Annual EIS Adjustments are more or less than the revenues collected as of the last billing cycle of March, the over or under collection will be subtracted from or added to the EIS calculation in the subsequent period subject to the overall cap of $0.00050 per kWh.

6. Filing and Procedural Deadlines

EIS Qualified Projects and the Annual EIS Adjustment calculation will be submitted by the Company to the ACC in the form of Schedules 1 through 3 as attached to this document and described in Section 7. *Compliance Reports*. APS will file the calculated EIS $/kWh rate including all supporting data, with the Commission for the previous year on or before February 1st.

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 $/kWh 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.

7. Compliance Reports

APS will provide an annual report to Staff and the Residential Utility Consumer Office detailing all calculations related to the EIS $/kWh rate. The reports will include the following Schedules 1 through 3 as attached to this document:

Schedule 1: Qualified Investments for EIS Electric Plant in Service
Schedule 2: Annual EIS Adjustment Calculation
Schedule 3: Current Year EIS Cap Calculation and Adjustment

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1 - EIS
QUALIFIED INVESTMENTS
ELECTRIC PLANT IN SERVICE
FOR CALENDAR YEARS 20XX - 20XX

Line No.	(A) Project Tracking Number	(B) Project Name	(C) Purpose	(D) In-Service Date	(E) Total Cost
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
Totals					$ -

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2 - EIS
ANNUAL EIS ADJUSTMENT CALCULATION
PLANT IN SERVICE CALENDAR YEARS 20XX-20XX
BILLING PERIOD 4/1/20XX - 3/30/20XX
(Thousands of Dollars)

Line No.	(A) Annual EIS Adjustment Calculation	(B) Reference	(C) Totals
Qualified Plant			
1.	Qualified Environmental Improvement Projects	Schedule 1, Total Line, Column F	$ -
2.	Accumulated Depreciation		-
3.	Cumulative Deferred Tax/Tax Credits/Excess Deferred Taxes[1]		-
4.	Qualified Net Plant	Line 1 - Line 2 - Line 3	$ -
5.	Pre-tax Weighted Average Cost of Capital	Decision No. XXXXX	0.0000%
Capital Carrying Cost			
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 Annual EIS Adjustment	Line 6 + Line 7 + Line 8 + Line 9	$ -

[1] In the event of a Federal Corporate Tax Rate Change

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3 - EIS
CURRENT YEAR EIS CAP CALCULATION AND ADJUSTMENT
PLANT IN SERVICE CALENDAR YEARS 20XX-20XX
BILLING PERIOD 4/1/20XX - 3/30/20XX
(Thousands of Dollars)

Line No.	(A) EIS Rate Calculation	(B) Reference	(C) Totals	
1.	EIS Adjustment Prior Year	Previous Filing Schedule 2, Line 10	$	-
2.	EIS Revenue Billed Prior Year			-
3.	EIS Balancing Account	Line 1 - Line 2	$	-
4.	Current Year Annual EIS Adjustment	Schedule 2, Line 10	$	-
5.	Total Current Year Annual EIS Adjustment	Line 3 + Line 4	$	-
6.	Applicable Company Sales, excluding E-36XL and AG-X (kWhs)	FERC Form 1		-
7.	EIS Rate ($/kWh)	Line 5 / Line 6	$	-
8.	EIS Rate Cap ($/kWh)		$	0.00050
9.	EIS $ per kWh Rate Applied to Customer's Bills ($/kWh)	(Lesser of Line 7 and Line 8)	$	-

Appendix Q

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 Arizona Public Service (APS or Company) 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 APS's Retail Electric Rate Schedules. For Standard Offer customers, the TCA is applied to the bill as a monthly kWh charge for Residential Service Customers and General Service Customers less than or equal to 20 kW. For all other Standard Offer customers, the TCA is applied to the bill as a monthly 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
General Service Customers over 20 kW and less than 3 MW
General Service Customers equal to and greater than 3 MW

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

APS's NITS rates will change annually, where ancillary service charges will change only through a separate filing when made by the Company to FERC.

The total APS OATT rate is the sum of the rates for providing these services. The revenue requirement resulting from the FERC APS OATT rate are collected by APS from its retail customers, partly in base rates and the remaining through the TCA rate.

3. TCA Balancing Account

APS will maintain accounting records that accumulate the difference in revenues anticipated to be recovered by the TCA, as compared to the actual revenues received by the Company through the TCA during the recovery period (June through May). The difference will be recorded to the TCA Balancing Account each month and will be provided annually in Attachment C of the filing. In the event the actual TCA revenues for the recovery period (June through the last billing cycle of May) are more or less than the anticipated revenues for that same period, the over or under collection will be subtracted from or added to the TCA balancing account calculation for the subsequent period.

4. Filing and Procedural Deadlines

APS will file the calculated TCA rates with the Commission each year no later than May 15th, in the form of Attachments A through H as attached to this document and described in Section 5. *Compliance Reports.*

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.

5. Compliance Reports

APS will provide an annual report to Staff detailing all calculations related to the calculated TCA rates. The reports will include the following Attachments A through H as attached to this document:

Attachment A:	Non-redlined version of the new Adjustment Schedule TCA-1 Revision
Attachment B:	Redlined version of the new Adjustment Schedule TCA-1 Revision
Attachment C:	Numerical inputs used to develop the new TCA-1 rates
Attachment D:	Estimated monthly bill impacts of the new TCA-1 rates
Attachment E:	Table illustrating the percentage demand of each of the classes for the 20XX OATT and 20XX OATT as filed with FERC

Attachment F:	Table illustrating the transmission cost embedded in base rates, the current and proposed TCA rates, and the differences in the current and new rates
Attachment G:	Actual and estimated transmission additions, dollars and estimated O&M for calendar years 20XX through 20XX (1 year actual and 2 years forecast)
Attachment H:	APS's Annual Update of transmission service rates pursuant to the APS OATT as filed with FERC

Attachment A

APPLICATION

The Transmission Cost Adjustment ("TCA") charge shall apply to all Standard Offer retail electric schedules. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

ANNUAL ADJUSTMENT

Standard Offer rate schedules covered by this charge include a transmission component of base rates that was originally established at $0.00000 per kilowatt-hour in accordance with A.C.C. Decision No. 67744. Decision No. 67744 also established the TCA. Decision No. 69663 modified the collection of transmission costs in retail rates to tie to the costs found in the FERC approved Open Access Transmission Tariff.

RATE

The charge shall be applied as follows:

Customer Class	**TCA Charge**
Residential	$0.000000/kWh
General Service 20 kW or less	$0.000000/kWh
General Service over 20 kW, under 3,000 kW	$0.000/kW
General Service 3,000 kW and over	$0.000/kW

APPLICATION

The Transmission Cost Adjustment ("TCA") charge shall apply to all Standard Offer retail electric schedules. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

ANNUAL ADJUSTMENT

Standard Offer rate schedules covered by this charge include a transmission component of base rates that was originally established at $0.00000 per kilowatt-hour in accordance with A.C.C. Decision No. 67744. Decision No. 67744 also established the TCA. Decision No. 69663 modified the collection of transmission costs in retail rates to tie to the costs found in the FERC approved Open Access Transmission Tariff.

RATE

The charge shall be applied as follows:

Customer Class	TCA Charge
Residential	$0.000000/kWh
General Service 20 kW or less	$0.000000/kWh
General Service over 20 kW, under 3,000 kW	$0.000/kW
General Service 3,000 kW and over	$0.000/kW

Attachment C

TCA Rate Calculation - Plan of Administration

Line	Service Type Retail Transmission Rates	Residential $/kWh (A)	GS≤20 kW $/kWh (B)	GS > 20 kW and < 3MW $/kW (C)	GS≥3 MW $/kW (D)
1.	NITS (A)	0.000000	0.000000	0.000	0.000
2.	Scheduling (B)	0.000000	0.000000	0.000	0.000
3.	Regulation & Frequency (B)	0.000000	0.000000	0.000	0.000
4.	Spinning Reserve (B)	0.000000	0.000000	0.000	0.000
5.	Operating Reserve (B)	0.000000	0.000000	0.000	0.000
6.	Energy Imbalance (B)	0.000000	0.000000	0.000	0.000
7.	Total (Lines 1 thru 7)	0.000000	0.000000	0.000	0.000
8.	Included In Retail Base Rates (C)	0.000000	0.000000	0.000	0.000
9.	Balancing Account (D)	0.000000	0.000000	0.000	0.000
10.	TCA (Line 7 - Line 8 + Line 9) (E)	0.000000	0.000000	0.000	0.000

(A) Source: Attachment H, Appendix A of Attachment H-1, Lines 161-164 - (APS's FERC Formula Rate Annual Update of transmission service rates pursuant to the APS OATT)

(B) Source: Ancillary Services as defined in Schedule 11 of the APS OATT

(C) Source: Base Transmission Rates as approved in Decision No. XXXXX

(D) Source: TCA Balancing Account Workpaper Detail (to be provided with TCA filing)

(E) Amounts presented in Attachment A and Attachment B

Attachment D

DOCKET NO. E-01345A-16-0036 ET AL.

ARIZONA PUBLIC SERVICE COMPANY
Bill Impact of TCA Reset June 20XX

	AVERAGE MONTHLY BILL IMPACTS				SEASONAL BILL IMPACTS			
	Current	Proposed			Current	Proposed	Current	Proposed
Residential (Avg - All Rates)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
Four Corners	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -

Residential (Rate E-12)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
Four Corners	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -

Commercial XS (E-32)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
Four Corners	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -

Attachment D

DOCKET NO. E-01345A-16-0036 ET AL.

ARIZONA PUBLIC SERVICE COMPANY
Bill Impact of TCA Reset June 20XX

	AVERAGE MONTHLY BILL IMPACTS				SEASONAL BILL IMPACTS			
	Current	Proposed			Current	Proposed	Current	Proposed
Commercial S (E-32)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-				-	-	-	-
Averge kW per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
Four Corners	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -

Commercial - M (E-32)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-	-			-	-	-	-
Averge kW per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
Four Corners	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -

Commercial - L (E-32)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-	-			-	-	-	-
Averge kW per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
Four Corners	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -

DECISION NO. 76295

Attachment D

ARIZONA PUBLIC SERVICE COMPANY
Bill Impact of TCA Reset June 20XX

	AVERAGE MONTHLY BILL IMPACTS				SEASONAL BILL IMPACTS			
	Current	Proposed			Current	Proposed	Current	Proposed
Industrial - XL (E-34,35)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-	-			-	-	-	-
Averge kW per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
Four Corners	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -

Notes:
(1) Bill excludes regulatory assessment charge, taxes and fees. All Adjustor levels in effect as of May 15, 20XX.
(2) Bill includes the projected impact to customers of the reset TCA adjustor.

Attachment E

Class Coincident Peak Demand

Class	20XX		20XX	
	MW	% of Coincident Demand	MW	% of Coincident Demand
Residential	0000.0	0.00%	0000.0	0.00%
General Service < 3MW	0000.0	0.00%	0000.0	0.00%
General Service > 3 MW	0000.0	0.00%	0000.0	0.00%
Total	0000.0	0.00%	0000.0	0.00%

Attachment F

Transmission Rates Embedded in Base Rates and TCA

Customer Group	Embedded Base Rate	Current TCA Rate	Proposed TCA Rate	Difference	Percentage Difference: TCA Rate	Percentage Difference: Total
	(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D)/(B)	(F) = (D)/[(A)+(B)]
Residential	$ 0.000000 /kWh	$ 0.000000 /kWh	$ 0.000000 /kWh	$ 0.000000 /kWh	0.0%	0.0%
General Service 20 kW or less	$ 0.000000 /kWh	$ 0.000000 /kWh	$ 0.000000 /kWh	$ 0.000000 /kWh	0.0%	0.0%
General Service over 20 kW and under 3,000 kW	$ 0.0000 /kW	$ 0.0000 /kW	$ 0.0000 /kW	$ 0.0000 /kW	0.0%	0.0%
General Service 3,000 kW and over	$ 0.0000 /kW	$ 0.0000 /kW	$ 0.0000 /kW	$ 0.0000 /kW	0.0%	0.0%

ATTACHMENT G

Arizona Public Service Company
20XX Transmission Actual Addition Dollars and O&M

Line No.	Funding Project	WA#	Description	Actual Cost	Purpose	Miles	Estimated O&M	In-Service Date
1							-	
2							-	
3							-	
4							-	
5							-	
6							-	
7							-	
8							-	
9							-	
10							-	
11							-	
12							-	
13							-	
14							-	
15							-	
16							-	
17							-	
18							-	
19							-	
20							-	
21							-	
22							-	
23							-	
24							-	
25							-	
26							-	
27							-	
28							-	
29							-	
30							-	
31							-	
32							-	
			Work Orders > $250k	-			$ -	
			Work Orders < $250K	-				
			Total	-				

ATTACHMENT G

Arizona Public Service Company
20XX Transmission Estimated Addition Dollars and O&M

Line #	Funding Project	WA#	Description	Total Estimate	Purpose	Miles	Estimated O&M	Estimated In-Service Date
1							-	
2							-	
3							-	
4							-	
5							-	
6							-	
7							-	
8							-	
9							-	
10							-	
11							-	
12							-	
13							-	
14							-	
15							-	
16							-	
17							-	
18							-	
19							-	
20							-	
21							-	
22							-	
23							-	
24							-	
25							-	
26							-	
27							-	
28							-	
29							-	
30							-	
31							-	
32							-	
			Work Orders > $250k	-				
			Work Orders < $250K	-				
			Total	$ -			$ -	

ATTACHMENT G

Arizona Public Service Company
20XX Transmission Estimated Addition Dollars and O&M

Line #	Funding Project	WA#	Description	Total Estimate	Purpose	Miles	Estimated O&M	Estimated In-Service Date
1							-	
2							-	
3							-	
4							-	
5							-	
6							-	
7							-	
8							-	
9							-	
10							-	
11							-	
12							-	
13							-	
14							-	
15							-	
16							-	
17							-	
18							-	
19							-	
20							-	
21							-	
22							-	
23							-	
24							-	
25							-	
26							-	
27							-	
28							-	
29							-	
30							-	
31							-	
32							-	
			Work Orders > $250k	-			$ -	
			Work Orders < $250K	-				
			Total	**$ -**				

Attachment H

Arizona Public Service Company

Formula Rate -- Appendix A

Shaded cells are input cells

Line	Description	Notes	FERC Form 1 Page # or Instruction	YEAR
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	0
2	Total Wages Expense		p354.28b	0
3	Less A&G Wages Expense		p354.27b	0
4	Total		(Line 2 - 3)	0
5	**Wages & Salary Allocator**		(Line 1 / 4)	**0.0000%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	Attachment 5	0
7	Total Plant In Service		(Sum Line 6)	0
8	Accumulated Depreciation (Total Electric Plant)		Attachment 5	0
9	Total Accumulated Depreciation		(Line 8)	0
10	Net Plant		(Line 7 - 9)	0
11	Transmission Gross Plant		(Line 22 - Line 38)	0
12	**Gross Plant Allocator**		(Line 11 / 7)	**0.0000%**
13	Transmission Net Plant		(Line 32 - Line 38)	0
14	**Net Plant Allocator**		(Line 13 / 10)	**0.0000%**
	Plant Calculations			
	Plant In Service (Note O)			
15	Transmission Plant In Service	(Note B)	Attachment 5	0
16	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)		Attachment 6	0
17	**Total Transmission Plant In Service**		(Line 15 + 16)	**0**
18	General & Intangible		Attachment 5	0
19	Total General		(Line18)	0
20	Wage & Salary Allocation Factor		(Line 5)	0.00000%
21	**General Plant Allocated to Transmission**		(19 * 20)	**0**
22	**TOTAL Plant In Service**		**(Line 17 + 21)**	**0**
	Accumulated Depreciation			
23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	0
24	Accumulated Depreciation for Transmission Plant Additions for Current Rate Year		Attachment 6	0
25	**Total Transmission Accumulated Depreciation**		(Line 23 + Line 24)	0
26	Accumulated General Depreciation		Attachment 5	0
27	Accumulated Intangible Depreciation		Attachment 5	0
28	Total Accumulated Depreciation		(Sum Lines 26 to 27)	0
29	Wage & Salary Allocation Factor		(Line 5)	0.0000%
30	**General Allocated to Transmission**		(Line 28 * 29)	**0**
31	**TOTAL Accumulated Depreciation**		**(Line 25 + 30)**	**0**
32	**TOTAL Net Property, Plant & Equipment**		**(Line 22 - 31)**	**0**

Attachment H

	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
33	ADIT net of FASB 106 and 109		Attachment 1	0
34	**Accumulated Deferred Income Taxes Allocated To Transmission**		(Line 33)	0
	Transmission O&M Reserves			
35	**Total Balance Transmission Related Account 242 Reserves**	Enter Negative	Attachment 5	0
	Prepayments			
36	Prepayments	(Note A)	Attachment 5	0
37	**Total Prepayments Allocated to Transmission**		(Line 36)	0
38	**Land Held for Future Use**	(Note C)	p214	0
	Materials and Supplies			
39	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	0
40	Wage & Salary Allocation Factor		(Line 5)	0.0000%
41	Total Transmission Allocated		(Line 39 * 40)	0
42	Transmission Materials & Supplies		p227.8c	0
43	**Total Materials & Supplies Allocated to Transmission**		(Line 41 + 42)	0
	Cash Working Capital			
44	Operation & Maintenance Expense		(Line 72)	0
45	Zero Cash Working Capital		Zero	0.0%
46	**Total Cash Working Capital Allocated to Transmission**		(Line 44 * 45)	0
	Network Credits			
47	Outstanding Network Credits	(Note N)	Attachment 5	0
48	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	Attachment 5	0
49	Net Outstanding Credits		(Line 47 - 48)	0
50	**TOTAL Adjustment to Rate Base**		(Line 34 + 35 + 37 + 38 + 43 + 46 - 49)	0
51	**Rate Base**		(Line 32 + 50)	0
	O&M			
	Transmission O&M			
52	Transmission O&M		p321.112.b	0
53	Less Account 565		p321.96.b	0
54	**Transmission O&M**		(Line 52 - 53)	0
	Allocated General Expenses			
55	Total A&G		p323.197.b	0
56	Less PBOP Adjustment		Attachment 5	0
57	Less Property Insurance Account 924		p323.185b	0
58	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	0
59	Less General Advertising Exp Account 930.1		p323.191b	0
60	Less EPRI Dues	(Note D)	p352-353	0
61	**General Expenses**		(Line 55) - Sum (56 to 60)	0
62	Wage & Salary Allocation Factor		(Line 5)	0.0000%
63	**General Expenses Allocated to Transmission**		(Line 61 * 62)	0
	Directly Assigned A&G			
64	Regulatory Commission Exp Account 928	(Note G)	Attachment 5	0
65	General Advertising Exp Account 930.1	(Note K)	Attachment 5	0
66	Subtotal - Transmission Related		(Line 64 + 65)	0
67	Property Insurance Account 924		p323.185b	0
68	General Advertising Exp Account 930.1	(Note F)	Attachment 5	0
69	Total		(Line 67 + 68)	0
70	Net Plant Allocation Factor		(Line 14)	0.0000%
71	**A&G Directly Assigned to Transmission**		(Line 69 * 70)	0
72	**Total Transmission O&M**		**(Line 54 + 63 + 66 + 71)**	0
	Depreciation & Amortization Expense			
	Depreciation Expense (Note P)			
73	Transmission Depreciation Expense		p336.7f	0
74	New plant Depreciation Expense		Attachment 6	0
75	**Total Transmission Depreciation Expense**		(Line 73 + Line 74)	0
76	General Depreciation		p336.10f	0
77	Intangible Amortization	(Note A)	p336.1f	0
78	Total		(Line 76 + 77)	0
79	Wage & Salary Allocation Factor		(Line 5)	0.0000%
80	**General Depreciation Allocated to Transmission**		(Line 78 * 79)	0
81	**Total Transmission Depreciation & Amortization**		**(Line 75 + 80)**	0

Attachment H

Line	Description	Note	Source	Value
	Taxes Other than Income			
82	**Taxes Other than Income**		Attachment 2	0
83	**Total Taxes Other than Income**		**(Line 82)**	0
	Return / Capitalization Calculations			
	Long Term Interest			
84	Long Term Interest		p117.62c through 67c	0
85	**Long Term Interest**		(Line 84)	0
86	**Preferred Dividends**	enter positive	p118.29c	0
	Common Stock			
87	Proprietary Capital		p112.16c	0
88	Less Preferred Stock	enter negative	(Line 96)	0
89	Less Accumulated Other Comprehensive Income Account 219	enter negative	p112.15c	0
90	Less Account 216.1	enter negative	p112.12c	0
91	**Common Stock**		(Sum Lines 87 to 90)	0
	Capitalization			
92	Long Term Debt		p112.18c through 23c	0
93	Less Loss on Reacquired Debt	enter negative	p111.81c	0
94	Plus Gain on Reacquired Debt	enter positive	p113.61c	0
95	Total Long Term Debt		(Sum Lines 92 to 94)	0
96	Preferred Stock		p112.3c	0
97	Common Stock		(Line 91)	0
98	**Total Capitalization**		(Sum Lines 95 to 97)	0
99	Debt %		(Line 95 / 98)	0%
100	Preferred %		(Line 96 / 98)	0%
101	Common %		(Line 97 / 98)	0%
102	Debt Cost		(Line 85 / 95)	0.0000
103	Preferred Cost		(Line 86 / 96)	0.0000
104	Common Cost	(Note J)	Fixed	0.1075
105	Weighted Cost of Debt		(Line 99 * 102)	0.0000
106	Weighted Cost of Preferred		(Line 100 * 103)	0.0000
107	Weighted Cost of Common		(Line 101 * 104)	0.0000
108	**Total Return (R)**		(Sum Lines 105 to 107)	**0.0000**
109	**Investment Return = Rate Base * Rate of Return**		**(Line 51 * 108)**	0
	Composite Income Taxes			
	Income Tax Rates			
110	FIT=Federal Income Tax Rate			0.00%
111	SIT=State Income Tax Rate or Composite	(Note I)		0.00%
112	p		FIT deductible for SIT	0.00%
113	T = 1-{[(1-SIT) * (1-FIT)]/(1-SIT * FIT * p)}			0.00%
114	T/ (1-T)			0.00%
	ITC Adjustment	(Note I)		
115	Amortized Investment Tax Credit	enter negative	p266.8f	0
116	T/(1-T)		(Line 114)	0.00%
117	Net Plant Allocation Factor		(Line 14)	0.0000%
118	**ITC Adjustment Allocated to Transmission**		(Line 115 * (1 + 116) * 117)	0
119	**Income Tax Component =**		[Line 114 * 109 * (1-(105 / 108))]	-
120	**Total Income Taxes**		**(Line 118 + 119)**	-
	REVENUE REQUIREMENT			
	Summary			
121	Net Property, Plant & Equipment		(Line 32)	0
122	Adjustment to Rate Base		(Line 50)	0
123	**Rate Base**		(Line 51)	0
124	O&M		(Line 72)	0
125	Depreciation & Amortization		(Line 81)	0
126	Taxes Other than Income		(Line 83)	0
127	Investment Return		(Line 109)	0
128	Income Taxes		(Line 120)	0
129	**Gross Revenue Requirement**		**(Sum Lines 124 to 128)**	**0**

Attachment H

	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
130	Transmission Plant In Service		(Line 15)	0
131	Excluded Transmission Facilities	(Note M)	Attachment 5	0
132	Included Transmission Facilities		(Line 130 - 131)	0
133	Inclusion Ratio		(Line 132 / 130)	0.00%
134	Gross Revenue Requirement		(Line 129)	0
135	**Adjusted Gross Revenue Requirement**		(Line 133 * 134)	**0**
	Revenue Credits & Interest on Network Credits			
136	**Revenue Credits**		Attachment 3	0
137	**Interest on Network Credits**	(Note N)	Attachment 5	0
138	**Net Revenue Requirement**		**(Line 135 - 136 + 137)**	**0**
	Net Plant Carrying Charge			
139	Net Revenue Requirement		(Line 138)	-
140	Net Transmission Plant		(Line 15 - 23)	-
141	Net Plant Carrying Charge		(Line 139 / 140)	**0.0000%**
142	Net Plant Carrying Charge without Depreciation		(Line 139 - 73) / 140	**0.0000%**
143	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 139 - 73 - 109 - 120) / 140	**0.0000%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
144	Net Revenue Requirement Less Return and Taxes		(Line 138 - 127 - 128)	-
145	Increased Return and Taxes		Attachment 4	-
146	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 144 + 145)	-
147	Net Transmission Plant		(Line 15 - 23)	-
148	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 146 / 147)	**0.0000%**
149	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation		(Line 146 - 73) / 147	**0.0000%**
150	**Net Revenue Requirement**		(Line 138)	-
151	True-up amount		Attachment 6	-
152	Plus any increased ROE calculated on Attachment 7		Attachment 7	-
153	Facility Credits under Section 30.9 of the APS OATT		Attachment 5	-
154	**Net Adjusted Revenue Requirement**		(Line 150 - 151 + 153)	-
	Annual Point-to-Point Transmission Rate			
155	Average of the 4 Summer CP	(Note L)	Network Transmission Peak Report	**0**
156	Annual Point-to-Point Transmission Rate		(Line 154 / 155)	**0.00**
157	Average of the 8 Non-Summer CP	(Note L)	Network Transmission Peak Report	**0**
158	Implied Non-Summer Revenue Requirement		((Line 156/12)*8* Line 157)	**0**
159	Implied Summer Revenue Requirement		(Line 138 - Line 158)	**0**
160	Implied Annualized Summer Point-to-Point Transmission Rate		((Line 154- line 158/Line 155/4)*12)	**0.00**
	Retail Transmission Rates			
161	Residential (kWh)		Rate Design Worksheet	**0.00000**
162	Gen Serv < 3MW Without Demand Meters -Includes All Customers 20 kW and less (kWh)		Rate Design Worksheet	**0.00000**
163	Gen Serv < 3MW (kW)		Rate Design Worksheet	**0.000**
164	Gen Serv > 3MW (kW)		Rate Design Worksheet	**0.000**

Notes

A Electric portion only

B Exclude Construction Work In Progress expensed as O&M (rather than amortized). New Transmission plant that is expected to be placed in service in the current calendar year weighted by number of months it is expected to be in-service. New Transmission plant expected to be placed in service in the current calendar year that is not included in the Transmission Plan must be separately detailed on Attachment 5.
For the Reconciliation, new transmission plant that was actually placed in service weighted by the number of months it was actually in service

C Transmission Portion Only

D All EPRI Annual Membership Dues

E All Regulatory Commission Expenses

F Safety related advertising included in Account 930.1

G Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.

I The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility includes taxes in more than one state, it must explain in Attachment 5 the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to use amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T). A utility must not include tax credits as a reduction to rate base and as an amortization against taxable income.
If the tax rates change during a calendar year, an average tax rate will be used - calculated based on the number of days each was effective in the calendar year.

J ROE of 10.75%

K Education and outreach expenses relating to transmission, for example siting or billing

L Based on APS Network Transmission Peak Report

M Amount of transmission plant excluded from rates per Attachment 5

N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments (net of accumulated depreciation) towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A
Interest on the Network Credits as booked each year is added to the revenue requirement to make the Transmisison Owner whole on Line 137

O AFUDC shall not be applied to the portion of a Network Upgrade for which the customer has provided the funds

P Changes in depreciation or amortization rates must be filed with the Commission, as well as any new depreciation or amortization rates

END

Arizona Public Service Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

	Transmission Related	Plant Related	Labor Related	Total ADIT
ADIT- 282	0	0	0	0
ADIT-283	0	0	0	0
ADIT-190	0	0	0	0
ADITC-255	0	0	0	0
Subtotal-End of Year	0	0	0	0
Subtotal-Beginning of Year	0	0	0	0
End of Year for Est./Average for Final	0	0	0	0
Wages & Salary Allocator (Appendix A, Line 5)			0.0000%	
Gross Plant Allocator (Appendix A, Line 12)		0.0000%		
ADIT-End of Year for Estimate	0	0	0	0
ADIT-Average for Final	0	0	0	0

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-E and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately

A ADIT-190		B Total	C Gas, Prod Or Other Related	D Only Transmission Related	E Plant Related	F Labor Related	G Justification
Subtotal - p234							
Less FASB 109 Above if not separately removed							
Less FASB 106 Above if not separately removed							
Total							

Instructions for Account 190:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A		B	C	D	E	F	G
ADIT- 282		Total	Gas, Prod Or Other	Only Transmission Related	Plant Related	Labor Related	Justification
Subtotal - p275 (Form 1-F filer: see note 6 below)						0	
Less FASB 109 Above if not separately removed							
Less FASB 106 Above if not separately removed							
Total						0	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A		B	C	D	E	F	G
ADIT-283		Total	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	Justification
Subtotal - p277 (Form 1-F filer: see note 6, below)							
Less FASB 109 Above if not separately removed							
Less FASB 106 Above if not separately removed							
Total							

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

ADITC-255

			Balance	Amortization	
1	Rate Base Treatment				
2	Balance to Attachment 1, Page 1, Transmission Related ADIT 255,				One or the other but not both
3	Amortization				
4	Amortization to line 115 of Appendix A			-	
5	Total			-	
6	Total Form No. 1 (p 266 & 267)			-	
7	Difference /1		-	-	

/1 Difference must be zero

Arizona Public Service Company

Attachment 2 - Taxes Other Than Income Worksheet

Other Taxes	*Page 263 Col (i)*	*Allocator*		*Allocated Amount*
Plant Related		***Gross Plant Allocator***		
1 Transmission Personal Property Tax (directly assigned to Transmission)		100%	$	-
2 Capital Stock Tax		0.0000%	$	-
3 Gross Premium (insurance) Tax		0.0000%	$	-
4 PURTA		0.0000%	$	-
5 Corp License		0.0000%	$	-
		0.0000%	$	-
Total Plant Related	0			0
Labor Related		***Wages & Salary Allocator***		
6 Federal FICA & Unemployment & state unemployment				
Total Labor Related	0	0.0000%		0
Other Included		***Gross Plant Allocator***		
7 Miscellaneous	0			
Total Other Included	0	0.0000%		0
Total Included				0
Currently Excluded				
8 Use & Sales Tax	0			
9 Adjust state and local tax reserve				
10 Other Sales & Use Tax	0			
11 Other Personal Property Tax (excluded)				
12				
13				
14				
15				
16				
17				
18				
19				
20				-
21 Total "Other" Taxes (included on p. 263)	0			
22 Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)				
23 Difference	-			

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be allocated based on the Gross Plant Allocator. If the taxes are 100% recovered at retail they will not be included

B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail they will not be included

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator

D Other taxes except as provided for in A, B and C above, that are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service will be allocated based on the Gross Plant Allocator; provided, however, that overheads shall be treated as in footnote B above

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year

Arizona Public Service Company

Attachment 3 - Revenue Credit Workpaper

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related (Note 3)		-
2	Total Rent Revenues	(Sum Lines 1)	-
	Account 456 - Other Electric Revenues (Note 1)		
3	Scheduling, System Control & Dispatch (Ancillary Service)	p398 line 1 column g	
4	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor (Note 4)		
5	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner (Note 4)		-
6	Transitional Revenue Neutrality (Note 1)		
7	Transitional Market Expansion (Note 1)		
8	Professional Services (Note 3)		-
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		-
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
11	Gross Revenue Credits	(Sum Lines 2-10)	-
12	Line 17g		-
13	Total Revenue Credits		-

Revenue Adjustment to determine Revenue Credit

14	Note 1: All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on line 171 of Appendix A.	
15	Note 2: If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.	
16	Note 3: Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). Company will retain 50% of net revenues consistent with Pacific Gas and Electric Company, 90 FERC ¶ 61,314. Note: in order to use lines 17a - 17g, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).	
17a	Revenues included in lines 1-11 which are subject to 50/50 sharing.	-
17b	Costs associated with revenues in line 17a	-
17c	Net Revenues (17a - 17b)	-
17d	50% Share of Net Revenues (17c / 2)	-
17e	Costs associated with revenues in line 17a that are included in FERC accounts recovered through the formula times the allocator used to functionalize the amounts in the FERC account to the transmission service at issue.	-
17f	Net Revenue Credit (17d + 17e)	-
17g	Line 17f less line 17a	-
18	Note 4: If the facilities associated with the revenues are not included in the formula, the revenue is shown here but not included in the total above and is explained in the Cost Support; for example revenues associated with distribution facilities.	-
19	Amount offset in line 4 above	
20	Total Account 454 and 456	-

Composite Tax Rate 0.00%

Arizona Public Service Company

Attachment 4 - Calculation of 100 Basis Point Increase in ROE

A	100 Basis Point increase in ROE and Income Taxes		Line 12 + Line 23	-
B	100 Basis Point increase in ROE			1.00%
Return Calculation				
1	Rate Base		Appendix A, Line 51	-
2	Debt %		Appendix A, Line 99	0.0%
3	Preferred %		Appendix A, Line 100	0.0%
4	Common %		Appendix A, Line 101	0.0%
5	Debt Cost		Appendix A, Line 102	0.00%
6	Preferred Cost		Appendix A, Line 103	0.00%
7	Common Cost	Appendix A % plus 100 Basis Pts	Appendix A, Line 104 + 1%	11.75%
8	Weighted Cost of Debt		Appendix A, Line 105	-
9	Weighted Cost of Preferred		Appendix A, Line 106	-
10	Weighted Cost of Common		Line 4 * Line 7	0.0000
11	**Total Return (R)**		Sum Lines 8 to 10	**0.0000**
12	**Investment Return = Rate Base * Rate of Return**		Line 11 * Line 1	**0**
Composite Income Taxes				
	Income Tax Rates			
13	FIT=Federal Income Tax Rate		Appendix A, Line 110	0.00%
14	SIT=State Income Tax Rate or Composite		Appendix A, Line 111	0.00%
15	p (percent of federal income tax deductible for state purposes)		Appendix A, Line 112	0.00%
16	T =1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		Appendix A, Line 113	0.00%
17	T/ (1-T)		Appendix A, Line 114	0.00%
	ITC Adjustment			
18	Amortized Investment Tax Credit		Appendix A, Line 115	-
19	1/(1-T)		Appendix A, Line 116	0.0000%
20	Net Plant Allocation Factor		Appendix A, Line 117	0.0000%
21	**ITC Adjustment Allocated to Transmission**		Appendix A, Line 118	**0**
22	**Income Tax Component = CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =**		Line 17*Line 12*(1-(Line 8/Line 11))	-
23	**Total Income Taxes**		**Line 21 + 22"**	-

Arizona Public Service Company

Attachment 5 - Cost Support

Plant in Service Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Details	
Calculation of Transmission Plant In Service	Source		Balance For True up	Balance for Estimate	
December	p206.58.b	2013			
January	company records	2014			
February	company records	2014			
March	company records	2014			
April	company records	2014			
May	company records	2014			
June	company records	2014			
July	company records	2014			
August	company records	2014			
September	company records	2014			
October	company records	2014			
November	company records	2014			
December	p207.58.g	2014		-	
Transmission Plant In Service			-	-	
Calculation of Distribution Plant In Service	Source				
December	p206.75.b	2013			
January	company records	2014			
February	company records	2014			
March	company records	2014			
April	company records	2014			
May	company records	2014			
June	company records	2014			
July	company records	2014			
August	company records	2014			
September	company records	2014			
October	company records	2014			
November	company records	2014			
December	p207.75.g	2014		-	
Distribution Plant In Service			-	-	
Calculation of Intangible Plant In Service	Source				
December	p204.5.b	2013			
December	p205.5.g	2014		-	
Intangible Plant In Service			-	-	
Calculation of General Plant In Service	Source				
December	p206.96.b	2013			
December	p207.96.g	2014		-	
General Plant In Service			-	-	
Calculation of Production Plant In Service	Source				
December	p204.46b	2013			
January	company records	2014			
February	company records	2014			
March	company records	2014			
April	company records	2014			
May	company records	2014			
June	company records	2014			
July	company records	2014			
August	company records	2014			
September	company records	2014			
October	company records	2014			
November	company records	2014			
December	p205.46.g	2014		-	
Production Plant In Service			-	-	
Total Plant In Service	Sum of averages above		0	0	

Accumulated Depreciation Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Details
Calculation of Transmission Accumulated Depreciation	Source		Balance For True up	Balance for Estimate	
December	Prior year p219.25	2013			
January	company records	2014			
February	company records	2014			
March	company records	2014			
April	company records	2014			
May	company records	2014			
June	company records	2014			
July	company records	2014			
August	company records	2014			
September	company records	2014			
October	company records	2014			
November	company records	2014			
December	p219.25	2014		-	
Transmission Accumulated Depreciation			-	-	
Calculation of Distribution Accumulated Depreciation	Source				
December	Prior year p219.26	2013			
January	company records	2014			
February	company records	2014			
March	company records	2014			
April	company records	2014			
May	company records	2014			
June	company records	2014			
July	company records	2014			
August	company records	2014			
September	company records	2014			
October	company records	2014			
November	company records	2014			
December	p219.26	2014		-	
Distribution Accumulated Depreciation			-	-	
Calculation of Intangible Accumulated Depreciation	Source				
December	Prior year p200.21 c	2013			
December	p200.21c	2014		-	
Accumulated Intangible Depreciation			-	-	
Calculation of General Accumulated Depreciation	Source				
December	Prior year p219.28	2013			
December	p219.28	2014		-	
Accumulated General Depreciation			-	-	
Calculation of Production Accumulated Depreciation	Source				
December	Prior year p219.20 thru 219.24	2013			
January	company records	2014			
February	company records	2014			
March	company records	2014			
April	company records	2014			
May	company records	2014			
June	company records	2014			
July	company records	2014			
August	company records	2014			
September	company records	2014			
October	company records	2014			
November	company records	2014			
December	p219.20 thru 219.24	2014		-	
Production Accumulated Depreciation			-	-	
Total Accumulated Depreciation	Sum of averages above		0	0	

Electric / Non-electric Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Electric Portion	Non-electric Portion	Details
	Plant Allocation Factors					
	Accumulated Intangible Depreciation	p200 21 c				
	Materials and Supplies					
	Undistributed Stores Exp	p227 16c				
	Depreciation Expense					
	Intangible Amortization	p336 1d&e				

Transmission / Non-transmission Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	End of Year	End of Year for Est. Average for Final	Details
38	**Plant Held for Future Use**	p214	Total			-	
			Non-transmission Related				
			Transmission Related			-	

PBOPs Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	PBOBs	All other		Details
56	**Allocated General Expenses**						
	Account 926 (2006)				-	Base year	
	Account 926 (Current Year)	p323 187b			-	Current Year	
	Change in PBOP Expense			-			

EPRI Dues Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	EPRI Dues	Details
	Allocated General Expenses		A&G		
60	Less EPRI Dues	p352-353			

Regulatory Expense Related to Transmission Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Directly Assigned A&G					
64	Regulatory Commission Exp Account 928	p350.1 thru 350.21				

Safety Related Advertising Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G					
68	General Advertising Exp Account 930.1	p323.191.b				

MultiState Workpaper

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	State 1	State 2	State 3	State 4	State 5	Composite
	Income Tax Rates						
111	SIT=State Income Tax Rate or Composite	AZ	NM	CA	TX	UT	

Education and Out Reach Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G					
65	General Advertising Exp Account 930.1	p323.191.b				-

Excluded Gross Plant Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Excluded Gross Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
131	Excluded Gross Transmission Facilities			**General Description of the Facilities**
	Instructions:		**Enter $**	**None**
1	Remove all investment below 69 kV facilities, including the investment allocated to distribution of a dual function substation, generator, interconnection and local and direct assigned facilities for which separate costs are charged and step-up generation substation included in transmission plant in service			
				Step Up Xfmrs
				West Phoenix to Lincoln Substation 345 kV transmission line
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV, the following formula will be used:	**Example**	**Or Enter $**	
	A Total investment in substation	1,000,000		
	B Identifiable investment in Transmission (provide workpapers)	500,000		
	C Identifiable investment in Distribution (provide workpapers)	400,000		
	D Amount to be excluded (A x (C / (B + C)))	444,444		
				Add more lines if necessary

Transmission Related Account 242 Reserves

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	End of Year	End of Year for Est. Average for Final	Allocation	Trans Related	Details
35	**Transmission Related Account 242 Reserves (exclude current year environmental site related reserves)**				Enter $				
	Directly Assignable to Transmission								
		Deposits							
		FERC Provision for Rate Refund							
		Land Rights							
			Sum Directly Transmission	-	-	-	100%	-	
	Total Not Directly Assignable to Transmission		(A) Total Not Directly Transmission	-	-	-			
	Labor Related, or General plant related								
		Vacation Accrual - Old Plan				-			
		Accrued Payroll				-			
		Medical - Dental				-			
		Short Term Software License				-			
		Workmen's Compensation Liability				-			
		Vacation Accrual				-			
		Vacation Accrual - Participants				-			
		SFAS 112				-			
		Incentive Accrual				-			
		Severance				-			
		SERBP				-			
		Deferred Compensation				-			
			(B) Sum Labor Related	-	-	-	0.0000%	-	
	Other								
			(A) - (B)	-	-	-	0.00%	-	
	Total Transmission Related Reserves			-	-	check		-	

Prepayments

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Beg of year	End of Year	End of Year for Est. Average for Final	Allocation	Trans Related	Details
36	**Prepayments**							
	Labor Related	Worksheet 5	-	-	-	0.000%	-	-
	Plant Related	Worksheet 5	-	-	-	0.000%	-	-
	100% Transmission Related	Worksheet 5	-	-	-	100.000%	-	-
	Other (Excluded)	Worksheet 5	-	-	-	0.000%	-	-
							-	-

Materials & Supplies

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Beg of year	End of Year	End of Year for Est. Average for Final	Details
39	Stores Expense Undistributed	p227.16	-	-	-	
42	Transmission Materials & Supplies	p227.8			-	

Outstanding Network Credits Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Beg of year	End of Year	End of Year for Est. Average for Final	Description of the Credits
	Network Credits							
47	Outstanding Network Credits							**General Description of the Credits**
	December	Account 252	2013		-			
	December	Account 252	2014			-		
	Average Beginning and End of Year			-			-	
48	Accumulated Depreciation Associated with Facilities with Outstanding Network Credits							
	December	Account 252	2013		-			
	December	Account 252	2014			-		
	Average Beginning and End of Year			-			-	

Interest on Outstanding Network Credits Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Interest on Network Credits	Description of the Interest on the Credits
137	Interest on Network Credits		
			Add more lines if necessary

Arizona Public Service Company

Attachment 6 - Estimate and Reconciliation Worksheet

Exec Summary

Step	Month	Year	Action
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form 1.
2	April	Year 2	TO estimates all transmission Cap Adds, Retirements, and associated depreciation for Year 2 based on Months expected to be in service in Year 2.
3	April	Year 2	TO adds estimates from Step 2 to Appendix A
4	May	Year 2	Post results of Step 3 on APS web site.
5	June	Year 2	Results of Step 3 go into effect.
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form 1.
7	April	Year 3	Reconciliation - TO calculates the true up amount by subtracting the results of Step 6 by Step 3.
8	April	Year 3	Reconciliation - TO calculates interst and ammortization associated with the true up calculated in Step 7 and applies that amount to line 151 of the formula.
9	April	Year 3	TO estimates all transmission Cap Adds, Retirements, CWIP and associated depreciation for Year 3 based on Months expected to be in service and monthly CWIP balances in Year 3.
10	April	Year 3	TO adds 13 month average Cap Adds and retirements (line 16 and 24) to the Formula.
11	May	Year 3	Post results of Step 10 on APS web site.
12	June	Year 3	Results of Step 9 go into effect for the Rate Year 2.

Reconciliation details

1 April Year 2 TO populates the formula with Year 1 data from FERC Form 1.
Rev Req based on Year 1 data — Must run Appendix A to get this number (without estimated cap adds) from Appendix A

2 April Year 2 TO estimates all transmission Cap Adds, Retirements, and associated depreciation for Year 2 based on Months expected to be in service in Year 2.

	(A) Other Project PIS	(B) other retirements	(C) Project X PIS	(D) Project X PIS retirements	(E) Accumulated Balance Other Project PIS	(F) Accumulated Balance Project X PIS	(G) Accumulated Balance Total
Dec					0	0	0
Jan				0	-	-	-
Feb				0	-	-	-
Mar				0	-	-	-
Apr				0	-	-	-
May				0	-	-	-
Jun				0	-	-	-
Jul				0	-	-	-
Aug				0	-	-	-
Sep				0	-	-	-
Oct				0	-	-	-
Nov				0	-	-	-
Dec				0	-	-	-
Total	-	-	-	-	-	-	-

13 month avg of new plant additions = Col F + Col H — - — goes to line 16 of the formula

	(I) =F Total Other Project PIS	(J) Composite Trans Deprec Rate	(K) = I * J Depreciation Expense	(L) Accum Deprec	(M) = H Total Project X PIS	(N) Composite Trans Deprec Rate	(O) = L * M Depreciation Expense	(P) Accum Deprec
			-	-				
Jan	0	0.00%	-	-	-	0.00%	-	-
Feb	0	0.00%	-	-	-	0.00%	-	-
Mar	0	0.00%	-	-	-	0.00%	-	-
Apr	0	0.00%	-	-	-	0.00%	-	-
May	0	0.00%	-	-	-	0.00%	-	-
Jun	0	0.00%	-	-	-	0.00%	-	-
Jul	0	0.00%	-	-	-	0.00%	-	-
Aug	0	0.00%	-	-	-	0.00%	-	-
Sep	0	0.00%	-	-	-	0.00%	-	-
Oct	0	0.00%	-	-	-	0.00%	-	-
Nov	0	0.00%	-	-	-	0.00%	-	-
Dec	0	0.00%	-	-	-	0.00%	-	-
Total			-	-			-	-

13 mo. Avg accumulated depreciation = Col L + Col P: - goes to line 24 of the formula
Depreciation Expense = Col K + Col O - goes to line 74 of the formula

3 April Year 2 TO adds estimates from Step 2 to Appendix A
Include inputs to Appendix A Lines 16, 24, and 74

4 May Year 2 Post results of Step 3 on APS web site.
$ -
Must run Appendix A to get this number (with results of step 2)

5 June Year 2 Results of Step 3 go into effect.
-

6 April Year 3 TO populates the formula with Year 2 data from FERC Form 1.

Rev Req based on Prior Year data step 6 file

7 April Year 3 Reconciliation - TO calculates the true up amount by subtracting the results of Step 6 by Step 3.

	Prior Year True Up	First Year True up	Total True Up
Results of Step 6	$ -		$ -
Results of Step 5	$ -		$ -
True up w/o interest			$ -

True Up to be recovered $ -

Divide True up w/o interest by the number of months the rate was in effect and place that result in the month that the rate went in effect in the interest calculation below

8 April Year 3

Reconciliation - TO calculates interst and ammortization associated with the true up calculated in Step 7 and applies that amount to line 151 of the formula.
Interest on Amount of Refunds or Surcharges
Interest 35.19a for 1st quarter Current Yr

Month	Yr	1/12 of Step 7	Interest 35.19a for and 35.19 b March Current Yr	Months	Interest	Refunds Owed
Jun	Year 1	-	0.00%	11.5	-	-
Jul	Year 1	-	0.00%	10.5	-	-
Aug	Year 1	-	0.00%	9.5	-	-
Sep	Year 1	-	0.00%	8.5	-	-
Oct	Year 1	-	0.00%	7.5	-	-
Nov	Year 1	-	0.00%	6.5	-	-
Dec	Year 1	-	0.00%	5.5	-	-
Jan	Year 2	-	0.00%	4.5	-	-
Feb	Year 2	-	0.00%	3.5	-	-
Mar	Year 2	-	0.00%	2.5	-	-
Apr	Year 2	-	0.00%	1.5	-	-
May	Year 2	-	0.00%	0.5	-	-
Total		-				-

Month	Yr	Balance	Interest	Amort	Balance
Jun	Year 2	-	0.00%	-	-
Jul	Year 2	-	0.00%	-	-
Aug	Year 2	-	0.00%	-	-
Sep	Year 2	-	0.00%	-	-
Oct	Year 2	-	0.00%	-	-
Nov	Year 2	-	0.00%	-	-
Dec	Year 2	-	0.00%	-	-
Jan	Year 3	-	0.00%	-	-
Feb	Year 3	-	0.00%	-	-
Mar	Year 3	-	0.00%	-	-
Apr	Year 3	-	0.00%	-	-
May	Year 3	-	0.00%	-	-
Total with interest				-	

The difference between the Reconciliation in Step 6 and the forecast in Prior Year with interest -

9 April Year 3 TO estimates all transmission Cap Adds, Retirements, CWIP and associated depreciation for Year 3 based on Months expected to be in service and monthly CWIP balances in Year 3.
Note: Jan and Feb are actuals, Mar-Dec forecasted. Retirements are not forecasted.

	(A) Other Project PIS	(B) other retirements	(C) Project X PIS	(D) Project X PIS retirements	(E) Accumulated Balance: Other Project PIS	(F) Accumulated Balance: Project X PIS	(G) Accumulated Balance: Total
Dec					0	0	0
Jan				0	-	-	-
Feb				0	-	-	-
Mar				0	-	-	-
Apr				0	-	-	-
May				0	-	-	-
Jun				0	-	-	-
Jul				0	-	-	-
Aug				0	-	-	-
Sep				0	-	-	-
Oct				0	-	-	-
Nov				0	-	-	-
Dec				0	-	-	-
Total	-	-	-		-	-	-

13 month avg of new plant additions = Col F + Col H - goes to line 16 of the formula

	(I) =F Total Other Project PIS	(J) Composite Trans Deprec Rate	(K) = I * J Depreciation Expense	(L) Accum Deprec	(M) = H Total Project X PIS	(N) Composite Trans Deprec Rate	(O) = L * M Depreciation Expense	(P) Accum Deprec
			-	-				
Jan	0	0.00%	-	-	-	0.00%	-	-
Feb	0	0.00%	-	-	-	0.00%	-	-
Mar	0	0.00%	-	-	-	0.00%	-	-
Apr	0	0.00%	-	-	-	0.00%	-	-
May	0	0.00%	-	-	-	0.00%	-	-
Jun	0	0.00%	-	-	-	0.00%	-	-
Jul	0	0.00%	-	-	-	0.00%	-	-
Aug	0	0.00%	-	-	-	0.00%	-	-
Sep	0	0.00%	-	-	-	0.00%	-	-
Oct	0	0.00%	-	-	-	0.00%	-	-
Nov	0	0.00%	-	-	-	0.00%	-	-
Dec	0	0.00%	-	-	-	0.00%	-	-
Total			-	-			-	-

13 mo. Avg accumulated depreciation = Col L + Col P - goes to line 24 of the formula
Depreciation Expense = Col K + Col O - goes to line 74 of the formula

10 April Year 3 TO adds 13 month average Cap Adds and retirements (line 110 and 120) to the Formula.
Rev Req based on Year 2 data with estimated Cap Adds, Rets, and Deprec for Year 3 Cap Adds (Step 9) and True up of Year 1 data (Step 8)
Must run App A to get this # (with 13 mo. avg cap adds, depreciation for Year 3 cap adds)

11 May Year 3 Post results of Step 10 on APS web site.
$ -

12 June Year 3 Results of Step 9 go into effect for the Rate Year 2.
- Step 11 plus the difference between the Reconciliation in Step 6 and the forecast in Prior Year with interest

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Attachment 7 - Transmission Enhancement Charge Worksheet

line #		Formula Line			
1		152	Plus any increased ROE calculated on Attachment 7 =Incentive - Revenue Credit for the corresponding rate year	$	-
	Fixed Charge Rate (FCR) if not a CIAC				
2	A	142	Net Plant Carrying Charge without Depreciation		0.0000%
3	B	149	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation		0.0000%
4	C		Line B less Line A		0.0000%
	FCR if a CIAC				
5	D	143	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		0.0000%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years

Beginning = 13 month Plant CWIP or Incentive Plant balance
Deprec = 13 month avg Accumulated Depreciation
Ending = Beginning - Deprec
Revenue= FCR* Ending + Ending

Total = Sum of Revenue for Project CWIP and PIS
Incentive = Total for "W Increased ROE" row
Revenue Credit = Total for "FCR W base ROE" row

	Details		Project A				Project B						
6	Life		-				-						
7	CIAC		No				No						
8	Increased ROE (Basis Points)		0				0						
9	FCR W base ROE		0.000%				0.000%						
10	FCR W increased ROE		0.000%				0.000%						
11	Investment		-				-						
12	Annual Depreciation Exp		-				-						
13	13 monthly Avg		-				-						
14		Invest Yr	Beginning	Depreciation	Ending	Revenue [(Beginning + Ending)/2* Line 11]	Beginning	Depreciation	Ending	Revenue [(Beginning + Ending)/2* Line 11]	Total	Incentive	Rev Credit
15	FCR W base ROE	2005	-	-	-	-	-	-	-	-	$ -		$ -
16	W Increased ROE	2005	-	-	-	-	-	-	-	-	$ -	$ -	
17	FCR W base ROE	2006	-	-	-	-					$ -		$ -
18	W Increased ROE	2006	-	-	-	-					$ -	$ -	
19	FCR W base ROE	2007	-	-	-	-					$ -		$ -
20	W Increased ROE	2007	-	-	-	-					$ -	$ -	
21	FCR W base ROE	2008	-	-	-	-					$ -		$ -
22	W Increased ROE	2008	-	-	-	-					$ -	$ -	
23	FCR W base ROE	2009	-	-	-	-					$ -		$ -
24	W Increased ROE	2009	-	-	-	-					$ -	$ -	
25	FCR W base ROE	2010	-	-	-	-					$ -		$ -
26	W Increased ROE	2010	-	-	-	-					$ -	$ -	
27	FCR W base ROE	2011	-	-	-	-					$ -		$ -
28	W Increased ROE	2011	-	-	-	-					$ -	$ -	
29	FCR W base ROE	2012	-	-	-	-					$ -		$ -
30	W Increased ROE	2012	-	-	-	-					$ -	$ -	
31	FCR W base ROE	2013	-	-	-	-					$ -		$ -
32	W Increased ROE	2013	-	-	-	-					$ -	$ -	
33	FCR W base ROE	2014	-	-	-	-					$ -		$ -
34	W Increased ROE	2014	-	-	-	-					$ -	$ -	
35	FCR W base ROE	2015	-	-	-	-					$ -		$ -
36	W Increased ROE	2015	-	-	-	-					$ -	$ -	
37	FCR W base ROE	2016	-	-	-	-					$ -		$ -
38	W Increased ROE	2016	-	-	-	-					$ -	$ -	
39	FCR W base ROE	2017	-	-	-	-					$ -		$ -
40	W Increased ROE	2017	-	-	-	-					$ -	$ -	
41	FCR W base ROE	2018	-	-	-	-					$ -		$ -
42	W Increased ROE	2018	-	-	-	-					$ -	$ -	
43	FCR W base ROE	2019	-	-	-	-					$ -		$ -
44	W Increased ROE	2019	-	-	-	-					$ -	$ -	
45	FCR W base ROE	2020	-	-	-	-					$ -		$ -
46	W Increased ROE	2020	-	-	-	-					$ -	$ -	
47	FCR W base ROE	2021	-	-	-	-					$ -		$ -
48	W Increased ROE	2021	-	-	-	-					$ -	$ -	
49	FCR W base ROE	2022	-	-	-	-					$ -		$ -
50	W Increased ROE	2022	-	-	-	-					$ -	$ -	
51	FCR W base ROE	2023	-	-	-	-					$ -		$ -
52	W Increased ROE	2023	-	-	-	-					$ -	$ -	
53	FCR W base ROE	2024	-	-	-	-					$ -		$ -
54	W Increased ROE	2024		-	-	-					$ -	$ -	
55		....		....	....	....							$ -
56		....	....	....	....	....						$ -	$ -

Arizona Public Service Company

Attachment 8 - Depreciation Rates

Plant Account	Depreciation Rates
352.01 - Structures	1.84%
353 - Station Equipment	2.14%
354 - Towers and Fixtures	1.34%
355.01 - Poles and Fixtures - Wood	2.21%
355.02 - Poles and Fixtures - Steel	2.10%
356 - Overhead Conductors and Devices	1.87%
357 - Underground Conduit	1.55%
358 - Underground Conductors and Devices	1.33%

Appendix R

RULE-BASED COMPLIANCE REQUIREMENTS ELIMINATED OR WAIVED

Rule	Topic	Frequency	Description
R14-2-1613(A)	Retail Competition	Annual	Report on competitive services and standard offer services provided by Electric Service Providers and Affected Utilities
R14-2-1617	Retail Competition	Annual	Provide a Consumer Disclosure Label containing price, fuel mix, and emissions data for the prior year
R14-2-2308	Net Metering	Annual	Provide the inverter or generator rating, monthly energy deliveries and if available the monthly peak demand for each net metering facility

DECISION-BASED COMPLIANCE REQUIREMENTS ELIMINATED OR WAIVED

Decision	Docket	Topic	Frequency	Description
Redundant Filings				
70531 Page 22, line 1 (09/30/08)	E-01345A-08-0106	RES	Annual	Report any damage payments received related to the Solana PPA contract
72058 Page 10, line 25 (01/06/11)	E-01345A-10-0314	RES	Annual	Report any damage payments received related to the Perrin Ranch PPA contract
71275 Page 15, line 4 (9/17/09)	E-01345A-09-0263	RES	Annual	Report production from systems installed as a result of the 2009 school UFI program and do not report "phantom" production
71244 Page 8, line 13 (08/06/09)	E-01345A-09-0255	Rates	Annual	Report detailing transmission projects and O&M costs included in each Transmission Cost Adjustor reset and expected future TCA costs
Outdated Filings				
68112 Page 7, line 3 (09/09/05)	E-01345A-03-0775 E-01345A-04-0657	Bill Estimation	Non-dated	Participate in benchmarking studies that compare APS estimation and other billing practices to other utilities

Decision	Docket	Topic	Frequency	Description
68645 Page 9, line 3 (04/12/06)	E-01345A-05-0674	Rates	Annual	Provide load shape data for participants served under experimental rates ET-2 and ECT-2
69569 Page 8, line 8 (05/21/07)	E-01345A-05-0711	Bill Estimation	Non-dated	Update allocation data for summer/winter on-peak usage, load factor, and usage per day when change is more than 5%
71448 Page 61, line 12 (12/30/09)	E-01345A-08-0172	Rate Case	As necessary	Notify Commission prior to replacing full-time employees with off-shored employees
71448 Page 61, line 26 (12/30/09)	E-01345A-08-0172	Rate Case	Annual	Develop a Carbon Credit Tracking Mechanism
71958 Page 6, line 26 (11/01/10)	E-01345A-10-0013	RES	Annual	Notify Commission if the Bagdad REC and Energy project has precluded any other commercial system from receiving incentives
72022 Page 29, line 1 (12/10/10)	E-01345A-10-0166 E-01345A-10-0262	RES	Annual	Summarize RES reports (Compliance Report and Implementation Plans) with 1-2 page summaries and a PowerPoint presentation
72022 Page 28, line 22 (12/10/10)	E-01345A-10-0166 E-01345A-10-0262	RES	Annual	Disclose if affiliates, employees, or directors have financial or other interest in renewable energy projects
72582 Page 14, line 22 (09/15/11)	E-01345A-10-0123	Technology Innovation	Annual	Report on the development of the EV market in APS territory
73089 (04/05/12) Page 62, line 1	E-01345A-11-0232	DSM/EE	Annual	Present an overview of the DSM Annual Progress Report at an Open Meeting
73089 (04/05/12) Page 61, line 6	E-01345A-11-0232	DSM/EE	Annual	Report spending associated with non-energy efficiency measures in the Appliance Recycling program
73089 (04/05/12) Page 61, line 11	E-01345A-11-0232	DSM/EE	Annual	Provide information on how savings from the Bid for Efficiency pilot measure are verified