BEFORE THE ARIZONA CORPORATION CO

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.

DOCKET NO. E-01345A-11-0224

STAFF'S OPENING BRIEF

The Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission") hereby submits its opening brief in the above-captioned matter as directed by the Administrative Law Judge ("ALJ") on February 3, 2011.[1]

I. INTRODUCTION.

On June 1, 2011, Arizona Public Service Company ("APS" or "Company") filed an application for an increase in its rates, a request for approval of new or amended rate mechanisms, and a request for approval of new or modified rate programs.

In its application, APS requested a revenue increase of approximately $95.49 million or approximately 3.3 percent over its current revenues using a test year ending December 31, 2010.[2] The requested revenue increase was based upon an 11.0 percent cost of equity with the Company's capital structure composed of 53.94 percent equity and 46.06 percent long-term debt. APS also requested the approval of two new rate mechanisms. The first request was for an Efficiency and Infrastructure Account ("EIA"), which is a full revenue per customer decoupling mechanism.[3] The second request was for an Environmental and Reliability Account ("ERA"), which is a mechanism that would allow the Company to recover certain investment associated with government mandated

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1 Tr. at 1266.
2 APS's Application at 1.
3 *Id.* at 6.

environmental improvements as well as new or acquired generation plant capacity additions and plant investment between rate case filings.[4]

APS also requested approval of amendments to the current Transmission Cost Adjustor ("TCA") and Power Supply Adjustor ("PSA"). With respect to the TCA, APS proposed two changes: 1) to remove the unbundled transmission service charges from base rates and consolidate these charges with the transmission charges already collected under the TCA and 2) to allow APS to charge the transmission rate approved by the Federal Energy Regulatory Commission ("FERC") to retail customers on the date that it becomes effective for wholesale customers without additional action by the Commission.[5] APS proposed to amend the PSA by eliminating the 90/10 sharing provision and by providing for a mechanism that would allow the Company to recover the costs of chemicals needed to operate environmental equipment at various generation facilities owned by APS.[6]

APS proposed new rate and service offerings, including Service Schedule 9 (an economic development schedule for large commercial and industrial customers), an experimental Peak-Time Rebate program (a rebate program for customers who reduce usage during critical peak hours), and an experimental Rate Service Rider Schedule AG-1 (an optional alternative generation service schedule for large customers).[7] APS also proposed modifications to existing service offerings, including Service Schedule 1 (a schedule of customer terms and conditions for standard offer and direct access) and Service Schedule 3 (a fee schedule for extensions of electric distribution lines and services).[8]

A number of parties intervened in this proceeding, including American Association of Retired Persons ("AARP"), AZAG Group ("AZAG"), the Arizona Association of School Business Officials ("AASBO"), the Arizona Association of Realtors ("AASR"), Arizona Competitive Power Alliance ("Alliance"), the Arizona Investment Council ("AIC"), the Arizona School Boards Association

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4 *Id.* at 7.
5 *Id.* at 8.
6 *Id.* at 7.
7 *Id.* at 12.
8 The Company's Service Schedule 3 was approved by the Commission in Decision No. 72684 (November 18, 2011). *See* Docket No. E-01345A-11-0207. Pursuant to Decision No. 72684, Service Schedule 3 will become effective as of the date of the Decision in this matter.

("ASBA"), Arizonans for Electric Choice and Competition and Freeport-McMoRan Copper & Gold Inc. (collectively "AECC"), Barbara Wyllie-Pecora, Bowie Power Station, LLC ("Bowie"), Constellation NewEnergy, Inc. ("Constellation"), Cynthia Zwick, Direct Energy, LLC ("Direct"), the Federal Executive Agencies ("FEA"), IBEW Locals 387, 640 and 769 ("IBEW"), Interwest Energy Alliance ("Interwest"), the Kroger Company ("Kroger"), Mel Beard,[9] Natural Resources Defense Council ("NRDC"), Noble Americas Energy Solutions, LLC ("Noble"), the Residential Utility Consumer Office ("RUCO"), Shell Energy North America (US), LP ("Shell"), Southwest Energy Efficiency Project ("SWEEP"), Southwestern Power Group, LLC ("SWPG"), the Town of Gilbert ("Gilbert"), the Town of Wickenburg ("Wickenburg"), Tucson Electric Power Company ("TEP"), Wal-Mart Stores, Inc. and Sam's West, Inc. (collectively "Wal-Mart"), and Western Resource Advocates ("WRA"). On November 18, 2011, Staff,[10] RUCO,[11] AECC, Kroger, Wal-mart, FEA, AIC, AARP, AASR, IBEW, Cynthia Zwick, NRDC, SWEEP, and WRA filed direct non-rate design testimony. Staff, RUCO,[12] AECC,[13] Kroger, Wal-mart, FEA, AARP, Cynthia Zwick, and SWEEP filed direct rate design testimony on December 2, 2011.

Staff made several recommendations pertaining to the Company's proposed rate base, expenses, revenues, and net operating income, resulting in a recommended revenue decrease of approximately $7.45 million.[14] Staff agreed with the Company's capital structure and embedded cost of long-term debt, but recommended a cost of common equity capital of 9.90 percent.[15] Staff recommended a fair value rate of return ("FVROR") of 6.05 percent using a 1.00 percent return on the fair value increment.[16]

Staff also recommended denial of the Company's proposed full revenue per customer decoupling mechanism in favor of a partial decoupling mechanism, referred to as the Lost Fixed Cost

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9 On December 2, 2011, the ALJ granted Mel Beard's request to withdraw as an Intervenor in this case.

10 Staff's Direct Testimony of November 18, 2011 inadvertently contained confidential information and was replaced and substituted with Direct Testimony filed on November 25, 2011. Staff filed the Direct Testimony of Laura Furrey on December 2, 2011 in accordance with the November 21, 2011 Procedural Order.

11 RUCO filed the Direct Decoupling Testimony of Frank Radigan on November 23, 2011 in accordance with the December 2, 2011 Procedural Order.

12 RUCO proposed a total rate decrease of zero dollars. *See* Radigan Dir. Test., Ex. RUCO-1 at 6.

13 AECC proposed a total rate increase of approximately $20.1 million. *See* Ex. Higgins Dir. Test., Ex AECC-1 at 6.

14 Smith Dir. Test., Ex. S-1 at 6.

15 Parcel Dir. Test., Ex. S-3 at 2.

16 *Id.* at 48-51.

Recovery ("LFCR") mechanism.[17] In addition, Staff recommended denial of the Company's ERA mechanism.[18] Staff further recommended denial of the Company's proposals to recover chemical costs through the PSA[19] and to consolidate the unbundled transmission service charges in the TCA.[20] Staff agreed with the Company's proposal to eliminate the 90/10 sharing provision contained in the PSA[21] and the Company's request to amend the TCA in order to charge the FERC approved transmission rate to retail customers on the date that it becomes effective for wholesale customers.[22] Staff also recommended that Service Schedule 9 be rejected[23] and that Service Schedule 1 include a cost of service study to be performed by the Company as part of its next rate case.[24]

Staff also made recommendations with respect to the Company's Renewable Energy Standard and Tariff ("REST") and Demand Side Management ("DSM") plans.[25] Specifically, Staff recommended that APS no longer be permitted to recover carrying costs for renewable energy-related capital investments beginning with the Company's 2013 REST Plan and that the proportionality requirement associated with the Renewable Energy Standard ("RES") adjustor rate and associated caps be removed.[26] In addition, Staff recommended that APS no longer be permitted to recover carrying costs for DSM-related capital investments beginning with the Company's 2013 DSM Implementation Plan. Staff also proposed a modified performance incentive structure to measure APS's implementation of its energy efficiency programs.[27]

APS filed a notice of settlement discussions on November 18, 2011. The parties of record subsequently held settlement discussions beginning on November 30, 2011. The parties reached an agreement in principal and filed a preliminary settlement term sheet on December 9, 2011, reflecting the agreements. An Open Meeting was held on December 16, 2011, wherein the Commissioners

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17 Solganick Dir. Test., Ex. S-12 at 4.
18 McGarry Dir. Test., Ex. S-6 at 12.
19 *Id.* at 25.
20 *Id.* at 30.
21 *Id.* at 19.
22 *Id.* at 32.
23 *Id.* at 34-35.
24 *Id.* at 30-34.
25 The Company's 2012 REST Plan was approved by the Commission in Decision No. 72737 (January 18, 2012). *See* Docket No. E-01345A-11-0264. The Company's 2012 DSM Implementation Plan is pending before the Commission. *See* Docket No. E-01345A-11-0232.
26 Furrey Dir. Test., Ex. S-9 at 2.
27 *Id.*

offered input on the term sheet. Staff filed a Proposed Settlement Agreement ("SA", "Agreement" or "Settlement Agreement") that was signed by APS, Staff, RUCO, Cynthia Zwick, FEA, Kroger, AECC, Wal-Mart, IBEW, AZAG, Alliance, AARP, AAR, Barbara Wyllie-Pecora, AIC, SWPG, Bowie, Noble, Constellation, Direct, and Shell (collectively "Signatories").[28] SWEEP, NRDC, the towns of Wickenburg/Gilbert, Interwest, WRA, ASBA and TEP did not sign the Agreement.[29]

The purpose of the Agreement is to settle all issues presented by Docket No. E-01345A-11-0224 in a manner that will promote the public interest. The Signatories agree that the terms of the Agreement are just, reasonable, fair, and in the public interest in that the Agreement results in a settlement package that provides both just and reasonable rates and significant benefits to customers.

II. BACKGROUND.

Arizona Public Service Company is the largest subsidiary of Pinnacle West Capital Corporation. APS is also the largest electric provider in Arizona serving more than 1.1 million customers in 11 of Arizona's 15 counties.[30] APS employs more than 6,600 employees, including employees at jointly-owned generating facilities for which APS serves as the generating facility manager.[31] In addition to the Palo Verde Nuclear Generating Station, APS owns and operates six natural-gas plants, one oil plant, two coal-fired plants, and an increasing array of renewable energy power generation.[32] APS has infrastructure consisting of more than 30,000 miles of transmission and distribution lines and 400 substations.[33]

The circumstances occasioning the last rate case filing of APS in 2008 were somewhat difficult. At that time, the S&P bond rating for APS had been hovering a step above junk level for several years, resulting in repeated rate case filings by APS for rate relief. The Company's last rate case resulted in a settlement agreement ("2009 Settlement Agreement") that attempted to improve the Company's financial standing with the investment community, provide for predictability with respect to rate case filings, and establish a strong commitment by the Company in Arizona's energy future.

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[28] Staff filed the Proposed Settlement Agreement on January 6, 2012.
[29] Wickenburg, Gilbert, and TEP participated in the settlement discussions and did not present evidence in opposition to the Agreement.
[30] White Dir. Test., Ex. APS-4, Att. REW-2 at 5.
[31] *Id.*
[32] *Id.*
[33] *Id.*

Since the Commission's approval of the 2009 Settlement Agreement, APS's financial ratings have improved.

The settlement package, in this case, balances the financial stability of the Company with benefits for customers. These benefits include, among others:

- An overall zero dollar base rate increase;
- A zero percent bill impact for the remainder of 2012 (Commission-approved adjustors (including the possibility of a Four Corners rider pursuant to paragraph 10.3 of the Agreement) may increase customer bills after December 31, 2012);
- An increase in rate stability, including a four year period without base rate increases;
- A buy-through rate for industrial and large commercial customers that holds residential customers harmless in the event that there are stranded fixed costs;
- A narrowly-tailored Lost Fixed Cost Recovery ("LFCR") mechanism that supports energy efficiency ("EE") and distributed generation ("DG") at any level or pace set by the Commission;
- An opt-out rate design for residential customers who choose not to participate in the LFCR;
- A process for simplifying customer bills; and
- Bill assistance for additional low income customers at shareholder expense.[34]

AIC Witness Fetter, a former chairman of the Michigan Public Service Commission and former Fitch Bond Rating analyst, stated the following with respect to the proposed Settlement Agreement: "I find it a thoughtful and creative package of provisions that: (1) are well-balanced across a disparate group of interests, (2) are likely to be well-received by the investment community and rating agencies in continuing to move APS away from the junk status precipice it was poised upon only a few years ago, and (3) afford the Commission considerable flexibility in fashioning energy policies."[35]

The Agreement in this matter is designed to continue the momentum achieved as a result of the Commission's order approving the Settlement in the last rate case while also preserving the Commission's flexibility to implement policy objectives in the areas of Energy Efficiency and

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[34] *See* Settlement Agreement at 5-6.
[35] Fetter Dir. SA Test., Ex. AIC-5 at 2.

Renewable Energy. The Agreement is endorsed by twenty-two of the twenty-nine parties to this proceeding, including Staff. The Proposed Agreement is the product of many hours of intense, transparent, and robust negotiations between multiple parties with divergent interests. Staff believes that the benefits from the Proposed Settlement Agreement are significant and that the record evidence supports its adoption.

III. THE VARIOUS PROVISIONS OF THE PROPOSED SETTLEMENT AGREEMENT ARE IN THE PUBLIC INTEREST AND THE COMMISSION SHOULD APPROVE THE AGREEMENT.

A. The Proposed Settlement Agreement Was The Result Of A Transparent And Open Process And Represents Agreement Among A Diverse Group Of Stakeholders.

Twenty-seven parties participated in some or all of the meetings.[36] Despite significantly divergent positions and interests, all of the parties, signatories and non-signatories alike, engaged in open, transparent, and arm's-length negotiations during a four-week period in November and December of 2011.[37] The diverse interests included Staff, RUCO, APS, an investment council, consumer representatives including AARP, demand-side management/energy efficiency advocates, low-income consumer advocates, renewable energy advocates, realtors, labor unions, large industrial users, competitive power producers, and mines.[38]

Throughout the settlement process, all parties were notified of the settlement meetings and had the opportunity to be heard and have their issues fairly considered.[39] During the course of negotiations, the signatories reviewed, discussed, and incorporated into the proposed Settlement Agreement some of the non-signatories' suggestions.[40] The extensive dialogue culminated in a productive, well-balanced and all-encompassing resolution between 22 of the 29 parties.[41]

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[36] Staff, APS, RUCO, Cynthia Zwick, FEA, Kroger, Freeport-McMoRan, AECC, Wal-Mart, IBEW, AzAG, AzCPA, AARP, AIC, SWPG, Bowie, Noble, Constellation, Direct, Shell, SWEEP, TEP, NRDC, AAR, WRA, ASBA and Interwest.

[37] Olea Dir. SA Test., Ex. S-10 at 4, 5, 6, 21;Guldner Dir. SA Test., Ex. APS-2 at 7:20-25; Chriss Dir. SA Test., Ex. WM-3 at 2-3; Jerrich Dir. SA Test., Ex. RUCO-6 at 2-3; Yaquinto Dir. SA Test., Ex. AIC-4 at 1, 5.

[38] Olea Dir. SA Test., Ex. S-10 at 5.

[39] Olea Dir. SA Test., Ex. S-10 at 4, 6; Guldner Dir. SA Test., Ex. APS-2 at 7; Tr. at 644.

[40] Guldner Dir. SA Test., Ex. APS-2 at 9.

[41] SWEEP and NRDC are in partial opposition to and did not execute the Settlement Agreement. In addition, Western Resource Advocates (WRA), Interwest Energy Alliances, the municipalities of Gilbert and Wickenberg, ASBA and AASBO did not sign. However they did not actively oppose the Agreement either.

B. Virtually All Parties Agree That The Proposed Settlement Agreement Is In The Public Interest.

The proposed Settlement Agreement comprehensively resolves all of the issues raised in this proceeding and carefully balances the interests of ratepayers and shareholders. That the Settlement Agreement is in the public interest is echoed by all signatories.[42] Most notably, Steve Olea, Utilities Director, testified that the proposed Settlement Agreement is fair and balanced and that the compromises made by the signatories will further the public interest.[43] Mr. Olea further stated that the proposed settlement package addresses APS's needs while balancing those needs with terms and conditions that provide customer benefits.[44]

Jeff Guldner of APS added that "the Settlement is a carefully crafted[,] cooperatively achieved balance of many important interests…."[45] Mr. Guldner also noted the importance of widespread support on APS's ratings:

> One of the reasons that we were upgraded from BBB minus to BBB with a positive outlook was because of the rating. S&P's view of the constructive regulatory environment that resulted after the last settlement agreement. And it was not just the product of the settlement agreement I think. I think it was also the fact that it was resolved, but a settlement agreement that brought a lot of parties together and demonstrated a significant amount of consensus. We hope that that's the similar reaction that would occur in this case if the settlement is approved, and it has got broad consensus and it continues to demonstrate constructive regulatory environment.[46]

RUCO witness Jerich noted the fact that "parties representing such varied interests were able to come together to reach consensus illustrates the balance, moderation and comprise of the document.[47]

While there was partial opposition to the proposed Agreement by two parties, that opposition was largely centered around the LFCR. Jeff Schlegel acknowledged that, were it not for the absence of a full revenue decoupling option therein, SWEEP would have signed the agreement.[48] In fact, Mr.

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42 Guldner Dir. SA Test., Ex. APS-2 at 6, 8; Brockway Dir. SA Test, Ex. AARP-3 at 1.
43 Olea Dir. SA Test., Ex. S-10 at 7, 8, 18.
44 *Id.* at 18.
45 Guldner Dir. SA Test., Ex. APS-2 at 9.
46 Tr. at 132.
47 Jerich Dir. SA Test., Ex. RUCO-6 at 4.
48 Tr. at 644, 675.

Schlegel admitted that adoption of the LFCR is in the public interest, because it is a positive step in the right direction:

> Q. Is addressing the unrecovered fixed cost issue through the LFCR mechanism in the public interest?
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> A. Yes, I would say that addressing the issue of lost fixed costs and unrecovered fixed costs through the lost fixed cost mechanism in the settlement is in the public interest. Again, SWEEP views decoupling as a better solution, but LFCR recovery as proposed in the settlement agreement is a positive step in the right direction.[49]

Ralph Cavanagh, testifying on behalf of NRDC, echoed Mr. Schlegel's position. Mr. Cavanagh acknowledged that he did not challenge any other portion of the settlement except for Section 9 (the LFCR mechanism), which he would replace with a full revenue per customer decoupling model.[50]

C. The Proposed Settlement Agreement Was Designed To Give The Commission Maximum Flexibility With Regard To Policy Determinations.

The Commission has recently indicated a preference for addressing policy matters in generic dockets rather than in rate cases, thereby retaining more flexibility between rate cases. The proposed Settlement Agreement was intentionally structured to give the Commission the flexibility it seeks in making policy determinations. With regard to energy efficiency and renewable energy, the Agreement provides the following at Section 9.2:

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

The Signatories' intent to provide the Commission with maximum flexibility in setting EE and DG policy is again reiterated at paragraph 9.13:

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49 *Id.* at 672.
50 *Id.* at 763-64.

> The LFCR was designed to be a flexible means to maximize the policy options available to the Commissioners and to customers, allowing the pursuit of EE and DG programs at any level or pace directed by the Commission. ....[51]

Unlike the 2009 Settlement Agreement adopted by the Commission, there are no specific EE or RES targets or requirements built into the Agreement which APS commits to achieving as part of the settlement. The Agreement does not contain any requirements in this regard and thus allows the Commission to set this policy in other proceedings on a prospective basis.

D. The Proposed Settlement Agreement Builds Upon The Progress Made With The 2009 Agreement To Improve The Company's Financial Standing.

The proposed Settlement Agreement builds on the progress made in APS's last rate case by including provisions designed to improve the Company's financial condition so it can compete in attracting capital for investments to meet the needs of its customers.[52]

At the outset of the hearing, counsel for APS, Meghan Grabel, stated the following:

> Many [of the parties] believed that the [2009] agreement that resulted marked a turning point for APS. Not only did [the agreement] keep the company financially healthy during a two and a half year stay-out, it demonstrated an impressive level of collaboration among a diverse group of stakeholders.
>
> That positive outcome facilitated a bond rating upgrade for APS, removing the company from the often discussed precipice of non-investment grade. The upgrade was especially significant in that it was coupled with what the rating agencies call a positive outlook, meaning that S&P might rate the company's credit rating again if such constructive outcomes continue.[53]

The proposed Agreement attempts to build on the progress from the last agreement, but also recognizes the need to moderate any bill impact associated with this case and otherwise balance customer interests in a difficult economy. Subsequently, Mike Grant, counsel for AIC, explained that due to a number of factors AIC witness Fetter believes the proposed Settlement Agreement will be favorably viewed by the ratings agencies:

> Number one, just the settlement itself, instead of weeks of hearings, of briefing, the decisional phase is a very strong, very constructive message about the positive climate of the Commission's process.

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[51] Settlement Agreement at ¶ 9.13.
[52] Yaquinto Dir. SA Test., Ex. AIC-4 at 2.
[53] Tr. at 17.

> Number two, the inclusion of 15 months of post test year plant yields two benefits. It is a signal to the market about positive benefits taken to reduce the effect of regulatory lag, and it counters rate shock for customers from the standpoint that that investment is not postponed to compound recovery necessary in APS' next rate case.
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> Number three, with a 10 percent ROE, it is a full 100 basis points below what the company requested, but it does creep into that 10 range, and that's good optics for investors and also for rating agencies.
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> Number four, while, as you know, like APS, the AIC also supported a revenue decoupler settlement agreement, a lost fixed cost recovery mechanism transmits a solid message that the Commission does understand that its EE and DG policies have revenue consequences that need to be dealt with in a very constructive way.
>
> And number five, although the four-year stay-out provision is a little risky, as a given in these uncertain economic times, there are other parts of the agreement which provide support over that 48-month term.[54]

RUCO also acknowledged the benefits of the proposed Settlement and how it is intended to continue to work to improve the Company's financial standing. Jodi Jerich, Director of RUCO, testified that the Agreement in the Company's last rate case has had a positive effect on the Company's financial standing, e.g., its credit rating has been upgraded to BBB with a positive outlook from BBB minus,[55] and that the proposed Settlement Agreement must be "read in harmony" with the 2009 Agreement."[56]

E. The Agreement Appropriately Balances Consumer And Shareholder Interests.

1. Many provisions of the proposed settlement agreement will benefit consumers.

The proposed Settlement Agreement has many provisions which will benefit consumers. Some of the more significant provisions are discussed below.

a. Rate case filing moratorium.

Under paragraph 2.1 of the Agreement, APS has agreed to a four-year stay-out in that the Company will not file its next general rate case prior to May 31, 2015. New base rates resulting from the next case will not be effective before July 1, 2016.

Mr. Olea highlighted the benefits of this provision in his testimony:

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[54] *Id.* at 26-27.
[55] Jerich Dir. SA Test., Ex-RUCO-6 at 6.
[56] *Id.* at 7; Tr. at 1145.

> Over the past few years, APS has filed a number of rate cases (e.g. 2005 settlement, 2006 emergency case, 2007 litigated case, 2009 emergency case, 2009 settlement). Under these circumstances, customers would benefit from a period of rate stability, and the four-year rate case moratorium is intended to achieve such stability. On the other hand, the Commission is not precluded from changing rates if necessary to protect the public interest. In my opinion, the proposed Agreement strikes the right balance between these interests. [57]

This provision was important to many signatories. AECC witness Higgins noted that a four-year stay-out is extraordinary in today's regulatory environment and conveys a very significant benefit to customers in terms of rate stability and rate certainty.[58] Kroger witness Baron stated "the rate base stability provision, freezing base rates until July 1, 2016 is likely to be a significant benefit to all of the Company's ratepayers."[59] "RUCO finds that a stable base rate with the ability for the Company to remain financially healthy through changes in its adjustors is in the public interest."[60] Mr. Guldner stated, that while a four-year moratorium is on the longer end of stay-out provisions, APS is comfortable with the four-year stay out given the other elements of the proposed settlement agreement.[61]

This provision ensures that APS's customers will have the benefit of rate stability during that period while also providing the Company with adequate revenue to enable it to provide safe and reliable electric service.[62]

2. No base rate increase.

APS proposed a total rate increase of approximately \$95.49 million.[63] Under the proposed Settlement Agreement (paragraph 3.1), APS's base rates will not increase. The zero increase to base rates is comprised of (1) a non-fuel base rate increase of \$116.3 million (which includes post test year plant in service as of March 31, 2012),[64] (2) a fuel base rate decrease of \$153.1 million,[65] and (3) a transfer of cost recovery from the Renewable Energy Surcharge ("RES") to base rates of

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57 Olea Resp. SA Test., Ex. S-11 at 3-4.
58 Higgins Dir. SA Test., Ex. AECC-3 at 5.
59 Baron Dir. SA Test., Ex. Kroger-3 at 3.
60 Jerich Dir. SA Test., Ex. RUCO-6 at 20.
61 Tr. at 130.
62 *Id.* at 206-09.
63 APS's Application at 1.
64 Olea Dir. SA Test., Ex. S-10 at 8-9.
65 Olea Resp. SA Test., Ex. S-11 at 5.

approximately $36.8 million.[66] (The Agreement lowers the base cost of fuel and purchased power from $0.037571 per kWh to $0.032071 per kWh on the effective date of new rates.)[67]

Adoption of the Agreement will mean that APS's base rates will not have been subject to increase for 6 years.[68]

> [I]f the Settlement is approved, APS customers will not have had a base rate increase for at least six and a half years by the time the company is next eligible for rate relief, a period measured from the January 2010 rate effective date of APS's last rate case until the end of this Settlement stay-out period.[69]

Even though adjustor mechanisms could fluctuate upwards and increase bills, the fact that base rates will remain constant for a four-year period is a significant benefit to customers.[70]

3. A bill impact of zero or slightly negative once new rates take effect for the remainder of 2012.

Another significant benefit of the proposed Settlement Agreement to customers is that it provides for a zero increase or a slight decrease for the bill impact for the remainder of 2012 due to continuing the PSA credit.[71] APS has agreed to delay recovery of a portion of its fuel and purchased power costs until early 2013. This delay allows for the zero or slightly negative bill impact until February 1, 2013.[72]

Under this provision, customers will benefit by (1) the absence of increased base rates during the summer when usage is typically high and (2) a decrease in the frequency of bill impacts associated with the reset of fuel and purchased power costs which, absent the proposed Settlement Agreement, would have also occurred in July of 2012.[73] APS's PSA will be reset in February of 2013 in order to true-up its recovery of fuel and purchased power expenses.[74]

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[66] Olea Dir. Test., Ex. S-10 at 9.
[67] Guldner Dir. SA Test., Ex. APS-2 at 13.
[68] *Id.* at 11.
[69] *Id.*
[70] Tr. at 945.
[71] Olea Resp. SA Test., Ex. S-11 at 6.
[72] *Id.* Tr. at 97-98, 242.
[73] Olea Resp. SA Test., Ex. S-11 at 7.
[74] *Id.* at 6.

4. A rate of return on equity that is 100 basis points below APS's existing ROE.

As part of the agreement relating to revenue requirement, the Company has agreed to a 10% authorized return on equity, which is a full 100 basis points below APS's existing equity of return of 11%.[75]

The agreed upon return on common equity is somewhat below recent ROEs authorized in other jurisdictions for vertically integrated electric utilities like APS. The agreed upon equity component of APS's capital structure (53.49%) together with the 10% return on equity should allow APS to improve its financial condition and credit ratings over time.[76] At the same time, this ultimately means that customers will pay less to finance plant and other items.

5. The low income provisions benefit consumers.

Section 14 of the proposed Settlement Agreement addresses programs specifically affecting low income customers. Paragraph 14.1 expands the bill assistance program by broadening the range of eligibility in order to assist customers whose incomes are less than 200% of the Federal Poverty Income Guidelines.

Paragraph 14.2 provides that the PSA and DSMAC adjustor rates will now apply to low income customers. Previously, low income customers were exempt from those adjustors; however, this exemption had the negative consequence of not allowing low income customers to take advantage of credits available due to over-collections. Under paragraph 14.2, the Signatories agreed to provide a uniform discount applicable to all services billed to residential customers.[77] In an effort to simplify billing methods, low income customers will be transferred to their respective non-low income rate schedules. The PSA and DSMAC rate adjustors will then be applied to those bills. However, a discount to the total bill will be applied to effectuate a zero impact on the bill.[78]

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[75] Settlement Agreement at ¶ 5.1; *see also* Guldner Dir. SA Test.; Ex. APS-2 at 12.
[76] Fetter Dir. SA Test., Ex. AIC-5 at 8.
[77] Tr. at 319.
[78] *Id.* at 320-21, 532.

6. Lost fixed cost recovery mechanism and residential consumer opt-out provision.

The Commission has received many comments from consumers in this docket who are opposed to the adoption of a full revenue decoupling mechanism.[79] The proposed Settlement Agreement does not adopt a full revenue decoupling mechanism. Rather, the proposed Settlement Agreement adopts a Lost Fixed Cost Recovery ("LFCR") mechanism. "The major difference between decoupling and lost fixed cost recovery is that lost fixed cost recovery is tied to measured and approved Corporation Commission programs for energy efficiency and for distributed generation."[80] Full revenue decoupling is indifferent as to what is causing the effect of the lower or higher sales.[81] Unlike the LFCR, full revenue decoupling ends up shifting all risk for lower per kWh sales to customers, in particular risks related to weather and the economy.[82]

Residential customers are given the option under paragraph 9.8 of the Agreement to opt-out of the LFCR. This is a unique provision, likely the first of its kind in the United States.[83] Many residential customers have expressed concern regarding full revenue decoupling because of the potential for widely varying bill impacts from year to year. The LFCR contained in the proposed Settlement Agreement is more narrow than a full revenue decoupling mechanism and any rate increases from year to year are likely to be quite moderate. The opt-out provision was nonetheless important to those parties representing the interests of residential ratepayers (RUCO) and senior citizens (AARP). While RUCO Witness Jerich supported both the LFCR and the residential opt-out rate, she stated that without the opt-out rate, it is highly unlikely that RUCO would have signed the proposed Settlement Agreement.[84] Those customers who choose to opt-out of the LFCR will instead be assessed an opt-out rate that is intended to replicate, on average, the effects of the LFCR.[85] The benefit of the opt-out rate bill is certainty with respect to the year-to-year level of rates (otherwise affected by the LFCR) established in the proposed Settlement Agreement. Residential customers

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79 *Id.* at 86, 494-95, 1121.
80 *Id.* at 203.
81 *Id.* at 203-04.
82 Solganick Dir. SA Test., Ex. S-12 at 7.
83 Guldner Dir. SA Test., Ex. APS-2 at 7.
84 Jerich Dir. SA Test., Ex. RUCO-6 at 17.
85 Settlement Agreement at ¶ 9.8

who elect the opt-out rate, will agree to an increase in the basic service charge and that rate will remain fixed for the entire term of the proposed Settlement Agreement.[86] If a customer elects to take the opt-out rate, it will not take effect prior to the first LFCR adjustment, sometime in 2013.[87]

There was some concern expressed at the hearing that the "opt-out" option would allow the customer to opt-out of participation in EE or RES programs.[88] This is not the case. The opt-out provision was established so that residential customers who do not want to be subject to the LFCR could elect an alternative basic service charge ("BSC") amount to pay. The opt-out rate option does not prevent customers from participating in EE or DG programs. Thus, the opt-out rate option does not discourage participation in EE or DG.

7. A lower systems benefits charge in 2016.

The Nuclear Decommissioning Trust Fund collects the costs required to decommission Palo Verde Unit 2 from customers.[89] These costs are included in the Systems Benefits Charge ("SBC"), which is part of base rates.[90] APS anticipates that Unit 2 will be fully funded by 2016, and has agreed to seek Commission approval of a corresponding reduction to the SBC.[91] A lower SBC will result in lower rates to customers. The effect of this would be about a $14 million revenue requirement reduction.[92]

8. A process for simplifying customer bills.

Section 16.1 requires APS to undertake stakeholder meetings to address issues related to the APS bill presentation with a goal of making the bill easier for customers to understand. APS witness Guldner explained the need for this process:

> What 16.1 reflects is, I think, a growing concern that over the last 10 or more years, as decisions and rate cases have gotten resolved and Commission policies have been implemented, the complexity of our bill has significantly increased.

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[86] Jerich Dir. SA Test., Ex. RUCO-6 at 17.
[87] Tr. at 117.
[88] *Id.* at 1046-47
[89] Guldner Dir. SA Test., Ex. APS-2 at 13.
[90] *Id.*
[91] *Id.*; proposed Settlement Agreement at ¶ 6.3. ("... Such filing shall be made in sufficient time for the reduction to occur by January 2016.")
[92] Tr. at 187-88.

> And we show a lot of information on the bill. And there is certain information on the bill that we might want to show that would be more helpful to customers than some of the information that we do show.[93]

Mr. Guldner further explained that the results of this process would be brought back to the Commission to approve.[94]

F. Provisions In The Agreement Provide Important Benefits To The Company But At The Same Time Balance The Consumer Interest. Other Provisions Are Intended To More Closely Align The Interests Of The Company And Consumers.

APS witness Guldner testified that certain terms are essential to sustain the four-year rate moratorium.[95] Those provisions include the LFCR mechanism, the proposed rate treatment of Four Corners, changes to the Transmission Cost Adjustor ("TCA"), elimination of the PSA 90/10 sharing provision, the EIS, and the property tax deferral. The other provisions discussed below related to the RES surcharge, the buy through rate for industrial and large commercial customers and the DSM changes are designed to more closely align the interest of the Company and its customers.

1. Energy efficiency and distributed generation – recouping lost fixed costs.

a. The LFCR mechanism allows APS to recoup lost fixed costs as a result of its EE and DG programs.

One of the primary issues that the parties had to grapple with in this proceeding was the issue of EE and DG and the 2008 Policy Statement, i.e., how the Company should recover its lost fixed costs associated with reduced kWh sales as a result of the Commission's EE and DG policies.

The Signatories collectively support energy efficiency as a low cost energy resource.[96] As far as anticipated growth in demand for the next 10 years, the Company sees energy efficiency as supplying at least half of the resources needed to meet that demand.[97] With EE and DG programs, there will be fixed cost revenue erosion experienced by the Company. This creates a disincentive for the Company to actively promote EE or DG, since, with the absence of some type of cost recovery mechanism, it would result in the Company not being able to recover a portion of its fixed costs that would otherwise be recovered.

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[93] *Id.* at 136.
[94] *Id.* at 138.
[95] Guldner Dir. SA Test., Ex. APS-2 at 5-6.
[96] Settlement Agreement at ¶ 9.1
[97] Tr. at 206-07.

To address these disincentives, in 2008 the Commission commenced an investigation of utility financial disincentives to energy efficiency and considered how it could address these issues and maximize energy efficiency efforts at the affected electric and gas companies. A series of workshops were held which culminated in a Policy Statement. On December 29, 2010, the Commission issued a policy directive on decoupling or alternative mechanisms to address these disincentives entitled "Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures" ("Policy Statement").[98] While the Policy Statement expressed a preference for full revenue decoupling, the Commission also stated that each utility may file a proposal for decoupling or an alternative mechanism for addressing disincentives in its next general rate case.[99]

The proposed Settlement Agreement provides for an alternative mechanism called the LFCR. Staff witness Solganick originally proposed a LFCR mechanism in Staff's Direct Testimony in this case. The LFCR adopted in the proposed Settlement Agreement is similar to the LFCR mechanism proposed by Mr. Solganick. As discussed earlier, it is different from a full revenue decoupling mechanism because it allows APS to recover only those "fixed costs that are not recovered due to reductions in volumetric sales required by the Commission's energy efficiency requirements or distributed generation requirements."[100] More specifically, it will cover "only the Test Year fixed costs that have been documented to be lost" as a result of Commission approved EE and DG programs.[101]

The LFCR is narrowly tailored and is designed to recover only a portion of distribution and transmission costs related to sales levels that are reduced by EE and DG.[102] It is designed to exclude the portion of distribution and transmission costs recovered through the Basic Service Charge and 50 percent of the costs that are recovered through non-generation/non-TCA demand charges.[103] The LFCR does not recover 100 percent of the demand charge because, if a customer reduces his or her

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98 Docket No. G-00000C-08-0314; also see Docket No. E-00000J-08-0314.
99 Policy Statement at 32.
100 Olea Resp. SA Test., Ex. S-11 at 2.
101 Solganick Dir. SA Test., Ex. S-12 at 2.
102 Settlement Agreement at ¶ 9.3.
103 *Id.*

energy consumption in response to one of the Company's programs, it is unlikely that there will be a proportional reduction in the demand level.[104] To recognize that there may be some demand reduction, a 50% Demand Stability Factor is applied.[105] The LFCR mechanism does not include generation costs for two reasons: 1) sales are forecasted to rise in the near future; and 2) APS has opportunities for off-system, ACC non-jurisdictional sales to sell any excess energy.[106]

"The major difference between decoupling and lost fixed cost recovery is that lost fixed cost recovery is tied to measured and approved Corporation Commission programs for energy efficiency and for distributed generation."[107] In contrast, full decoupling is indifferent as to what is causing the effect of the lower or higher sales.[108] While the LFCR does not break the incentive to increase sales volumes to achieve higher revenues,[109] it does break the disincentive to not invest in EE and DG due to lower sales volumes. The LFCR allows the Company to recoup its demonstrated lost fixed costs due to EE and DG programs. When questioned whether the LFCR in any way undercuts EE or RES standards or goals, APS witness Guldner stated "I don't believe it does."

The LFCR utilizes existing processes to determine applicable sales reductions recoverable through the mechanism on an annual basis. APS will use the Measurement, Evaluation and Research ("MER") report of its EE program results[110] to determine the applicable sales reduction for its EE programs and add the sales reduction for the applicable Distributed Generation ("DG") programs; the sum of these results is called the Total Recoverable MWh Savings. If the Company is unable to document any sales reductions from its EE and DG programs, then customers would see no charge under the LFCR mechanism.[111]

Under the Plan of Administration, the Company must file its Annual LFCR Adjustment for the previous year by January 15th, and Staff will use its best efforts to process the matter by March 1 of each year. The LFCR will not appear on customer bills before March 1, 2013, and the LFCR will

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[104] Solganick Dir. SA Test., Ex. S-12 at 4.
[105] *Id.*
[106] *Id.*
[107] Tr. at 203.
[108] *Id.* 203-04.
[109] *Id.* 204.
[110] Solganick Dir. SA Test., Ex. S-12 at 2.
[111] *Id.* at 6.

be assessed only if the Company demonstrates sales reductions from its EE and DG programs. Any charge must be approved by the Commission.[112] The March 1, 2013 adjustment will include reduced sales from EE and DG for 2012 and will be pro-rated from the date rates become effective pursuant to a Commission Decision approving the proposed Settlement Agreement.[113]

Not all customers will be subject to the LFCR. General service customers served under rate schedules E-32 L, 3-32 L TOU, E-34, E-35 E-36 XL, unmetered general service customers served under rate schedule E-30, and lighting customers are excluded from the mechanism because they all have fixed charges that are not expected to be impacted by EE and DG programs.[114] For customers with billing demands of 400 kW or greater, the proposed Settlement Agreement addresses through rate design concerns over fixed cost recovery.[115] And, residential customers may elect an opt-out rate rather than be subject to the LFCR.

Unlike full revenue decoupling, both weather and business risk stay with the Company and are not transferred to ratepayers.[116] Because the mechanism does not shift weather or business risks to customers, no rate of return adjustment is necessary as with full revenue decoupling.[117]

Annual adjustments are limited to one percent of APS's applicable revenue and are estimated to be below that level for the next four years based on the expected EE and DG programs.[118] Thus, estimates are that there would be no deferrals because lost Kwh sales associated with the Company's DG and EE programs are not expected to exceed the 1 percent cap while this proposed Settlement Agreement is in effect. The year to year increase in the LFCR is expected to be about a half percent. So it amounts to approximately $12 million a year in 2014, 2015, and 2016.[119] In 2013, the LFCR is expected to recover about four and a half million dollars, on a prorated basis from the effective date of new rates on July 1, 2012.[120] The cumulative impact on customers is expected to be approximately

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112 *Id.* at 3; *see also* Settlement Agreement at ¶ 9.6.
113 Settlement Agreement at ¶ 9.6.
114 *Id.*
115 Higgins Dir. SA Test., Ex. AECC-3 at 3.
116 *Id.* at 8.
117 *Id.*
118 *Id.* at 4.
119 Tr. at 422.
120 *Id.* at 192.

$16 million in 2014;[121] approximately $30 million in 2015; and approximately $40 million in 2016.[122] All else equal, the cumulative impacts under a full revenue decoupling proposal would be much greater: 2014 - $26.9 million; 2015 - $49 million; and 2016 - $70 million.[123]

While APS proposed a full revenue per customer decoupling mechanism in its original case, the Company supports the LFCR because it will allow the Company to meet the current EE and DG standards and requirements through 2016.[124] APS witness Guldner further stated, "I don't think we would have had the same makeup of parties to such a settlement proposal [with full revenue decoupling]."[125]

2. The proposed changes to the RES surcharge are in the public interest.

The proposed Settlement Agreement contains several important changes to APS's RES surcharge. First, APS will no longer be permitted to recover carrying costs for renewable energy-related capital investments beginning with the Company's 2013 REST Plan. Section 8.2 of the proposed Agreement provides that:

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

Staff witness Olea testified that plant associated with renewable energy projects should be treated no differently than other plant investments that the Company makes.[126] The Agreement does recognize, however, that projects authorized by Decision No. 71448 would continue to be recovered through the RES adjustor unless authorized for recovery in another manner. In addition, Section 8.1 provides that, consistent with the Agreement's treatment of other post-test year plant, the portion of the renewable projects closed to plant in service as of March 31, 2012 will be recovered through base rates.

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121 Tr. at 193.
122 *Id.*
123 *Id.* at 192-93.
124 *Id.* at 88.
125 *Id.*
126 *Id.* at 1033-34.

Finally, the proposed Settlement Agreement eliminates the proportionality requirement associated with the RES adjustor rate and associated caps established in Decision No. 67744.[127] This will give the Commission greater flexibility in setting the RES adjustor rates and caps. Some concern was expressed at the hearing on this matter to the effect that elimination of these requirements would mean that the Commission could no longer set rates proportionally among customer classes.[128] This is not the case. The Commission can set rates proportionally if it chooses to do so. However, elimination of a proportionality <u>requirement</u> will allow the Commission greater flexibility in designing the RES adjustor rate.

3. The provisions relating to APS's DSM programs are in the public interest.

The proposed Settlement Agreement contains several provisions relating to APS's DSM programs. APS will no longer be permitted to recover carrying costs for DSM-related capital investments beginning with the Company's 2013 Implementation Plan (filed in 2012).[129] The only exception to this is for DSM projects already authorized by the Commission. Again, as Mr. Olea testified, there is no reason to treat DSM related capital investments differently from other plant that the Company invests in and places in service.[130]

In addition, the proposed Settlement Agreement changes the current performance incentive to eliminate the top two tiers of percentages to be applied to Net Benefits or Percent of Program Costs based on APS's achievement relative to the EE standard.[131] With respect to the fourth tier, a uniform performance incentive capped at 105% would be applied to APS's performance relative to the EE standard. APS also committed in the proposed Agreement to use the inputs and methodology that Staff uses in calculating the present value of benefits and costs for DSM measures in its Societal Test.

Under the proposed Settlement Agreement, APS will work with stakeholders and Staff to develop a new performance incentive structure by December 31, 2012.[132] The Agreement specifically provides for the rate case to be held open so that the Commission may approve the new

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[127] Furrey Dir. Test., Ex. S-9 at 2.
[128] Tr. at 1033, 1040-42.
[129] *See* Settlement Agreement at ¶ 9.14(a).
[130] Tr. at 1033-34.
[131] *See* Settlement Agreement at ¶ 9.14(b).
[132] *Id.* at ¶ 9.14(d).

performance incentive structure which would then become effective on the plan year the Commission first determines it should apply.

There was a question raised at the hearing as to why the section relating to performance incentives was addressed in the agreement and why it couldn't instead be established in the annual EE implementation plan.[133] Because the performance incentive impacts Company revenues, a strong argument can be made that any change or adjustments to the performance incentive structure or DSMAC adjustor plan of administration needs to occur in the context of a rate case.

A question was also asked at the hearing whether the performance incentive was necessary if the company has an LFCR. The LFCR and the performance incentive are different mechanisms, each with a particular purpose. The LFCR makes the Company indifferent to sales lost as a result of DSM and DG programs. The purpose of a performance incentive, however, is to encourage the Company to achieve the most cost-effective energy savings possible through its DSM programs, which ultimately, will save the ratepayers money. The proposed Settlement Agreement will allow the Commission to evaluate APS's performance incentive and make any changes it desires.

Another important commitment made by APS regarding its DSM programs is the agreement to develop a technical manual documenting program and measure saving assumptions and incremental costs no later than December 31, 2012.[134]

Finally, the proposed Agreement provides that APS's DSM programs and savings shall be independently reviewed every five years by an evaluator selected by Staff and paid for by APS shareholders in an amount not to exceed $100,000.[135]

4. A buy through rate for industrial and large commercial customers.

In its rate application, APS proposed Experimental Rate Service Rider Schedule AG-1 ("AG-1"), a buy-through rate for large commercial and industrial customers. This provides a four-year experimental buy-through rate program as an option to standard generation.[136] Large commercial customers can now obtain alternative sources of generation to serve their power requirements. While

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[133] Tr. at 306.
[134] Settlement Agreement at ¶ 9.15.
[135] *Id.* at ¶ 9.14(c).
[136] Tr. at 20.

the Agreement does not adopt the identical APS proposal, it does adopt a buy-through rate program that is acceptable to the Signatories to the Agreement, including large customers of APS that will have access to AG-1. The Signatories to the proposed Settlement Agreement spent considerable time developing the parameters for Experimental Rate Schedule AG-1. The experimental rate schedule is intended to give larger customers of APS greater control over their energy costs.

The program is capped at 200 megawatts.[137] Applicants must be able to aggregate into a 10 megawatt group.[138] That means the applicant would have to have a single site like a manufacturing facility or major university that's 10 megawatts or above or the business would have to have multiple sites in APS's service territory which would add up to at least 10 megawatts.[139] APS has about 65 very large commercial customers with 3,000 KW or above of typical monthly usage.[140] In the large commercial groups, there are about a thousand customers that could be eligible. Their loads range from 400 KW to 3,000 KW.[141] APS will purchase and manage the generation on behalf of the customer for a management fee of $.0006 per Kwh.

APS witness Guldner explained that, in a 2009 workshop, customers like Wal-Mart, Kroger, Sam's Club, Costco and others expressed an interest in having more control over their generation costs.[142] Generation Service Provider ("GSP") Parties witness Mary Lynch explained in the following passage why AG-1 is different from retail electric competition:

> There are at least two significant differences between retail electric competition as contemplated under Arizona law and the electric service that is provided for under Rate Schedule AG-1. First and foremost, the GSP will transfer title to the electricity the GSP bought, at the direction of an eligible Rate Schedule AG-1 customer, to APS at a delivery point outside of APS' network delivery. Upon taking title to the electricity, APS remains the transmission and distribution provider for the Rate Schedule AG-1 customer. In essence, service under Rate ScheduleAG-1 is not unlike the type of contractual hedging that APS performs to manage its system-wide portfolio of energy costs, except that the contract executed between the GSP and APS pursuant to Rate Schedule AG-1 will be "earmarked" on behalf of a specific customer, who will be billed for energy at the price the Rate Schedule AG-1 customer in question negotiated with the GSP, thereby bypassing the unbundled generation component of their otherwise applicable APS rate schedule.

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[137] *Id.* at 543.
[138] *Id.* at 544.
[139] *Id.*
[140] *Id.* at 543.
[141] *Id.*
[142] *Id.* at 126.

A second significant difference between service under Rate Schedule AG-1 and retail electric competition is that in Arizona, the retail supplier is required to have first obtained a Certificate of Convenience and Necessity ("CC&N") for that purpose from the Commission, because the retail supplier under retail electric competition is considered to be a load serving entity of the end use customer. A GSP providing energy to APS pursuant to Rate Schedule AG-1 is not required to secure a CC&N because the electricity that the GSP is providing is delivered to APS at a wholesale delivery point; and, as noted above, title to the electricity passes to APS at that time. In that regard, the GSP is NOT utilizing nor paying for access to APS' transmission and distribution network, and APS remains the load serving entity for the retail customer providing all services, including the generation delivery and billing under a Commission approved rate schedule. In this instance, that rate schedule would be Rate Schedule AG-1.

This structure described above, while significantly different from the typical retail model as implemented across the United States, does contain many program similarities that are in place in a few other states in the West, most notably in Washington and Montana.[143]

The experimental AG-1 schedule is supported by large customers that plan to take service under AG-1 including Wal-Mart and Sam's West.[144] Kroger also supports AG-1 as well.[145] It is also supported by competitive generation service providers, including Noble Energy Solutions LLC, Constellation New Energy, Inc., Direct Energy LLC, and Shell Energy North America (US), L.P.[146]

Program guidelines covering such topics as the customer enrollment process, APS's provision of Imbalance Energy, billing by the GSP to APS for energy deliveries, and energy scheduling protocals, competitive bidding process as well as other issues identified by the parties will be worked out in a collaborative process.[147]

If AG-1 is approved, GSPs will structure wholesale supply agreements with the customers pricing and risk management requirements, and requirements that meet the contracting and pricing established by AG-1.[148]

Rate Rider AG-1 is very customer friendly and innovative, and has the potential to enable Arizona businesses to improve their economic health through energy cost savings at no risk to other customers.[149]

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[143] Lynch Dir. SA Test., Ex. GSP-1 at 10-12.
[144] Hendrix Dir. SA Test., Ex. WM-4 at 4.
[145] Baron Dir. SA Test., Ex. Kroger-3 at 3.
[146] Lynch Dir. SA Test., Ex. GSP-1 at 3, 4.
[147] *Id.* at 5; *See also* tr. at 617.
[148] Lynch Dir. SA Test., Ex. GSP-1 at 5.
[149] Higgins Dir. SA Test., Ex. AECC-3 at 10.

5. Rate treatment related to APS proposed acquisition of Four Corners.

In Docket No. E-01345A-10-0474, APS has sought a determination by the Commission that it is not prohibited by the self-build moratorium from acquiring Southern California Edison's ("SCE") current ownership interest in Four Corners Units 4 and 5. It also seeks the Commission's approval to retire Four Corners Units 1 through 3. The merits of APS's application in Docket No. E-01345A-10-0474 are not at issue and will not be determined in this case. The provisions of the Proposed Agreement in this case will only come into play if the Commission approves APS's application in Docket No. E-01345A-10-0474, and the Four Corners transaction ultimately closes.

If all of this happens, then under Section 10.2 of the proposed Settlement Agreement, APS would be allowed to file a request to adjust its rates to reflect the proposed Four Corners transaction. In essence, this rate case would remain open for this limited purpose.

The proposed Settlement Agreement (Section X) allows APS (within 10 business days after the closing date but no later than December 31, 2013) to file an application seeking to reflect in rates, the rate base and expense effects associated with the acquisition of SCE's share of Units 4 and 5, the rate base and expense effects associated with the retirement of Units 1-3, and any cost deferral authorized in Docket No. E-01345A-10-0474.[150] APS is also allowed to seek authorization to amend the PSA Plan of Administration to include in the PSA the post-acquisition Operations and Maintenance expense associated with Units 1-3 as a cost of producing off-system sales until closure of Units 1-3, provided that such costs do not exceed off-system sales revenue in any given year.[151]

If the Commission finds the transaction prudent, APS may seek a rate rider to reflect the transaction rates. "This provision offers a fine and equitable path forward for recovery of these potential costs if the Commission finds the Four Corners action to be prudent."[152]

Mr. Guldner stated that this term is essential to sustain the 4 year rate moratorium.[153] The non-fuel related annual revenue requirement associated with Four Corners transaction is significant, amounting to approximately $70 million annually.[154] In the Four Corners Docket, APS requested a

150 Settlement Agreement at ¶ 10.2.
151 *Id.*
152 Higgins Dir. SA Test., Ex. AECC-3 at 11.
153 Guldner Dir. SA Test., Ex. APS-2 at 5.
154 *Id.*

cost-deferral order related to the purchase of Units 4 and 5, and the retirement of Units 1-3. "The Settlement would allow APS to seek timely rate relief associated with the transaction to help mitigate the impact of the partial deferral, thus facilitating closing of the transactions."[155] The Settlement Agreement would lower the balance of the cost deferral that APS has requested in the Four Corners docket, which would be significantly higher were it carried over to the Company's next rate case, causing a higher customer bill impact.[156]

The treatment of Four Corners in the proposed Settlement Agreement is similar (but not identical) to the treatment of the Black Mountain Generating Station in UNS-Electric 2009 rate case[157] Decision No. 71914.[158] In that case, subsequent rate base treatment and rate reclassification was allowed only upon completion of certain steps by Staff and the Company.[159]

6. Elimination of the 90/10 sharing is in the public interest.

Section 7.1 of the Agreement provides for elimination of the 90/10 sharing provision. Staff witness Olea testified that as long as the Company's fuel purchases are prudent, there is no reason to penalize the Company and not allow it to recover all of its costs.[160]

> Fuel and purchased power, that's a normal course of business for any electric utility. That's something they have to do everyday. That's actually how they provide service to customers.
>
> And if those costs are being incurred prudently, I don't see any reason why the company shouldn't be allowed to recover those prudently incurred costs that have to be incurred in order to actually provide service and proper reliable service to the customers. So that's a cost that customers should have to pay for because it's something the company has to do in order to keep the lights on.[161]

Mr. Guldner also explained that current fuel costs are lower than the rates established by the Commission in the last rate case.[162] So, with the 90/10 sharing mechanism, APS is now benefiting by collecting 10 percent of the difference between actual costs and current rates. APS has also been harmed by the operation of this mechanism, in 2006 and 2007 when fuel prices were higher than

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155 *Id.* at 23-24.
156 *Id.* at 24.
157 Docket No. E-04204A-09-0206.
158 Decision No. 71914 at 13-14.
159 *Id.*
160 Tr. at 979.
161 *Id.* at 997.
162 *Id.* at 123.

APS's rates.[163] In that instance, APS had to absorb approximately $100 million of costs under the 90/10 sharing provision.[164]

The proposed Agreement contains two provisions designed to benefit consumers in lieu of the 90/10 sharing provision and to more appropriately balance consumer and shareholder interests. First, to incent prudent fuel and power procurement and use, the proposed agreement provides that APS shall be subject to periodic audits. The first audit will be for calendar year 2014 with the consultant selected by Staff and the audit to be funded by APS shareholders up to an amount not to exceed $100,000.[165]

Second, the proposed Agreement changes the interest rates that will apply to over- and under-collections in the future. APS is required to apply interest on the PSA balance annually, rather than monthly, in the future. Any over-collection existing at the end of the PSA year will accrue interest at a rate equal to APS's authorized ROE or its then-existing short term borrowing rate, whichever is greater, and will be refunded to customers over the following 12 months. Any under-collection existing at the end of the PSA year will accrue interest at a rate equal to APS's authorized ROE or then-existing short term borrowing rate, whichever is less, and will be recovered over the following 12 months.[166] APS is allowed to make a request to reduce the PSA rate at any time with the request becoming effective beginning with the first billing cycle of the month following the request.[167]

APS witness Guldner stated the following regarding the impact of these changes on the Company's operations:

> And that's where you see there is also an incentive mechanism here that says when we get a large overcollected balance in our PSA, because of the asymmetrical interest rates applied at the end of the year, we are incented to come and seek authority to lower rates.
>
> And this would happen – for example, last summer we had an overcollected fuel balance. Had this provision been in place last summer, we would have likely been in asking to lower- have essentially an adjustment to our PSA to lower rates so that could get rid of that overcollected balance before the end of the year.

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163 *Id.* at 123-24.
164 *Id.*
165 Settlement Agreement at ¶ 7.4.
166 *Id.* at 7.3.
167 *Id.*

> And so I think just making sure we manage that more towards the equilibrium is the idea and that that will bring customer benefits.[168]

In the end, these changes will produce benefits for customers when there are lower fuel prices and will incent APS to better manage its PSA balances.

7. The EIS and property tax deferrals were important in achieving a longer stay-out and are both in the public interest as well.

a. The environmental improvement surcharge.

In its application, APS requested an Environmental Reliability Account ("ERA") that would have allowed the Company to obtain through a surcharge not only the costs associated with implementing environmental mandates, but also the costs of new or acquired generation plant capacity additions and plant investment between rate case filings.[169] The Company had proposed to include the cost of environmental mandates with Units 4 and 5 of Four Corners in the adjustment, if the transaction were ultimately approved by the Commission.[170] The proposed Settlement Agreement rejects this proposal.

Instead, the Agreement keeps the current Environmental Improvement Surcharge ("EIS") but modifies it in a significant fashion. The EIS is a surcharge that currently collects customer dollars to offset the cost associated with government-mandated environmental controls.[171] As amended, APS will no longer receive customer dollars up front to pay for government-mandated environmental controls.[172] Instead, APS must first invest its own funds to make these improvements, and the EIS will recover associated capital carrying costs, subject to a cap equal to the charge currently in place for the EIS.[173] The existing EIS will be reset to zero on the effective date of new rates in this case.[174] Finally, APS must demonstrate that the environmental controls were government-mandated and represented a reasonable and prudent option available to the Company.[175]

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168 Tr. at 125.
169 APS's Application at 7.
170 Guldner Dir. Test., Ex. APS-1 at 12-13.
171 Guldner Dir. SA Test., Ex. APS-2 at 25.
172 Settlement Agreement at ¶ 11.2.
173 *Id.*
174 *Id.* at ¶ 11.5.
175 *Id.* at ¶ 11.3.

Mr. Guldner testified that the "electric utility industry as a whole is currently in a major build cycle to support environmental compliance, among other things."[176] He also referred to the testimony of APS witness Schiavoni who noted that APS's fossil fleet faces several environmental related regulatory pressures from federal, state and local regulators. At Four Corners alone, APS expects to invest hundreds of millions of dollars to install environmental control equipment for Units 4 and 5 over the next 5 years.[177]

b. The property tax deferral.

Section 12 of the proposed Settlement Agreement allows APS to defer for future recovery a certain amount of Arizona property tax expense above or below the test year revenue level of $141.5 million caused by changes in the applicable Arizona composite property tax rate. The Agreement provides for the following amounts to be deferred from 2012 to 2014 respectively when APS experiences a property tax increase: 1) for 2012 – 25% (prorated with an assumed July 1 rate effective date); 2) for 2013 – 50%; and 3) for 2014 and all subsequent years – 75%. When there is a property tax rate decrease, the amount deferred will be 100%.[178] APS cannot apply interest on the deferred balance. The Agreement also provides that any final property tax rate deferral that has a positive balance will be recovered from customers over 10 years and any deferral that has a negative balance will be refunded to customers over 3 years.[179]

APS witness Guldner stated that current estimates place the amount (increase) to be deferred at roughly $50 million.[180] Witness Guldner further stated that this was "an important financial component needed to sustain the four-year rate case stay out…."[181] APS is concerned that its property tax rate and related expense could increase significantly during the course of the proposed 4 year stay-out, as it has over the past few years.[182]

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176 Guldner Dir. SA Test., Ex. APS-2 at 25.
177 *Id.* at 25-26.
178 Settlement Agreement at ¶ 12.1
179 *Id.* at ¶ 12.2.
180 Tr. at 191.
181 Guldner Dir. SA Test., Ex. APS-2 at 26.
182 *Id.* at 27.

IV. THE PROPOSED SETTLEMENT AGREEMENT RESULTS IN JUST AND REASONABLE RATES AND THE IMPACT ON CUSTOMER BILLS IS REASONABLE.

APS filed a letter on January 9, 2012 in which it set forth the impacts of the Proposed Settlement Agreement on customer rates. In the letter, APS stated that the Proposed Settlement Agreement results in "a modest rate reduction across customer classes, generally around one percent, on the assumed rate effective date (July 1, 2012) and for the remainder of 2012."[183]

The slight rate reduction for the remainder of 2012 results from delaying the reset of the existing PSA to reflect the new base fuel rates established in the proposed Settlement Agreement until early 2013.[184] Thus, customers will continue to receive a credit for the PSA until early 2013, when the PSA will be reset again.

In early 2013, when the PSA resets, APS estimates that average residential customer bills will increase by 6.4% above what they had been just before the proposed Settlement Agreement rates took effect.[185] It is important to note that an annual PSA reset occurs in February of 2013, regardless of the rate case or proposed Settlement Agreement. However, there would be some impact due to the credit carryover provided in the Settlement Agreement.

If the Four Corners transaction is ultimately approved by the Commission, however, and if the transaction closes, there would be a reduction in the PSA Forward Component associated with the Four Corners acquisition. The combined effect of the Four Corners Units 1-3 Off System Sales together with the Four Corners Units 4-5 base fuel effect to the PSA would produce a negative 2.9% bill impact.[186] If the transaction was approved and closed in 2012, the February 2013 PSA reset would reflect this reduction with the total bill impact in February 2013 being approximately 3.5%.[187]

If the Four Corners transaction is approved and the transaction closes, then no earlier than July 2013, there would likely be another 3% nonfuel increase to the average residential customer bill.[188] With respect to any Four Corners rate rider, it is important to note that this would be subject

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[183] APS letter at 1.
[184] *Id.* and att. at 2.
[185] APS Late Filed Ex. 17 at 2.
[186] Ex. S-14.
[187] APS Late Filed Ex. 17 at 2.
[188] *Id.* and att. At 5.

to a separate Commission proceeding to evaluate the prudency of the transaction, among other things.[189]

When the first LFCR adjustment is approved by the Commission, a 0.2% adjustment to bills would occur March 1, 2013.[190]

Other adjustor charges which could impact customer bills include the Demand-Side Mangement Adjustment Clause ("DSMAC"), the Transmission Cost Adjustor ("TCA"), and the Renewable Energy Surcharge ("RES").[191] However, many of these resets are not related to the Settlement Agreement, and would occur irrespective of this case.

V. RESPONSE TO NRDC'S AND SWEEP'S "PARTIAL" OPPOSITION TO THE PROPOSED SETTLEMENT AGREEMENT.

Despite the many benefits of the proposed Settlement Agreement, NRDC and SWEEP have expressed limited disagreement with it. Although both NRDC and SWEEP characterize their positions as "partial" opposition to the proposed Settlement Agreement, it is important to clarify that the proposed Settlement Agreement is a global resolution of issues that were in dispute between the signing parties. Provisions within the proposed Settlement Agreement specify that rejection of any component of the proposed Settlement Agreement by the Commission may amount to a material change in the view of a Signatory.[192] In that circumstance, the party would not be obliged to support the Settlement Agreement, and all Signatories, except Staff, would be required to support that party in requesting a rehearing to reinstate the provision.[193] In light of several Signatories' stated interest in rejecting the modifications that NRDC and SWEEP proposed, NRDC's and SWEEP's characterization of their positions as "partial" opposition understates the significance of the changes they advocate.[194]

The primary criticism that NRDC and SWEEP have leveled at the LFCR is that it retains the relationship between fixed cost recovery and volume sales.[195] From their perspective, the

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[189] Settlement Agreement at ¶¶ 10.2, 10.3.
[190] APS Late filed Ex. 17 at 2.
[191] Olea Dir. SA Test., Ex. S-10 at 95; Olea Resp. SA Test., Ex. S-11 at 7.
[192] Settlement Agreement at ¶ 20.5.
[193] *Id.*
[194] Tr. at 398-99, 491-95, 942-43, 1120-21.
[195] Schlegel Test. In Partial Opp. To SA, Ex. SWEEP-3 at 6; Tr. at 771.

preservation of this relationship perpetuates the utility's disincentive to wholeheartedly encourage measures that reduce ratepayer consumption.[196] Additionally, NRDC and SWEEP[197] claim that the LFCR amounts to a rate increase outside of a rate case. Finally, SWEEP suggests that the proposed Settlement Agreement provisions related to a rate case filing moratorium effectively binds the Commission's policymaking.[198]

A. The LFCR Is Preferable To Full Revenue Decoupling In The Context Of This Case.

Both NRDC[199] and SWEEP[200] advocate substituting the Efficiency and Infrastructure Account ("EIA") mechanism for the LFCR proposed by the proposed Settlement Agreement. The EIA, which APS proposed in its application, would implement full per-customer revenue decoupling for the Company. Both NRDC and SWEEP assert that full revenue decoupling presents advantages over an LFCR including elimination of a utility's disincentive to engage in energy efficiency,[201] production of a credit under certain circumstances,[202] and elimination of a utility's disincentives to support activities that reduce sales but are not directly linked to the utility's portfolio of energy efficiency programs.[203]

Staff evaluated the EIA that APS had proposed and found that, under the circumstances presented by this case, a LFCR mechanism would be a better approach. The LFCR is responsive to the impacts on the Company due to energy efficiency and distributed generation and is directed at only the fixed costs that APS actually loses rather than all of the Company's non-variable costs.[204] Being more specifically tailored than full revenue decoupling, the LFCR does not immunize APS against weather and economic risks.[205] Far from being a weakness, the very specificity of the LFCR makes it a more direct solution to APS's lost fixed cost concerns than the EIA. Likewise, the LFCR

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196 Schlegel Test. In Partial Opp. To SA, Ex. SWEEP-3 at 5.
197 *Id.*; Cavanagh Test.In Partial Opp. To SA, Ex. NRDC-2 at 7.
198 Schlegel Test. In Partial Opp. To SA, Ex. SWEEP-3 at 6.
199 Cavanagh Test. In Partial Opp. To SA, Ex. NRDC-2 at 12.
200 Schlegel Test. In Partial Opp. To SA, Ex. SWEEP-3 at 6.
201 Cavanagh Dir. Test., Ex. NRDC-1 at 15; Schlegel Test. In Partial Opp. To SA, Ex. SWEEP-3 at 5.
202 Schlegel Test. In Partial Opp. To SA, Ex. SWEEP-3 at 5.
203 *Id.*
204 Solganick Dir. Test., Ex. S-4 at 18-19.
205 *Id.* at 19.

is a more practical alternative in light of the number of interests that are opposed to full revenue decoupling.

1. A principal benefit of the LCFR is that it is more narrowly crafted than a full per customer revenue decoupling mechanism.

NRDC and SWEEP contend that the LFCR deprives customers of benefits presented by full decoupling, such as the availability of a credit under circumstances where weather and economic conditions increase volumetric sales. In response, Staff witness Howard Solganick identified a number of problems with the EIA proposal that are remedied by the LFCR mechanism.

The first issue that Mr. Solganick identified was the susceptibility of full revenue decoupling to "pancaking" increases under certain circumstances.[206] As explained by Mr. Solganick, a season of mild weather, producing reduced demand for electric utility service, would generate a surcharge under full decoupling. If the following period had adverse weather customers would be paying higher bills for both their increased weather driven consumption and for the surcharge from the previous period due to the mild weather. Consequently, the same weather event could generate multiple rate increases for the ratepayer.[207]

Additionally, as Mr. Solganick explained at hearing, full decoupling can give rise to scenarios where a utility perversely benefits from prolonged outage events. As Mr. Solganick explained,

> [a]nother reason that revenue decoupling can be considered broad is during a mass outage it becomes a cash register for the company, that when customers cannot use electricity because of an outage, the full revenue decoupling mechanism just keeps that cash register rolling.[208]

As with any regulatory mechanism or structure, full decoupling is not immune to being anticipated, predicted and "gamed" to produce undesirable effects.[209] Mr. Solganick illustrated one such example at hearing. By converting master meters to individual meters, one can reasonable anticipate a decrease in consumption as individual customers see and respond to their specific energy bills.[210] The immediate reduction in consumption is predictable both as a reflection of ordinary

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[206] Solganick Resp. SA Test., Ex. S-12 at 5.
[207] Tr. at 1210-11.
[208] *Id.* at 1211.
[209] *Id.* at 1213-15.
[210] *Id.* at 1214-15.

consumer behavior, but also because revenue is determined on a per customer basis and algebraically, dividing customers into individually metered accounts may produce a "numerical" depression in per customer consumption.[211] Other scenarios whereby full decoupling could be gamed to produce undesired results are not difficult to conceive of either.[212]

The final issue is the perennial concern with how full decoupling affects the risks a utility faces. As multiple witnesses have recognized, it is common to incorporate a cost of equity adjustment to reflect the risk-alleviating quality of full revenue decoupling.[213] In the recent rate decision for Southwest Gas Company, the full revenue decoupling alternative presented to the Commission incorporated an adjustment to reduce the return on equity if the Commission selected full decoupling.[214] Problematically, APS did not incorporate a risk adjustment to its requested cost of equity in the event that its EIA would be adopted. Determining an appropriate return on equity is frequently one of the most contentious issues presented in a rate case, and determining what the adjustment should be, as well as whether to implement one in conjunction with full decoupling, or after the implementation of full decoupling is an issue that will not be resolved by simple substitution of the EIA for the LFCR.[215]

2. Residential Opt-Out is not feasible with full decoupling.

In addition to the technical challenges presented by full revenue decoupling, a significant feature of the LFCR that some parties view as a benefit is that it is more amenable to rate design changes, such as institution of an opt-out provision. As explained in the testimony of APS witness Leland Snook, incorporating an opt-out provision into full revenue decoupling would have been complex and unworkable.[216] The addition of new variables and the inherent unpredictability of full revenue decoupling mean that the Opt-Out provision is "a somewhat unique feature made possible by the narrowly-tailored LFCR mechanism proposed in the Settlement Agreement."[217]

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211 *Id.* at 1215.
212 *Id.* at 1227-28.
213 Brockway Dir. SA Test., Ex. AARP-3 at 2; Higgins Dir. SA Test., Ex. AECC-3 at 5-6.
214 Decision No. 72723 at 39.
215 *See e.g.* Solganick Dir. Test., Ex. S-4 at 20 (recommending an adjustment to return on equity if the EIA is adopted).
216 Snook Dir. SA Test., Ex. APS-9 at 2.
217 *Id.* at 7.

Both RUCO and AARP cited the Opt-Out provision as a key feature of the LFCR in their views. As explained by Jodi Jerich on behalf of RUCO,

> RUCO supports the settlement agreement because it contains the LFCR plus opt-out rate. RUCO supports this because it resolves a highly contentious issue of revenue decoupling that RUCO sees as a fair and creative manner.[218]

Testifying on behalf of AARP, Ms. Nancy Brockway similarly emphasized the importance of the opt-out provision. "I think AARP would sincerely want [the LFCR Opt-Out] provision not to be rejected by the Commission. I think it would be considered material, and it would unravel the settlement if it were rejected."[219] In light of the significance that parties attach to the opt-out provision, the fact that it is only possible under the LFCR demonstrates the advantages of the LFCR's narrower scope.

3. "Precedent" does not preclude adoption of the LFCR in this matter.

NRDC repeatedly turns to the recent Southwest Gas rate decision and the Commission's policy statement[220] regarding decoupling to suggest that the Commission is somehow bound by precedent to implement full revenue decoupling. Staff disagrees. Administrative agencies do not adhere to *stare decisis* and as such are not bound to follow prior precedent. Additionally, as Staff explained through the testimony of Mr. Solganick, there were reasons present in the Southwest Gas case justifying full revenue decoupling that are not present in this matter. Finally, nowhere within the Commission's Policy Statement on revenue decoupling is there a command that the Commission must rigidly apply full revenue decoupling for all gas and electric utilities to the exclusion of alternative measures to deal with a utility's recovery of fixed costs.

It is well established that administrative agencies are not constrained by the dictates of *stare decisis*. "[A]n administrative agency is not absolutely bound by its prior determinations. It may adjust its standards and policies in light of experience, as long as the adjustments are not arbitrary and capricious."[221] By their nature, administrative agencies require flexibility in order to respond to

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[218] Tr. at 1120.
[219] *Id.* at 492-9.
[220] Final ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures ("Policy Statement") filed December 29, 2010, Docket Nos. E-00000J-08-0314 and G-00000C-08-0314.
[221] *Illinois Council of Police v. Illinois Labor Relations*, 404 Ill. App.3d 589, 596-97, 936 N.E.2d 1212, 1218 (Ill. App. 2010), citations omitted.

varying circumstances.[222] Consequently, NRDC's implication that the Commission is required to implement full decoupling in this case because of the Commission's approval of full decoupling in the Southwest Gas case must fall flat.

Staff explained that the Southwest Gas rate decision stands on its own merits and involved different considerations than are present in this case. First, natural gas service is driven by considerations such as population density whereas electric service is nearly ubiquitous.[223] Because of the prevalence of electric utility service, electric utilities may focus their efforts on preserving efficient appliance saturation.[224] These inherent differences in utility service propel differences in strategies adopted by the respective utility industries. These distinctions between gas utility service and electric utility service demonstrate that ample factual bases exist to justify alternative treatment under these circumstances from what was approved for Southwest Gas.

Likewise, the Policy Statement does not require the implementation of full revenue decoupling in this case. The Policy Statement explicitly acknowledges that approaches other than full revenue decoupling may be appropriate.[225] Likewise, the Policy Statement does not preclude alternatives such as the LFCR. Although the Policy Statement voices a preference for full decoupling over partial decoupling methodologies, nowhere in the Policy Statement is there a rejection of LFCR type mechanisms.[226] Clearly, the Commission's adoption of the Policy Statement does not compel the adoption of full revenue decoupling in this case.

B. The rate case moratorium does not hinder the Commission's ability to implement policy changes.

Opponents to the proposed Settlement Agreement allege that the four-year moratorium "ties the Commission's hands" for purposes of implementing policy changes.[227] To that end, SWEEP recommends reducing the rate case stay-out provision from four years to three years.[228] Staff

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[222] *See e.g. Chevron v. Natural Resources Defense Council*, 467 U.S. 837 (1984).(explaining that an administrative agency's policies, once made, are not cast in stone; rather to engage in informed decision making, the agency must consider the wisdom of its policy on a continuing basis).
[223] Solganick Resp. SA Test., Ex. S-13 at 7.
[224] *Id.*
[225] Policy Statement at 30, ¶ 4.
[226] *Id.* at 31, ¶ 8.
[227] Tr. at 666-67; Schlegal Test. In Partial Opp. To SA, Ex. SWEEP-3 at 6.
[228] Schlegel Test. In Partial Opp. To SA, Ex. SWEEP-3 at 7.

believes that the length of the rate case stay-out provision is appropriate and does not need to be shortened.

As acknowledged by SWEEP, rate case moratoriums can provide benefits to ratepayers by way of producing rate stability,[229] a benefit cited by other parties as well.[230] Stay-out provisions also encourage utilities to control costs which, in turn, can lead to lower rates in future rate cases.[231]

The concerns raised by SWEEP are misplaced. The proposed Settlement Agreement was crafted to permit maximum flexibility to the Commission in the implementation of new policy while providing a means to make the Company whole. The LFCR mechanism that the proposed Settlement Agreement recommends permits the Commission maximum flexibility with regard to the energy efficiency and distributed generation policy issues of direct concern to SWEEP. The LFCR only operates to the extent that the Commission requires the Company to achieve measurable energy efficiency and distributed generation goals.[232] As Staff explained,

> [i]f the Commission were to increase the [energy efficiency and distributed generation] requirements under these programs, the LFCR would provide for APS to recover the lost fixed costs attributable to the increased requirements. By contrast, if the Commission were to reduce or eliminate these requirements, the LFCR would appropriately decrease to correspond to the new requirements.[233]

It is abundantly clear that the proposed Settlement Agreement preserves the utmost flexibility for the Commission to change policy through the duration of APS's rate case stay out.

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[229] *Id.*
[230] Tr. at 945, 1122; Olea Dir. SA Test., Ex. S-10 at 18 (citing the four-year stay-out as a benefit).
[231] Tr. at 261.
[232] Settlement Agreement at 12, Tr. at 844-45.
[233] Olea Resp. SA Test., Ex. S-11 at 2; *see also* Tr. at 977.

IV. CONCLUSION.

For the reasons discussed above, Staff requests that the Commission approve the proposed Settlement Agreement as the resolution for APS's rate case.

RESPECTFULLY SUBMITTED this 29th day of February, 2012.

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