ORIGINAL

OPEN MEETING ITEM

E000014911

Commissioners
Lea Márquez Peterson - Chairwoman
Sandra D. Kennedy
Justin Olson
Anna Tovar
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Matthew J. Neubert
Executive Director

ARIZONA CORPORATION COMMISSION

DATE: AUGUST 2, 2021

DOCKET NO.: E-01345A-19-0236

TO ALL PARTIES:

Enclosed please find the recommendation of Assistant Chief Administrative Law Judge Sarah N. Harpring. The recommendation has been filed in the form of an Opinion and Order on:

ARIZONA PUBLIC SERVICE COMPANY
(RATES)

Pursuant to A.A.C. R14-3-110(B), you may file exceptions to the recommendation of the Administrative Law Judge by efiling at https://efiling.azcc.gov/ or filing an original and thirteen (13) copies of the exceptions with the Commission's Docket Control at the address listed below by **4:00** p.m. on or before:

AUGUST 23, 2021

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

TBD

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

MATTHEW J. NEUBERT
EXECUTIVE DIRECTOR

1200 W. Washington Street, Phoenix, AZ 85007 | 6(

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

LEA MÁRQUEZ PETERSON CHAIRWOMAN
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JUSTIN OLSON
ANNA TOVAR
JIM O'CONNOR

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-19-0236 DECISION NO. _____ **OPINION AND ORDER**

DATE OF HEARING: January 14, 15, 19-22, 25-29, February 8-12, 16-19, 22, 24-26, and March 1-3, 2021.

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Sarah N. Harpring

APPEARANCES: Melissa M. Krueger, Thomas L. Mumaw, Theresa Dwyer, Ray Heyman, Rachael Leonard, David Hinkson, and Jeff Allmon, on behalf of Arizona Public Service Company;

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Albert Acken, DICKINSON WRIGHT PLLC, on behalf of Constellation New Energy, Inc. and Direct Energy Business, LLC;

Holly L. Buchanan and Robert J. Friedman, on behalf of Federal Executive Agencies;

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Maureen A. Scott, Deputy Chief of Litigation and Appeals, and Robert W. Geake, Robyn Poole, and Stephen Emedi, Staff Attorneys, on behalf of the Utilities Division of the Arizona Corporation Commission.[1]

[1] The following intervenors did not enter appearances during the prehearing conference or hearing in this matter: Shelly A. Kaner, Patricia Madison, Jonathan Jones, John Thornton, and Distributed Energy Resource Association. Patricia Madison subsequently withdrew as an intervenor.

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BY THE COMMISSION:

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Arizona Corporation Commission ("Commission") finds, concludes, and orders that:

DISCUSSION

I. Parties

The following table shows the parties[2] to this case along with their shortened and, if applicable,[3] group names:

Party Name (Shortened Name)	Group Name
Arizona Public Service Company ("APS")	
Calpine Energy Solutions, LLC ("Calpine")	
Direct Energy Business, LLC ("Direct Energy")	
Constellation NewEnergy, Inc. ("Constellation")	
Federal Executive Agencies ("FEA")	
Arizona School Boards Association	"ASBA/AASBO"
Arizona Association of School Business Officials	
Walmart Inc. ("Walmart")	
The Kroger Co. ("Kroger")	
Manufactured Housing Communities of Arizona, Inc. ("MHCA")	
International Brotherhood of Electrical Workers, AFL-CIO, Local 387 ("IBEW Local 387")	"IBEW Locals"
International Brotherhood of Electrical Workers, AFL-CIO, Local 769 ("IBEW Local 769")	
Navajo Nation ("Nation")	
Hopi Tribe ("Tribe")	
Sierra Club	
Southwest Energy Efficiency Project ("SWEEP")	
Western Resource Advocates ("WRA")	
San Juan Citizens Alliance ("SJCA")	"Citizen Groups"
Tó Nizhoní Ání ("TNA")	
Diné CARE ("DC")	
Vote Solar	

[2] As indicated in the procedural history for this matter, Patricia A. Madison was granted withdrawal as an intervenor by Procedural Order issued on April 7, 2021.

[3] Additional group names are provided later for those parties that provided joint briefs although they also had participated individually in this case.

Evgo Services LLC ("EVgo")	
ChargePoint, Inc. ("ChargePoint")	
Solar Energy Industries Association ("SEIA")	"SEIA/AriSEIA"
Arizona Solar Energy Industries Association ("AriSEIA")	
Richard Gayer	
AARP	
Freeport Minerals Corporation ("Freeport")	"AECC/Freeport"
Arizonans for Electric Choice and Competition ("AECC")	
Wildfire: Igniting Community Action to End Poverty in Arizona ("Wildfire")	
Arizona Solar Deployment Alliance ("ASDA")	
The Property Owners and Residents Association of Sun City West ("PORA")	
Arizona Competitive Power Alliance ("ACPA")	
Aguila Irrigation District	"Districts"
Buckeye Water Conservation and Drainage District	
Electrical District Number Six of Pinal County	
Electrical District Number Seven of Maricopa County	
Electrical District Number Eight of Maricopa County	
Harquahala Valley Power District	
Maricopa County Municipal Water Conservation District Number One	
McMullen Valley Water Conservation & Drainage District	
Tonopah Irrigation District	
Shelly A. Kaner	
Jonathan Jones	
John Thornton	
Tesla, Inc. ("Tesla")	
Distributed Energy Resource Association ("DERA")	
Residential Utility Consumer Office ("RUCO")	
Utilities Division ("Staff")	

II. Procedural History

On October 1, 2019, APS filed with the Commission a Notice of Intent to File a Rate Case Application and Request to Open Docket. As a result, this docket was opened.

On October 31, 2019, APS filed its Rate Application, which uses a test year "TY" ending June 30, 2019. The Rate Application included the direct testimony of Jeffrey Guldner, Chief Executive Officer and President of APS and Chairman of the Board, Chief Executive Officer, and President of

Pinnacle West Capital Corporation; Barbara Lockwood, Vice President of Regulation for APS;[4] Leland Snook, Director of Rates and Rate Strategy for APS; Jessica Hobbick, Manager of Regulation and Pricing for APS; Brad Albert, Vice President of Resource Management for APS; Elizabeth Blankenship, Vice President, Controller, and Chief Accounting Officer for APS; Ann Bulkley, Senior Vice President for Concentric Energy Advisors, Inc. ("Concentric"); and Dr. Ronald White, President of Foster Associates Consultants, LLC ("Foster Associates").

On November 1, 2019, Richard Gayer filed an application to intervene.

On November 5, 2019, Kroger and SWEEP each filed an application to intervene.

On November 6, 2019, WRA filed an application to intervene.

On November 7, 2019, AECC/Freeport filed an application to intervene.

On November 12, 2019, SOLON Corporation ("SOLON") filed an application to intervene.

On November 18, 2019, Mr. Gayer filed a Motion to Prohibit Settlement Conference and Settlement Agreement and Demand Litigation ("Motion to Prohibit Settlement"), specifically requesting that all issues impacting residential customers be fully litigated.

On November 19, 2019, by Procedural Order, intervention was granted to Mr. Gayer, Kroger, SWEEP, WRA, and AECC/Freeport.

On November 22, 2019, RUCO filed an application to intervene.

On November 25, 2019, APS filed a Response to the Motion to Prohibit Settlement, opposing both the substance and timing due to the preliminary stage of the matter.

On November 26, 2019, PORA filed an application to intervene.

On November 27, 2019, by Procedural Order, intervention was granted to SOLON.

On November 29, 2019, Staff filed a Letter of Sufficiency, stating that APS's rate application had met the sufficiency requirements as outlined in Arizona Administrative Code ("A.A.C.") R14-2-103(B)(7) and that APS had been classified as a Class A Utility.

On December 2, 2019, Mr. Gayer filed a Reply on Motion to Prohibit Settlement, stating that the Motion did not request resolution of any issue at that time, only that all issues be resolved as part

[4] Ms. Lockwood has since been promoted to Senior Vice President of Public Policy for APS. (See Ex. APS-2 at 1.)

of litigation conducted in public and streamed live via the Commission's website.

On December 2, 2019, by Procedural Order, a procedural conference was scheduled for December 9, 2019, and intervention was granted to RUCO.

On December 3, 2019, ACPA filed an application to intervene.

On December 6, 2019, Wildfire filed an application to intervene; Mr. Gayer filed a document entitled Proposed Rules and Procedures for Litigation;[5] and Staff made two filings including a proposed procedural schedule that included a hearing to commence on September 14, 2020.

On December 9, 2019, the procedural conference was held as scheduled, with APS, SWEEP, Wildfire, WRA, AECC/Freeport, ACPA, RUCO, and Staff appearing through counsel and Mr. Gayer appearing *pro se*. Several potential intervenors were also represented.[6] During the procedural conference, intervention was granted to PORA, ACPA, and Wildfire. Additionally, the Motion to Prohibit Settlement was considered and denied, and discussions were held concerning Staff's proposed procedural schedule as well as party access to APS discovery requests and responses. The parties generally supported a schedule that would provide 6 weeks for Staff/Intervenor surrebuttal testimony to be filed; would include public comment sessions in Phoenix, Flagstaff, and Yuma; would have a hearing commence on September 28, 2020; and would establish a deadline for discovery requests approximately five days before the first day of hearing. There was also general agreement that the hearing was likely to take three to four weeks. APS agreed to have the Commission's time clock deadline extended to accommodate the hearing beginning in late September. At the conclusion of the procedural conference, the parties' input was taken under advisement.

Also on December 9, 2019, Kroger filed a Motion to Associate Counsel Pro Hac Vice for Kurt J. Boehm.

On December 12, 2019, at its Staff Open Meeting, the Commission discussed the procedural schedule for this matter, including what would be necessary to have the Recommended Opinion and Order ("ROO") produced for consideration by the Commission at an Open Meeting in October or November 2020. The Hearing Division discussed the typical timeline for processing a Class A rate

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[5] Mr. Gayer also again filed the Motion to Prohibit Settlement.
[6] These included Sierra Club, Calpine, Constellation, Direct Energy, and SEIA.

case and provided background information on processing times of previous APS rate cases. The Hearing Division was directed to provide the background information in writing along with three different scenarios to accomplish consideration at an Open Meeting in 2020.

On December 13, 2019, the Hearing Division filed a memorandum providing the information requested by the Commission.

Also on December 13, 2019, Staff filed correspondence providing information "crucial to the consideration of an expedited case processing timeline" for this matter. Staff included a copy of a Request for Proposal ("RFP") for an expert consultant for this matter, which had been issued by Staff on November 8, 2019, and in response to which Staff had received only one bid that did not propose to address all of the work elements in the RFP. Staff stated that the responding consultant did not propose to address the cost of service study, engineering analysis, or rate design; that Staff might need to seek out a consultant to complete those work elements; and that an expedited timeline could result in a need to issue a new RFP if the responding consultant could not perform within the timeline due to other commitments.

On December 17, 2019, the Commission provided public notice of a Special Open Meeting to be held on December 19, 2019, regarding the process and procedural schedule for this matter.

Also on December 17, 2019, Mr. Gayer filed a document entitled Comments on Hearing Division Memo on Scheduling and Objection to Short Notice of Meeting. Additionally, a Procedural Order was issued that, *inter alia*, granted Mr. Boehm admission *pro hac vice*.

On December 18, 2019, SEIA/AriSEIA filed an application to intervene.

On December 19, 2019, the Commission held a Special Open Meeting at which the procedural schedule for this matter was discussed. The Commission voted to adopt as a goal the third illustrative expedited schedule from the Hearing Division memorandum, but with the express acknowledgment that requests for extension made for good cause could be granted. The parties who appeared (APS, Wildfire, PORA, SOLON, AECC/Freeport, WRA, SWEEP, Mr. Gayer, RUCO, and Staff) were all provided the opportunity to speak to the potential schedules included in the Hearing Division memorandum, and public comment was accepted.

Also on December 19, 2019, by Procedural Order, a hearing in this matter was set to commence

on July 17, 2020, and other procedural deadlines were set, including an intervention deadline of February 11, 2020.

On December 20, 2019, ASBA/AASBO filed an application to intervene.

On December 30, 2019, by Procedural Order, SEIA/AriSEIA and ASBA/AASBO were granted intervention.

On January 2, 2020, Vote Solar filed an application to intervene.

On January 3, 2020, the IBEW Locals filed an application to intervene.

Also on January 3, 2020, APS filed a letter stating that it had provided notice to parties inviting them to attend two rate case technical conferences, to be held in February and March 2020, to discuss APS's rate case requests in detail and ask questions.

On January 6, 2020, the Districts filed an application to intervene.

On January 10, 2020, Sierra Club filed an application to intervene.

On January 23, 2020, by Procedural Order, Vote Solar, the IBEW Locals, the Districts, and Sierra Club were granted intervention. Additionally, Shelly A. Kaner filed an application to intervene.

On January 27, 2020, Patricia Madison filed an application to intervene.

On January 28, 2020, APS filed an Affidavit of Mailing and Publication, stating that public notice had been sent as a separate mailing to each APS customer between January 7 and 13, 2020, and had been published in the *Sedona Red Rock News*, *Payson Roundup*, and *White Mountain Independent* on January 10, 2020; in the *Casa Grande Dispatch* on January 11, 2020; and in the *Arizona Republic*, *Prescott Daily Courier*, *Yuma Sun*, *Arizona Daily Sun*, and *Sierra Vista Herald* on January 12, 2020.

Also on January 28, 2020, Jonathan Jones filed an application to intervene.

On February 4, 2020, APS filed a copy of the presentation made at its first rate case technical conference.

On February 5, 2020, FEA filed an application to intervene.

On February 6, 2020, by Procedural Order, Shelly A. Kaner, Patricia Madison, and Jonathan Jones were granted intervention.

On February 7, 2020, the Citizen Groups and John S. Thornton, Jr. each filed an application to intervene.

On February 10, 2020, FEA filed a Motion to Associate Counsel *Pro Hac Vice* for Thomas A. Jernigan.

On February 10, 2020, Walmart filed an application to intervene.

On February 11, 2020, applications to intervene were filed by the Nation, Tesla, Calpine, Constellation and Direct Energy (jointly), and ChargePoint. Additionally, Calpine filed a Motion for *Pro Hac Vice* Admission of Gregory M. Adams.

On February 13, 2020, a Procedural Order was issued granting FEA intervention and admitting Mr. Jernigan *pro hac vice* to represent FEA in this matter. Additionally, Alex-Sandra L. Wolf filed an application to intervene in this matter.

On February 19, 2020, by Procedural Order, intervention was granted to the Citizen Groups, Mr. Thornton, Walmart, the Nation, Tesla, Calpine, Constellation, Direct Energy, and ChargePoint; Gregory M. Adams was granted temporary admission *pro hac vice* until April 20, 2020; Calpine was ordered to file a Notice of Receipt by State Bar of Complete Application by April 20, 2020; and Alex-Sandra L. Wolf was ordered to file a certificate of service for her application to intervene by March 13, 2020, if she desired to be granted intervention.

Also on February 19, 2020, Sierra Club filed a Motion to Associate Counsel *Pro Hac Vice* for Louisa Eberle, and Commissioner Marquez Peterson[7] filed a letter in the docket.

On February 20, 2020, ASDA filed a late application to intervene.[8]

On February 25, 2020, by Procedural Order, Louisa Eberle was granted admission *pro hac vice*.

Also on February 25, 2020, by Procedural Order, public comment meetings were scheduled to be held in Douglas, Flagstaff, Yuma, and Phoenix in June 2020, and APS was required to provide notice of those public meetings by mail and publication by March 31, 2020, and by posting on its website.

On February 27, 2020, APS filed a request for a two-day extension to complete mailing of the notice, to fit within its March-April 2020 billing cycle.

On February 28, 2020, a Procedural Order was issued granting intervention to ASDA and

[7] Commissioner Marquez Peterson became Chairwoman in January 2021. This Order uses her title as appropriate at the time of the various events described.

[8] The intervention deadline was February 11, 2020.

extending until April 2, 2020, APS's deadline to complete mailing of notice.

On March 2, 2020, APS filed a Motion for Judicial Notice ("Motion for Judicial Notice") requesting that judicial notice be taken of a list of documents that had been filed in Docket No. E-01345A-16-0036 ("2016 Rate Case") between April 27, 2018, and January 20, 2019 ("SCRs Phase"), concerning recovery of the costs incurred by APS for the Selective Catalytic Reduction equipment ("SCRs") installed at the Four Corners Power Plant ("4CPP"). APS requested that judicial notice be taken of the documents filed in the SCRs Phase because although a ROO for the SCRs Phase ("SCRs ROO") had been issued on November 27, 2018, no decision had been issued, and it would be inefficient to require duplication of the SCRs Phase evidentiary record in this docket.

On March 4, 2020, Sierra Club filed a Response to the Motion for Judicial Notice, requesting that any decision on the scope of this docket be held in abeyance.

Also on March 4, 2020, AARP filed an application to intervene.

Also on March 4, 2020, Staff filed a Motion to Modify Procedural Order ("Staff Rescheduling Motion"), requesting that the schedule in this proceeding be delayed by 75 days due to Staff's RFP issues and workload.

On March 9, 2020, APS filed a Reply to Sierra Club's Response.

On March 10, 2020, EVgo filed an application to intervene.

On March 13, 2020, APS filed a Response to the Staff Rescheduling Motion along with a Motion for Additional Time to Respond to Discovery ("APS Motion re Discovery Timing").

On March 16, 2020, Calpine filed a Notice of Receipt by the State Bar of Arizona of Complete Application for *Pro Hac Vice*.

On March 17, 2020, DERA filed an application to intervene.

On March 18, 2020, a Procedural Order was issued that took official notice of the documents from the SCRs Phase; granted intervention to AARP and EVgo; granted admission *pro hac vice* to Gregory Adams; vacated the previously established hearing dates, except that July 17, 2020, at 10:00 a.m. was retained for public comment only; rescheduled the hearing to commence on September 30, 2020, in response to the Staff Rescheduling Motion; ruled on the APS Motion re Discovery Timing; and extended the time clock for this matter by 79 calendar days. On March 19, 2020, a Procedural

Order was issued modifying the Procedural Order to include an accidentally omitted Attachment A.

On March 20, 2020, Mr. Gayer filed "Intervenor Gayer's Objections to APS's Attachment A Because It Does Not Include Intervenor Gayer's Filings and Motion to Compel Inclusion" ("Motion to Compel Inclusion").

On March 25, 2020, SOLON filed a Motion to Withdraw from Intervention ("Motion to Withdraw").

On March 31, 2020, by Procedural Order, intervention was granted to DERA, Mr. Gayer's Motion to Compel Inclusion was denied, and SOLON's Motion to Withdraw was granted.

On April 6, 2020, APS filed documentation establishing that the required notice of the June 2020 public comment meetings had been provided by mail, publication, and posting. APS also filed a copy of the presentation made at its second rate case technical conference.

On April 22, 2020, AARP's local counsel, Armando Nava, filed a Motion to Associate Counsel *Pro Hac Vice* for John B. Coffman.

On April 23, 2020, a Procedural Order was issued that canceled the public comment meetings scheduled to be held in June 2020 due to the COVID-19 pandemic; scheduled telephonic public comment meetings to be held on July 27 and 28, 2020; ordered that the public comment meeting scheduled to be held on July 17, 2020, proceed telephonically only; ordered APS to provide prescribed notice of the changes to the public comment meetings by mail and newspaper publication by May 22, 2020, and by posting on the APS website by May 4, 2020; and required APS to file an Affidavit of Mailing, Publication, and Posting by June 8, 2020.

Also on April 23, 2020, by Procedural Order, John B Coffman was granted admission *pro hac vice.*

On April 27, 2020, APS filed a request to extend the May 22, 2020, notice deadline to June 1, 2020.

On April 28, 2020, by Procedural Order, APS's request to extend the deadline to complete notice was granted only as to mailing.

On May 11, 2020, Karen S. White, as local counsel for FEA, filed a Motion to Associate Counsel *Pro Hac Vice* for Maj. Scott L. Kirk and Capt. Robert J. Friedman.

On May 13, 2020, by Procedural Order, Scott L. Kirk and Robert J. Friedman were granted admission *pro hac vice*.

Also on May 13, 2020, AARP filed a Motion Requesting that APS Be Ordered to File Supplemental Testimony Regarding Impacts of the COVID-19 Crisis ("AARP Motion").

On May 19, 2020, Staff filed a report by a Staff-hired consultant, Barbara R. Alexander, entitled "An Evaluation of Arizona Public Service Company's Customer Education Plan and its Implementation." The evaluation had been completed at the direction of the Commission.[9]

On May 20, 2020, APS filed a Response to the AARP Motion, AECC/FREEPORT filed Opposition to the AARP Motion, and RUCO filed a Response to the AARP Motion.

On May 22, 2020, APS filed a Supplemental Response to the AARP Motion.

On May 29, 2020, Chairman Burns[10] filed a letter in the docket.

On June 2, 2020, Sierra Club filed a Notice of Change to Admission Status regarding Louisa Eberle, informing the Commission that Ms. Eberle had been admitted to the State Bar of Arizona.

On June 3, 2020, APS filed proof that the required notice regarding public comment meetings had been posted on APS's website on April 30, 2020; mailed to APS customers as a bill insert between May 1 and June 1, 2020; published in the *Arizona Republic* on May 17, 2020; and published in nine regional newspapers[11] between May 13 and May 17, 2020.

On June 4, 2020, by Procedural Order, the AARP Motion was denied.

On June 11, 2020, Vote Solar filed a Motion to Associate Counsel *Pro Hac Vice* for Marta Darby.

On June 17, 2020, Commissioner Boyd Dunn filed a letter in the docket.

On June 18, 2020, by Procedural Order, Marta Darby was admitted *pro hac vice.*

On July 2, 2020, Vote Solar filed a Motion to Associate Counsel *Pro Hac Vice* for David Bender.

On July 16, 2020, Commissioner Marquez Peterson filed a letter in the docket indicating some

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[9] The evaluation was required by the Commission in Decision No. 77270 (June 27, 2019), which is discussed below.

[10] Commissioner Bob Burns was Chairman until early January 2021. This Order uses his title as appropriate at the time of the various events described.

[11] The regional newspapers were the *Prescott Daily Courier*, *Sedona Red Rock News*, *Yuma Sun*, *Payson Roundup*, *Arizona Daily Sun*, *Casa Grande Dispatch*, *Sierra Vista Herald*, *White Mountain Independent*, and *Douglas Dispatch*.

of the issues that she would like to see addressed by the parties in this matter and that she would be filing future letters with specific requests.

On July 17, 2020, a morning telephonic public comment meeting was held, and no members of the public provided comment.

On July 21, 2020, Staff and RUCO filed a Joint Motion to Modify Procedural Order ("Second Rescheduling Motion"), requesting that the procedural schedule for this matter be extended by 60 days due to the COVID-19 pandemic's impacts on work processes and Staff's and RUCO's caseloads.

On July 22, 2020, Commissioner Marquez Peterson filed a letter to Chairman Burns and the presiding Administrative Law Judge ("ALJ") requesting that targeted virtual or socially distanced in-person public comment sessions be held in this matter.

On July 24, 2020, APS filed a Response to the Second Rescheduling Motion, providing conditional support.

On July 27, 2020, SWEEP, WRA, Wildfire, and Sierra Club jointly filed an Objection to APS's Request to Limit Discovery as a Condition of Extending Procedural Schedule, strenuously objecting to and opposing APS's request that any Procedural Order granting the Second Rescheduling Motion contain a prohibition on discovery regarding post-TY events.

On July 27, 2020, an evening telephonic public comment proceeding was held, and comments were received from 60 members of the public.

On July 28, 2020, an evening telephonic public comment proceeding was held, and comments were received from 55 members of the public.

On July 28, 2020, RUCO filed a Reply also objecting to APS's requested discovery restrictions.

On July 29, 2020, Staff filed Opposition to APS's Proposed Discovery Limitations, strongly opposing APS's proposed conditions on discovery.

On July 30, 2020, by Procedural Order, David Bender was admitted *pro hac vice.*

On July 31, 2020, by Procedural Order, the hearing was rescheduled to commence on December 14, 2020, and other procedural deadlines were extended. The Procedural Order retained the September 30, 2020, hearing date for a public comment meeting, but did not schedule any additional public comment meetings or require APS to provide additional notice of public comment opportunities. The

Procedural Order did not grant APS's requested discovery restrictions. Additionally, the time clock was extended by 96 days.

At the Commission's Staff Open Meeting on August 5, 2020, the Commission directed that five additional telephonic public comment meetings be held to accept oral comment on this matter, with specific direction as to the preferred weeks for the public comment meetings to be held and a requirement that at least one be held on a Saturday.

On August 7, 2020, by Procedural Order, telephonic public comment meetings were scheduled to be held on September 1, 25, and 30, October 24, and November 7 and 30, 2020. Two of the dates were Saturdays, and two of the non-Saturday meetings were scheduled to be held at 6:00 p.m. The Procedural Order required APS to provide public notice of the telephonic public comment meetings by mail or email by September 1, 2020; by publication in more than 20 newspapers in Arizona by September 8, 2020; and by posting notice on its website by August 21, 2020. The Procedural Order also required APS to file proof of compliance with each notice requirement by October 8, 2020.

On August 10, 2020, Kroger filed the direct testimony (cost of service and rate design) of Stephen J. Baron, President and a Principal of J. Kennedy and Associates, Inc., a consulting firm.

On August 11, 2020, Chairman Burns filed a letter requesting that APS perform analyses using four different methods of cost recovery for the stranded costs resulting from early closure of the 4CPP in 2031; the first method was to use accelerated depreciation, and the second through fourth methods were to use securitization.[12]

On August 12, 2020, APS filed a Motion to Extend Deadline to Complete Notice (Expedited Consideration Requested) ("APS Notice Motion").

On August 13, 2020, by Procedural Order, the APS Notice Motion was granted, extending the deadline for mailing notice to September 18, 2020, and the deadline for publication of notice to the next available publication date for those non-metro newspapers for which the next available publication date was later than September 8, 2020. The Procedural Order further required APS to file a list showing the next available publication date for each newspaper in which publication of notice was required.

[12] This letter was admitted herein as exhibit FWR-5 to Exhibit RUCO-1. APS's response to the letter has been admitted into evidence as Exhibit SC-27 and as exhibit FWR-6 to Exhibit RUCO-1.

On August 25, 2020, APS filed a table showing APS's intended publication date for each newspaper listed in the August 7, 2020, Procedural Order. Only one of the publication dates was after September 8, 2020.

On August 28, 2020, the Citizen Groups and Sierra Club filed a Joint Motion for Deadline to Respond to Chairman Burns and Request for Additional Information ("Joint Motion for Deadline"), requesting to have APS ordered to respond to Chairman Burns's August 11, 2020, letter by September 18, 2020. The Joint Motion for Deadline also requested that APS be required to analyze a 2023 (or earlier if feasible) closure of the 4CPP and to develop analyses using Chairman Burns's four requested methods for the 2025 closure of Units 1 and 3 at the Cholla Power Plant.

On August 31, 2020, Karen S. White, as local counsel for FEA, filed a Motion to Associate Counsel *Pro Hac Vice*, requesting that Holly L. Buchanan be permitted to appear before the Commission as counsel *pro hac vice* for FEA in this matter.

On September 1, 2020, Chairman Burns filed two letters in the docket: one concerning executive positions and compensation, requesting that APS, Staff, and RUCO respond, and inviting other parties to respond, through written testimony to specific questions; and the other requesting that APS file the information requested in his August 11, 2020, letter, as well as the additional information requested by the Citizen Groups and Sierra Club in the Joint Motion for Deadline, by October 2, 2020.[13]

Also on September 1, 2020, an evening telephonic public comment meeting was held, and comments were received from 38 members of the public. Several members of the public criticized the Commission for not providing interpretation for Spanish speakers.

On September 2, 2020, counsel for IBEW Locals filed a Notice of Appearance.

On September 3, 2020, by Procedural Order, Holly L. Buchanan was admitted *pro hac vice*.

On September 4, 2020, APS filed a Response to the Joint Motion for Deadline, requesting that it be denied. Additionally, APS filed a letter to Chairman Burns stating that APS was working to develop the analyses requested and would be able to file the information with its rebuttal testimony on November 6, 2020.

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[13] Chairman Burns's letter concerning executive compensation was admitted herein as exhibit FWR-17 to Exhibit RUCO-1. Official notice is taken of the other letter.

On September 10, 2020, the Citizen Groups and Sierra Club filed a Joint Reply to APS's Response, requesting that APS be required to file the analyses by October 2, 2020.

On September 11, 2020, Commissioner Olson filed a letter in the docket requesting that the parties develop a record on whether APS's territory should be opened to competition as part of this rate case.

Also on September 11, 2020, Chairman Burns filed a letter in the docket, requesting that APS provide the analyses requested in his September 1, 2020, letter by November 6, 2020, and that Staff and RUCO (and any other parties desiring to do so) provide responses to those analyses by December 31, 2020. Chairman Burns stated that he was not requesting issuance of a Procedural Order or alteration of any established procedural dates.

On September 22, 2020, the Retail Energy Supply Association ("RESA") filed a late application to intervene, in response to Commissioner Olson's letter requesting development of a record on opening up APS's territory to competition.

Also on September 22, 2020, APS filed a copy of a September 21, 2020, letter to Commissioner Marquez Peterson, sent in response to her August 28, 2020, request made in the 2020 Summer Preparedness and Winter Preparedness docket, Docket No. AU-00000A-20-0069. Additionally, Mr. Gayer filed his direct testimony.[14]

On September 25, 2020, an evening telephonic public comment proceeding was held, with Spanish interpretation available, and comments were received from 38 members of the public.

On September 29, 2020, APS filed Opposition to RESA's application to intervene, arguing that RESA's application was untimely; that RESA has other forums to raise its arguments in favor of retail electric competition, such as the open retail electric competition docket (Docket No. RE-00000A-18-0405); that retail electric competition is a state-wide matter not specific to APS; and that treating retail electric competition as only an APS matter would risk denying APS equal protection of the law and violate its substantive due process rights.

On September 30, 2020, a morning telephonic public comment proceeding was held, with

[14] Mr. Gayer is an APS residential customer and retired electronics engineer and attorney. (Ex. Gayer-4 at 1.)

Spanish interpretation available, and comments were received from 23 members of the public.

On October 1, 2020, a Procedural Order was issued denying RESA's application to intervene because the issues in this docket were focused on determining an appropriate revenue requirement and rate design, as well as resolving other issues raised by the APS rate application; retail electric competition is a statewide issue appropriately resolved in a docket that applies to utilities other than APS and allows for stakeholder involvement broader than that available in a rate case; and RESA had failed to establish that it would be directly and substantially affected by this matter or that its intervention would not unduly broaden the issues in this matter.

On October 1 and 2, 2020, non-rate design direct testimonies were filed for the following witnesses:

Party	**Witness/es & Occupation/s or Role/s**
AECC/Freeport	Kevin Higgins, Principal, Energy Strategies, LLC
ChargePoint	Justin Wilson, Director of Public Policy, ChargePoint
Citizen Groups	David Schlissel, President, Schlissel Technical Consulting, Inc., and Director of Resource Planning Analysis, Institute for Energy Economics and Financial Analysis
	Mike Eisenfeld, Energy and Climate Program Manager, SJCA
	Nicole Horseherder, Executive Director, TNA
EVgo	Sara Rafalson, Senior Director of Market Development, EVgo
FEA	Michael Gorman, Managing Principal, Brubaker & Associates, Inc.
	Christopher Walters, Associate, Brubaker & Associates, Inc.
IBEW Locals	G. David Vandever, Business Manager/Financial Secretary, IBEW Local 387
Nation	Jonathan Nez, Nation President
RUCO	Frank Radigan, Principal, Hudson River Energy Group
	John Cassidy, Public Utilities Analyst V, RUCO
	Jordy Fuentes,[15] Executive Director, RUCO
Sierra Club	Cheryl Roberto, Senior Principal, Synapse Energy Economics, Inc.
	Tyler Comings, Senior Researcher, Applied Economics Clinic
Staff	Ralph Smith, Senior Regulatory Consultant, Larkin & Associates, PLLC
	David Parcell, Principal and Senior Economist, Technical Associates, Inc.

[15] Mr. Fuentes has since left RUCO.

	Gurudatta Belavadi,[16] Electrical Engineer, Staff
	Matt Connolly, Executive Consultant III, Staff
	Phillip Metzger, Executive Consultant, Staff

On October 5, 2020, Staff filed a Notice of Errata to Mr. Parcell's direct testimony.

On October 7, 2020, Walmart filed the rate design direct testimony of Steve Chriss, Director, Energy Services, for Walmart.

Also on October 7, 2020, Staff filed a Notice of Errata to Mr. Smith's direct testimony.

On October 8, 2020, by Procedural Order, a telephonic procedural conference was scheduled for October 23, 2020, to discuss the format for the hearing in light of COVID-19 pandemic control measures in place for the Commission.

Also on October 8, 2020, APS filed a letter stating that APS had provided public notice of the additional telephonic public comment meetings as a bill insert between August 18 and September 18, 2020; as a link on the main page of the APS website beginning on August 22, 2020; in the newspapers required by the Procedural Order with publication dates between August 23 and September 11, 2020; and as a link on APS's Facebook and Twitter accounts. APS provided screenshots from its website and social media accounts and Affidavits of Publication from *The Arizona Republic*, *The Gila Bend Sun*, the *Casa Grande Dispatch*, the *Florence Reminder & Blade-Tribune*, the *Sedona Red Rock News*, the *Arizona Daily Sun*, the *Navajo-Hopi Observer*, *The Daily Courier*, the *Verde Independent/Bugle*, the *Payson Roundup*, the *Arizona Silver Belt*, the *White Mountain Independent*, *The Tribune*, the *Yuma Sun*, *Today's News-Herald*, *The Parker Pioneer*, the *Desert Messenger*, the *Herald/Review*, *The Bisbee Observer*, *The Tombstone News*, the *Globe Miami Times*, the *Superior Sun*, the *Ajo Copper News*, and the *Arizona Daily Star*.

On October 9, 2020, cost of service/rate design direct testimonies were filed for the following witnesses:

Party	**Witness/es &** (unless listed above) **Occupation/s or Role/s**
AARP	Scott Rubin, independent consultant and attorney
AECC/Freeport	Mr. Higgins
ASBA/AASBO	Travis Sarver, Principal, AES Defined
Calpine	William Goddard, Technical and Management Consultant – Electricity and Energy, WBG Consulting

[16] Mr. Belavadi has since left the Commission.

Calpine and Direct Energy (jointly)	Greg Bass, Western Regulatory and Legislative Director, Calpine
EVgo	R. Thomas Beach, Principal Consultant, Crossborder Energy
FEA	Amanda Alderson, Associate, Brubaker & Associates, Inc.
RUCO	Mr. Radigan
SEIA	Kevin Lucas, Senior Director of Utility Regulation and Policy, SEIA
SWEEP and WRA (jointly)	Brendon Baatz, Vice President, Gabel Associates, Inc.
Vote Solar	Ronny Sandoval, Regulatory Director, Vote Solar
Wildfire	Cynthia Zwick, Executive Director, Wildfire
	John Howat, Senior Policy Analyst, National Consumer Law Center
Staff	Dr. David Dismukes, Consulting Economist, Acadian Consulting Group; Full Professor, Executive Director, and Director of Policy Analysis, Louisiana State University ("LSU") Center for Energy Studies; Full Professor, LSU Department of Environmental Sciences; Director, Coastal Marine Institute, LSU College of the Coast and Environment; Senior Fellow, Institute of Public Utilities, Michigan State University

Also on October 9, 2020, PORA filed a Response to APS's First Set of Data Requests; APS filed a Response to Chairman Burns's September 1, 2020, letter; and RESA filed a Response to Denial of Application for Leave to Intervene, requesting that the denial be reversed.

On October 12, 2020, Commissioner Olson filed a letter in the docket requesting that the issue of whether to grant RESA's application to intervene be placed on the next Open Meeting agenda for discussion and a vote.

On October 19, 2020, ASBA/AASBO filed a Notice of Errata to the direct testimony of Mr. Sarver.

On October 22, 2020, ChargePoint filed a Motion to Associate Counsel *Pro Hac Vice* for Scott F. Dunbar.

Also on October 22, 2020, APS filed a Response to the October 8, 2020, Procedural Order, providing a summary of parties' recommendations and concerns related to the format for the hearing.

On October 23, 2020, Sierra Club filed a Response to the October 8, 2020, Procedural Order, providing its recommendations and concerns related to the format for the hearing.

Also on October 23, 2020, the telephonic procedural conference was held as scheduled, with APS, AECC/Freeport, WRA, SWEEP, Wildfire, ASBA/AASBO, the Citizen Groups, Vote Solar,

PORA, ACPA, FEA, SEIA, AriSEIA, Tesla, EVgo, the IBEW Locals, the Districts, Walmart, Calpine, Constellation, Direct Energy, ChargePoint, Sierra Club, ASDA, AARP, RUCO, and Staff appearing through counsel. Discussion occurred concerning the hearing format, including the handling of exhibits, and the parties were directed to create and to file a joint proposal for the order of party presentations and to identify dates certain for witnesses as needed.

On October 24, 2020, a Saturday morning telephonic public comment proceeding was held, and comments were received from 10 members of the public.[17]

On October 26, 2020, PORA filed a Response to APS's First Sets of Data Requests.

On October 28, 2020, AARP filed a Notice of Errata to Mr. Rubin's direct testimony.

On November 2, 2020, APS filed a Report Re Extranet Site for Hearing Exhibit Repository.

On November 5, 2020, MHCA filed a late application to intervene.

Also on November 5, 2020, at its Staff Open Meeting, the Commission considered Commissioner Olson's request regarding RESA's application to intervene, discussing the request but not voting on it.

On November 6, 2020, RUCO filed a Response to Chairman Burns's September 1, 2020, letter, stating that it would provide its opinion on executive compensation in its surrebuttal testimony.

Additionally, on November 6, 2020, APS filed the rebuttal testimonies of Mr. Guldner; Ms. Lockwood; Mr. Albert; Ms. Blankenship; Ms. Hobbick; Mr. Snook, Dr. White; Ms. Bulkley; Jacob Tetlow, Senior Vice President of Non-Nuclear Operations for APS; Monica Whiting, Vice President of Customer Experience and Chief Customer Officer for APS; and Todd Shipman, Executive Advisor to Concentric Energy Advisors, Inc..

Also on November 6, 2020, APS filed a Response to Chairman Burns's August 11 and September 1, 2020, letters.[18]

On November 7, 2020, a Saturday morning telephonic public comment proceeding was held, with Spanish interpretation available, and comments were received from 12 members of the public.

On November 12, 2020, by Procedural Order, Scott F. Dunbar was admitted *pro hac vice*.

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[17] Due to unforeseeable circumstances, Spanish interpretation services were not available. Fortunately, they were not needed.

[18] The APS letter to Chairman Burns dated November 6, 2020, was admitted herein as Exhibit CG-9 and Exhibit SC-27.

Also on November 12, 2020, APS filed Opposition to MHCA's application to intervene.

On November 13, 2020, by Procedural Order, intervention was granted to MHCA.

On November 17, 2020, Commissioner Marquez Peterson filed a letter in the docket requesting that the parties explore a number of cost reductions in this matter, with the goal of achieving a retail rate of or near $0.09/kWh.

Also on November 17, 2020, Staff filed a Motion to Amend Procedural Schedule ("Third Rescheduling Motion"), requesting on behalf of itself, APS, and more than 25 intervenors ("Joint Parties") that the procedural schedule be revised to have the hearing commence on January 14, 2021, and that other deadlines be adjusted accordingly. The Joint Parties stated that the proposed schedule would allow additional time to address issues raised in the docket.

On November 18, 2020, APS filed a Supplemental Report Re Extranet Site for Hearing Exhibit Repository.

On November 19, 2020, the Citizen Groups filed a Joinder in the Third Rescheduling Motion.

On November 20, 2020, Mr. Gayer filed surrebuttal testimony.

Also on November 20, 2020, the Tribe filed an Application to Intervene and Request for Docket Extension. The Tribe requested that the deadline for surrebuttal testimony be extended from November 20, 2020, to December 20, 2020, to allow for its participation. Additionally, Tribe Chairman Timothy Nuvangyaoma filed comments in the docket.

Also on November 20, 2020, by Procedural Order, the hearing was rescheduled to commence on January 14, 2021; other procedural deadlines were extended; the hearing date of December 14, 2020, was retained for telephonic public comment; an additional telephonic public comment session was scheduled for the evening of January 11, 2021; APS was required to provide prescribed notice of the public comment sessions; and the time clock for this matter was extended by 23 days.

Also on November 20, 2020, APS filed a Notice of Errata to Mr. Albert's rebuttal testimony.

On November 23, 2020, APS filed a Motion to Extend Deadline to Complete Notice (Expedited Consideration Requested), seeking an extension of the deadline to complete the direct mailing of the prescribed notice to its customers, from December 13 to December 31, 2020.

On November 24, 2020, by Procedural Order, APS's Motion to Extend Deadline to Complete

Notice was granted; due to the delay in notice, another public comment session was scheduled to be held on the first day of hearing and the notice amended accordingly; the Tribe's intervention was granted; and the Tribe's request to extend the deadline for surrebuttal testimony was denied.

On November 30, 2020, Sierra Club filed a Motion to Associate Counsel *Pro Hac Vice* for Rose Monahan.

Also on November 30, 2020, a morning telephonic public comment proceeding was held, with Spanish interpretation available, and comments were received from 50 members of the public.

On December 1, 2020, by Procedural Order, Rose Monahan was admitted *pro hac vice.*

On December 3 and 4, 2020, surrebuttal testimonies were filed for the following witnesses:

Party	**Witness/es &** (unless listed above) **Occupation/s or Role/s**
AARP	Mr. Rubin
AECC/Freeport	Mr. Higgins
ASBA/AASBO	Mr. Sarver
Calpine	Mr. Goddard
Calpine and Direct Energy (jointly)	Mr. Bass
ChargePoint	Mr. Wilson
Citizen Groups	Ms. Horseherder, Mr. Schlissel, and Mr. Eisenfeld
EVgo	Ms. Rafalson
FEA	Ms. Alderson, Mr. Gorman, and Mr. Walters
IBEW Locals	Mr. Vandever
MHCA	Neal Haney, Designated Broker and Co-Owner, NTH Property Management, LLC
Nation	President Nez
RUCO	Mr. Radigan, Mr. Cassidy, and Mr. Fuentes
SEIA	Mr. Lucas
Sierra Club	Ms. Roberto; Mr. Comings; and Sandy Bahr, Chapter Director, Sierra Club's Grand Canyon Chapter
SWEEP and WRA (jointly)	Mr. Baatz
Tribe	Timothy Nuvangyaoma, Tribe Chairman
Vote Solar	Mr. Sandoval
Walmart	Mr. Chriss
Wildfire	Ms. Zwick and Mr. Howat
Staff	Mr. Smith; Mr. Parcell; Dr. Dismukes; Mr. Connolly; and Margaret ("Toby") Little, Electric Utilities Consultant, Staff

Additionally, on December 4, 2020, APS filed its Response to Commissioner Marquez Peterson's letter of November 17, 2020, and Sierra Club filed a Notice of Errata to the direct testimony of Mr. Comings.

On December 7, 2020, RUCO filed a Notice of Errata to the surrebuttal testimony of Mr. Fuentes, Staff filed a Notice of Errata to the surrebuttal testimony of Mr. Parcell, and APS filed a Notice of Errata to Mr. Tetlow's rebuttal testimony.

On December 14, 2020, a morning telephonic public comment proceeding was held, with Spanish interpretation available, and comments were received from 3 members of the public.[19]

On December 17, 2020, a Procedural Order was issued adopting a remote hearing format and associated requirements for the hearing, consistent with Commission COVID-19 restrictions.

On December 21, 2020, Chairman Burns filed a copy of a news article concerning the Michigan Public Service Commission's approval of low-interest securitization bonds.

On December 22, 2020, APS filed the rejoinder testimonies of Mr. Guldner, Ms. Lockwood, Mr. Albert, Ms. Blankenship, Mr. Tetlow, Ms. Hobbick, Mr. Snook, Ms. Whiting, Dr. White, Ms. Bulkley, and Mr. Shipman.

On December 30 and 31, 2020, the Districts, Kroger, MHCA, RUCO, FEA, Walmart, WRA, SEIA/AriSEIA, EVgo, Tesla, ChargePoint, the Tribe, Constellation and Direct Energy (jointly), Vote Solar, the IBEW Locals, Mr. Gayer, AECC/Freeport, Sierra Club, Calpine, ASDA, the Nation, the Citizen Groups, SWEEP, Wildfire, ASBA/AASBO, Mr. Thornton, APS, and Staff filed their lists of witnesses to cross-examine at hearing, several[20] indicating that they did not intend to engage in any cross examination. RUCO's filing also indicated that the testimony of Mr. Fuentes would be adopted by Laurie Woodall, Interim Director of RUCO. Subsequently, and throughout the hearing in this matter, various parties revised their lists of witnesses to cross-examine at hearing, through additional filings and/or requests made during the hearing.

On December 31, 2020, the Citizen Groups filed a Response to APS's 4CPP early retirement analysis.[21]

Also on December 31, 2020, Sierra Club filed a Response to APS's 4CPP analysis.

On January 4, 2021, Mr. Gayer filed a "Notice of Deception" by counsel for APS, alleging that

[19] Due to an electrical outage in the main Commission building, this telephonic public comment proceeding was not recorded or streamed on the Commission's website.

[20] The Districts, MHCA, Walmart, Tesla, Vote Solar, and Mr. Thornton indicated an intention not to cross-examine any witnesses.

[21] This was admitted herein as Ex. CG-10.

he had not been informed of the final date of the conference call regarding scheduling, although he had been able to participate in the call after contacting counsel for APS.

On January 4, 2021, a Procedural Order was issued directing each party to be prepared to respond at the prehearing conference to whether the party was available for the additional hearing dates of February 8 through 12, 2021.

Also on January 4, 2021, APS filed a "Notice of Clarification" in response to Mr. Gayer's Notice of Deception, stating that APS had, on December 28, 2020, sent all parties a WebEx meeting invitation for the conference call regarding scheduling. Additionally, Staff filed a Notice of Errata to its witness list filed on December 31, 2020.

On January 5, 2021, the Tribe filed a Proposed Witness Schedule, the Citizen Groups filed a Notice of Errata to the surrebuttal testimony of Mr. Eisenfeld, RUCO filed a Notice of Filing of Witness Topic List, Mr. Gayer filed a Response to APS's Notice of Clarification, and APS filed a Joint Proposed Witness and Hearing Schedule.

Also on January 6, 2021, APS filed proof that it had provided public notice as required by the Procedural Orders of November 20 and 24, 2020, by sending the public notice as a bill insert between December 2 and 31, 2020; by posting a link on the main page of APS's website starting on November 25, 2020; by posting on APS's Facebook and Twitter accounts on November 25 and December 3, 10, and 17, 2020 (with two additional posts planned for January 6 and 11, 2021); and by publication in newspapers between December 6 and 11, 2020. APS provided screenshots from its website and social media accounts and Affidavits of Publication from the *Arizona Daily Sun*, *The Arizona Republic*, the *Casa Grande Dispatch*, the *Payson Roundup*, *The Daily Courier*, the *Sedona Red Rock News*, the *Herald/Review*, the *White Mountain Independent*, and the *Yuma Sun*.

Also on January 6, 2021, APS filed a Notice of Errata to Mr. Shipman's rejoinder testimony and a Motion for Clarification regarding other parties' requests, made in testimony, for judicial notice or official notice to be taken of reports and other attached documents.

On January 7, 2021, the prehearing conference was held, with APS, Calpine, Constellation, Direct Energy, FEA, SWEEP, Wildfire, ASBA, ASBO, the Citizen Groups, Vote Solar, Walmart, Kroger, MHCA, the IBEW Locals, the Nation, the Tribe, Sierra Club, WRA, SEIA, AriSEIA,

ChargePoint, AARP, AECC/Freeport, ASDA, PORA, ACPA, RUCO, and Staff appearing through counsel and Mr. Gayer appearing *pro se*.

Between December 31, 2020, and January 8, 2021, hearing exhibits lists (some with previously unfiled exhibits) and witness summaries were filed by FEA, MHCA, Calpine, AARP, SEIA/AriSEIA, Wildfire, ASBA/AASBO, the Citizen Groups, EVgo, Kroger, IBEW Locals, the Tribe, AECC/Freeport, Vote Solar, Mr. Gayer, Sierra Club, the Nation, Walmart, WRA and SWEEP (jointly) ("WRA/SWEEP"), ChargePoint, APS, RUCO, and Staff. Subsequently, and through the end of the hearing in this matter, updated hearing exhibit lists and exhibits were filed by many of these parties, some on numerous occasions.

On January 11, 2021, the Nation filed a Motion to Associate Counsel *Pro Hac Vice* for Todd F. Kimbrough.[22]

On the same date, by Procedural Order, Todd F. Kimbrough was admitted *pro hac vice*.

Also on January 11, 2021, an evening telephonic public comment proceeding was held, with Spanish interpretation available, and comments were received from 3 members of the public.

On January 12, 2021, FEA filed a Notice of Errata to the direct testimony of Mr. Gorman.

Also on January 12, 2021, WRA/SWEEP filed a Notice of Filing Unredacted Versions of Brendon Baatz's Direct and Surrebuttal Testimony, advising that APS had removed the highly confidential designation from specific documents attached to Mr. Baatz's direct testimony, resulting in his testimony no longer containing confidential information.

On January 14, 2021, the Tribe filed the testimony of Kendrick Lomayestewa, Renewable Energy Program Manager for the Tribe.

Also on January 14, 2021, Staff filed a Notice of Errata to Staff's Exhibit S-11.

Also on January 14, 2021, a morning telephonic public comment proceeding was held, with Spanish interpretation available, and comments were received from 30 members of the public.[23]

Following the public comment proceeding on January 14, 2021, the evidentiary hearing

[22] This motion was also filed on January 14, 2021.

[23] During the telephonic public comment proceeding, it was determined that the Commission's online calendar had included a typographical error in the phone number for the public comment proceeding. The error was corrected immediately, but it was announced during the public comment proceeding that another telephonic public comment proceeding would be held.

commenced with opening statements.

Also on January 14, 2021, a Procedural Order was issued scheduling another telephonic public comment meeting to be held on the evening of February 1, 2021, and requiring APS to provide prescribed notice of the additional public comment meeting, by January 22, 2021, by emailing the notice to each customer for which APS had an email address and posting the notice on its website. The Procedural Order also required APS to post notice of the public comment meeting on its social media accounts on at least three occasions (during the weeks of January 18 and 25, 2021, and on the morning of February 1, 2021).

On January 15, 2021, FEA filed a Notice of Errata to the direct testimony of Mr. Walter.

Also on January 15, 2021, APS filed a Notice of Filing Regarding Protective Agreements, including a list of Staff and Intervenors who had not entered into Protective Agreements with APS in this matter.

On January 19, 2021, Staff filed a Notice of Errata to Staff Exhibit S-18, and Wildfire filed the corrected surrebuttal testimony of Mr. Howat.

On January 20, 2021, Staff filed a Notice of Errata to Staff's Exhibit List.

On January 21 and 22, 2021, APS filed a letter to Commissioner O'Connor and a letter to Commissioner Kennedy in response to questions asked by each of them during the hearing.

On January 25, 2021, APS filed a Notice of Errata to Mr. Albert's rebuttal testimony.

On January 26, 2021, APS filed a letter to Commissioner Kennedy, providing information requested during the hearing on January 22, 2021.

On January 29, 2021, APS filed a letter to Commissioner O'Connor, providing responses to questions asked during the hearing on January 26, 2021.

Also on January 29, 2019, APS filed a letter to Commissioner Kennedy, supplementing information provided in its letter to Commissioner Kennedy dated January 21, 2021.

On February 1, 2021, APS filed proof that public notice had been providing as required by the Procedural Order of January 14, 2021, by emailing all customers for whom email addresses were available, on January 21 and 22, 2021; by posting public notice on the main APS website beginning on January 15, 2021; and by posting public notice on APS's Facebook and Twitter accounts on January

20 and 25 and February 1, 2021. APS included copies of the email, the website posting, and the social media postings.

Also on February 1, 2021, an evening telephonic public comment proceeding was held, with Spanish interpretation available, and comments were received from 12 members of the public.

On February 5, 2021, Commissioner Kennedy filed a letter to Mr. Guldner requesting responses to specific follow-up questions related to the Pinnacle West Capital Corporation's Political Action Committee ("PNW PAC") and its activities.

On February 8, 2021, APS filed a letter to Commissioner Kennedy, responding to questions asked during the hearing on January 27 and 28, 2021, concerning, *inter alia*, APS's website and mobile app and communication with non-English-speaking customers.

On February 11, 2021, Commissioner Kennedy filed a letter to Mr. Guldner requesting information related to termination of service to customers unable to make their first deferred payment arrangement payments.[24]

On February 12, 2021, APS filed a letter to Commissioner Kennedy stating that information regarding the PNW PAC and its activities would be provided on February 16, 2021.

On February 16, 2021, APS filed a letter to Commissioner Kennedy responding to the questions posed in her February 5, 2021, letter about the PNW PAC and its activities.

On February 17, 2021, the Citizen Groups filed a Notice of Errata to the direct testimony of Mr. Schlissel.

On February 18, 2021, the Nation filed a letter to Commissioner O'Connor responding to a question posed during the hearing on February 12, 2021.

On February 19, 2021, APS filed a letter to Commissioner Kennedy, responding to her February 11, 2021, letter.

On February 22, 2021, APS filed Notice of Filing Updated Exhibit List and Exhibit.

On February 23, 2021, the Tribe filed a Notice of Errata correcting data included in its Exhibit

[24] Pursuant to Decision No. 77849 (December 17, 2020), issued in Docket No. E-00000A-19-0128, regulated Class A, B, and C electric utilities providing retail residential electric service were required, *inter alia*, automatically to enroll residential customers with accounts in arrearages into deferred payment arrangements of not less than eight months. (See Ex. APS-78.)

7, Staff filed a Notice of Errata to the surrebuttal testimony of Mr. Parcell, and SEIA/AriSEIA filed a Notice of Errata to the direct testimony of Mr. Lucas.

Also on February 23, 2021, Staff filed a Notice of Filing the Complaint and Consent Agreement Between APS and the Arizona Attorney General's Office.[25]

On February 24, 2021, Staff filed a Notice of Errata to the direct testimony of Mr. Metzger, and AECC/Freeport filed a Notice of Errata to the surrebuttal testimony of Mr. Higgins.

On February 25, 2021, Commissioner Kennedy filed a letter requesting that Mr. Guldner be prepared to provide responses to a list of questions, related to customers not on their most economical rate plans, when he returned to testify during the week of March 1, 2021.

On March 2, 2021, APS filed a Notice that Ms. Lockwood and Mr. Guldner would be provided to testify on March 3, 2021, in response to a request made by Commissioner Kennedy.

Also on March 2, 2021, APS filed a letter to Commissioner Kennedy responding to her letter dated February 25, 2021.

The hearing in this matter, presided over by a duly authorized ALJ of the Commission, commenced on January 14, 2021, and concluded on March 3, 2021.[26] During the hearing, the parties presented the testimony of all of the witnesses listed above who had pre-filed testimony, with the exception of Mr. Fuentes, whose testimony was adopted by Ms. Woodall, and Mr. Belavadi, whose testimony was adopted by Ms. Little. At the conclusion of the hearing, a briefing schedule was established, with initial briefs due by April 6, 2021, and responsive briefs due by April 30, 2021, and APS was directed to make a late-filed exhibit filing by March 17, 2021. Additionally, each party proposing a revenue requirement, rate base, rate of return, or rate design was directed, by April 6, 2021, to file final schedules with Docket Control and to submit to the Hearing Division electronic copies of each electronic file prepared in reaching its final positions, with calculations and formulas intact and billing determinants/proof of revenue included. In light of the briefing schedule, with APS's consent, the Commission's time clock for this matter was extended by 14 days.

On March 4, 2021, Commissioner Tovar filed a letter to Mr. Guldner, asking whether APS

[25] The Consent Agreement has been admitted herein as Exhibit APS-83.
[26] The hearing was held remotely via WebEx and, for some participants, via telephone.

supported HB2248 or SB1175 in their current forms.

On March 5, 2021, APS filed a letter to Commissioner Tovar, in which APS took no position on HB2248 or SB1175.

On March 15, 2021, Sierra Club filed a Motion to Admit Late-Filed Exhibit & Updated Exhibit List ("Sierra Club's 1st LFE Motion"), including proposed Late-Filed Exhibit ("LFE") SC-40, an APS press release dated March 12, 2021, announcing that APS and the other owners of the 4CPP had reached an agreement to move toward operating the plant seasonally beginning in fall 2023, subject to necessary approvals, meaning that one of the 4CPP units would operate only from June through October while the other unit would operate year-round. Sierra Club requested that LFE SC-40 be admitted and presented argument supporting such a ruling and concerning the ramifications of the seasonal operation agreement for this matter.

On March 16, 2021, in response to requests made at hearing, APS filed a Notice of Filing Updated Exhibit List and Late-Filed Exhibits, including LFE APS-85, a letter responding to Commissioner Kennedy's questions regarding support and Most Economical Plan ("MEP") calculations for business customers, and LFE APS-86, a letter concerning the new residential rate plan names proposed by APS.

On March 17, 2021, APS filed a Response to Sierra Club's 1st LFE Motion, not opposing the admission of LFE SC-40 but disagreeing with Sierra Club's argument regarding the impact of the seasonal operation agreement on this matter.

On March 19, 2021, Sierra Club filed a Motion to Admit Late-Filed Exhibit & Updated Exhibit List ("Sierra Club's 2nd LFE Motion"), including proposed LFE SC-41, a March 15, 2021, letter from Public Service Company of New Mexico ("PNM") to the New Mexico Public Regulation Commission ("NMPRC") that accompanied an amended application for abandonment and transfer of the 4CPP and for a financing order as well as supplemental testimony to support the amended application. LFE SC-41 included an excerpt from the supplemental testimony of Thomas G. Fallgren, dated March 15, 2021, in which the Agreement in Principal for seasonal operation of the 4CPP is discussed.

Late on March 26, 2021, APS filed a Response to Sierra Club's 2nd LFE Motion, not opposing admission of LFE SC-41 but requesting that the entire supplemental testimony of Mr. Fallgren, rather

than an excerpt, be admitted as LFE SC-41. APS expressed concern about the relevancy of Mr. Fallgren's testimony, asserting that it relates to matters that are not at issue in this case and that are, in any event, outside of the TY and, further, that Sierra Club may be attempting to use this case to interfere with complex negotiations among 4CPP owners with divergent interests.

On March 29, 2021, Sierra Club and APS filed a Joint Motion to Admit Late-Filed Exhibit & Request for Expedited Consideration ("Joint LFE Motion"). In the Joint LFE Motion, Sierra Club and APS stated that they had recently learned that communications between APS and PNM concerning the 4CPP had been made public and that certain of the documents might be relevant to issues raised by Sierra Club in discovery requests in this matter and had not previously been produced by APS. Sierra Club and APS stated that the documents had been produced by PNM through discovery in the abandonment and financing proceeding before the NMPRC. Sierra Club and APS stated that they agreed that the communications might be relevant to issues raised by Sierra Club in this matter, including whether TY expenditures at the 4CPP were prudent, and agreed that it is appropriate for the documents to be included in the record in this matter to allow the Commission to evaluate fully the relevant issues and avoid prejudice to either party. Sierra Club and APS requested the admission of LFE SC-42, attached to the Joint LFE Motion, and requested expedited consideration because of the briefing schedule. LFE SC-42 is a collection of emails occurring between March 20, 2018, and April 13, 2020. Some of the emails involve Mr. Fallgren and various persons identifiable (from their email addresses) as associated with APS, Pinnacle West Capital Corporation, the Salt River Project ("SRP"), and Tucson Electric Power ("TEP") as well as others whose affiliations are not readily apparent. Other emails involve Charles Eldred, identified as the Executive Vice President and CFO of PNM, and persons whose affiliations are not readily apparent from their email addresses.

On March 30, 2021, a Procedural Order was issued granting Sierra Club's 1st LFE Motion and admitting LFE SC-40; granting Sierra Club's 2nd LFE Motion but requiring Sierra Club, by April 6, 2021, to refile LFE SC-41 with a complete copy of Mr. Fallgren's supplemental testimony, and admitting LFE SC-41 in that refiled form; granting the Joint LFE Motion and admitting LFE SC-42; requiring APS and Sierra Club, by April 6, 2021, to file a document labeled LFE SC-43, to identify with business affiliations those persons involved in the email correspondence included in LFE SC-42

whose email addresses did not identify them as affiliated with APS, Pinnacle West, PNM, SRP, or TEP; and admitting LFE APS-85 and LFE APS-86.

On April 5, 2021, Intervenor Patricia A. Madison filed a Request to Withdraw as an Intervenor for this docket.

Also on April 5, 2021, Sierra Club and APS jointly filed LFE SC-43 and requested that it be admitted, and Sierra Club refiled the complete LFE SC-41.

Between March 31 and April 6, 2021, initial briefs[27] were filed by Mr. Gayer, the IBEW Locals, MHCA, Wildfire, ASBA/AASBO, FEA, ChargePoint, RUCO, Walmart, Calpine and Direct Energy (jointly) ("Calpine/Direct"), ASDA, Nation, Kroger, WRA/SWEEP, SEIA/AriSEIA, Tesla, EVgo, AARP, Sierra Club, Vote Solar, AECC/Freeport, the Citizen Groups, the Tribe, APS, and Staff. Final schedules have also been filed separately by FEA, AECC/Freeport, and APS. In its filing, APS broke its final schedules down into three LFEs: APS-87, APS-88, and APS-89.

On April 7, 2021, a Procedural Order was issued granting Ms. Madison's Request to Withdraw; admitting LFE SC-43; admitting LFE APS-87, LFE APS-88, and LFE APS-89; and deeming admitted other parties' final schedules.

On April 20, 2021, Staff filed a Notice of Errata to replace errors in several pages of its opening brief.

Also on April 20, 2021, Commissioner Kennedy filed a letter to the docket requesting that APS, Staff, and RUCO file, by April 30, 2021, responses addressing whether the record in this matter is sufficient to allow the Commission to expand, reduce, eliminate, or otherwise modify each of APS's currently approved adjustor mechanisms and, if not, addressing a number of additional questions. The letter invited other parties to respond as well.

On April 23, 2021, FEA filed a Notice of Withdrawal of Counsel for Thomas Jernigan, Robert Friedman, and Scott Kirk.

On April 26, 2021, a Procedural Order was issued approving the withdrawals and requiring that service for this matter be made upon FEA's remaining attorneys.

[27] Initial briefs are cited herein using an abbreviated version of the party's name and "Br."

On April 29 and 30, 2021, responsive briefs[28] were filed by IBEW Locals, MHCA, ASBA/AASBO, Wildfire, Calpine/Direct, AARP, Walmart, FEA, RUCO, Vote Solar, Nation, Sierra Club, WRA/SWEEP, the Citizen Groups, AECC/Freeport, Staff, and APS. Additionally, Kroger, EVgo, SEIA/AriSEIA, and Tesla filed notice that they would not be filing responsive briefs.

Also on April 30, 2021, RUCO, Sierra Club, the Tribe, Staff, and APS filed responses to Commissioner Kennedy's letter.

At its Open Meeting on May 5, 2021, the Commission discussed whether to open the evidentiary record in this matter to ensure that the evidence is sufficient to address the items and topics identified in Commission letters to the docket. The Commission did not take a vote whether to open the record. Commissioner Tovar requested that APS file in the docket all of the documents it provided to the Attorney General's office in the case that resulted in APS's paying a fine related to its rate tool. Chairwoman Marquez Peterson requested that official notice be taken of the following Commission decisions in their entirety, with particular attention to be paid to the pages provided:[29]

- Decision No. 54247 (November 28, 1984)—pages 11-17
- Decision No. 55118 (July 24, 1986)—pages 6-16
- Decision No. 55228 (October 9, 1986)—page 16
- Decision No. 55325 (December 5, 1986)—pages 4-8
- Decision No. 55931 (April 1, 1988)—pages 92-100
- Decision No. 56133 (September 15, 1988)—"the whole decision and any subsequent decisions related to APS's purchased power and fuel adjustor mechanism and PIMs that the Commission issued between September 15, 1988, and December 31, 1988"[30]
- Decision No. 57649 (December 6, 1991)—page 10
- Decision No. 58644 (June 1, 1994)—pages 7-11
- Decision No. 59601 (April 24, 1996)—pages 3-4 and 6-7

Between October 4, 2019, and May 7, 2021, public comments were filed by or on behalf of

[28] Responsive briefs are cited herein using an abbreviated version of the party's name and "RBr."
[29] Official notice is taken of these decisions.
[30] No such decisions appear on the Commission's eDocket system for the consolidated docket numbers in which Decision No. 56133 was issued.

more than 5,880 members of the public. The vast majority of the commenters expressed opposition to any rate increase for APS. Likewise, the oral public comments received during the 13 telephonic public comment meetings almost exclusively opposed a rate increase for APS. A small percentage of commenters supported a just and equitable transition away from a coal-based economy for coal-impacted communities.

III. Background

A. APS Generally

APS is wholly owned by Pinnacle West Capital Corporation ("PNW"), which is publicly traded.[31] (Ex. S-7 at 4; Ex. S-12 at 32.) APS is the largest electric utility in Arizona, providing electricity to more than 1.26 million customers in 11 of Arizona's 15 counties. (Ex. S-12 at 6-7; Ex. S-7 at 44-45; Ex. APS-44.) APS's service territory is diverse and ranges from densely populated urban areas to sparsely populated rural areas, covering 35,000 square miles. (Ex. S-7 at 3; Ex. APS-44.) The service territory is divided into divisions (Metro, Northeast, Northwest, and Southeast) and further divided into districts, as follows:[32]

Divisions	Districts
Metro	Deer Valley/Central, Goodyear/Western, Paradise Valley/Eastern
Northeast	Coconino, Navajo, Payson
Northwest	Prescott, Verde, Wickenburg
Southeast	Buckeye, Cochise, Mountain, Pinal,
Southwest	La Paz, Yuma

As of 2019, APS had 33,283 miles of energy distribution lines and 6,241 miles of transmission lines. (Ex. S-7 at 4-5; Ex. APS-44.) Additionally, APS's facilities included 439 substations, more than 300,000 transformers, and more than 550,000 power poles and structures. (Ex. S-7 at 15.) APS owns, wholly or in part, several major transmission paths in Arizona, New Mexico, and Nevada that transport electricity from fossil fuel, nuclear, and renewable facilities and from long-term purchase agreements. (*Id.*) From its virtual site visit, conducted in place of an in-person site visit due to the COVID-19 pandemic, Staff found APS's system to be well planned and maintained with no deficiencies or obvious

[31] PNW is a holding company, and essentially all of its revenues and earnings come from APS, although PNW also owns three other subsidiaries. (Ex. S-1 at 16.)
[32] Ex. S-7 at 39-40.

problems and found the facilities and equipment inspected to be operational and used and useful in the provision of service. (*Id.* at 34-35.)

APS is a summer-peaking utility, with most of its revenues generated during the summer months although its expenses are spread out over the year. (Tr. at 584, 933.) From 2015 through 2019, APS's electric system peak demand decreased at an annual average rate of 1%, from 7,320 MW to 7,030 MW. (Ex. S-7 at 6.) On July 30, 2020, however, APS experienced record peak demand of between 7,500 and 8,000 MW. (Tr. at 584, 2126-2127; Ex. APS-26 at 15-16.)

Although APS experienced steady customer growth averaging approximately 1.7% per year from 2015 through 2019, its energy delivery on average decreased by approximately 0.1% annually, from 27,950,491 MWh to 27,844,577 MWh. (Ex. S-7 at 5-6.) In 2019, APS sold 13,147,884 MWh to residential customers, mostly in the Metro division, and 14,614,163 MWh to nonresidential customers, also mostly in the Metro division. (Ex. S-7 at 44.) In 2019, APS had 1,123,829 residential customers, mostly in the Metro division, and 136,286 nonresidential customers, also mostly in the Metro division. (*Id.* at 44-45.)

According to its 2020 Integrated Resource Plan ("2020 IRP"), APS currently has 10,773 MW of resources, broken down as follows:[33]

Resource Type	MW	%[34]
Nuclear[35]	**1,146 MW**	**10.64%**
Coal	**1,357 MW**	**12.60%**
Natural Gas	**5,233 MW**	**48.58%**
Owned by APS	3,573 MW	
Purchased Power Agreements ("PPAs")	1,660 MW	
Microgrid	**32 MW**	**0.30%**
Energy Storage Systems ("ESS")	**2 MW**	**0.02%**
Renewables	**883 MW**	**8.20%**
Solar	567 MW	
Owned by APS	242 MW	
PPAs	325 MW	
Wind (PPAs)	289 MW	
Other (PPAs)	27 MW	
Customer-Based	**2,120 MW**	**19.68%**

[33] Ex. S-7 at 12.
[34] Numbers were rounded to show only two decimal places.
[35] APS owns 29.1% of and operates the Palo Verde Nuclear Plant ("Palo Verde"). (Ex. APS-4 at 15.)

Energy Efficiency	1,038 MW	
Distributed Energy	1,044 MW	
Demand Response	38 MW	

In January 2020, APS announced a "Clean Energy Commitment" to deliver its customers 100% clean, carbon-free, and affordable electricity by 2050, with interim targets of 65% clean energy and 45% renewables by 2030. (Ex. APS-5 at 5.) APS also committed to ceasing all coal-fired generation by 2031. (*Id.*)

B. The 4CPP

The 4CPP, located near Farmington, New Mexico, is a coal-fired generation plant now comprised of two 770-MW coal-fired units, Units 4 and 5, which have been in operation since 1969 and 1970.[36] (Ex. SC-1 at 6.) APS owns 63% of Units 4 and 5, representing capacity of 970 MW, and is the operator of the 4CPP. (Ex. SC-1 at 6; Ex. Navajo-1 at 14-15.) The other owners are Public Service Company of New Mexico ("PNM"), SRP, TEP, and Navajo Transitional Energy Company ("NTEC").[37] (LFE SC-40.) The coal to fuel Units 4 and 5 comes from the nearby Navajo Mine, owned by NTEC. (Ex. SC-1 at 6.) The 4CPP Coal Supply Agreement ("CSA") does not expire until July 6, 2031.[38] (Ex. SC-1 at 6; LFE SC-41 at 8, 24.) The 4CPP operating agreement also does not expire until 2031. (Ex. SC-1 at 6; LFE SC-41 at 8, 24.) The lease agreement with the Nation for the 4CPP site expires in 2041. (Ex. CG-3 at 9.) PNM is in the process of selling its interest in Units 4 and 5 to NTEC. (See LFE SC-41.)

In March 2021, the 4CPP owners entered into an Agreement in Principle ("Seasonal Agreement") to transition the 4CPP to seasonal operations beginning in fall 2023, which would involve operating one unit year-round and the second unit only during the summer peak season of June through October. (LFE SC-41 at 28, 30.) The seasonal operations idea came from PNM, which had previously also attempted to obtain the other non-NTEC owners' approval for closure before 2031 or to sell them

[36] APS retired 4CPP Units 1-3 in 2012. (Ex. SC-1 at att. TC-2.)
[37] NTEC was developed for the transition away from coal and is a subgroup of the Nation with its own board of directors. (Tr. at 3320, 3434.)
[38] The term of the coal contract, between NTEC and the other 4CPP owners, is July 1, 2018, to July 6, 2031. (Ex. SC-1 at att. TC-2.)

its shares.[39] (Ex. LFE-SC-42; Ex. LFE SC-41 at 3-4, 29.) As part of the Seasonal Agreement, the 4CPP owners agreed to increase the notice period for possible early (before 2031) shutdown of 4CPP from two years to four years, although they maintain the right to give three-year notice upon payment of $100 million or two-year notice upon payment of $200 million.[40] (LFE SC-41 at 31.) The communications that resulted in the Seasonal Agreement began in some form in 2018; APS has maintained that it needs the 4CPP to operate until 2031. (LFE SC-42 at 7, 13-14.)

C. Cases Relating to 4CPP Units 4 and 5

In Decision No. 73130 (April 24, 2012),[41] issued in Docket No. E-01345A-10-0474 ("SCE Purchase Docket"), the Commission authorized APS to acquire Southern California Edison's ("SCE's") 48% interest in 4CPP Units 4 and 5, under a waiver from a "self-build" moratorium[42] imposed by Decision No. 67744 (April 7, 2005),[43] and to defer, for possible recovery through rates, all "non-fuel costs"[44] of owning, operating, and maintaining the SCE interest in Units 4 and 5 and associated facilities, as well as all unrecovered costs associated with Units 1-3 and additional costs incurred in connection with the closure of Units 1-3. The Commission did not approve APS's request to accrue carrying charges on the deferred costs. (Decision No. 73130 at 34-37.) The Decision acknowledged that APS planned to accelerate retirement of 4CPP Units 1-3 upon acquisition of Units 4 and 5 and to add Selective Catalytic Reduction equipment ("SCRs") to Units 4 and 5 by 2018. (Decision No. 73130 at 7.)

In Decision No. 73183 (May 12, 2012),[45] issued in Docket No. E-01345A-11-0224 ("2011 Rate Case"), the Commission approved a rate case settlement agreement that held open the docket to allow

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[39] NTEC is prohibited from voting on early closure of 4CPP due to its conflict of interest as the coal supplier. (LFE SC-41 at 26.)

[40] These amounts are in contrast to the PNM-calculated $60 million termination fee for the combined owners upon an early termination in 2024 and APS's own estimate that its share of termination expense for termination on July 1, 2024, would be approximately $36.3 million, both of which were based on the effective CSA. (See LFE SC-42 at 7; Ex. SC-1 at att. TC-2.)

[41] Official notice is taken of this decision. Sierra Club, WRA, and RUCO participated in the case regarding APS's purchase from SCE.

[42] Decision No. 67744 included a very broad definition of "self-build."

[43] Official notice is taken of this decision.

[44] The decision defined the "non-fuel costs" as "depreciation, amortization of the acquisition adjustment, decommissioning costs, operations and maintenance costs, property taxes, final coal reclamation costs, the documented debt costs of acquiring SCE's interest in Units 4 and 5, and miscellaneous other costs." (Decision No. 73130 at 37.) APS was required to reduce the deferrals by non-fuel O&M and property tax savings associated with the closure of Units 1-3. (*Id.* at 43.)

[45] Official notice is taken of this decision.

APS to file a request to reflect the rate base and expense effects associated with its acquisition of SCE's ownership interest in Units 4 and 5, the retirement of Units 1-3, and any cost deferral authorized in the SCE Purchase Docket through an adjustment rider. (Decision No. 73183 at 46-47, ex. A at 15-16.)

In Decision No. 74876 (December 23, 2014), issued in the 2011 Rate Case, the Commission found that APS's acquisition of SCE's interest in Units 4 and 5 was prudent and that rate recovery pursuant to the settlement agreement adopted by Decision No. 73183 was appropriate. (Decision No. 74876 at 46.) The Commission approved an annual revenue increase of $57.05 million to be collected through a 4CPP Rate Rider assessed at 2.03% of customer bill base rates. (*Id.* at 46-47.)

D. Most Recent APS Rate Case

APS's last fully litigated rate case before the Commission resulted in Decision No. 69663 (June 28, 2007),[46] which used a TY ending September 30, 2005. Since that time, APS has had three general rate cases resulting in the following Commission Decisions approving, with slight modifications, Settlement Agreements involving the majority of parties to the rate cases: Decision No. 71448 (December 30, 2009),[47] issued in Docket No. E-01345A-08-0172 ("2008 Rate Case"); Decision No. 73183 (May 24, 2012), issued in the 2011 Rate Case; and Decision No. 76295 (August 18, 2017), issued in Docket No. E-01345A-16-0036 et al. ("2016 Rate Case").[48]

In Decision No. 76295, issued in the 2016 Rate Case, the Commission approved, with slight modifications, a Settlement Agreement signed and supported by APS, the Arizona Investment Council, the IBEW Locals, REP America dba ConservAmerica, ASDA, Vote Solar, the Energy Freedom Coalition of America ("EFCA"), SEIA, AriSEIA, the Arizona Utility Ratepayer Alliance, AECC/Freeport, Direct Energy, Constellation, Calpine, ACPA, Walmart, Kroger, Granite Creek Power & Gas and Granite Creek Farms LLC, FEA, the City of Coolidge, WRA, ASBA/AASBO, Sun City Homeowners Association, PORA, Wildfire (then known as the Arizona Community Action Association), RUCO, and Staff. The parties to the 2016 Rate Case who did not sign the Settlement Agreement were Mr. Gayer; Patricia Ferré; Warren Woodward; IO Data Centers, LLC; Cynthia Zwick

[46] Decision No. 69663 was admitted herein as Exhibit APS-76 and was issued in Docket No. E-01345A-05-0816 et al. ("2005 Rate Case").
[47] Official notice is taken of this decision.
[48] Decision No. 76295 was admitted herein as Exhibit APS-70.

(in her individual capacity); SWEEP; the Districts;[49] AARP, and the City of Sedona.

Under the Settlement Agreement, APS's fair value rate base ("FVRB") was set at $9,990,561,000, and its total adjusted test year revenue was set at $2,888,903,000. The Settlement Agreement allowed APS a return on common equity of 10.0%, a fair value rate of return of 5.59% (including a 0.8% return on the fair value increment), and an embedded cost of debt of 5.13%. The Settlement Agreement provided for a total base rate revenue increase of $362.58 million, comprised of a non-fuel base rate increase of $148.25 million (including a return on and of 12 months of post-TY plant that was in service as of December 31, 2016), a base fuel rate decrease of $53.63 million, and the transfer to base rates of $267.95 million in "adjustor mechanism revenues" (described as revenue neutral). The "adjustor mechanism revenues" included revenues collected during the TY (or otherwise as specified[50]) through the Renewable Energy Adjustment Clause ("REAC"), the Demand Side Management Adjustment Clause ("DSMAC"), the Lost Fixed Cost Recovery Adjustor ("LFCR"), the Transmission Cost Adjustor ("TCA"), the Environmental Impact Surcharge ("EIS"), and the 4CPP Rate Rider ("FCRR") as well as a negative transfer from the System Benefits Charge.[51] The Settlement Agreement provided that the transfers would become effective on the effective date of the new rates.

Most notably as to rate design, the Settlement Agreement, as modified and adopted by the Commission:

- Replaced the E-12 Residential Basic Rate with three separate basic rate plans available to residential customers based on monthly kWh consumption (R-XS for up to 600 kWh/month, R-Basic for 601-999 kWh/month, and R-Basic Large for 1,000 or greater kWh/month);
- Replaced the Time Advantage Rate, which had a peak period of noon to 7 p.m., with the TOU-E rate, which has a peak period of 3 p.m. to 8 p.m. and a winter super off-peak period of 10 a.m. to 3 p.m. and also includes four additional off-peak holidays;
- Adopted the 3-part residential demand rates R-2 and R-3;

[49] In the 2016 Rate Case, the Districts did not include the Buckeye Water Conservation and Drainage District, and ED8 and MVWCDD jointly had separate representation from the other entities comprising the Districts.

[50] The Settlement Agreement provided that adjustor rates would be "zeroed out or reduced." (Ex. APS-70 at ex. A at 11, § 8.1.)

[51] The System Benefits Charge is discussed more fully below; it does not have a Plan of Administration and is not a traditional adjustor mechanism.

- Adopted the on-site Technology Pilot Program R-Tech, a 3-part residential demand rate, which is available to residential customers with specified on-site technologies;
- Made TOU-E, R-2, R-3, and R-Tech available to all residential customers, including those with distributed generation ("DG"), but precluded customers with DG from obtaining service through R-XS, R-Basic, and R-Basic-Large;
- Required new residential customers to obtain service through TOU-E, R-2, R-3, R-Tech, or R-XS;
- Required new residential customers to stay on R-TOU-E, R-2, R-3, or R-Tech for at least 90 days before being eligible to obtain service through R-Basic or R-Basic-Large;
- Required any residential customer who chose to obtain service through R-Basic or R-Basic-Large to stay on the rate plan for at least 12 months;
- Froze R-Basic-Large as a choice for new residential customers on May 1, 2018, and as a choice for existing (as of April 30, 2018) residential customers on September 1, 2018;
- Changed the bill discount for the E-3 Energy Support Program for limited income customers from a scaled discount of up to 65% based on usage to a flat 25% discount;
- Adopted transition rates using the updated revenue requirement with existing residential and extra small general service rate schedules, and required that customers who did not select a different rate by May 1, 2018, be moved to the updated rate plan "most like their existing rate"[52] plan;
- Adopted a rate rider providing a discount per kWh for public schools and public school districts;
- Required APS to reduce the unbundled delivery charge for service at military sites for primary voltage under E-34 and E-35 to a level resulting in the military customer getting a net impact bill increase equal to the average for all retail customers;
- Adopted a General Service XS non-demand rate;
- Changed the on-peak period for General Service rates XS through E-32L to 3 p.m. to 8 p.m.

[52] APS Ex. 70 at ex. A at 24, § 26.1.

but retained the existing on-peak period for E-35;

- Required APS to redesign E-32L in a revenue neutral manner to recover an additional $1.36 per kW in the unbundled generation charges;
- Replaced the Experimental Rate Rider AG-1 buy-through program with the revised AG-X buy-through program; and
- Required APS to file an optional Large General Service Time-of-Use Storage Program Tariff that would, *inter alia*, eliminate the demand ratchet, off-peak demand charge, and declining block demand charge included in APS's E-32L and E-32L TOU rates.

The Settlement Agreement asserted that residential customers would experience an average 4.54% bill impact while general service customers would experience an average 1.93% bill impact. The Settlement Agreement provided that to lessen first year impacts, APS would refund to customers, through the DSMAC, $15 million in collected but unspent funds for Demand Side Management ("DSM") programs and also required APS to use $5 million in over-collected DSMAC funds "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."[53] The Settlement Agreement required APS to file an outreach and education plan and to provide stakeholders with an opportunity to review and comment on the draft plan before completing its final plan; Decision No. 76295 added timing requirements to this process.

Notably, the Settlement Agreement, as adopted by the Commission, also:[54]

- Required APS, in future rate cases, to impute net revenue growth for any revenue-producing plant included in post-TY plant;
- Required APS not to file another rate application before June 1, 2019, and to use a test year ending no earlier than December 31, 2018, in its next rate application;
- Required APS, in its next rate case, to file a depreciation rate study including alternative calculations for cost of removal and dismantlement (negative net salvage) using the Financial Accounting Standard ("FAS") 143 discounted net present value ("NPV") method

[53] Ex. APS-70 at ex. A at 24, § 27.1.
[54] This list is not exhaustive of the remaining provisions of the Settlement Agreement and Decision No. 76295.

and a discount rate to be agreed upon;

- Required that the 2016 Rate Case docket remain open for the sole purpose of allowing APS to file a request for its rates to be adjusted, no later than January 1, 2019, to reflect the proposed addition of the SCRs at the 4CPP;
- Authorized APS to defer for possible later recovery through rates all non-fuel costs of owning, operating, and maintaining[55] the SCRs at the 4CPP from the time the SCRs went into service until the costs were included in rates, with the interest component of the SCRs deferral set at APS's embedded cost of debt (per the 2016 Rate Case);
- Provided that the Settlement Agreement language regarding the SCRs deferral was not to be construed in a 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 [Decision No. 76295]"[56];
- Prohibited signatories to the Settlement Agreement from presenting any issues in the SCRs rate adjustment proceeding other than those specifically described in Section 9 of the Settlement Agreement;
- Authorized APS to defer for possible later recovery through rates all non-fuel costs of owning, operating, and maintaining[57] the Ocotillo Modernization Project ("OMP") and retiring the existing steam generation at the Ocotillo Plant;
- Required that the entire OMP investment be addressed and resolved in APS's next general rate case;
- Expressly stated that the Settlement Agreement did not address the prudence of the OMP and that a deferral of the OMP costs did not guarantee recovery of the costs;
- Authorized APS to defer for future recovery (or credit to customers) its Arizona property tax expense above or below its TY expense, to the extent caused by changes to the applicable Arizona composite property tax rate, without interest during the deferral period

[55] The Settlement Agreement defined these non-fuel costs as "all O&M, property taxes, depreciation, and a return at APS's embedded cost of debt." (Ex. APS-70 at ex. A at 12, § 9.2.)
[56] Ex. APS-70 at ex. A at 12, § 9.2.
[57] The Settlement Agreement defined these non-fuel costs as "all O&M, property taxes, depreciation, and a return at APS's embedded cost of debt." (Ex. APS-70 at ex. A at 13, § 10.1.)

unless the deferred amount were negative, in which case interest would be accrued at APS's short term debt rate;

- Required that beginning with the effective date of a Commission decision in its next general rate case, any final positive property tax rate deferral amount be recovered from customers over 10 years, with a return at APS's short term debt rate, and that any unrefunded negative balance earn a return at the short term debt rate;
- Required APS in its next general rate case to use the Average and Excess methodology to allocate production demand costs to residential and general service classes and then to reallocate production demand within the residential subclasses based on 4CP, although APS was not precluded from proposing alternative allocation methods;[58]
- Required APS to address any potential impacts of the closure of the Navajo Generating Station in Docket No. E-00000C-17-0039[59] before filing its next rate case;
- Prohibited APS from pursuing any new self-build generation with an in-service date before January 1, 2022, with some exceptions, unless it had express authorization from the Commission, and extended the prohibition to December 31, 2027, for combined-cycle generating units;
- Authorized APS to create a new Tax Expense Adjustor Mechanism ("TEAM") to enable APS to pass-through to customers the income tax effects from significant federal income tax reform legislation enacted and effective before the conclusion of APS's next general rate case, to the extent the legislation materially impacted APS's annual revenue requirements;
- Required that the TEAM be computed on a prospective basis each year, with filing on December 1 and an effective date in March; be assessed to each customer through an equal charge per kWh; include a balancing account with any under- or over-collected balance to be recovered or refunded the following year, with interest at APS's cost of short term debt;

[58] The Settlement Agreement also provided that other parties could propose alternative allocation methods. (Ex. APS-70 at ex. A at 14, § 12.2.)

[59] This generic docket was opened "[i]n the matter of the Arizona Corporation Commission Investigation Concerning the Future of the Navajo Generating Station." The docket has not had any substantive activity since September 2018, and no decisions have been issued therein.

and terminate with the effective date of APS's next general rate case;

- Required that DG customers filing a completed interconnection application before the effective date for the rates approved in the Decision be grandfathered for 20 years from the date of system interconnection, that grandfathered DG customers be permitted to continue to take service under full retail rate net metering on their current tariff schedules (E-12, ET-1, ET-2, ECT-1, or ECT-2) for the length of the grandfathered period, and that grandfathered DG customers served under E-3 or E-4 be permitted to continue on the current E-3 or E-4 for as long as they meet eligibility;
- Required APS, in its next rate case, to propose that the rates for the legacy DG tariffs (E-12, ET-1, ET-2, ECT-1, and ECT-2) be updated with a percentage increase equal to the residential average base rate increase approved to be applied to every rate component;
- Retained the current net metering structure for non-residential solar customers (and anticipated that it would be addressed in a future Value of Solar or other proceeding);
- Authorized the experimental AG-1 program to continue in the form of the AG-X program, with, *inter alia*, an increased capacity reserve charge, an increased administrative management fee, and a new retail energy imbalance protocol intended to measure how well a GSP matched its retail buy-through customer load on an hourly basis;
- Required reevaluation in APS's next rate case of the AG-X capacity reserve charge and other parameters and whether AG-X should be evaluated as a separate customer class in the Cost of Service Study ("COSS");
- Modified the PSA mitigation from the AG-1 program for AG-X by setting the resale of capacity and energy displaced by AG-X at $1,250,000 per month of off-system sales margins and excluding it from the PSA;
- Required that the AG-1 deferral be recovered over five years from all non-residential customer classes other than the street and area lighting customer classes, based on adjusted test year kWh, and prohibited APS from proposing, before or in its next rate case, either a deferral of any unmitigated costs resulting from AG-X or collection of any unmitigated costs resulting from AG-X;

- Authorized APS to implement a new three-year program called AZ Sun II under which access to rooftop solar for low- and moderate-income residential customers (as well as non-profits that serve low- or moderate-income APS residential customers, Title I schools, and rural government customers) would be expanded by having APS purchase photovoltaic ("PV") solar generation systems, to be installed by competitively selected third-party solar contractors and interconnected to the distribution system, with APS owning the generation, renewable energy credits, and other attributes of the solar generation; with each participating residential customer receiving a monthly bill credit of $10 to $50; and with all reasonable and prudent costs[60] incurred by APS to be recoverable through the REAC until APS's next rate case;
- Required that APS propose annual direct capital costs of between $10 million and $15 million for AZ Sun II, with a carve out for residential installations, and allowed APS to request inclusion of the capital costs in rate base in its next rate case, at which time the capital costs would be reviewed for prudence;
- Prohibited APS from implementing any utility-owned residential solar DG programs other than AZ Sun II before its next general rate case;
- Required APS to fund its crisis bill program in the amount of $1.25 million annually and for the program to be available to customers with incomes lower than or equal to 200% of the federal poverty level ("FPL");
- Removed the LFCR opt-out rate option approved in Decision No. 73183, changed the LFCR recovery method from an equal percentage to a capacity (demand) charge per kW for customers on a demand rate and a kWh charge for customers not on a demand rate, and required LFCR compliance filings by February 15 and new LFCR rates to take effect in May (with Commission approval);
- Increased the cumulative per-kWh cap rate for the EIS; and

[60] The expenses eligible for recovery through the REAC included all operating and maintenance expenses, property taxes, marketing and advertising expenses, and the capital carrying costs of any capital investment made by APS through the program, with depreciation set at rates established by the Commission and the return on debt and equity set at the pre-tax weighted average cost of capital.

- Added a balancing account to the TCA and required that the annual TCA adjustment become effective on June 1 without Commission approval.

The Commission declined to adopt the Advanced Metering Infrastructure ("AMI") Opt-Out Program as included in the Settlement Agreement and instead bifurcated the issues surrounding the proposed AMI Opt-Out Program for resolution in a separate decision. Those issues were subsequently resolved in Decision No. 76374 (September 19, 2017),[61] which addressed positions taken by Mr. Gayer, Mr. Woodward, APS, and Staff concerning AMIs and the AMI Opt-Out Program; concluded that the AMI Opt-Out Program as set forth in Section 30 and Schedule M of the Settlement Agreement was in the public interest; and adopted Section 30 and Schedule M of the Settlement Agreement.

The additional proceeding concerning APS's recovery for its portion of the costs to install and operate the SCRs is discussed below in the section concerning the SCRs.

E. Champion Complaint Case, Rate Review Docket, & Customer Education & Outreach Program

On January 3, 2018, in Docket No. E-01345A-18-0002 ("Champion Complaint Case"), Stacey Champion, an APS residential customer, filed a formal complaint against APS in the form of a Change.org petition including her own name and those of 425 additional persons characterized as APS customers. The complaint referenced A.R.S. § 40-246(A), alleged that APS was in violation of a Commission order, and demanded a rate rehearing. (Decision No. 77292 (July 19, 2019).[62]) Ms. Champion's complaint was subsequently deemed amended through an additional filing. The amended complaint focused on the assertions made by APS and in Decision No. 76295 that the average residential rate increase resulting from the 2016 Rate Case would be 4.54% as well as APS's assertions that a significant majority of APS customers would save money on time- or demand-differentiated rates even without behavioral modifications and shifted usage.[63] Ms. Champion requested that the Commission hold a hearing to determine whether the real average bill impact on residential customers was greater than 4.54% and what effect that had on APS's revenue and the overall justness and

[61] Official notice is taken of this Decision.
[62] Official notice is taken of this decision.
[63] Mr. Gayer and Warren Woodward intervened in the Champion Complaint Case, with Mr. Gayer filing his own complaint therein. Mr. Gayer's First Amended Complaint was dismissed with prejudice, with no objection from Mr. Gayer, in Decision No. 77501 (December 17, 2019).

reasonableness of APS's rates approved in Decision No. 76295. A hearing was held concerning the amended complaint in late September and early October 2018. During the hearing, Abhay Padgaonkar appeared as an expert witness for Ms. Champion and provided testimony that, *inter alia*, the average base rate increase for residential customers under the new rates was 17.89%. Additionally, Ms. Champion and Mr. Gayer provided evidence and argument related to the impact of APS's adjustors on residential customer bills, due to increases in adjustors occurring close in time to the effective date of the new rates, and the lack of notice provided to customers concerning those adjustor increases. In its defense, APS presented evidence and argument to show, *inter alia*, that it had implemented the rates and charges approved in Decision No. 76295 in accordance with the decision, that it was not overearning, and that the fluctuations in collections within adjustor mechanisms have no effect on earnings (because revenues are not the same as earnings).

On January 9, 2019, in Docket No. E-01345A-19-0003 ("Rate Review Docket"), Staff, in response to a Commission directive, filed a memo opening a new docket for the purpose of conducting a rate review for APS,[64] to determine whether APS was over-earning based on a 2018 TY, and a review of the effectiveness of APS's Customer Education and Outreach Program ("CEOP") created after the 2016 Rate Case. (Ex. RUCO-14 at 1.) Ms. Champion intervened in the Rate Review Docket. After issuing a Request for Proposal ("RFP"), Staff hired Overland Consulting to assist it in performing the rate review audit. (*Id.* at 2.) Staff filed the final Report completed by Overland Consulting ("Overland Report") in the Rate Review Docket on June 4, 2019.[65] (*Id.*) On June 27, 2019, in the Rate Review Docket, the Commission issued Decision No. 77270,[66] finding, *inter alia*, that:

- The majority of the information communicated to customers in APS's CEOP was not reasonable and understandable;
- The CEOP had not explained adjustor mechanisms or that they would be updated annually and could result in increased bills;

[64] Official notice is taken of this filing.
[65] The final Overland Report was admitted in this matter as Exhibit RUCO-13 and is cited herein as the "Overland Report." On October 24, 2019, the Commission's Legal Division filed a Notice of Filing along with an unredacted copy of the draft Report created by Overland Consulting, which Staff had used in part to prepare the Overland Report, as well as copies of changes subsequently made by Staff and Overland. Official notice is taken of this filing.
[66] This decision was admitted herein as Exhibit RUCO-14.

- Fewer than anticipated medium- and large-usage customers had transitioned to demand rates, which could result in higher than anticipated revenues in future years;
- APS's new rate plans may have incentivized demand rates over basic rates and energy rates;
- Customers on their "most like" rate plan were less likely to be on their MEP;
- $6.7 million of gross margin in 2018 was associated with higher than expected revenues due to variances between the assumptions made in the billing determinants APS used in the 2016 Rate Case and actual 2018 billing determinants;
- There had been significant changes in customer billing determinants, customer growth, plant and infrastructure investments, and APS's embedded cost of debt; and
- A review of all the adjustor mechanisms in a rate case could lead to potential modifications.

In Decision No. 77270, the Commission adopted the following requirements:

- For APS to fund and implement a CEOP, to be developed and administered by Staff, to properly and adequately educate customers on all aspects of APS's rate plans, and for APS to pay for an independent consultant, selected and hired by Staff, to develop the CEOP;
- For APS to provide customers pro forma billing information based on their actual monthly usage and the customer's MEP, for each billing period over the past 12 months for each customer not on their MEP and on an ongoing basis for each month until the conclusion of APS's next rate case or further order of the Commission;
- For APS to explain thoroughly and quantify the impact of adjustor mechanisms on rates in its future rate cases;
- For APS to fund and organize, with assistance from an independent consultant, a stakeholder group to collaborate and suggest better ways to communicate the impact of changes and adjustor mechanisms to residential customers, including regarding rate plans and ways to reduce energy usage;
- For APS to provide customers an additional opportunity to switch rate plans during an enrollment period of at least six months;
- For APS to identify ratepayers whose bills increased by more than 9% under the new rate plans, based on 2015 TY determinants, and those ratepayers not on their MEPs, and provide those

ratepayers with targeted educational materials about rate plans, their current rate plan and MEP based on usage data, and the opportunity to switch plans;

- For APS to prepare and Staff to use a "bin analysis" to provide more meaningful notice of estimated bill impacts to customers;
- For APS to provide grandfathered net metered solar customers on legacy demand rates (ECT-1R, EPR, and ECT-2-EPR) targeted information about the legacy rate plans available and an opportunity to switch to another legacy rate plan that would enable them to benefit fully from net metering (E12, ET-1, or ET-2), with APS to make changes available until all such customers either transition to another legacy rate plan or confirm that they wish to remain on their existing demand rate;
- For APS to track and report quarterly, in the Rate Review Docket, the status of the CEOP, including stakeholder engagement, customer plan selection, and changes in customer usage patterns;
- For APS to prepare a metric to track the progress of residential customer rate plan conversions as compared to the assumed billing determinants used in the 2016 Rate Case;
- For APS to provide updated excess earnings data through June 2019 associated with higher than expected revenues due to the new rate designs adopted in the 2016 Rate Case;
- For APS to track and report quarterly, in the Rate Review Docket, the gross margins associated with the higher than projected revenues resulting from the variances between the assumptions made in the billing determinants in the 2016 Rate Case and actual 2018 billing determinants;
- For APS to file a new rate case application no later than October 31, 2019, using a 12-month TY ending on June 30, 2019; and
- For APS to file its 2017 expenditures as a supplemental report.

On July 19, 2019, in the Champion Complaint Docket, the Commission issued Decision No. 77292, finding that the evidence presented had not established (1) that APS had improperly implemented the rates and charges approved in Decision No. 76295, (2) that the projected 4.54% average residential bill impact had been calculated incorrectly, (3) that APS had failed to enact a CEOP or to expend $5 million on the CEOP as required by Decision No. 76295, (4) that APS was over-

earning; or (5) that the new rates established in Decision No. 76295 were unfair. The Commission also found that APS's CEOP may not have been effective in accomplishing its intended goal and that it was possible that APS was exceeding its authorized rate of return. Decision No. 77292 found that because Decision No. 77270, issued in the Rate Review Docket, had incorporated all of the recommendations contained in the Champion Complaint Docket ROO issued in April 2019, as amended at the Commission's May 2019 Open Meeting, it was reasonable and in the public interest to adopt the same directives in the Champion Complaint Docket. Decision No. 77292 ordered that the Rate Review Docket had adequately addressed the relief sought in the Champion Complaint Docket concerning the reasonableness of APS's rates and charges established in the 2016 Rate Case and the adequacy of the CEOP.

Subsequent to the issuance of Decision Nos. 77270 and 77292, and due to concerns about the inaccuracy of an online Rate Comparison Tool ("RC Tool 1") developed by APS as part of its 2016 Rate Case CEOP, and of the testing of a replacement Rate Comparison Tool ("RC Tool 2") performed by APS's hired contractor, the Brattle Group, the Commission directed Staff to hire a consultant to conduct an independent investigation of the development, implementation, and post-completion assessment of RC Tool 1 and RC Tool 2. (Ex. S-9 at 2.) This investigation, conducted by consultant energytools, llc, culminated in a report that was filed in the Rate Review Docket on August 20, 2020 ("EnergyTools Report"[67]). The EnergyTools Report determined, *inter alia*, that RC Tool 1 was tested adequately to ensure proper operation when launched; that there was no evidence to suggest that RC Tool 1 was providing inaccurate data when launched in August 2018; that an error was introduced into RC Tool 1 on February 4, 2019, when APS updated its meter data management system and integrated it with RC Tool 1, inputting incorrect TOU on-peak hours (2 p.m. to 7 p.m. instead of 3 p.m. to 8 p.m.); that if APS had tested RC Tool 1 again then as rigorously as it had initially, it would have detected the error; that APS's website did not fully log the data of users of RC Tool 1, making it impossible to assess how many customers used it and were influenced by it in selecting rate plans; and that the incorrect TOU hours caused RC Tool 1 to make incorrect MEP recommendations with a potential

[67] The EnergyTools report was admitted in this matter as an attachment ("exhibit 1") to Exhibit S-9 and is cited herein as the "EnergyTools Report."

cumulative value of $479,338. (EnergyTools Report at 10, 12-14, 26, 29-31, 40.) The EnergyTools Report also found that APS had removed RC Tool 1 from its website on November 14, 2019, at which time it was already developing RC Tool 2 in response to Decision No. 77270. (EnergyTools Report at 10.) APS made RC Tool 2 available on its website on January 29, 2020. (*Id.* at 34.) RC Tool 2 uses a customer's actual billing usage and information from APS's billing system to calculate the customer's MEP. (*Id.*) The EnergyTools Report concluded that the Brattle Group's analysis of RC Tool 2 had been appropriate and that RC Tool 2 had an accuracy level of 99.98%. (EnergyTools Report at 14, 38-40.)

Also subsequent to the issuance of Decision No. 77270, in the Rate Review Docket, Staff hired, at APS expense, an independent consultant to create a CEOP. On May 19, 2020, a report by Barbara R. Alexander of Barbara Alexander Consulting LLC, entitled "An Evaluation of Arizona Public Service Company's Customer Education Plan and Its Implementation" ("Alexander Report") was filed in the Rate Review Docket.[68] The Alexander Report "identifie[d] the shortcomings" of APS's CEOP but recommended that the Commission and Staff not develop or implement a CEOP but instead order APS to create and propose a CEOP providing education concerning rate design options, limited income programs, DSM programs, and consumer protection rights and remedies to ensure retention of essential electricity service. (Ex. RUCO-15 at 36.) The Alexander Report asserted that the new CEOP should address all the "many deficiencies" in the prior CEOP, as identified in the Alexander Report, especially concerning ongoing customer research and feedback mechanisms, and that the Commission should require APS to include performance standards and reporting mechanisms so that APS's progress in implementing the CEOP and achieving the goals and objectives of the CEOP can be meaningfully and regularly reviewed. (*Id.*) The Alexander Report identified minimum performance standards to be measured and reported on quarterly; recommended that the future CEOP be developed with substantive consumer stakeholder involvement; recommended that the future CEOP be the subject of a formal review process with hearing opportunity if substantive disagreements could not be resolved collaboratively; and suggested that the Commission regularly consider whether the number and

[68] The Alexander Report was admitted in this matter as an attachment to Exhibit S-11 and separately as Exhibit RUCO-15. It is cited herein as the "Alexander Report."

complexity of residential rate plans, especially those with demand charges, should be simplified, based on customer feedback and the actual impact of the plans on reducing peak usage or contributing to lower cost generation supply. (*Id.* at 36-37.)

In response to the Alexander Report, APS hired Guidehouse Inc. ("Guidehouse") to review and analyze the Alexander Report and advise APS of improvements to consider for future customer education and outreach efforts. (Ex. APS-23 at 16-17.) Guidehouse prepared a report entitled "Review of the 2017 Customer Education and Outreach Plan & Response to the Plan," dated November 2, 2020 ("Guidehouse Report").[69] The Guidehouse Report "identified a few minor inaccuracies or mischaracterizations in the Overland Report." (Guidehouse Report at 20.) Specifically, the Guidehouse Report concluded that the Overland Report's list of Spanish-language marketing materials was incomplete; that no customers were moved to a rate plan with a demand component unless they were already on a rate plan with a demand component; and that customers were not moved to new, differently structured rate plans during the rate transition. (*Id.* at 21-22.) The Guidehouse Report also examined the Alexander Report's findings, "provide[d] counterpoints . . . in many areas," and explained Guidehouse's opinion that it was inappropriate to compare the best practices identified in the Alexander Report with APS's CEOP. (*Id.* at 23-24.) The Guidehouse Report made a number of clarifications to statements made in the Alexander Report. (*Id.* at 24-27.) The Guidehouse Report also disagreed with a statement in the Alexander Report about flat rate customers being moved to a time of use ("TOU") or demand rate due to strict annual usage limitations associated with service under flat rate options, countering that customers could not be involuntarily moved to demand rates during the rate transition or during the annual rate reassignment process and that customers could not be moved to TOU rates for the first time as part of the rate transition, but acknowledging that the statement might be a reference to the annual rate reassignment process that could result in a customer being moved to a TOU rate if the customer were no longer eligible for a basic rate due to electricity consumption over the prior 12-month period. (*Id.* at 24-25.) The Guidehouse Report also disagreed with two statements concerning APS's reliance on its experience explaining demand rates when they were voluntary and

[69] The Guidehouse Report, admitted herein as attachment MW-03RB to Exhibit APS-23, is cited herein as the "Guidehouse Report."

not including in the CEOP specific messages or educational content to explain demand rate plans or how to explain the rate-specific criteria to move customers to those plans. (*Id.* at 26.) In response, the Guidehouse Report stated that demand rates remain voluntary, that APS did not involuntarily move any customer to demand rates, that it was appropriate for APS to rely on its experience with voluntary demand rates, and that APS included educational content to explain the demand rates throughout the CEOP implementation. (*Id.*) In addition to its criticisms of the Alexander Report, the Guidehouse Report also stated that the Alexander Report includes "valuable recommendations . . . that should not be dismissed." (*Id.* at 24.) The Guidehouse Report provided a number of recommendations for APS for a multi-year customer engagement initiative with both long-term goals and objectives and near-term goals and objectives related to the outcome of this matter. (*Id.* at 67-69.)

F. Current Rate Plans & Rate Riders

1. Rate Plans

APS provides service and organizes its rate plans and rate riders under three classifications: Residential Service, General Service, and Classified Service. Residential Service is provided to residential dwelling units, generally with a separate meter for each dwelling unit and with restrictions on the use of property for business, professional, or other gainful purposes. (Ex. APS-53.) General Service is provided to any establishment for any purpose not prohibited by the rate schedule or agreement for service, with all electric service required on the premises to be taken through one meter at one point of delivery, or through separately metered and billed multiple points of delivery. (*Id.*) General Service may also be used alongside Residential Service or Classified Service at a property, for that portion of the property's usage that is not eligible for Residential Service or Classified Service. (*Id.*) Classified Service is provided to a Customer when the Customer's operations, due to the nature and load characteristics, are eligible for a specific rate schedule created for that type of operation. (*Id.*)

Currently, APS's eligible non-DG residential customers may select service under two separate tariffs that charge a daily basic service charge ("BSC")[70] and a charge per kWh ("energy charge")—R-XS (annual monthly usage ≤600 kWh) and R-Basic (annual monthly usage of 601-999 kWh)—both of

[70] All of APS's BSCs are expressed as a daily rather than a monthly rate.

which are subject to annual reassignment based on annual monthly usage. (Ex. APS-53.) R-Basic customers are also required to stay on the tariff for at least 12 months, and new APS customers are ineligible for R-Basic for their first 90 days of service. (*Id.*) Any APS residential customer may select service under TOU-E, which has a BSC, on-peak and off-peak energy charges (lower in winter), a summer[71] on-peak period of weekdays from 3 p.m. to 8 p.m., a winter super off-peak period of weekdays from 10 a.m. to 3 p.m., and a Grid Access Charge for DG customers based on the nameplate kW-dc of generation. (*Id.*) Any APS residential customer may also select service under R-2 or R-3, each of which has a BSC, on-peak and off-peak energy charges (lower in winter), and on-peak charges per kW ("demand charges"). (*Id.*) The on-peak demand charges for R-2 and R-3 are calculated using the highest amount of demand (kW) averaged in a one-hour on-peak period each month, and the on-peak periods are weekdays from 3 p.m. to 8 p.m. (*Id.*) The on-peak demand charge on the R-3 tariff is lower in winter than in summer. (*Id.*) Under both R-2 and R-3, non-DG customers (i.e., "full requirements customers") have the kW used to calculate their billed demand charge each month capped at the kW that would result in a 15% load factor for the month based on monthly kWh usage. (*Id.*) This demand charge cap does not apply to DG customers. (*Id.*) Residential customers with certain qualifying on-site technologies (such as a recently installed rooftop solar photovoltaic ("PV") system, an electric car, or some combination of technologies) may select service under the R-Tech Pilot tariff, which has a BSC, on-peak and off-peak energy charges (on-peak is lower in winter), an on-peak demand charge (lower in winter), and an off-peak demand charge that applies for demand >5kW. (*Id.*) The on-peak period is weekdays from 3 p.m. to 8 p.m., and demand charges are calculated using the highest amount of demand (kW) averaged in a one-hour on-peak and off-peak period each month. (*Id.*)

In addition to the residential tariffs available for new selection, APS continues to provide service under a handful of residential tariffs that are no longer available to be newly selected: R-Basic Large, which was available to customers with annual monthly energy usage ≥ 1,000 kWh, has a BSC and an energy charge, was not available to DG customers, and was frozen in 2018, and five separate legacy DG rates (Legacy E-12, Legacy ECT-1R, Legacy ECT-2, Legacy ET-1, and Legacy ET-2).

[71] For APS's seasonal rates, summer is May-October, and winter is November-April. (Ex. APS-53.)

(*Id.*)

For general service customers, APS has E-30, which has a BSC and energy charge and requires a constant level of demand or energy within a specific range and an unmetered single point of delivery; E-32 XS, which has a BSC and energy charges (lower in winter), an eligibility requirement based on average summer monthly maximum demand (one-hour period), and is subject to annual reassignment; E-32 XS D, E-32 S, E-32 M, and E-32 L, which have BSCs, energy charges (lower in winter), demand charges, eligibility requirements based on average summer monthly maximum demand (one-hour period for E-32 XS D and 15-minute periods for the others), and are subject to annual reassignment; E-32 TOU XS, E-32 TOU S, E-32 TOU M, and E-32 TOU L, which have BSCs, on-peak (from 3 p.m. to 8 p.m. weekdays) and off-peak energy charges (lower in winter), demand charges, eligibility requirements based on average summer monthly maximum demand (one-hour period for E-32 TOU XS and 15-minute periods for the others), and are subject to annual reassignment; E-34 ("Extra Large General Service"), which has a BSC, an energy charge, a demand charge, and an eligibility requirement based on monthly maximum demand for three consecutive months over the prior 12 months; and E-35 ("Extra Large General Service Time of Use"), which has a BSC, on-peak and off-peak energy charges, an on-peak period of 11 a.m. to 9 p.m. weekdays, a demand charge, and an eligibility requirement based on monthly maximum demand for three consecutive months over the prior 12 months; and XHLF ("General Service Extra High Load Factor", which has a BSC, a demand charge based on the average kW supplied during the 15-minute period of maximum use during the billing period, an energy charge, an eligibility requirement based on monthly maximum demand and load factor, and optional Economic Development and Sustainability features for those who demonstrate a 50% carbon-free commitment. (*Id.*) E-32 L, E-32 TOU L, and E-34 all have provisions that the kW (on-peak kW if applicable) used for billing will be the greater of the average kW supplied during the 15-minute period of maximum use during the month (in on-peak periods if applicable), or 80% of the highest kW (on-peak kW if applicable) measured during the six summer billing months of the 12 months ending with the current month, or the minimum kW specified in the agreement for service or individual contract ("demand ratchets"). (*Id.*) E-35 also has a demand ratchet, but its on-peak kW for billing is based on the greater of the average kW supplied during the 15-minute period of maximum use during the billing period or

80% of the highest on-peak kW measured during the six summer billing months of the 12 months ending with the current month, and its off-peak kW for billing is based on the average kW supplied during the 15-minute period of maximum use during off-peak hours. (*Id.*)

APS also has classified rates including E-32 L SP (a pilot), E-36 XL, E-47 and E-58 (both Dusk to Dawn Lighting), E-59 and E-67 (government-owned street lighting and City of Phoenix public area lighting, respectively), E-221 and E-221-8T (water pumping), and GS Schools M and L. The E-20 tariff (Churches) was frozen in 2013 and has a BSC, on-peak and off-peak energy charges, an on-peak period of 11 a.m. to 9 p.m. weekdays, and a demand charge based on the 15-minute period of maximum use.

2. Rate Riders

APS has a number of rate riders that are available for new enrollment by residential customers:[72]

- CPP-RES ("Critical Peak Pricing – Residential") is available to residential customers who can reduce their energy usage when called upon to do so, has 6-18 Critical Peak Pricing ("CPP") events per year (five hours each, in the summer, between 3 p.m. and 8 p.m. weekdays, with advance notice the day before), and results in a CPP hours energy charge surcharge and an energy charge discount for summer non-CPP hours.
- E-3 ("Energy Support Program") is available to those with gross monthly household income at or below 150% of the Federal Poverty Level ("FPL") and provides a 25% pre-tax discount per bill.
- E-4 ("Medical Care Equipment Support") has the same income eligibility requirement as E-3, also requires that the customer need qualifying life-sustaining medical equipment, and provides a 35% pre-tax discount per bill.
- GPS-1, GPS-2, and GPS-3 are available to customers who want to purchase energy generated from renewable sources ("Green Power"), either in blocks or as a set percentage of total kWh usage (depending on the rider), and impose an energy charge surcharge per kWh of Green Power.

[72] Ex. APS-53.

- RCP ("Partial Requirements Service for New On-Site Solar DG Resource Comparison Proxy Export Rate") is available to customers with qualifying on-site PV generation served under an applicable residential rate, pays the RCP rate for exported energy, establishes the RCP rate applicable for 10 years from the annual tranche assigned based on interconnection application timing, limits RCP rate reduction year-over-year to 10% for each new tranche, and provides for the bill credit to apply after 10 years.
- EPR-6 is available to customers (residential and non-residential) who have on-site renewable DG systems (which for residential customers cannot be interconnected PV systems); provides for net metering of energy exported to the grid; and provides a monetary bill credit, at the rate of $0.02895/kWh, after the December bill for any export energy that has not already been netted on a bill during the year.

APS also has several rate riders that are, at least theoretically, available for new enrollment by general service customers:[73]

- AG-X ("General Service Alternative Generation") is APS's buy-through tariff, and allows customers served under E-34, E-35, E-32 L, or E-32 TOU L (or an aggregated group including metered accounts served under E-32 M or E-32 TOU M, if the accounts are on the same premises and under the same name) and who have an aggregated peak load of 10 MW or more to purchase wholesale power from Generation Service Providers ("GSPs"), which is delivered to APS at the Palo Verde hub or another point of delivery agreed to by APS. The total enrollment for AG-X is limited to 200 MW of customer load. The AG-X customer's applicable retail rate schedule continues to apply, but the AG-X customer is exempted from generation charges, the PSA adjustor, and the EIS adjustor, and taxes or governmental impositions are applied proportionately. AG-X customers are required to pay APS an administrative fee of $0.00180/kWh, applied to all billed kWh, and a reserve capacity charge of $5.5398/kW applied to 100% of billed kW (or to on-peak kW for E-32 TOU L and E-35). Under AG-X, APS contracts with the GSP for the delivery of "firm power" sufficient to meet the customer's total

[73] Ex. APS-53.

load requirements, with "firm power" meaning generation resources identified in Western System Power Pool ("WSPP") Schedule C or a reasonable equivalent as determined by APS, and the GSP is responsible for transmission costs to the point of delivery and to bill APS monthly for each customer for generation service and imbalance service. A GSP's contract must provide for generation service charges that fall within a specified range—if the contract pricing is based on a specific index price, the charge must fall within 35% under and 35% over that index price; if the contract pricing is fixed for the contract term, the charge must fall within 35% under and 35% over the customer's applicable retail rate schedule generation rate. APS enters into contracts with both the GSP and the customer and is required to provide transmission, delivery, and network services to the customer; to settle with the GSP for imbalance service and other costs on a monthly basis; to bill the customer for the GSP's charged amounts; and to remit the customer's payments to the GSP. APS is also required to serve as the scheduling coordinator, and the GSP is required to provide APS monthly schedules of hourly loads along with day-ahead hourly load deviations from the monthly schedule. APS provides imbalance service according to set terms and provisions, including for financial penalties to be paid by GSPs based on the extent to which the power delivered by the GSP deviates from the schedule. If a GSP is unable to meet its contractual obligations, the customer is required to notify APS and select a replacement GSP within 60 days. Additionally, APS may terminate a GSP for excessive imbalances, and if that occurs, the customer must secure a replacement GSP within 60 days. During the interim period when the customer has no GSP, APS must provide power to the customer at the Palo Verde Peak or off-peak Intercontinental Exchange day-ahead power prices, plus $10/MWh, or at the customer's applicable retail rate. A GSP or its parent company is required to have at least an investment grade credit rating or to demonstrate creditworthiness in another specified manner. An AG-X customer must provide at least 12 months' notice to leave AG-X and, if automatically returned to standard generation service due to failure to select a replacement GSP, will be charged for power as during the interim period described above until 12 months has been reached. APS is prohibited from proposing a deferral of any unmitigated costs resulting from AG-X and from seeking recovery

of any unmitigated costs from AG-X in its rate case, but AG-X is to be reevaluated in the rate case.

- CPP-GS is available to customers on E-32 M, E-32 L, E-32 TOU M, E-32 TOU L, E-34, E-35, and E-221 and is similar in design to CPP-RES.
- EPR-6 is described above because it is also available to residential customers.
- IRR ("Extra Large General Service Interruptible Rate Rider") is available to customers on E-34 or E-35, if they are not participating in other demand response programs, and allows a customer to choose to be subject to up to 80 hours of uninterrupted service (in two-hour or four-hour events) between noon and 8 p.m. in the summer months, with brief notice provided (either 30 minutes or two hours before), and a guarantee of at least two events per year, in return for a capacity credit and energy credit annually for interrupted demand and energy reduction during events (with the rates based on the options selected).
- PPR ("Preference Power Rider") is for retail customers who have been awarded hydro power from a federal dam, and it provides a credit per kWh based on the preference power allotment capacity, with higher credits for lower capacity allotments.
- SD-1 ("School Discount") is available to all public elementary and secondary schools served under E-32 XS, E-32 S, E-32 M, E-32 L, E-32 TOU XS, E-32 TOU S, E-32 TOU M, E-32 TOU L, GS-Schools M, and GS-Schools L, and provides a discount of $0.0024/kWh per month.

APS also has several rate riders that are available for new enrollment by classified service customers:[74]

- EPR-2 is applicable to a customer with an interconnected qualifying on-site cogeneration or small power production facility with a generating nameplate capacity ≤100 kW-ac, and it provides the customer credits for export energy at a firm rate[75] or non-firm rate, with variances based on peak periods and seasons.
- E-56 is applicable to a customer with interconnected qualifying on-site generation equipment

[74] Ex. APS-53.

[75] For purposes of EPR-2, "Firm Power is power available, upon demand, at all times (except for forced outages) during the period covered by the Purchase Agreement from the Customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources." (Ex. APS-53.)

with a continuous nameplate rating of ≥100 kW for other than emergency purposes and who require Supplemental and Back-up or Maintenance Power and energy from APS; it requires customers to pay, in addition to applicable regular rate schedule charges, back-up power charges per kW/day (with variations based on peak and rate schedule or whether during scheduled maintenance) and excess power charges per kW when power taken exceeds contracted demand.

- E-56R is applicable to a Customer with an on-site Qualifying Renewable Facility that requires Supplemental and Standby Power and energy from APS and that may have Excess Generation, and it provides for supplemental demand and energy to be billed per the customer's retail rate schedule, standby service and standby energy charges based on the customers' retail rate schedule, and APS purchase of excess generation at the applicable per kWh seasonal non-firm purchase rate provided in EPR-2.

G. Current APS Adjustors/Surcharges & Revisions Since Decision No. 76295

1. Power Supply Adjustment Mechanism ("PSA")

The PSA was originally approved for APS in Decision No. 67744,[76] to collect fuel and purchased power costs exceeding the base fuel costs included in base rates. The PSA compared one year of actual historical fuel and purchased power costs with the actual fuel and purchased power costs recovered through base rates and collected/refunded the difference over the next year through an adjustor mechanism set once a year. (Ex. APS-76 at 107-108.) The PSA was significantly modified from its original form in Decision No. 69663, by increasing the base cost of fuel and purchased power to $0.032941 per kWh, incorporating a forward-looking cost of fuel and purchased power based on projected costs expected to be experienced while the PSA is in effect, modifying the 90/10 sharing

[76] Decision No. 67744 noted that Decision No. 61973 (October 6, 1999) had adopted a settlement requiring APS to request, and the Commission to approve, a "power supply adjustor" mechanism to recover the cost of providing power for standard offer and/or provider of last resort customers and, further, that Decision No. 66567 (November 18, 2003) had approved the concept of a purchased power adjustor ("PP Adjustor") to include purchased power costs but not the cost of fuel and had noted that the PP Adjustor approved therein could be modified or eliminated in the rate case that led to Decision No. 67744. In Decision No. 67744, the Commission modified the PSA as included in the settlement agreement reached in that case to provide additional protections to ratepayers.

requirement to exclude certain costs,[77] eliminating a $776.2 million lifetime total fuel cost recovery cap, replacing a $0.004 ("four mill") lifetime cap with a four mill annual cap, and eliminating the requirement for mandatory PSA surcharge applications when deferrals reach $100 million.[78] (Ex. APS-76 at 62-63, 67-68, 105-113, 147-148.) Additionally, E-3 program participants were exempted from PSA charges. (*Id.* at 100.)

The PSA year begins on February 1 and ends on the next January 31. (Ex. APS-76 at 109.) APS submits a PSA rate filing on or before September 30 of each year that calculates the PSA rate and provides supporting information. (Ex. APS-76 at 109.) APS then makes a supplemental filing by December 31 to replace estimated balances with actual balances. (*Id.* at 109.) The PSA rate is determined using three components: (1) the Forward Component, which recovers or refunds differences between the expected PSA Year costs and those embedded in base rates; (2) the Historical Component, which tracks the differences between the actual PSA Year costs and the costs recovered through base rates and the Forward Component and provides for their recovery during the next PSA Year; and (3) the Transition Component, which provides for refund/recovery of balances arising under the old PSA, an opportunity to seek mid-year change in the PSA rate when cost variances are very large, and tracking of balances resulting from the Transition Component to provide a basis for their refund or recovery. (*Id.* at 108-109.)

The PSA was subsequently modified in Decision Nos. 71448, 73183, and 76295. (Ex. APS-53 at PSA POA.) In Decision No. 71448, the PSA base cost of fuel and power increased to $0.037571 per kWh, and the PSA was adjusted to allow gains on sulfur dioxide ("SO_2") allowances over or under the normalized jurisdictional TY amount in base rates ($7.045 million) to be recovered/refunded through the PSA, to allow for accelerated reset to correspond with the effective date of new rates, and to increase the amount of fuel costs recovered in base rates rather than the PSA. (Decision No. 71448

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[77] The newly excluded costs included the fixed or demand element of long-term purchase power agreements acquired through competitive procurement and the costs of renewable energy purchases not otherwise recoverable through APS's EPS/REST mechanism. (Ex. APS-76 at 106-107.)

[78] Staff's recommendations for changes to the PSA were due to substantial under-collections in 2005-2006, which had caused concern and threats of credit rating downgrades from rating agencies. (Ex. APS-76 at 108.) As part of the rate case resulting in Decision No. 69663, Staff engaged The Liberty Consulting Group to conduct an examination and audit of the management and operations of APS's fuel and purchased power functions, including PSA costs. (Ex. APS-76 at 101-105.) The findings were generally favorable. (*See id.*)

at 9, 17, 22, 45, 56, 60.)

In Decision No. 73183, the PSA base cost of fuel and power decreased to $0.032071 per kWh, and the PSA was modified by eliminating the 90/10 sharing provision, requiring the application of different annual interest rates for over- and under-recoveries,[79] subjecting APS to periodic fuel and power procurement audits by Staff-selected consultants funded by APS in amounts of up to $100,000 per audit; and eliminating the exclusion of E-3 customers from the application of the PSA.[80] (Decision No. 73183 at 12, 16, 25, 42.) Additionally, the docket was held open to allow APS to seek to amend the PSA Plan of Administration ("POA") to reflect inclusion of Federal Energy Regulatory Commission ("FERC") Account 509 to allow APS to offset the cost of carbon dioxide ("CO_2") allowances needed for off-system sales to California against revenues received from such sales as recorded in FERC Account 509.[81] (*Id.* at 47.) APS was also required to file with its yearly PSA filings (through 2015) information concerning what the impact of the 90/10 sharing would have been had it been retained. (*Id.* at 48.)

In Decision No. 76295, the PSA base fuel rate was decreased to $0.030168 per kWh and the PSA was modified to allow APS to include chemical costs incurred in the generation process for lime, ammonia, and sulfur;[82] to include third-party storage expenses, provided that APS files for approval to include any third-party storage contract 90 days before it becomes effective; and to consolidate the September 30 annual PSA rate filing and the December 31 annual PSA rate filing into a single annual PSA reset filing to occur on or before November 30, with the PSA rate to become effective February 1 unless the Commission otherwise acts on the APS PSA rate calculation before that time. (Ex. APS-

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[79] APS must pay annual interest at the end of the PSA year for over-collected amounts at the authorized ROE or then-existing short-term borrowing rate, whichever is greater, and the amount must be refunded to customers over the next 12 months. (Decision No. 73183 at ex. A at 8.) If APS has under-collected, interest is to accrue at the authorized ROE or then-existing short-term borrowing rate, whichever is lower, and is to be recovered over the next 12 months. (*Id.* at ex A at 8-9.) Additionally, APS was authorized to request to reduce the PSA rate at any time during the PSA year. (*Id.* at ex. A at 9.)

[80] Low-income customers were also newly required to pay the DSMAC; this was presented as a bill simplification method that would not result in a bill impact to low-income customers because a discount was to be applied to the total bill. (Decision No. 73183 at 16.) It also allowed low-income customers to benefit from the credits that could result from the PSA. (*Id.* at 20, 38.) The Decision also approved a delay in the reset of the existing PSA. (*Id.* at 26.)

[81] The PSA POA was amended in Decision No. 73650 (February 6, 2013), of which official notice is taken, to allow recovery of the cost of CO_2 allowances incurred to make off-system sales when it is economical to incur the costs in making the short-term off-system sales.

[82] Decision No. 76295 established the base cost for these environmental chemicals at $0.000500 per kWh. (Ex. APS-70 at ex. A at app. C.)

70 at ex. A at 10-11.) Decision No. 76295 also established that the base net margins on the sale of SO_2 emission allowances was ($0.000001) per kWh. (Ex. APS-70 at ex. A at app. C.) Additionally, PSA mitigation for the resale of capacity and energy displaced by AG-X was established at $1.25 million per month of off-system sales margins to be excluded from the PSA. (*Id.* at ex. A at 22-23.) The purpose of the PSA mitigation mechanism is to eliminate or mitigate any unrecovered costs resulting from the AG-1/AG-X buy-through programs. (Decision No. 73183 at 30.)

As described by Mr. Snook, the PSA passes through the actual cost of fuel and purchased power, along with any profits APS receives from wholesale power sales. (Ex. APS-28 at 20.) The PSA rate is applied as a monthly kWh charge that is the same for all customer classes to which it applies,[83] and annual changes in the PSA rate are capped at plus or minus 4 mill per kWh unless the Commission provides express approval for a greater amount. (Ex. APS-53 at PSA POA.) For 2018 through 2020, the PSA rate changed as follows:

February 1, 2018	February 1, 2019	February 1, 2020
$0.004555 per kWh[84]	$0.001658 per kWh[85]	($0.000457) per kWh[86]

On November 30, 2020, APS filed its annual update to its PSA rate, proposing a PSA rate of $0.003544 per kWh, to become effective February 1, 2021.[87] On February 12, 2021, APS filed a letter voluntarily delaying implementation of the PSA increase to the first billing cycle of April 2021, at which time, APS stated, it would implement a PSA increase of four mill per kWh; APS stated that it was delaying implementation due to the ongoing COVID-19 pandemic.[88] On March 11, 2021, in response to a letter filed by Commissioner Jim O'Connor, Staff filed a Memorandum including three potential options for implementing APS's 2021 PSA.[89] The issue was included on the Commission Open Meeting Agenda for March 23 and 24, 2021, and the Commission voted to allow APS to

[83] The PSA Rate currently applies to APS's retail electric rate schedules except for E-36 XL, AG-X, and Direct Access service. (Ex. APS-53 at PSA POA.)
[84] Official notice is taken of APS's November 30, 2017, filing made in the 2016 Rate Case.
[85] Official notice is taken of APS's November 30, 2018, filing made in the 2016 Rate Case.
[86] Official notice is taken of APS's November 27, 2019, filing made in the 2016 Rate Case.
[87] Official notice is taken of this filing made in the 2016 Rate Case.
[88] Official notice is taken of this filing made in the 2016 Rate Case.
[89] Official notice is taken of this filing made in the 2016 Rate Case.

implement half of the 4 mill PSA rate increase in April 2021 and the remainder of the 4 mill PSA rate increase in November 2021.[90] Additionally, the Commission directed Staff to engage an independent third-party consultant to conduct an audit of APS's 2020 and 2021 fuel costs. Decision No. 77959, memorializing the Commission's vote, was issued on April 15, 2021.[91] Thus, APS's approved PSA rates are as follows:

Effective April 2021	Effective November 2021
$0.001544/kWh	$0.003544/kWh

2. Environmental Improvement Surcharge ("EIS")

The EIS was originally approved for APS in Decision No. 69663 (June 28, 2007)[92] as a surcharge (as opposed to an adjustor mechanism) through which APS would collect from ratepayers the funds needed to pay for government-mandated environmental controls. Decision No. 73183 modified the EIS by making it an adjustor mechanism allowing APS to recover capital carrying costs incurred for such investments. (Decision No. 73183 at ex. A at 16, att. H.) Decision No. 76295 modified the EIS by increasing the per kWh cap rate from $0.00016 to $0.00050 and adding a balancing account. (See Ex. APS-53 at EIS POA; Ex. APS-70 at ex. A at 28.) The EIS recovers the capital carrying costs effect of actual plant investments designed to comply with environmental standards established by federal, state, tribal, or local laws or regulations and is imposed on a per kWh basis. (Ex. APS-53 at EIS POA.) APS is required to file its calculated EIS rate for the prior year by February 1 annually, and the EIS rate goes into effect with the first April billing cycle unless the Commission otherwise acts or Staff files an objection before that time. (*Id.*) Since Decision No. 76295, the EIS rate has changed as follows:

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[90] Official notice is taken of the discussion and vote that occurred at the Commission's Open Meeting on March 24, 2021.
[91] Official notice is taken of this decision.
[92] The EIS was adopted instead of an APS-proposed Environmental Improvement Charge adjustor mechanism and originally authorized APS to collect a surcharge of $0.00016 per kWh from all standard offer customers (except those on Schedules SP-1, GPS-2, and Solar-2) beginning on July 1, 2007; required APS to deposit the EIS funds in a separate interest-bearing account; authorized APS to use the funds only for funding environmental improvements; required that the EIS account balance be considered a regulatory liability and funds drawn therefrom be considered Contributions in Aid of Construction; and required a compliance filing each August in the 2005 Rate Case Docket. (Ex. APS-76 at 86.)

April 1, 2019	May 1, 2020	April 1, 2021
$0.000253 per kWh[93]	$0.000329 per kWh[94]	$0.000365 per kWh[95]

3. Transmission Cost Adjustment ("TCA")

The TCA was originally approved for APS in Decision No. 67744, to ensure that potential direct access customers would pay the same amount for transmission as standard offer customers do, and was limited to recovery/refund of costs associated with changes in APS's Open Access Transmission Tariff ("OATT") approved by FERC, or equivalent tariff; the TCA was not to take effect until the transmission component of retail rates exceeded $0.000476 by 5% and APS obtained Commission approval of a TCA rate. (Decision No. 67744 at 28-29, ex. A at 21.) The TCA was revised in Decision No. 73183 to allow annual TCA adjustments to become effective without affirmative Commission approval unless Staff requests review or the Commission orders otherwise. (Decision No. 73183 at 33, 46, ex. A at 17, att. I.) The TCA allows APS to recover the net difference between the transmission charges embedded in APS's base rates and APS's OATT rates, which are adjusted annually by FERC using a formula rate. (See Decision No. 72430 (June 27, 2011)[96] at 2, 5-6; Ex. APS-28 at 20; Ex. APS-53 at TCA POA.) For all standard offer residential and some standard offer general service customers (20 kW or less), the TCA is applied as a monthly charge per kWh; for all other standard offer customers, it is applied as a monthly kW charge. (Ex. APS-53 at TCA POA.) APS is required to file its calculated TCA rates by May 15 each year, and they are to go into effect with the first billing cycle in June unless Staff requests review or the Commission otherwise orders. (*Id.*) The TCA has a balancing account. (*Id.*)

On May 15, 2019, APS filed its TCA calculations with supporting data for TCA charges to go

[93] Official notice is taken of APS's February 1, 2019, filing made in the 2016 Rate Case.
[94] Official notice is taken of APS's January 31, 2020, filing made in the 2016 Rate Case, and of APS's March 19, 2020, Notice of Thirty-Day Suspension filing made in the 2016 Rate Case, in which APS stated that due to the COVID-19 pandemic, APS would hold the increase of the EIS adjustor in abeyance for 30 days so that it would become effective with the first billing cycle in May 2020.
[95] Official notice is taken of the APS filing regarding adjustment of the EIS made on February 1, 2021, and the Staff Notice of Compliance filing for approval of the EIS tariff made on April 6, 2021, in the 2016 Rate Case.
[96] Official notice is taken of this decision,

into effect with the first billing cycle in June 2019 and to remain in effect through May 2020.[97] APS's calculations resulted in reduction to the TCA charges for residential customers, general service customers between 20 kW and 2,999 kW, and general service customers at or over 3,000 kW and an increase to the TCA charges for general service customers at or lower than 20 kW. APS projected that the revised TCA rates would increase overall annual retail revenues by approximately $4.9 million.

On May 15, 2020, APS filed its TCA calculations with supporting data for TCA charges to go into effect with the first billing cycle in June 2020 and to remain in effect through May 2021.[98] APS's calculations resulted in reduction to the TCA charges for residential and general service customers, with the TCA charges for all general service customers over 20 kW becoming negative. APS projected that the revised TCA rates would decrease overall annual retail revenues by approximately $7.4 million.

On May 14, 2021, APS filed its TCA calculations with supporting data for TCA charges to go into effect with the first billing cycle in June 2021 and to remain in effect through May 2022.[99] APS's calculations resulted in reduction to the TCA charges for residential and general service customers, with the TCA charges for all general service customers becoming negative. APS projected that the revised TCA rates would decrease overall annual retail revenues by approximately $28.4 million.

4. Lost Fixed Cost Recovery Mechanism ("LFCR")

The LFCR was originally approved in Decision No. 73183, to allow APS to recover certain documented and verified fixed costs unrecovered due to reduced volumetric sales caused by Commission-approved energy efficiency ("EE") and DG programs, as a means of removing APS's disincentive to invest in EE and DG programs because they reduce sales, and included both a balancing account and an annual cap on changes of 1% of applicable APS revenues (with amounts in excess of the 1% deferred for later recovery). (Decision No. 73183 at 21-23, 38, 40, 45, ex. A at 10-12.) The LFCR was assessed as a percentage of the customer's monthly bill or, if a customer opted out of the regular LFCR, as a flat charge daily rate based on consumption. (*Id.* at ex. A at att. E, att. F.) The LFCR was modified in Decision No. 74202 (December 3, 2013)[100] to include an interim LFCR DG

[97] Official notice is taken of this filing made in the 2016 Rate Case.
[98] Official notice is taken of this filing made in the 2016 Rate Case.
[99] Official notice is taken of this filing made in the 2016 Rate Case.
[100] Decision No. 74202 was admitted as Exhibit APS-69.

adjustment of $0.70 per kW per month, charged to new residential DG customers on or after January 1, 2014, to address the cost shift from APS's residential DG customers to APS's residential non-DG customers due to increased residential rooftop solar installations.[101] (Ex. APS-69 at 23-24, 26-27.)

The LFCR was modified in Decision No. 76295 by eliminating the LFCR opt-out provision; making the LFCR a charge per kW for customers on a demand rate and a charge per kWh for customers not on a demand rate; requiring APS to make its LFCR compliance filings on February 15 each year (instead of January); and to have the new LFCR rates take effect, upon Commission approval, in the first May billing cycle. (See Ex. APS-70 at ex. A at 27-28.) Since Decision No. 76295, the LFCR rates have changed as follows:

Effective Date	March 2019	July 2019	May 2020
Demand Rate	$0.838 per kW	$0.511 per kW	$0.372 per kW
Non-Demand Rate	$0.00288 per kWh	$0.00172 per kWh	$0.00125 per kWh
Decision Approving LFCR Rates	Decision No. 77089 (February 20, 2019)[102]	Decision No. 77280 (July 10, 2019)[103]	Decision No. 77605 (April 22, 2020)[104]

On February 15, 2021, APS filed its annual application for LFCR rate adjustment, requesting an increase in the LFCR rate for customers on a demand rate to $0.509 per kW per month and for customers on a non-demand rate to $0.00170 per kWh per month.[105] On March 26, 2021, Staff filed a Proposed Order recommending approval of APS's proposed LFCR rates. At its Open Meeting on April 13, 2021, the Commission voted not to approve the Staff Proposed Order and directed Staff to prepare a short conforming order. On May 5, 2021, Decision No. 77998[106] was issued, denying APS's proposed increase to the LFCR and ordering that the current LFCR rate remain in effect until further order of the Commission.

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[101] The Commission found that DG customers were contributing less to APS's recovery of its annual LFCR revenue than non-DG customers were and that DG customers were responsible for creating more of those lost fixed costs. (Decision No. 74202 at 25.)

[102] Official notice is taken of this decision. The LFCR adjustment was based on an annual application filed by APS on February 15, 2018.

[103] Official notice is taken of this decision.

[104] Official notice is taken of this decision.

[105] Official notice is taken of this filing made in the 2016 Rate Case.

[106] Official notice is taken of this decision.

5. Demand Side Management Adjustment Charge ("DSMAC")

The DSMAC was originally approved in Decision No. 67744 (April 7, 2005),[107] and has since been revised in Decision Nos. 69663, 71448, 73183, and 76295. (Ex. APS-53 at DSMAC POA; Ex. APS-76 at 155.) In its current form, the DSMAC allows APS to recover the costs to design and implement cost-effective DSM programs (both EE and demand response) approved by the Commission in APS's DSM Implementation Plan, which is to be filed for approval by June 1 of each year. (Ex. APS-53 at DSMAC POA.) Upon Commission approval, the DSMAC becomes effective with the first billing cycle for the following March. (*Id.*) The DSMAC is charged on a per kWh basis for all residential customers and for general service customers on a non-demand rate and on a per kW basis for general service customers on a demand rate. (*Id.*) For residential customer billing, the DSMAC and Renewable Energy Adjustment Charge (described below) are combined into an "Environmental Benefits Surcharge" line item. (*Id.*)

At the same Open Meeting at which the Commission adopted Decision No. 76295, the Commission adopted Decision No. 76313 (August 23, 2017),[108] which approved APS's 2017 DSM Implementation Plan ("2017 DSM Plan") and a 2017 DSM budget of $66.6 million as well as DSMAC rates of $0.000982 per kWh and $0.353 per kW.

Although APS applied for approval of APS's 2018 DSM Implementation Plan ("2018 DSM Plan") in September and November 2017 (after receiving an extension of the filing deadline), the Commission has not acted on the 2018 DSM Plan.[109]

In Decision No. 76714 (May 22, 2018),[110] APS was granted an extension of the filing deadline for its 2019 DSM Implementation Plan ("2019 DSM Plan"), to September 7, 2018, as consideration of its 2018 DSM Plan had not yet been completed. In Decision No. 76878 (September 17, 2018),[111] the deadline was again extended until December 31, 2018, although APS had requested that it be extended

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[107] Official notice has already been taken of this decision, which approved a Settlement Agreement with modifications. The Settlement Agreement adopted in Decision No. 67744 created the DSMAC to allow APS to recover the costs of any approved DSM expenditures exceeding an annual $10 million base rate DSM allowance, with the DSMAC to be reset on March 1 of each year beginning on March 1, 2006, and with APS required to spend on average at least $6 million annually on approved eligible DSM-related items.

[108] Official notice is taken of this decision.

[109] Official notice is taken of these filings made in Docket No. E-01345A-17-0134.

[110] Official notice is taken of this decision.

[111] Official notice is taken of this decision.

until 60 days after a decision on its 2018 DSM Plan.

On December 30, 2019, APS filed, in the docket for the 2018 DSM Plan and in the docket for the 2019 DSM Plan, notices that it had filed its 2020 DSM Implementation Plan ("2020 DSM Plan") in another docket and that the 2020 DSM Plan addressed all components of the 2018 DSM Plan/2019 DSM Plan and could be reviewed by Staff without Staff also reviewing the 2018 DSM Plan/2019 DSM Plan.[112]

On October 2, 2020, in Decision No. 77763,[113] the Commission approved a 2020 DSM Plan for APS, with a budget of $51,592,500 and no change in the DSMAC charges approved by Decision No. 76313. Decision No. 77763 further provided that if APS does not, by the end of its current budget year, have a new DSM budget and DSMAC surcharge approved for the ensuing budget year, then the DSM budget and surcharge last approved by the Commission shall continue until further order of the Commission.[114]

On December 31, 2020, APS filed an application for approval of its 2021 DSM Implementation Plan ("2021 DSM Plan").[115] In the application, APS requested a budget of $63.7 million for 2021, with $20 million to be funded through base rates, approximately $5.65 million to come from collected and unspent DSMAC funds, and approximately $38.07 million to come from the DSMAC. APS proposed to increase the DSMAC from $0.000982 per kWh to $0.001357 per kWh and from $0.353 per kW to $0.502 per kW. On April 6, 2021, APS filed an amendment to its application,[116] correcting errors therein and newly requesting to offer an additional upfront incentive to participants in the Residential Energy Storage Pilot who agree to share battery capacity as well as performance data. On June 29, 2021, Staff filed a Memorandum and Proposed Order recommending approval of the updated

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[112] Official notice is taken of these filings made in Docket No. E-01345A-17-0134 and Docket No. E-01345A-18-0105. Decision No. 77281 (July 10, 2019), filed in Docket No. E-01345A-19-0088 and of which official notice is taken, extended the deadline for APS to file its 2020 DSM Plan to December 31, 2019.

[113] Official notice is taken of this decision.

[114] Decision No. 77763 also ordered APS, "as part of its corporate obligations to support a just and equitable transition of communities impacted by early power plant closure," to develop and file for Commission review and approval a Tribal Energy Efficiency Program proposal and budget to implement energy efficiency projects with Navajo and Hopi tribal communities impacted by the closure of Navajo Generating Station, 4CPP, and Cholla Power Plant. (Decision No. 77763 at 38-39.) In addition, APS was ordered to seed-fund the Tribal Energy Efficiency Program with at least $457,000 annually, and cost-effectiveness requirements for the program were waived. (*Id.* at 39.)

[115] Official notice is taken of this filing made in Docket No. E-01345A-20-0151.

[116] Official notice is taken of this filing made in the 2021 DSM Plan docket.

total 2021 DSM Plan budget of $64,214,480, with $38,567,283 to be collected through the DSMAC using updated DSMAC rates of $0.001374/kWh and $0.508/kW.[117] The Staff Memorandum and Proposed Order is scheduled for consideration by the Commission at its Open Meeting on July 13 and 14, 2021. On July 28, 2021, the Commission issued Decision No. 78164, approving the Proposed Order with amendments.

6. Renewable Energy Standard Adjustment Clause ("REAC")

The REAC was originally approved in Decision No. 70313 (April 28, 2008),[118] along with APS's 2008 Renewable Energy Standard Tariff ("REST") Implementation Plan ("2008 REST Plan"), to fulfill requirements of the Commission's REST Rules approved in Decision No. 69127 (November 14, 2006). (Ex. APS-53 at REAC POA.) The REAC is assessed as a charge per kWh on all standard offer and direct access service and is subject to a monthly surcharge limit. (*Id.*) In Decision No. 73183, the REAC was modified, *inter alia*, to prohibit APS from recovering carrying costs for renewable energy-related capital investments through the REAC (with an exception), and to make the allocation of charges between customer classes more flexible. (Ex. APS-53 at REAC POA; Decision No. 73183 at ex. A at 9-10.) APS is required to file its request to update the REAC along with its annual REST Plan, due on July 1 each year, and the REAC is intended to go into effect in the first January billing cycle of the following year after Commission approval. (*Id.*)

At the same Open Meeting at which the Commission adopted Decision No. 76295, the Commission adopted Decision No. 76312 (August 23, 2017),[119] which approved APS's 2017 REST Implementation Plan ("2017 REST Plan") and a 2017 REST Plan budget of $129.3 million, $110.9 million of which was to be collected through the REAC. Under Decision No. 76312, the REAC rate was set at $0.010694 per kWh, and monthly caps were set at $4.28 for residential customers without DG or with DG predating July 1, 2012; at $158.88 for extra small and small commercial customers (based on all usage or usage over 835 kWh depending on DG status); and at larger amounts for other commercial customers.

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[117] Official notice is taken of this filing made in the 2021 DSM Plan docket.

[118] Official notice is taken of this decision. Decision No. 70313 further ordered that because the REST Rules superseded the Environmental Portfolio Standard Rule (A.A.C. R14-2-1618), all monies collected under the prior EPS Adjustor mechanism were to be transferred to the REST Program.

[119] Official notice is taken of this decision.

In Decision No. 76771 (June 26, 2018),[120] the Commission approved a 2018 REST Plan budget for APS of $92.0 million, with the REAC to be set to collect $81.6 million of that amount. The REAC tariff compliance filing made by APS included a REAC charge of $0.007513 per kWh and monthly surcharge caps of $3.01 for residential customers and from $111.62 up for non-residential customers as well as alternative REAC charges, flat charges, and minimum charges, such as a flat charge per month of $2.74 for residential customers.[121]

In Decision No. 77463 (November 7, 2019),[122] the Commission approved a 2019 REST Plan budget for APS of $89.9 million, with the REAC to be set to collect $60.3 million of that amount, resulting in a REAC charge of $0.005712 per kWh and monthly surcharge caps of $2.28 for residential customers and from $84.86 up for non-residential customers as well as alternative REAC charges, flat charges, and minimum charges, such as a flat charge per month of $1.99 for residential customers.

In Decision No. 77762 (October 2, 2020),[123] the Commission approved a 2020 REST Plan budget for APS of $86.3 million, with the REAC charges to remain unchanged from those approved in Decision No. 77463.

On July 1, 2020, APS filed an application for approval of its 2021 REST Plan.[124] In the application, APS requested a budget of $84.7 million for 2021, with $73.5 million to be funded through the REAC. APS proposed a REAC charge of $0.006888 per kWh, monthly surcharge caps of $2.76 for residential customers and from $102.34 up for non-residential customers, as well as alternative REAC charges, flat charges, and minimum charges, such as a flat charge per month of $2.32 for residential customers. APS also requested a full, permanent waiver of the residential portion of the residential DG requirement in A.A.C. R14-2-1805 because since the Commission phased out up-front incentives for DG PV installations,[125] APS no longer receives Renewable Energy Credits ("RECs") from those installations. In Decision No. 78076 (June 24, 2021),[126] the Commission approved APS's REST budget of $84.7 million and that the REAC adjustor rate and monthly caps be set to collect $68.3

[120] Official notice is taken of this decision.
[121] Official notice is taken of APS's compliance filing made on June 27, 2018, in Docket No. E-01345A-17-0224.
[122] Official notice is taken of this decision.
[123] Official notice is taken of this decision.
[124] Official notice is taken of this filing made in Docket No. E-01345A-20-0199.
[125] This occurred through Decision No. 73636 (January 31, 2013), in the docket for APS's 2013 REST Plan.
[126] Official notice is taken of this decision.

million, with a REAC charge of $0.006403/kWh, monthly surcharge caps of $2.56 for residential customers and from $95.13 up for non-residential customers, as well as alternative REAC charges, flat charges, and minimum charges, such as a flat charge per month of $2.19 for residential customers. The Commission also approved the requested waiver.

7. Tax Expense Adjustor Mechanism ("TEAM")

The TEAM was originally approved in Decision No. 76295; the Settlement Agreement allowed APS to create a rate adjustment mechanism to enable the pass-through of income tax effects to customers "[i]n the event that significant [f]ederal income tax reform legislation" became effective before the conclusion of APS's next rate case and "materially impact[ed] the Company's annual revenue requirements." (Decision No. 76295 at ex. A at 16.) The TEAM was designed to cover changes from APS's adjusted 2015 TY in the 2016 Rate Case, including from the income tax rate, annual amortization of the excess deferred income tax regulatory account, and permanent income tax adjustments, and was to terminate with the effective date of APS's next general rate case (i.e., this rate case). (*Id.* at 16-17.) In its original form, the TEAM application was to be filed on December 1, with the TEAM rate to become effective with the first March billing cycle of the following year. (*Id.* at 17.) The TEAM is assessed to each customer as an equal per kWh charge and includes a balancing account, with interest accrual. (*Id.*)

In Decision No. 76601 (March 5, 2018),[127] the Commission approved Phase I of APS's plan to implement the TEAM, addressing the reduction in APS's federal income tax expense (and thus its annual revenue requirement) by $119.074 million and authorizing APS to implement a TEAM credit rate of $0.0049212 per kWh effective with the first billing cycle in March 2018.[128]

In Decision No. 77139 (March 19, 2019),[129] the Commission approved Phase II of APS's plan to implement the TEAM, authorizing APS to refund an additional $86.5 million of tax savings resulting from calculation of the unprotected portion of excess deferred income taxes ("EDIT"),[130] in the form

[127] Official notice is taken of this decision.

[128] The reduced income tax expense was caused by the 2017 Tax Cuts and Jobs Act, which became effective January 1, 2018, and reduced the corporate income tax rate from 35% (at its highest) to 21%. AG-X customers and HLF-1, HLF-2, and HLF-3 customers were authorized to receive a reduced credit amount per kWh.

[129] Official notice is taken of this decision.

[130] Accumulated deferred income taxes ("ADIT") result from timing differences between recognition of income for accounting purposes, primarily due to depreciation of assets. (Decision No. 77139 at 2.) Two types of EDIT are created

of a credit of $0.003048 per kWh to be applied over a period of 12 months beginning in April 2019. The Commission also approved an APS request to reset the Phase I TEAM credit to $0.004194 per kWh to prevent over-refunding that would have resulted because the original credit was based on 10 rather than 12 months of sales; approved APS's request to combine the Phase I and Phase II TEAM credits on customer bills at $0.007242 per kWh to be applied over a period of 12 months; required APS to file a revised TEAM POA to reflect modifications approved in the Decision (such as the filing date and effective date); and authorized a Phase III to address APS's protected EDIT.

In Decision No. 77464 (November 7, 2019),[131] the Commission addressed Phase III of the TEAM concerning the amortization of $881 million of jurisdictional protected EDIT, which APS requested to occur over 28.5 years. APS estimated an annual amortization of $31 million of protected EDIT and a $34.452 million decrease in revenue requirement and requested Commission approval to refund $103.5 million related to protected EDIT from January 1, 2018, through December 31, 2020. APS proposed to refund $64 million (for the period of January 1, 2018, through October 31, 2019) as a one-time bill credit to each customer, to be paid in December 2019 at the rate of $0.006945/kWh applied to the customer's aggregated kWh consumption for August through October 2019. APS proposed to refund the remaining $39.5 million in protected EDIT (for the period of November 1, 2019, through December 31, 2020) through a monthly bill credit rate of $0.001169/kWh, to be paid beginning in December 2019. APS also requested approval to modify its TEAM POA to include the option to hold any under- or over-refunded amounts in a balancing account until its next rate case (i.e., this rate case) rather than making an annual adjustment. In the Decision, the Commission approved all of APS's proposals.

In Decision No. 77852 (December 17, 2020),[132] the Commission approved an APS request to reconstitute and recalculate the TEAM Phase III credit to allow $34.452 million in credits to be provided to customers to reflect tax savings from January 1 through December 31, 2021, in

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when marginal tax rates are reduced—unprotected EDIT and protected EDIT. (*Id.*) Because the Internal Revenue Service ("IRS") has not prescribed the amortization or treatment of unprotected EDIT, the amortization period is flexible and can be set by the Commission. (*Id.*) The IRS prescribes the manner in which protected EDIT must be amortized over the remaining life of the underlying plant assets, allowing either of two methods to be used. (*Id.* at 2-3.)

[131] Official notice is taken of this decision.

[132] Official notice is taken of this decision.

conformance with IRS normalization rules, with the credits to end on December 31, 2021, or upon conclusion of this matter.

IV. APS's Application as Amended[133]

As required by Decision No. 77270, APS's application uses a TY ending June 30, 2019. As amended, APS's application reports the following adjusted TY results for APS's jurisdictional operations and requests the following ($ amounts are in thousands):[134]

Original Cost Rate Base ("OCRB")	$8,896,268
Reconstruction Cost New Depreciated Rate Base ("RCND")	$15,734,140
Fair Value Rate Base ("FVRB")	$12,315,204
Fair Value Increment ("FVI")	$3,418,936
Operating Revenues	$3,437,440
Operating Income	$648,909
Current Rate of Return on OCRB	7.29%
Required Operating Income	$652,096
Required Rate of Return on OCRB	7.33%
Operating Income Deficiency on OCRB	$3,187
Gross Revenue Conversion Factor	1.3346
Increase in Base Revenue Requirement Based on OCRB	$22,948
After Tax Return on FVI	$35,973
Requested Increase in Base Revenue Requirement	$40,226
Required Rate of Return with FVI	5.51%

APS continues to propose the same capital structure as in the original application, with which AECC/Freeport, FEA, RUCO, and Staff agree. (Ex. APS-20 at 60; Ex. AECC-1 at ex. KCH-1; Ex. FEA-2 at 20-21; Ex. RUCO-4 at 34; Ex. S-1 at 3.)

APS proposes the following adjusted capital structure and weighted average cost of capital ("WACC") ($ amounts are in thousands):[135]

Invested Capital	Amount	%	Cost Rate	Composite Cost
Long-Term Debt	$4,726,125	45.33%	4.10%	1.86%
Preferred Stock	0	0.00%	0.00%	0.00%
Common Equity	$5,700,968	54.67%	10.00%	5.47%
Short-Term Debt	0	0.00%	0.00%	0.00%
Total	$10,427,093	100.00%		**WACC: 7.33%**

[133] Although APS's schedules provided in this matter typically included figures for both "Total Company" and "ACC" (to reflect jurisdictional amounts for APS), the discussion and figures herein relate only to APS's operations as a public service corporation under the jurisdiction of the Commission.
[134] LFE APS-87 at Sched. A-1, Sched. C-1.
[135] Ex. APS-39 at Sched. D-1; *see* Ex. APS-21 at 122, att. AEB-9RB; Ex. APS-22 at 17.

Regarding its adjustors, APS's application, as amended, proposes:[136]

- Incorporating the TEAM Phase I benefits of $119 million into base rates and continuing the TEAM;
- Recalculating the LFCR to include new lost fixed costs and retaining in the LFCR (rather than moving into rate base) the revenue requirement related to lost fixed cost MW-hours due to EE and DG from January 2016 through June 30, 2019, to help ensure consistency between the estimated bill impacts in this matter and what customers experience on the effective date of rates approved herein;
- Transferring into base rates the $3.8 million currently collected under the EIS;
- Transferring into base rates the $321,000 related to Solar Communities[137] currently being collected under the REAC; and
- Implementing a new AEM adjustor to collect $13 million annually for Coal Community Transmission costs and to recover investments related to the Clean Energy Commitment.[138]

Regarding its programs for limited-income customers, APS proposes:[139]

- Increasing the amount of funding for Crisis Bill Assistance[140] from $1.25 million to $2.5 million; and
- Modifying Rate Riders E-3 and E-4 by providing a bill credit for credit card processing fees when enrolled customers pay by credit card.

APS proposes the following changes to its residential rate design:[141]

- Freezing residential demand rate R-2;
- Adding a super off-peak feature to residential demand rate R-3;
- Eliminating certain customer charges in Service Schedule 1 and recovering them through

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[136] Ex. APS-41 at 6-7, 11-12; Ex. APS-29 at 12-15.
[137] Solar Communities was previously known as AZ Sun II. (Tr. at 1305.)
[138] APS also suggested that the AEM could eventually be modified to include the DSMAC , REAC, and LFCR because all are related to a clean energy future. (Ex. APS-29 at 15.)
[139] Ex. APS-41 at 7-8.
[140] Crisis Bill Assistance is a program under which APS provides grants for bill assistance up to twice per year per customer, and up to a total of $800 per year, to customers whose household income is at or below 200% of the FPL and who provide a crisis reason that they need assistance. (Ex. Wildfire-1 at 10.) APS increased the maximum annual grant amount from $400 to $800 per customer during the COVID-19 pandemic. (*Id.*)
[141] Ex. APS-41 at 8-9; Ex. APS-26 at 2, 40; Ex. APS-23 at 10.

base rates instead;

- Waiving certain customer charges in Service Schedule 1 once per year per customer; and
- Modifying Service Schedule 1 to increase the amount of time customers have to remit payment after a bill is issued from 14 to 21 days.[142]

APS proposes the following changes to its General Service Rate Design:[143]

- Implementing an experimental AG-Y program to provide eligible medium and large General Service customers with access to market index pricing;
- Revising streetlight rates to simplify and conform them to current conditions;
- Revising E-221 to distinguish between agricultural and non-agricultural uses and better align the rates with cost of service; and
- Canceling the E-36 M rate rider due to low enrollment.

APS also requests two accounting orders:[144]

- One that would allow it to track and defer for future recovery the jurisdictional component of all increases or decreases in Arizona property taxes that are above or below the levels reflected in rates in this matter and that are attributable to increases or decreases in tax rates (as opposed to changes in assessed tax value), without a return, until the next general rate case; and
- One that would allow it to track and defer for future recovery the amounts paid to customers under "certain limited-income discount programs, Rate Riders E-3 and E-4," including for the newly proposed credit card processing fee credits.

APS proposes to increase its base rate revenues by approximately $41 million, which it states represents an overall base rate increase of 1.23% and, with the TEAM and EIS transfers to base rates and assuming approval of the AEM, would result in an overall net impact to customers of 5.14%, a net impact to the residential class of 4.99%, and a net impact to the general service class of 5.33%. (Ex. APS-29 at 12; Ex. APS-26 at 2-4.)

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[142] Ex. APS-26 at 46.
[143] Ex. APS-41 at 9.
[144] Ex. APS-41 at 5-6, 8, 12.

V. Contested Issues (Other than Cost of Capital & Rate Design)

A. Adjusted TY Results

1. Parties' Positions

APS, AECC/Freeport, FEA, RUCO, and Staff propose the following adjusted TY results ($ are in thousands):[145]

	APS	AECC/Freeport	FEA	RUCO	Staff
Total Operating Revenues	$3,437,440	$3,437,440	$3,437,440	$3,437,672	$3,437,672
Total Operating Expenses	$2,788,530	$2,738,048	$2,781,560	$2,750,457	$2,761,072
Operating Income	$648,909	$699,392	$655,880[146]	$687,215	$676,600

RUCO and Staff's TY total operating revenues differ from those of APS, AECC/Freeport, and FEA because neither reflects the minor reduction in actual TY "other electric revenues" made by APS in its rebuttal schedules. (See Ex. APS-39 at sched. C-1; Ex. APS-13 at att. EAB-25RB.) APS attributes the difference to an adjustment provided to the other parties during discovery, which was not picked up by RUCO and Staff. (APS Br. at 30.)

2. Resolution

We conclude that APS's adjusted TY total operating revenues were $3,437,440,000. The issues that drive the differences in adjusted TY operating expenses and operating income are described and resolved below.

B. SCRs and SCRs Deferral

1. Background

The SCRs project installed two SCR reactors into the exhaust gas stream of each operating unit

[145] LFE APS-87 at sched. C-1; Ex. AECC-3 at ex. KCH-1-S at 8; FEA-Final Shed. C-1 at 2; RUCO-Final Sched. C-1; Staff-Final Sched. C (att. RCS-9 at 9).

[146] FEA's final schedules showed two different TY operating income amounts ($ in thousands): $653,284 and $655,880. (*See* FEA-Final Sched. at sched. A-1, sched. C-1.) Schedule C-1 shows that the $655,880 figure is TY operating income and that $653,284 is net income. (*Id.*)

at the 4CPP. (SCRs Ex. APS-3 at 2.[147]) The SCRs project was necessary to comply with the Regional Haze Regulations authorized under the federal Clean Air Act and the EPA's 2012 Federal Implementation Plan for the 4CPP ("4CPP FIP").[148] (SCRs Ex. APS-3 at 2.) The 4CPP FIP allowed for two alternatives, the less costly of which involved permanently closing Units 1-3 by 2014 and installing on Units 4 and 5 add-on post combustion controls that would bring each Unit into compliance with a NOx emission limit of 0.098 lb/MMBtu by July 31, 2018. (4CPP FIP at 51621.) As part of the analysis required to find the Best Available Retrofit Technology ("BART"), APS evaluated more than a dozen alternatives for reducing NOx emissions from Units 4 and 5, none of which met the EPA standard. (SCRs Ex. APS-3 at 3.) The EPA determined that SCRs were the BART to reduce the NOx emissions for Units 4 and 5. (SCRs Ex. APS-3 at 2.)

The conceptual engineering and project planning approval for the SCRs project was received in March 2013; the contractor was selected in March 2014, after a Request for Proposals ("RFP") process; and preliminary engineering began in April 2014. (SCRs Ex. APS-3 at 3.) In August 2015, the 4CPP SCRs Engineering, Procurement, and Construction contract ("SCRs contract") was executed, and the contractor was authorized to proceed. (Ex. SC-1 at att. TC-2; SCRs Ex. APS-3 at 3.) Construction on the SCRs began in September 2015. (Ex. SC-1 at att. TC-2; SCRs Ex. APS-3 at 3.) Structural steel installation for the SCRs began in March 2016, major foundation installation was completed in April 2016, and SCRs reactor installation began in January 2017. (SCRs Ex. APS-3 at 3.) The outage to tie-in Unit 5 began in September 2017, and the SCRs for Unit 5 went into service on December 17, 2017. (SCRs Ex. APS-3 at 3.) The outage to tie-in Unit 4 began in January 2018, and the SCRs for Unit 4 went into service on April 24, 2018. (SCRs Ex. APS-3 at 3.) The actual emissions from Units 4 and 5 were less than 0.0065 lbs/MMBtu as of August 2018.[149] (SCRs Ex. APS-3 at 5.)

The SCRs were in service during the TY and are currently in service. (Ex. APS-1 at 8.) The SCRs were installed at a total cost to APS of approximately $467 million. (Ex. RUCO-1 at 11 n.1;

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[147] In the Procedural Order issued on March 18, 2020, official notice was taken of virtually all of the documents filed from April 27, 2018, to January 30, 2019, i.e., during the "SCRs Phase" of the 2016 Rate Case. Exhibits from the SCRs Phase are cited herein as "SCRs Ex.-*Name-#*."

[148] Official notice is taken of the Source Specific Federal Implementation Plan for Implementing Best Available Retrofit Technology for Four Corners Power Plant: Navajo Nation, published at 77 FR 51620-01 (August 24, 2012).

[149] The currently required federal NOx emissions limit is 0.08 lbs/MMBtu pursuant to a Clean Air Act Consent Decree between the EPA, 4CPP ownership, and several environmental groups. (SCRs Ex. APS-3 at 5.)

RUCO Br. at 19 n.8.)

2. SCRs Phase

On April 27, 2018, in the 2016 Rate Case docket, APS filed a Request for Approval of a SCR Adjustment ("SCRs Application"). APS requested that the Commission approve recovery of a $67.5 million annual revenue requirement, which APS identified as its share of the installation of the SCRs on Units 4 and 5 and the related deferred costs authorized in Decision No. 76295. APS asserted that under the Consent Decree entered on August 17, 2015, APS was required to have the first Unit's SCRs in operation by March 31, 2018, and the second Unit's SCRs in operation by July 31, 2018. The SCRs Application assumed a 2038 end-of-life for the SCRs, consistent with the end-of-life used for 4CPP Units 4 and 5 in the 2016 Rate Case. APS requested that the revenue requirement be recovered as an equal percentage adjustment to the base rate portion of customers' bills[150] and estimated a base rate bill impact of approximately 2%.

In June 2018, Sierra Club was granted intervention for the SCRs Phase, and APS, in response to a Sierra Club data request, filed a Motion for Protective Order to restrict discovery concerning the continued operation or retirement of the 4CPP and the prudency of its continued operation. After a Response from Sierra Club opposing APS's Motion, a procedural conference was held on July 10, 2018. On July 11, 2018, a Procedural Order was issued limiting the scope of the SCRs Phase proceeding to the prudency and recovery of all non-fuel costs of owning, operating, and maintaining the SCRs at the 4CPP, as contemplated by Decision No. 76295.[151] In August 2018, Sierra Club filed to withdraw as an intervenor in the SCRs Phase,[152] and its withdrawal was granted by Procedural Order.

A hearing was held for the SCRs Phase on September 5, 6, and 7, 2018, with APS, AECC/Freeport, Wildfire,[153] WRA, Electric District Number Eight, McMullen Valley Water Conservation & Drainage District, the Citizen Groups, Arizona Energy Policy Group, Walmart, RUCO, and Staff appearing through counsel. Subsequently, Staff filed a late-filed exhibit, and APS, Wildfire, WRA, AECC/Freeport, Walmart, Arizona Energy Policy Group, the Citizen Groups, and

[150] For AG-X customers, APS proposed to have the 2% applied only to the APS portion of the customer's bill.
[151] This Procedural Order was admitted in this matter as Exhibit SC-30.
[152] Sierra Club's Notice of Withdrawal was admitted in this matter as Exhibit SC-31.
[153] At the time, Wildfire was known as the Arizona Community Action Association.

Staff filed post-hearing briefs.

During the SCRs Phase, APS identified its jurisdictional portion of the SCRs costs to go into rate base as $365.873 million for the plant addition ($169.496 million for Unit 5 and $196.377 million for Unit 4) plus its after-tax cost deferral of $17.223 million ($10.404 million for Unit 5 and $6.819 million for Unit 4), for a total of $383.096 million. (SCRs Ex. APS-5 at att. EAB-17RB; *see* SCRs Ex. APS-5 at att. EAB-16RB.) APS identified its deferred debt return (total company basis) as $16.036 million ($9.070 million for Unit 5 and $6.965 million for Unit 4),[154] and the annual amortization amount for the deferral on a jurisdictional basis (over five years) as $4.579 million ($2.768 million for Unit 5 and $1.813 million for Unit 4). (SCRs Ex. APS-5 at att. EAB-16RB.) APS also proposed jurisdictional operating expense adjustments totaling $29.892 million, most of which was depreciation and amortization expense. (SCRs Ex. APS-5 at att. EAB-17RB.) APS asserted that the SCRs were financed through a mix of debt and equity, not through debt as asserted by RUCO. (SCRs Ex. APS-7 at 8.)

In the SCRs Phase, APS used an end-of-life for Units 4 and 5 of 2038, 20 years after installation of the second Unit's SCRs, as it had in the earlier phase of the 2016 Rate Case. (SCRs Ex. S-1 at 15; SCRs Ex. S-2 at 8; *see*, *e.g.,* SCRs Ex. APS-2 at 2; SCRs Ex. APS-5 at 3.) In response to testimony suggesting that the 4CPP would be closed in 2031 and that the SCRs' depreciation should reflect that, APS acknowledged that "2031 [would] be an inflection point for the [4CPP] and its participants" but stated that no decisions had been made regarding what would happen post-2031 and that the approved depreciable life for the 4CPP was through 2038. (SCRs Ex. APS-2 at 2.) Additionally, APS stated, "if at some point in the future a decision is made that shortens the expected life of the [4CPP], the issue of the remaining book value or other financial obligations will need to be discussed in a later proceeding, such as APS's next rate case."[155] (SCRs Ex. APS-2 at 3.) Staff's witness also stated that if the useful life of Units 4 and 5 ended up being shorter than APS estimated, "that could affect the economic viability of the plant and the period over which costs related to the plant are being recovered." (SCRs Ex. S-1 at 16.)

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[154] On a jurisdictional basis, the numbers would be $15.949 million ($9.021 million for Unit 5 and $6.927 million for Unit 4). (*See* SCRs Ex. APS-5 at att. EAB-16RB.)

[155] This testimony was dated August 9, 2018. (SCRs Ex. APS-2.)

Staff hired Critical Technologies Consulting ("CTC") to perform an independent engineering and prudence review of the SCRs project for the SCRs Phase. (SCRs Ex. S-2 at 9.) CTC found that SCRs were the only acceptable BART, that the projected cost of the SCRs project at $625 million was "very reasonable," that the SCRs project had met its regulatory milestones and that its performance against the milestones had been "very commendable," and that the engineering and construction were well-executed and quality efforts. (SCRs Ex. S-3 at 7, 9, att. at 6, 16.) CTC recommended that the SCRs project be found prudent and opined that the systems installed with the SCRs project are able to operate effectively until 2038. (SCRs Ex. S-3 at 13.)

On November 27, 2018, the SCRs ROO was issued. The SCRs ROO found that the SCRs project had been completed in a cost-efficient, reasonable, and prudent manner and that the FVRB associated with APS's 63% ownership interest in the SCRs was $383.096 million. The SCRs ROO further found that it was appropriate to apply the 5.59% FVROR approved in the 2016 Rate Case and that the resulting incremental annual revenue requirement of $58.474 million was reasonable and should be adopted. Additionally, the SCRs ROO found that the estimated cost deferral amount of approximately $23 million, amortized at 5.13% over five years, was reasonable and that the SCRs had a 20-year useful life and should be depreciated at 5% per year. The SCRs ROO included the following language pertaining to the closure of the 4CPP, which WRA had asserted would probably occur in 2031:

> At present, there is no evidence – only conjecture – that Four Corners will close in 2031. Thus, we decline to adopt WRA's proposals. We find that the five percent depreciation rate on the SCR's, based on the straight-line method, using an end-of-life assumption of 2038, and the amortization of the deferral costs over five years, are reasonable and we adopt them.[156]

The SCRs ROO was placed on the agenda for the Open Meeting of February 5 and 6, 2019, and was subsequently pulled from the agenda. The Commission has not yet considered the SCRs ROO.

3. APS Recovery Request

APS seeks to include in rate base both its portion of the SCRs investment and the approximately

[156] SCRs ROO at 13.

$32.771 million[157] balance of the SCRs deferral through December 31, 2020. (Ex. APS-4 at 3-4; Ex. APS-12 at 35-36; LFE APS-87 at sched. B-2.) APS proposes to amortize the SCRs deferral over a 10-year period, rather than its originally requested five-year period, to reduce the rate impact on APS customers. (Ex. APS-1 at 9-10; ex. APS-39 at sched. C-2.) At the time of its application in this matter, APS stated that the SCRs project, which included the deferral through December 31, 2020, and a full return at APS's then-requested cost of capital, would produce an annual revenue requirement of $73 million and alone would result in a 2.2% bill impact. (Ex. APS-1 at 5-6; Ex. APS-25 at 3.) In addition to recovering the SCRs deferral described above, APS proposes to continue deferring costs for the SCRs until the effective date of the rates approved in this case and to address this additional cost deferral (the deferred costs from January 1, 2021, until the rate effective date) in its next rate case. (Ex. APS-13 at 17.)

To support recovery for the SCRs and SCRs deferral in this case, APS points to CTC's conclusions from the SCRs Phase. (APS Br. at 11 (citing SCRs ROO at 9-10); Tr. at 500-501.) APS also points out that RUCO was a party to the SCRs Phase and did not file any exceptions to the SCRs ROO. (Ex. APS-3 at 9.) APS emphasizes that the EPA required the installation of the SCRs as the BART for the 4CPP and that the 4CPP could not have continued to operate without the SCRs. (Ex. APS-3 at 10; Tr. at 253, 258.) APS also asserts that the Commission already determined the prudence of the SCRs in Decision No. 73130, when the Commission approved acquisition of Units 4 and 5.[158] (Ex. SC-1 at att. TC-2 (Lockwood response to SC 1.26); *see* APS Br. at 16-18; APS RBr. at 10-11.) APS emphasized the importance of the 4CPP, and thus the SCRs, to maintaining reliable service to APS customers during summer 2020, the hottest summer on record in Arizona. (Ex. APS-2 at 14.) Ms. Lockwood testified that the 4CPP and SCRs are "critical" to maintaining reliable service for APS customers during the summer months and, further, that the SCRs are providing benefits by reducing emissions and providing jobs and revenue to the community. (Tr. at 253, 258.) APS proposes that the 4CPP (including the SCRs) be depreciated until 2038, seven years beyond its 2031 closure date, in

[157] APS's final schedules provide two different figures for the ADIT on the deferred debt return for the SCRs; the other figure results in $32.594 million.

[158] Mr. Smith also took this position, stating his understanding that "whether the SCR should have been constructed at all was reviewed in a prior docket." (Tr. at 5109.)

order to keep rates lower than if depreciation were accelerated to end in 2031. (Ex. APS-2 at 14.) Ms. Lockwood asserted that because the SCRs are used and useful and have been in service and providing benefits for years, APS needs to be authorized rate recovery for the SCRs. (Tr. at 253, 260-261.)

4. Other Parties' Positions

a. Sierra Club

Sierra Club's primary position is that APS should not be allowed recovery of the SCRs expenditures because the SCRs were not a prudent investment. (Sierra Club ("SC") Br. at 29-30.) In the alternative, if the Commission concludes that the SCRs were a prudent investment, Sierra Club asserts that the Commission should not allow APS a return on the SCRs investment. (SC Br. at 30.) Sierra Club asserts that APS knew or should have known, when the SCRs expenditures were made, that the 4CPP was becoming uneconomical to operate and would need to be retired earlier than 2038 (the publicly announced retirement date until recently). (See SC Br. at 4-30.) Sierra Club argues that it is not requesting that the Commission evaluate prudency in hindsight, but instead that the Commission evaluate prudency in light of the information APS knew or should have known at the time each investment was made. (SC RBr. at 2-3.)

In response to APS's and Staff's position that the Commission has already determined the prudency of the SCRs, Sierra Club argues that acquisition of a power plant, and the prudency of that acquisition, does not automatically make all subsequent investments in that plant prudent, as APS and Staff acknowledged, and that APS's position would result in APS receiving a "blank check" for all expenditures made after December 2014 when the Commission approved the SCE acquisition in Decision No. 74876. (SC RBr. at 3-4 (citing Tr. at 1456-1457, 4814).) Sierra Club states that the Commission provided no opinion in Decision No. 74876 concerning whether installing the SCRs would be prudent and further argues that "[i]t is irrational to believe that the Commission would determine prudency . . . by implication and without knowing all of the facts." (SC Br. at 28.) Sierra Club further asserts that Decision No. 76295 explicitly preserved the Commission's right to review the prudency of the SCRs investments, making it clear that their prudency had not already been resolved. (SC Br. at 29; SC RBr. at 12-13.) Sierra Club argues that APS waived any objection to consideration of the SCRs' prudency in this matter by requesting recovery and asserts that the Commission should determine the

prudency of the SCRs in this case. (SC Br. at 28; SC RBr. at 12-14.)

Sierra Club also argues that "APS succumbed to the 'sunk cost fallacy': it had already spent hundreds of millions of dollars acquiring a greater share in [the 4CPP], so it spent hundreds of millions more on the SCRs even when doing so was no longer economically justified." (SC Br. at 25.) Sierra Club argues that APS's installation of the SCRs was imprudent due to the dramatic changes in the economics of operating the 4CPP between 2012 and 2017, which should have caused APS to reexamine its decision to install the SCRs. (SC Br. at 25.) Sierra Club further argues that APS made new decisions subject to Commission prudency review each time it decided to spend money to maintain, fuel, or operate Units 4 and 5. (SC RBr. at 4.) According to Sierra Club, it has presented clear and convincing evidence that overcomes the presumption of prudency for APS's ongoing rate base investments in the 4CPP, including the SCRs, and no other party has persuasively demonstrated that the SCRs investments were prudent.[159] (SC RBr. at 4, 10-11, 14-15.) Additionally, Sierra Club argues, because fuel and O&M costs are not subject to a prudence presumption, APS had the burden of proving that those costs were prudent and failed to do so.[160] (SC RBr. at 4-5 (citing Decision No. 77130 (March 13, 2019)).)

According to Mr. Comings, APS's 2012 IRP included a low-gas-cost forecast under which APS concluded it would save $497 million net present value ("NPV") from 2012-2041 if it did not acquire Units 4 and 5. (Ex. SC-1 at 11.) Mr. Comings testified that this low-gas-cost forecast had become reality by APS's 2014 IRP and opined that APS should have been carefully monitoring gas price developments and should have reevaluated spending millions more on the SCRs, but did not make such an evaluation in its 2014 IRP and instead assumed in every scenario that the 4CPP would operate until 2038.[161] (Ex. SC-1 at 10-16; SC Br. at 25-26.) Sierra Club asserts that APS had an opportunity to reevaluate the economics of the SCR investments before it began construction in September 2015, but

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[159] Sierra Club notes that the Commission's definition of original cost rate base includes "used and useful" and "prudently invested" as separate elements and that parties' assertions that the SCRs are in use do not establish prudence. (SC RBr. at 14-15 (citing A.A.C. R14-2-103(A)(3)(h)).)

[160] Sierra club cited testimony that APS spends approximately $150 million on O&M at the 4CPP each year and spent over $187 million on fuel for the 4CPP in the TY and noted that APS did not make any attempt to justify the ongoing 4CPP expenses in its brief. (SC RBr. at 5.)

[161] Mr. Comings testified that the low-gas-cost forecast in the 2012 IRP for 2019 was $4.68 MMBtu, which is almost double the actual 2019 Henry Hub price of $2.56 per MMBtu. (Ex. SC-1 at 12.) Mr. Comings showed that the Energy Information Administration's Annual Energy Outlook's forecasted Henry Hub natural gas prices from 2012 through 2019 have generally exceeded the actual Henry Hub prices. (Ex. SC-1 at 14.)

instead ignored the economics. (SC Br. at 27.) Sierra Club points out that at least one other coal plant owner has done so—in 2016, Dynegy, the merchant owner of the Newton coal plant in Illinois, abandoned a $186 million pollution control project in mid-construction and decided to retire one of the units, even though it had already spent $148 million on the project, because doing so was the best option for Dynegy and its shareholders. (Ex. SC-1 at 19.) Sierra Club also notes that the New Mexico Public Regulation Commission ("NMPRC") denied PNM a return on PNM's share of the SCRs and other 4CPP capital expenditures, determining that PNM had been imprudent in deciding to install the SCRs, in deciding to make additional investments in the 4CPP, and in deciding to continue using the 4CPP as base load generation.[162] (Ex. SC-1 at 17-18; Ex. SC-38 at 19-20.) This disallowance resulted in a $21.2 million write-off for PNM, and the NMPRC indicated that the propriety of additional disallowances should be addressed in a future case. (Ex. SC-38 at 20, 32.)

Beyond arguing that the Commission should deny APS recovery for the SCRs expenditures, Sierra Club also asserts that APS (1) should be ordered to conduct a comprehensive retirement assessment for the 4CPP, including evaluation of near-term retirements, as part of its 2020 IRP; (2) should be denied recovery of TY capital expenditures that were not needed for the 4CPP's safe, near-term operations; (3) should be denied recovery of TY O&M and fuel expenses for the 4CPP; and (4) should be required to issue an all-source RFP for the 4CPP's replacement. (SC Br. at 21-22; Ex. SC-1 at 41-43; SC RBr. at 5-10.)

In his initial analyses[163] made based on "high" replacement costs of $50 per MWh, Mr. Comings found that APS would save at least $521 million NPV if it were to retire the 4CPP at the end of 2023 rather than in 2031, with the annual savings (if the replacement were in the form of purchase power agreements) beginning in 2024 at $25.8 million and escalating through 2030. (Ex. SC-1 at 32-33.) In his analyses made based on a "low" replacement cost of $30 per MWh, Mr. Comings found that the savings would be nearly $1.1 billion NPV. (Ex. SC-1 at 32.) Mr. Comings testified that because his analysis used deliberately conservative assumptions, the savings could be greater. (Ex.

[162] The disallowance was made in an Order Partially Adopting Certification of Stipulation in NMPRC Case No. 16-00276-UT, issued on December 20, 2017. (Ex. SC-38.)

[163] Mr. Comings conducted his initial analyses using forecast data for the 4CPP provided by APS in early March 2020. (Ex. SC-1 at 35.)

SC-1 at 34.) Mr. Comings also concluded that the break-even replacement cost was $68.12 per MWh in 2024 (escalating at 2% annually), with replacement costs below that level resulting in savings. (Ex. SC-1 at 34.)

Mr. Comings subsequently conducted analyses using APS's 2020 IRP modeling and concluded that using APS's bridge portfolio and a base carbon cost, APS would save between $775 million and $1.36 billion by retiring the 4CPP at the end of 2023. (Ex. SC-1 at 36-37.) Mr. Comings found that the break-even replacement cost under the 2020 IRP forecasts was between $61.50 and $78.20 per MWh. (Ex. SC-1 at 36-37.) Mr. Comings further determined that if the March 2020 fixed O&M costs (rather than the lower 2020 IRP fixed O&M costs) are used with the updated 2020 IRP forecasts, the savings from retirement would increase by another $174 million. (Ex. SC-1 at 39.)

Mr. Comings recommended that the Commission order APS to identify the avoidable TY and future spending on the 4CPP[164] and that this matter be held open so that the Commission and parties are able to review the evaluation and the Commission is able to disallow all avoidable costs.[165] (Ex. SC-1 at 42-43.) Mr. Comings was unable to identify the capital costs that could have been avoided during the TY or going forward, stating that APS refused to provide him such an evaluation. (Ex. SC-1 at 42.)

Mr. Comings further recommended that the Commission open a docket to address the 4CPP replacement process so that stakeholders can be involved in developing the RFP, choosing the independent evaluator, and selecting the replacement resources.[166] (Ex. SC-1 at 43.) On brief, Sierra Club asserted that the new docket should be opened if the Commission's Energy Rules are not finalized. (SC Br. at 23.) According to Mr. Comings, even if the Commission disagrees that the 4CPP should be retired in 2023, it should still require APS to issue the all-source RFP to evaluate the future of the

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[164] A data response from APS showed that APS's share of 2019 coal fuel costs for Unit 4 was approximately $93 million and for Unit 5 was approximately $78 million, while its share of 4CPP common costs was approximately $524,000. (Ex. SC-1 at att. TC-2.) Additionally, Mr. Tetlow testified that APS is likely to spend approximately $150 million on O&M and to incur capital expenditures of approximately $30 to $100 million for the 4CPP each year until at least 2025. (Tr. at 1463-1464.)

[165] Sierra Club cited testimony that costs related to a coal plant can and should ramp down in the years before a planned retirement because coal-burning plants are capital intensive, and capital expenditures and O&M projects tend to extend the life of a plant for more than one year. (SC Br. at 8-9 (citing Tr. at 929, 1456-57, 4812).)

[166] Mr. Comings opined that the all-source RFP process should allow more than one month for bidders to respond; should not give preference by technology type, project size, or ownership; and should involve an independent evaluator. (Ex. SC-1 at 43.)

4CPP. (Ex. SC-1 at 43.)

Sierra Club characterizes APS's desire to continue operating the 4CPP until 2031 as an attempt to protect the 4CPP from competition at the expense of APS's customers, arguing that the 4CPP has become unreliable and expensive to operate and that this this will only become worse. (SC Br. at 8-9.) According to Sierra Club, the Commission's IRP process is not a replacement for considering 4CPP's future in this matter because there are no repercussions for a utility even if its IRP is not acknowledged, such as occurred with APS's 2017 IRP. (SC Br. at 10.) Sierra Club further asserts that APS's claims that it cannot retire the 4CPP early due to the CSA, the co-owner agreement, APS's asserted inability to influence the replacement resource market, and reliability concerns should be ignored as red herrings because the CSA can be terminated with notice (24 months' notice as of the hearing, although Sierra Club noted that APS's finalization of the Seasonal AIP would require four years' notice and cost ratepayers millions); the co-owners have expressed a desire to consider and are likely in support of early retirement; APS can influence the market for replacement resources by issuing an RFP in anticipation of the 4CPP retirement; and the 4CPP's electricity can be replaced reliably, safely, and cost-competitively through a detailed and fully vetted process. (SC Br. at 12-19.) Sierra Club asserts that APS's announcement of seasonal operations at the 4CPP, which occurred only nine days after conclusion of the hearing in this matter, should cause the Commission to question APS's arguments and testimony that fossil generation is required for reliability. (SC Br. at 18.) Sierra Club further calls into question APS's motives for continued operation of the 4CPP (and its failure to analyze earlier retirement), noting Mr. Schlissel's testimony that having the 4CPP in rate base would earn APS and PNW nearly $600 million pre-tax from 2020 through 2035 and Mr. Guldner's testimony that the long-term equity incentive portion of executive compensation (stock compensation) has historically rewarded high coal capacity factors even when reduced capacity would save money.[167] (SC Br. at 19-20.)

In response to RUCO's position that the decision on recovery of the SCRs and the SCRs deferral

[167] Mr. Guldner testified that the long-term incentive implemented in 2021 will not include the coal capacity factor as a metric to reflect operational performance and that APS plans to introduce a carbon-reduction target in 2022. (Tr. at 563-566.) Mr. Guldner stated that the long-term incentive is based on both total shareholder return and operational performance and is not recovered in rates. (Tr. at 563-564.)

should be addressed in the 2016 Rate Case, Sierra Club asserts that the Commission should reopen the SCRs Phase to consider all relevant information, including Sierra Club's evidence that APS's decision to install the SCRs was imprudent. (SC RBr. At 16.)

b. Citizen Groups

Although the Citizen Groups did not take a position on recovery for the SCRs, and did not recommend that APS retire the 4CPP any time in the next couple of years,[168] they did take the position that the 4CPP is likely to be retired much earlier than 2031 because it is uneconomic, unreliable, and increasingly expensive to operate and maintain and will only become more unreliable and expensive with time. (CG Br. at 9; Ex. CG-8 at 3, 6.) Mr. Schlissel provided APS data responses showing the following: (1) as of mid-2020, APS had not analyzed retiring the 4CPP earlier than 2031; (2) since 2015, APS has only analyzed a 4CPP retirement earlier than 2038 in its 2017 IRP; (3) since the SCRs project began in early 2014, APS had not conducted any forward-looking economic analysis of Units 4 and 5; (4) to date, APS had not analyzed the economic costs and benefits of continuing to operate the 4CPP; and (5) to date, APS had not analyzed the impact on retail rates of a pre-2031 retirement of the 4CPP (either or both units).[169] (CG-6 at ex. DAS-2, ex. DAS-3, ex. DAS-4, ex. DAS-5, ex. DAS-6.) Mr. Schlissel asserted that in light of the significant changes in the 4CPP's performance as well as the energy market, APS's failure to perform such analyses was imprudent and unreasonable. (Ex. CG-6 at 5.)

Mr. Schlissel asserted that the 4CPP has become much less reliable and much more expensive to operate and that alternatives such as renewables have become much more plentiful and economically competitive, leading him to conclude that APS is likely to retire the 4CPP earlier than 2031.[170] (Ex. CG-6 at 6-9; Ex. CG-8 at 6.) Specifically, Mr. Schlissel observed that solar PPA prices have declined by more than 80% nationwide and even more in the southwest, with average capacity-weighted utility-

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[168] Ms. Horseherder testified that it is critical for the 4CPP to retire no later than 2031 because it is an obstacle to a transition away from a coal economy. (Ex. CG-2 at 14.)

[169] Mr. Schlissel testified that APS included the 4CPP as a "must run" resource in every scenario considered in its 2020 IRP, with the same level of generation regardless of the carbon costs or gas costs used, which he found not to make sense. (Ex. CG-6 at 6.)

[170] Mr. Schlissel noted that approximately 82 GW of coal-fired capacity has been retired since 2011, with more than half of the capacity younger than Units 4 and 5, and another 34 GW of coal-fired plants are scheduled to be retired or converted to burn gas in 2020-2025. (Ex. CG-6 at 28.)

scale solar prices falling from $168.49 per MWH in 2009 to $23.51 per MWh in 2019 (all in 2018 dollars); that median installed PV project prices decreased by 70% between 2010 and 2019; that adding battery storage to a PV project now costs approximately $5 per MWh for batteries sized at 25% of the PV capacity and up to approximately $15 per MWh for batteries sized at 75% of the PV capacity;[171] that PPA prices for wind resources have fallen dramatically to between $15 and $35 per MWh depending on the area of the country; that natural gas prices at the SoCal Border Hub have declined substantially since 2008 and are expected to stay low (projected not to exceed $3.00 per MMBtu from 2022-2029); and that the Palo Verde Hub market price was $28.10 per MWh in 2019 and was projected to be lower than $40 per MWh from 2021-2029. (Ex. CG-6 at 8-13.) According to Mr. Schlissel, the Western Energy Imbalance Market ("EIM"), launched in 2014, undermines the economic viability of the 4CPP because the EIM provides member utilities (such as APS and the other 4CPP owners) with access to trade low-cost renewable generation and reduces market costs for power, which will inevitably result in reduced market share for higher cost and more polluting resources such as the 4CPP. (Ex. CG-6 at 11.) Mr. Schlissel further pointed out that California, the largest electricity market in the west, requires a greenhouse adder for coal-generated power sold in the state, which further undercuts potential sales of coal-generated power. (Ex. CG-6 at 11.) Mr. Schlissel observed that the 4CPP's annual capacity factor declined from an 81% average in 2005-2009 to a 71% average in 2010-2014, and further to a 62% average in 2015-2019.[172] (Ex. CG-6 at 14.) Mr. Schlissel attributed this decline to lower natural gas prices starting around 2009, growing competition from renewable resources, and the 4CPP's declining reliability.[173] (Ex. CG-6 at 14.) Mr. Schlissel showed that the 4CPP's equivalent

[171] Mr. Schlissel cited two El Paso Electric PPAs signed in early 2020—one for 100 MW of solar resources at $15 per MWh and the other for 100 MW of solar resources and 50 MW of storage for $30 per MWh. (Ex. CG-6 at 9-10.)

[172] These capacity factors do not include the three-month downtime for each unit during SCR construction. (Ex. CG-6 at 15.)

[173] An immutable factor impacting the 4CPP's reliability is the high ash content of the coal supplied by the Navajo Mine, which makes the coal more abrasive and erosive, causes stress to the plant equipment, and increases maintenance needs. (Tr. at 1263-1266, 3667-3669.)

availability factor ("EAF")[174] and equivalent forced outage rate ("EFOR")[175] both demonstrate that the 4CPP did not operate up to the industry average for similarly sized coal plants in 2010-2019. (Ex. CG-6 at 16-18; Ex. CG-8 at 5.) Mr. Schlissel also observed that the 4CPP's production costs have increased dramatically over the past 10 years and opined that they will continue to rise. (Ex. CG-6 at 14-15.) Mr. Schlissel showed that the O&M costs (including fuel) for the 4CPP increased significantly between 2010 and 2019, from $23.95 per MWh in 2010 to $45.23 per MWh in 2019, with prices exceeding $54.00 per MWh in 2016-2018. (Ex. CG-6 at 18-20.) Mr. Schlissel added that these O&M costs do not include capital expenditures, annual depreciation expenses, annual property taxes, interest costs, or annual profits to shareholders, all of which are paid by ratepayers. (Ex. CG-6 at 20-21.) Mr. Schlissel noted that the annual depreciation expense for the 4CPP has risen from $4.747 million in 2010 to $37.355 million in 2019, as APS's rate base investment in the 4CPP has increased from $112 million to approximately $1.1 billion. (Ex. CG-6 at 21-22.) Mr. Schlissel also showed that since 2012, the average O&M expenses per MWh for the 4CPP have exceeded the average cost for power at the Palo Verde Hub. (Ex. CG-6 at 23.)

Mr. Schlissel concluded that from 2014-2019, APS's ratepayers paid more than $550 million more for power from the 4CPP than they would have paid had APS purchased the energy from the Palo Verde Hub. (Ex. CG-6 at 23.) Mr. Schlissel did not assume that APS would rely exclusively on power purchases from the Palo Verde Hub to replace the 4CPP, however, and instead opined that APS needs a long-term plan to replace the 4CPP, whether it is retired in 2031 or before, and should move to develop a plan to replace the 4CPP with renewables plus storage. (Ex. CG-6 at 24.) Comparing projected market prices at the Palo Verde Hub for 2021-2031 to projected costs to operate the 4CPP (APS-projected production costs, APS-projected capital expenditures, and APS's share of the

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[174] The EAF measures the power levels at which a plant actually operates, reflecting reductions in the power output while the plant is connected to the grid and capable of operation (i.e., "derates"). (Ex. CG-6 at 16.) The average EAF for similarly sized coal plants was 82% for the period from 2010-2014 and 80% for the period from 2015-2019. (Ex. CG-6 at 16-17.) The 4CPP had an average EAF of 76% for the period from 2010-2014 and of 66% for the period from 2015-2019 (including an increase to 78% in 2019). (Ex. CG-6 at 16-17.)

[175] The EFOR measures how much of the time a plant must reduce power fully or partially as a result of unplanned equipment problems. (Ex. CG-6 at 16.) For the period from 2010-2019, only in 2011 did either 4CPP unit have an EFOR lower than the industry average, with the 4CPP's EFORs instead being up to four times as high as the industry average. (Ex. CG-6 at 17-18.) From January-October 2020, the EFOR for Unit 4 was 17.1% while the EFOR for Unit 5 was 12%, while the industry average was approximately 8%. (Ex. CG-8 at 5.)

applicable CSA contract termination costs), Mr. Schlissel determined that APS ratepayers would pay between $1.1 and $1.3 billion less during that period if APS were to cease 4CPP operations in 2021 and between $934 million and $1.1 billion less if APS were to cease 4CPP operations in 2024. (Ex. CG-6 at 24-27.) Mr. Schlissel also concluded that if the 4CPP continues to operate until 2031 and to be included in rate base, PNW will earn almost $600 million pre-tax between 2021 and 2031. (Ex. CG-6 at 27.) Mr. Schlissel further opined that the costs to operate the 4CPP may be higher than APS projected because older coal plants tend to cost more to operate and maintain and are less reliable, less available, and less efficient than younger plants. (Ex. CG-6 at 28.)

Mr. Eisenfeld likewise testified that the 4CPP is likely to close sooner, citing Strategen Consulting's Arizona Coal Plant Valuation Study (September 2019), which concluded that every coal-burning unit that serves Arizona utility customers, whether located in or outside of Arizona, is more expensive to operate on a levelized cost than alternatives such as solar and wind and, further, that Units 4 and 5 were the two worst performers on an economic basis out of the 11 studied. (Ex. CG-3 at 15-16.) According to Mr. Eisenfeld, the data showed that closing down the 4CPP in 2023 and switching to solar plus storage would save customers almost $750 million, even when the "must take" provisions of the CSA were considered. (*Id.* at 16.) Mr. Eisenfeld also cited a July 2020 report from the Institute for Energy Economics and Financial Analysis ("IEEFA"), which identified factors that make the 4CPP no longer economically viable, and concluded that the average cost of power from the 4CPP has for the past eight years been substantially higher than what would have been paid to purchase energy on the open market instead. (*Id.* at 16-17.) Mr. Eisenfeld also provided a chart from TEP and UNSE, prepared in April 2018, projecting that the cost of energy from the 4CPP for 2020-2030 would be $79.54 per MWh while the costs from solar resources, wind resources, and a new build natural gas combined cycle plant would be $29.36, $32.10, and $52.13 per MWh, respectively. (*Id.* at 17-18.) Mr. Eisenfeld cited a dozen recent examples of power providers from western energy markets suddenly deciding to retire coal-burning power plants that had been slated to run for decades more. (*Id.* at 19-21.)

The Citizen Groups roundly criticized APS's 4CPP early retirement analyses filed in this docket on November 6, 2020, in response to Chairman Burns's letter of August 11, 2020, pointing out that

APS failed to include any CO_2 costs, although such costs had been included in its 2020 IRP; that APS failed to consider an optimized alternative portfolio for its analyses; that APS failed to analyze retirement of the 4CPP before the end of 2026, although Chairman Burns had requested such an analysis;[176] that APS optimistically assumed that the 4CPP's annual generation will remain flat between 2019 and 2031, that its EFOR will decline substantially, and that its O&M costs will grow at less than half the rate they grew between 2010 and 2019; and that APS overstated the reliability and technology risks of replacing the 4CPP with a portfolio of renewable resources plus storage while downplaying the significant risks for future declines in the 4CPP's operating performance and substantial increases in 4CPP O&M costs and capital expenditures. (Ex. CG-10.)

c. IBEW Locals

The IBEW Locals assert that APS should be authorized to recover its SCRs investments without further delay and should not be obligated to close the 4CPP before 2031. (IBEW Br. at 2; IBEW RBr. At 4-6.) The IBEW Locals assert that the SCRs investments are reasonable and prudent because they were mandated by federal environmental requirements and have allowed APS to keep the 4CPP open to serve APS's customers and provide economic benefits to the Nation and surrounding communities. (IBEW Br. at 9.) The IBEW Locals agree with APS's characterization of Sierra Club's position as an attempt to relitigate the prudence of the 4CPP and the SCRs. (IBEW RBr. At 5.) The IBEW Locals assert that the 4CPP is a valuable resource to APS customers and the overall APS system and crucial to APS's ability to serve reliably, particularly because of the record heat in summer 2020. (IBEW Br. at 9-10.)

d. Nation

The Nation asserts that APS should be authorized recovery of the SCRs investments because the SCRs were necessary and appropriate to allow the 4CPP to remain operational and were in service and contributed to the provision of service during the TY. (Nation Br. at 20.) The Nation asserts that the prudence of the SCRs investment is established by the fact that they were installed to comply with federal environmental regulations. (*Id.*) The Nation also states that APS is entitled to a reasonable

[176] Chairman Burns's August 11, 2020, letter does not request analyses for closure before 2026. However, in his letter dated September 1, 2020, Chairman Burns asked APS to develop and submit analyses using the four different described methods in his prior letter for a 2023 4CPP retirement scenario and for Cholla Units 1 and 3.

return upon the fair value of its properties at the time the rate is fixed[177] and that the fact that the 4CPP will be retired in the future does not impact the used and usefulness of the SCRs during the TY. (*Id.*)

e. Mr. Gayer

Mr. Gayer opposed having APS customers pay any costs for the 4CPP because it is "totally obsolete now, and is likely to lead to a future request for stranded costs upon . . . closure[.]" (Ex. Gayer-4 at 4.) Mr. Gayer asserted that it would be a waste for APS customers to pay $73 million for the "dying" 4CPP and that the costs "should be absorbed by PNW's shareholders." (*Id.*)

f. RUCO

RUCO adjusted rate base to remove the SCRs (a deduction of $399 million from net plant) and reversed APS's pro forma rate base adjustment of $33 million net plant for the SCRs deferral. (Ex. RUCO-1 at 16.) RUCO also reversed APS's pro forma operating expense adjustment of $8.3 million that reflected amortization of the SCRs deferral over 10 years. (RUCO Br. at 22.)

RUCO asserts that the SCRs deferral issue should not be resolved in this case and instead should be part of a separate proceeding. (RUCO Br. at 18; RUCO RBr. At 4.) RUCO asserts that 40% of the 5.6% increase in rates APS seeks in this matter is attributable solely to the SCRs. (RUCO Br. at 20.) RUCO argues that with APS's Clean Energy Commitment announcement that it would end all coal generation by 2031, seven years after investing $467 million in the SCRs, APS completely changed the circumstances of the SCRs deferral, because APS, ratepayers, the Commission, and other stakeholders intended and bargained for the 4CPP to operate during those seven years. (RUCO Br. at 20-21.) According to RUCO, the Commission relied on the 4CPP's operating until 2038 when it approved APS's acquisition of Units 4 and 5. (RUCO Br. at 20-21.) RUCO concedes that prudency is time-specific and should not be second guessed in hindsight, but also asserts that later developments should be considered if they were or should have been part of the prudency determination and that unilateral decisions that change financial dynamics after a prudency determination, such as APS's Clean Energy Commitment, are fair to consider when determining cost recovery. (RUCO Br. at 21.) According to RUCO, consideration of APS's SCRs recovery should be affected by the circumstances

[177] The Nation cited *Ariz. Corp. Comm'n v. Ariz. Pub. Serv. Co.*, 113 Ariz. 368 (1976) and *Simms v. Round Valley Light & Power Co.*, 80 Ariz. 245 (1956).

at the time the SCRs deferral was approved through the time the Commission makes its final decision on the deferral, because the Commission's deferral recovery decision must be backward looking to avoid having authorization for a deferral be equivalent to a "blank check." (RUCO RBr. at 3-4.)

RUCO argues that the Commission does not currently have enough information to make an informed decision on the SCRs and SCRs deferrals and urges the Commission "not to rush to judgment" unless it has all necessary facts.[178] (RUCO Br. at 22.) RUCO argues that because of the Clean Energy Commitment, ratepayers will be paying a return of and a return on the 4CPP for seven years beyond its useful life while they are also paying for the alternative generation and associated costs to replace the 4CPP generation. (RUCO Br. at 21.) Mr. Radigan testified that APS has made a number of bond offerings since the end of the TY, totaling approximately $1.7 billon with a weighted average interest rate of 3.05%, and that APS filed a prospectus with the SEC for $400 million of long-term debt to fund "Green Energy Expenditures." (Ex. RUCO-3 at 12.) RUCO suggests that securitization should be used to reduce the rates resulting from the SCRs, but acknowledges that securitization would require legislation. (Ex. RUCO-3 at 12; RUCO Br. at 20-21.) RUCO also notes Sierra Club's testimony showing that earlier retirement of the 4CPP would result in substantial savings for APS. (RUCO Br. at 21-22.)

g. Staff

Staff supports allowing APS to include the SCRs and associated deferrals in rate base and in the revenue requirement in this case. (Staff Br. at 6, 34; Staff RBr. at 11.) Mr. Smith recommended that the SCRs investment and SCRs deferrals be recognized in APS's rate base and the amortization of the SCRs deferrals be recognized as an amortization expense because the 4CPP has been providing service and has been a valuable generating capacity resource for APS. (Staff Br. at 32-33.) Staff cited CTC's findings in the SCRs Phase to support its position. (Staff Br. at 32; Staff RBr. at 11; Tr. at 5016-5017.) Staff also cited Mr. Albert's testimony that the 4CPP is needed to provide reliable service, particularly in the summer months; noted that both Mr. Radigan and Mr. Comings agreed that reliability should be a paramount concern with respect to the 4CPP retirement; and noted that Mr. Comings

[178] In addition to consideration of the SCRs and SCRs deferral recovery, Mr. Radigan suggested that the other proceeding should also address the Clean Energy Commitment, the Coal Community Transition Plan, retirement of the 4CPP, the AEM, securitization, and the possibility of a forecasted capital structure. (Ex. RUCO-3 at 12-13.)

acknowledged that he had not looked at reliability. (Staff Br. at 34 (citing Ex. APS-8 at 11); Staff RBr. at 12 (citing Tr. at 3087-3089, 4277).)

Staff asserts that the Commission should reject arguments that the Commission should not resolve the SCRs' prudency and inclusion in the revenue requirement until after recently raised issues about the 4CPP's retirement date are addressed, stating that those parties are arguing for prudency to be determined in hindsight, although prudency must be determined at the time of the key decisions to invest in plant and then concerning the construction of the plant. (Staff Br. at 34.) Staff also noted the risk, voiced by APS, that GAAP could require APS to write-off or write-down the costs of the SCRs if the Commission does not recognize them as prudent and rate recoverable in this matter and opined that this could result in a downgrade of APS's bond ratings. (Staff RBr. at 12-13.)

Staff identifies the SCRs deferral balance as $81.470 million as of December 31, 2020,[179] and asserts that the SCRs deferral would result in a net rate base increase of $32.771 million ($43.55 million minus ADIT of $10.779 million) in this case, consistent with APS's position. (Staff Br. at 11-12, 21.)

Staff supports APS's proposal to continue the deferred accounting for the 4CPP SCRs from January 1, 2021 (the originally anticipated new rates effective date), to the actual effective date for rates approved in this case and supports APS's proposal to address the additional deferrals in APS's next rate case. (Ex. S-15 at 42; Staff Br. at 31-32.)

In light of APS's announcement that the 4CPP will be retired in 2031 rather than 2038, the likelihood that APS will have large amounts of remaining net book value for the 4CPP if it is retired in 2031 or before, and some parties' advocacy for another proceeding in which the Commission would determine what the 4CPP retirement date should be or direct APS to retire the 4CPP as quickly as possible, Staff recommends that APS be required to update its economic analysis of the 4CPP and that a follow-up proceeding be held to address those issues. (Staff Br. at 33-34.) Staff recommends that the Commission reserve judgment in this case concerning whether the 4CPP should be retired sooner than 2031. (Staff Br. at 33-34.) Staff also advocates for APS to be required in the separate proceeding to analyze the impact of the 4CPP's seasonal operations on reliability. (Staff RBr. at 13.)

[179] The SCRs cost deferral balance is $37.919 million.

5. APS Response

According to Mr. Albert, the Citizens Group and Sierra Club witnesses inappropriately considered the 4CPP retirement independent of APS's overall resource plan, which must focus on reliability as well as other resource challenges such as meeting customer growth, retiring other coal-fired power plants, and adding sizeable amounts of renewable and battery energy storage capacity to further APS's Clean Energy Commitment. (Ex. APS-9 at 7-8; Ex. APS-8 at 1, 3-4.) Mr. Albert estimated that if the 4CPP were retired before 2031, APS's share of the 4CPP would need to be replaced by more than 1,000 MW of additional renewable generation plus 1,400 MW of battery energy storage, on top of what APS included in its 2020 IRP.[180] (Ex. APS-8 at 6-7, 11-12.) According to Mr. Albert, APS already plans to install 1,500-2,200 MW of battery storage by 2026 to meet customers' needs, and installing the additional battery storage necessary to replace the 4CPP would place too much reliance on a relatively new technology not yet in broad use.[181] (Ex. APS-9 at 8.) Mr. Albert stated that this would present a substantial reliability risk. (Ex. APS-8 at 7, 14.) Mr. Albert also testified that a 2023 shutdown of the 4CPP would not allow sufficient time to procure and assure the replacement resources needed to maintain reliability and that he even has concerns about the viability of retiring the 4CPP in 2026. (Ex. APS-9 at 10.)

Mr. Albert also testified that the generation market is currently too tight to assume that it could provide a reliable replacement for the 4CPP if it were retired before 2031 and that APS opposes relying on non-asset backed market purchases to meet fundamental reliability requirements both because having non-asset backed power become unavailable was one of the issues that caused California's rolling blackouts during the August 14-15, 2020, heat storm[182] and because EIM rules prohibit APS

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[180] Mr. Albert stated that it would take a total of 1,400 MW of storage (600 MW standalone and 800 MW combined with solar PV) and 750 MW of renewables to provide the same approximate on-peak value as APS's 970 MW share of the 4CPP. (Ex. APS-8 at 7, 14.)

[181] Mr. Albert stated that APS believes battery storage will be the technology that can fill the gap left by renewables after the 4CPP is retired and that having battery replacements of that scale will be feasible in the long term. (Ex. APS-9 at 10.)

[182] Mr. Albert initially suggested that the rolling blackouts California experienced on August 14-15, 2020, were a result of California's planning processes not keeping pace with the state's incorporation of large amounts of renewables, retirement of thermal generating assets, and reliance on imported power and demonstrated that the regional wholesale market does not have surplus generation resources available during peak customer usage periods. (Ex. APS-8 at 9-10.) Mr. Albert subsequently acknowledged at hearing that the rolling blackouts were not caused by California's environmental goals, adoption of renewable resources, and retirement of traditional generation, but rather by inadequate planning for replacement of declining solar output with flexible dispatchable generation as the sun goes down. (Tr. at 1081-1082; Ex. SC-15 at 10-11.) Mr. Albert stated that this situation creates a "critical reliability challenge" that must be addressed. (Tr. at 1082.) Mr.

from meeting its reliability requirements with capacity from the EIM. (Ex. APS-8 at 1, 3-4, 5-6, 9-10.) According to Mr. Albert, the 4CPP was operating essentially at full capacity in the late afternoon and evening hours on August 14 and 15, 2020, and APS was able to meet demand, although it did request voluntary conservation.[183] (Ex. APS-8 at 10-11.)

In response to Mr. Eisenfeld's testimony, Mr. Albert stated that using a levelized cost comparison is inappropriate, as energy wholesale market purchases and renewables plus storage do not provide the same reliability as the 4CPP. (Ex. APS-8 at 7.) Mr. Albert further asserted that because the capacity value of solar generation and storage systems decreases as penetration increases on a system, it would take far more solar plus storage to replace the 4CPP than Mr. Eisenfeld assumes.[184] (Ex. APS-8 at 7.) Additionally, Mr. Albert asserted that the Strategen study upon which Mr. Eisenfeld relied had major flaws, including failure to consider system reliability, using public cost information from a single project that would not apply to APS, assuming a 30% Investment Tax Credit that is unlikely to be available for a replacement project, assuming 4CPP retirement in 2038, and assuming costs for the entire 4CPP rather than APS's 63% share. (Ex. APS-8 at 8-9.)

APS opposes Sierra Club's advocacy for a 2023 retirement of the 4CPP and Sierra Club's recommendation for the Commission to require APS to evaluate earlier retirement of the 4CPP in its 2020 IRP and issue an all-source RFP for replacement of the 4CPP. (APS RBr. at 11.) Mr. Albert asserted that Sierra Club's 4CPP analysis should be entirely disregarded because APS would need to increase the amount of renewables plus storage significantly beyond Sierra Club's assumptions to provide the same reliability as the 4CPP, and generic market purchases are insufficient to replace the 4CPP. (Ex. APS-8 at 11-12.) Mr. Albert also asserted that APS is only one of five owners of the 4CPP and cannot retire the 4CPP unless the other owners agree. (Ex. APS-8 at 13.) According to Mr. Albert,

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Albert also acknowledged that the CAISO, CPUC, and California Energy Commission had determined that root causes of the rolling blackouts included natural gas plants that were offline altogether or were unable to produce at capacity due to ambient conditions and the failure of a generating unit owner to provide replacement capacity for almost 400 MW of planned gas outages. (Tr. at 1083-87; Ex. SC-16.)

[183] APS had a small amount of market purchases from the CAISO curtailed and was able to replace them with APS resources so that APS customers did not experience curtailments. (Ex. APS-12 at 11.)

[184] Subsequently, Mr. Albert clarified that this is related to timing and the system peak and that there will come a point when APS's system has enough solar to serve its demand during the hours that solar produces, at which point adding solar resources will no longer benefit its system. (Tr. at 1190-1192.) Mr. Albert testified that the same can happen with energy storage systems, although he acknowledged that it is possible to stagger battery operations based on their duration. (Tr. at 1192-1193.)

APS analyzed a 2031 (versus 2038) 4CPP retirement in its 2017 IRP and concluded that costs would be slightly increased in the 15-year term with the 2031 retirement and would be slightly reduced over 30 years. (Ex. APS-8 at 12.) APS also criticized Sierra Club for failing to address or even acknowledge the significant community impacts that will come with the 4CPP's retirement. (APS RBr. at 11.)

In response to Chairman Burns's request for APS to evaluate retiring the 4CPP before 2031, APS hired Energy and Environmental Economics Consulting ("E3") to evaluate the four different cost-recovery alternatives proposed by Chairman Burns at a high level, using information from APS's 2020 IRP. (Ex. APS-8 at 13-14; Tr. at 1092-1093.) Per Mr. Albert, the E3 analysis shows that with securitization of APS's unrecovered book value of the 4CPP upon retirement, regardless of the retirement date, APS's customers could save approximately $200 million NPV over the base case (retirement in 2031 and full depreciation by 2038), not that the economics favor an early retirement of the 4CPP if securitization is available. (Ex. APS-9 at 9; Tr. at 1095-1098.) According to Mr. Albert, the E3 analysis was only intended to compare ratemaking treatments using accelerated depreciation or securitization, not to analyze early retirement. (Ex. APS-9 at 9; Tr. at 1091, 1095, 1098.) Mr. Albert acknowledged that the resource mix used for the E3 analyses was not an "optimized" replacement portfolio but defended it as a reasonable and representative mix of solar, wind, and battery storage designed to meet peak evening capacity needs. (Ex. APS-9 at 10; Tr. at 1093-1094.) Mr. Albert acknowledged that the capacity credit E3 used for battery storage in its analyses was between 50% and 60% and had been decided upon jointly with APS.[185] (Tr. at 1097.) Mr. Albert acknowledged that the E3 analysis did not assume any carbon costs, although APS had assumed carbon costs in its 2020 IRP, and Mr. Albert believed it was reasonable to include them. (Tr. at 1094-1097.) Mr. Albert further acknowledged that the E3 analysis did not attempt to evaluate what maintenance or capital expenditures could be avoided leading up to a 2026 retirement and that APS had instructed E3 that a 2023 retirement could not realistically be done. (Tr. at 1095, 1099.)

APS disagrees with RUCO's position that the SCRs should be removed from rate base and the related depreciation accrual eliminated because, APS asserts, the investments in the SCRs were

[185] Sierra Club presented evidence that E3 assumed much higher capacity credit for battery storage in California for 2025 (90%) and 2030 (80%) under situations with higher projected battery penetration levels. (Ex. SC-6 at 5-6.)

reasonable and prudent, and the SCRs were placed into service before the TY. (Ex. APS-13 at 12, 19-20.) APS argues that RUCO has provided no credible evidence or reason to delay APS's requested SCRs recovery in this case and that further delay of such recovery would be inappropriate, contrary to prior Commission decisions, and potentially unlawful. (APS Br. at 13.) APS asserts that the continued delay increases the risk that APS will need to write-off or write-down the investment and any related costs due to disallowance under GAAP. (APS Br. at 13; Ex. APS-14 at 11; Tr. at 1503-1506.) APS further asserts that Mr. Radigan is focusing on prospective events that will not occur until 2031 to argue that the Commission should not permit cost recovery for facilities that are used and useful today and will be for years to come. (APS Br. at 14.) APS cites Mr. Smith's testimony that the issues in this case are what should be included in rate base for the plant that is in service and how the SCRs deferrals should be addressed, not what to do about remaining net book value at the 4CPP when it is retired. (APS Br. at 14 (citing Tr. at 5141-5143).) APS argues that its decision to retire the 4CPP in 2031 instead of 2038 has no bearing on the prudency of APS's decisions to invest in the SCRs and does not call into question the Commission's decisions that approved those investments. (APS Br. at 15 (citing Decision No. 76295).)

According to APS, its decision to invest in the SCRs must be evaluated with the information that was available to APS at the time it purchased SCE's shares in the 4CPP. (APS R. Br. at 9-10.) APS asserts that the Sierra Club's attempts to relitigate the prudence of the 4CPP and SCRs wrongly ignores prior Commission decisions and the Commission's own definition of prudency. (APS Br. at 16 (citing Decision No. 74786).) APS further argues that because Sierra Club was a party to the SCE acquisition case that resulted in Decision No. 74876, and Sierra Club did not appeal Decision No. 74876, Sierra Club may not now challenge its validity. (APS Br. at 17 (citing *Kunkle Transfer & Storage Co. v. Super. Ct.*, 22 Ariz. App. 315, 317 (1974); Ariz. Const. Art. XV, § 17; A.R.S. §§ 40-252, 40-253, 40-254.01).) APS characterizes Sierra Club's arguments as effectively trying to reopen Decision No. 74876 and Decision No. 76295 and as "impermissible collateral attacks" on those decisions. (APS Br. at 18 (citing A.R.S. § 40-252; *Miller v. Ariz. Corp. Comm'n*, 227 Ariz. 21, 24 (App. 2010); *Mountain States Tel. & Tel. Co. v. Ariz. Corp. Comm'n*, 124 Ariz. 433, 436 (App. 1979)).) APS further argues that Sierra Club does not understand the meaning of prudency, which is based on

circumstances at the time of investment, is presumed for utility investments under A.A.C. R14-2-103(A)(3)(l), and must be rebutted by clear and convincing evidence. (APS Br. at 18-19; APS RBr. at 4, 9.) Additionally, APS argues that allowing Commission decisions to be revisited "for any reason whatsoever" would eliminate the finality and precedential value of Commission decisions, would adversely impact utilities' ability to raise capital, and would increase the cost of capital, harming ratepayers. (APS RBr. at 5-6.)

6. Resolution

The prudency of the SCRs project investments has not yet been determined by the Commission. In Decision No. 74876, the Commission expressly determined the prudency of APS's investment in Units 4 and 5.[186] The Commission did not expressly determine the prudency of the SCRs, although the Commission was aware that the SCRs would need to be added to Units 4 and 5 to allow for continued operation of the 4CPP beyond 2018. We concur with the Sierra Club's position that the Commission would not and did not implicitly find the SCRs investment to be prudent, as we do not believe that the Commission could make such a finding without knowing the extent of the SCRs project investments and APS's capacity needs at the time those investments were made. The language of the Settlement Agreement approved in Decision No. 76295 also supports a determination that the prudency of the SCRs project has not yet been determined, as it expressly retained the Commission's authority to review the entire SCRs project and make disallowances for imprudence, errors, or inappropriate application of the requirements of Decision No. 76295.[187] (Ex. APS-70 at 23-24, ex. A at 12.)

RUCO urges the Commission not to rule on the prudency of the SCRs project investments in this docket and instead to consider them in a separate proceeding where additional evidence can be obtained. We surmise that RUCO is hopeful securitization will become an option before the Commission issues a decision on prudency so that recovery through securitization can be used to save ratepayers a significant sum. The Sierra Club supports RUCO's argument for delay, with the 2016

[186] The Commission found prudent in the Decision "the transaction by which APS acquired SCE's share of Units 4 and 5" and "the Four Corners acquisition transaction." (Decision No. 74876 at 43, 46.) The Commission did not say anything about prudency related to the future investments to install the SCRs.

[187] APS interprets this language to mean that the Commission can review the prudency of the installation costs incurred for the SCRs and the execution of installing the SCRs, not the prudency of investing in the SCRs in the first instance, which APS believes was settled when the acquisition of SCE's interest in Units 4 and 5 was approved. (Tr. at 199-200, 240-241, 450-452.)

Rate Case docket as the vehicle, but presumably only if the Commission does not find herein that APS's SCRs project investments were imprudent, as that is Sierra Club's primary position. The evidence herein shows that APS may be forced to write-off or write-down its SCRs project investments if the Commission does not soon act on its request for recovery. It would be inappropriate for the Commission's decision on APS's recovery for the SCRs project investments to come through inaction and further delay and the operation of GAAP. A rate case is the most appropriate context in which to determine recovery for the SCRs, and this rate case is the best vehicle for the decision because the evidentiary record from the SCRs Phase (although now outdated) has been made part of the record in this case. Thus, the Commission will determine in this case the prudency of the SCRs project investments and the extent to which APS should receive recovery.

When the Commission determined that the SCE acquisition was prudent in December 2014, the Commission made that finding with the understanding that Units 4 and 5 would be operating at the same capacity through 2038,[188] and after rejecting Sierra Club's contentions that the acquisition was imprudent because future natural gas and carbon emission prices would render continued operation of Units 4 and 5 uneconomical and would result in early closure of the plant and that there was a risk of decreased output from Units 4 and 5. When APS filed its application in this matter on October 31, 2019, APS indicated that the 4CPP would not shut down earlier than 2038. Only a few months thereafter, in January 2020, APS made its Clean Energy Commitment, indicating that it would exit coal generation by 2031. During this matter, APS consistently emphasized the importance of Units 4 and 5 to the reliability of APS's service, particularly during the peak summer months, and the need to keep Units 4 and 5 in service until 2031. Since the hearing, APS has announced that the 4CPP will switch to seasonal operations in fall 2023, so that both Units 4 and 5 will be in service only during the summer months (June through October), and only one of the Units will be in service the remaining months.

Sierra Club has mounted an aggressive case to demonstrate that the SCRs investments were imprudent and that recovery of those costs should not be allowed. Its evidence suggests that APS may have willfully maintained ignorance concerning whether it would be beneficial (at least from a

[188] 2011 Rate Case 4CPP Rate Rider Tr. at 248, 304, 307, 309, 534. Official notice is taken of these transcripts.

ratepayers' perspective) to change direction at some point prior to the completion of the SCRs. We agree with Sierra Club that a utility has a duty to monitor the economics of its investments and the market consistently to determine whether it should alter its prior choices for the benefit of itself and its shareholders, its ratepayers, and/or the public at large. The evidence presented suggests that APS did not do this and may instead have become entrenched in continued operation of the 4CPP, and thus installation of the SCRs, without seriously considering whether better or less expensive alternatives had become available.

It is concerning that APS did not evaluate a pre-2038 retirement of the 4CPP until its 2017 IRP, did not conduct any forward-looking economic analysis of Units 4 and 5 after the SCRs project began in early 2014, and to date has not meaningfully analyzed the costs and benefits and rate impacts of a pre-2031 retirement of the 4CPP. For a number of reasons it is difficult to believe that APS was not aware that its need for the 4CPP might soon change and that there might be more economical alternatives than going forward with the SCRs for both Units 4 and 5. For example, Sierra Club challenged APS's NPV analyses presented in the 2011 Rate Case as well as its failure to perform a sensitivity analysis for the continued operation of Units 4 and 5 for another 25 years;[189] the single pre-2038 retirement analysis conducted in the 2017 IRP analysis showed long-term savings and only minor short-term increases from retiring the 4CPP in 2031; the energy industry and market, in which APS participates, have changed dramatically since 2014, with renewables in particular experiencing significant cost declines; and in August 2016, the Commission opened a docket for review, modernization, and expansion of the Arizona energy standards and tariff rules and associated rules, in which APS and a number of other parties participated. Additionally, and notably, on October 31, 2017, a Certification of Stipulation[190] was issued by Hearing Examiners in the NMPRC PNM rate case, which had commenced in December 2016. In the Certification of Stipulation, the Hearing Examiners found that permitting PNM recovery on the cost of the SCRs at its embedded cost of debt would be unreasonable and not in accordance with the law because PNM's decision to continue using the 4CPP was not prudent. (Ex. SC-38 at 5.) In the case order, issued by the NMPRC on December 20, 2017,

[189] *See, e.g.,* 2011 Rate Case 4CPP Rate Rider Tr. at 506-521.
[190] The language of the NMPRC order suggests that this is analogous to a ROO.

the NMPRC went further:

> [T]he Commission also finds that PNM's imprudence extended not just to the decision to install SCR and make additional investments in [the 4CPP], but to PNM's determination that continued use of [the 4CPP] as base load generation was necessary. This is especially concerning in light of evidence adduced at the hearing in this matter concerning [the 4CPP's] poor operating performance and impaired availability rate, as well as PNM's prior representations to the Commission . . . concerning the necessity for acquiring and retaining baseload generation capacity at Palo Verde Nuclear Generating Station . . . .[191]

APS does not appear to have been a party to the NMPRC PNM case, but it would stretch credulity to believe that it was not aware of the case from its inception and of the developments therein concerning its co-owner PNM's recovery of and on SCRs costs. Thus, by no later than October 31, 2017 (and probably much earlier), APS should have been well aware that the operations and economics of the 4CPP had changed enough to cause reasonable minds to question whether the 4CPP should continue to operate and whether the SCRs were a prudent investment. At that point, the SCRs installations had not been completed for either Unit 4 or Unit 5, although the record does not establish definitively how much had already been invested in the SCRs.[192]

It cannot reasonably be disputed that APS's decision to retire the 4CPP seven years earlier than previously indicated has fundamentally altered the situation that existed during the SCRs Phase and that was reflected in the evidentiary record and the SCRs ROO. Nor can it reasonably be disputed that APS's decision to move the 4CPP to seasonal operations since the conclusion of the hearing in this case has further altered the situation.[193] In light of the fundamental changes, it would be inappropriate for the Commission to rely upon the recommendations contained in the SCRs ROO to reach its decision concerning recovery for the SCRs in this matter.

Because of APS's failure to reevaluate the need for Units 4 and 5 and the SCRs over the intervening years since Decision No. 74876, we cannot conclude that the SCRs investments were made prudently and should be included in rate base. We base this on our conclusion that APS either knew

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[191] Ex. SC-38 at 19-20.

[192] Evidence in the SCRs Phase suggests that as of December 2017, $166.767 million had been spent for the Unit 5 SCRs. (*See* SCRs Ex. APS-5 at att. EAB-16RB.)

[193] LFE SC-41 makes it clear that APS is able to control the manner in which the 4CPP's operations change, as its majority ownership would suggest.

or should have known by no later than November 1, 2017, that the economics of continuing to operate Units 4 and 5 had changed such that going forward to complete the SCRs investments for both Units 4 and 5, without first performing additional economic analysis to ensure that all of the investments were necessary for continued reliable service to its customers and would be beneficial to APS and its ratepayers, was imprudent. We are cognizant that Units 4 and 5 and their respective SCRs were used and useful during the TY and that both will continue to be used and useful until fall 2023, when one will become used and useful only part-time. But the fact that plant is used and useful, alone, is not tantamount to prudency.

In light of our conclusion that prudency of the SCRs project investments has not been demonstrated, and the SCRs costs will not be allowed in rate base, we conclude that it would not be just and reasonable and in the public interest to allow APS to recover the SCRs cost deferral and the SCRs deferred debt return or to authorize continuation of the deferrals. When APS was granted authority to defer the SCR costs, with a rate of return, APS was given preferential ratemaking treatment. In the absence of the deferrals, APS would never have had an opportunity to recover those costs. That preferential ratemaking treatment provided APS an opportunity to demonstrate that its decisions related to the SCRs were undertaken after due care and consideration of the optimal choices for itself and its customers, whom APS expected to shoulder the burden of the deferred costs and return. By willfully failing to reevaluate its choices concerning the SCRs installations, APS failed to meet the expected standard of due care. Accordingly, recovery of the existing deferrals for the SCR costs and the SCR deferred debt return will be denied, and authorization to record future SCR cost deferrals will be terminated herein.

These determinations result in a rate base disallowance for the SCRs of $398.743 million and for the SCRs deferrals of $61.128 million. Additionally, they result in a disallowance of $16.715 million in depreciation expense for the SCRs and $8.147 million in amortization expense for the SCRs deferrals.

C. OMP & OMP Deferral

1. APS Recovery Request

In 1960, the Ocotillo Power Plant ("Ocotillo"), located in Tempe, started providing service to

APS customers with two 110 MW gas-fired steam turbines. (Ex. APS-7 at 2.) In the early 1970s, two 55 MW combustion turbine ("CT") units were added, bringing its generation capacity to 330 MW. (*Id.*) Ocotillo is served by an El Paso Natural Gas pipeline and, according to Mr. Albert, has been critical to APS's ability to provide reliable service, providing generation capacity inside the Phoenix area load pocket and supporting local transmission infrastructure. (*Id.*)

Through the OMP, APS retired the 1960 steam units (220 MW) and replaced them with modern CTs (five 102 MW units for a total 510 MW) that provide greater operational flexibility,[194] are more efficient, have lower nitrogen oxide ("NOx") and carbon monoxide (CO) emissions, and use less water per kWh. (Ex. APS-7 at 3.) The Ocotillo steam units were retired in fall 2018. (Ex. APS-7 at 6.) Mr. Albert testified that the old steam units had become difficult to repair and maintain and had safety issues, that the OMP presented a unique opportunity to add capacity within the Phoenix load pocket to meet peak loads in summer months[195] and to use existing infrastructure (natural gas pipeline, transmission, and water infrastructure), and that the OMP was needed to support integration of increasing levels of renewable energy. (Ex. APS-7 at 4.) Mr. Albert stated that due to its location, the OMP provides valuable voltage support for the load in the Phoenix area, because voltage support from generation declines with distance, and helps APS maintain the Phoenix Area Maximum Load Serving Capability ("MLSC").[196] (*Id.* at 4-5.) APS made its decision to go forward with the OMP after issuing a peaking Request for Proposals ("RFP") in 2015 to assess whether there were better market alternatives and analyzing 21 market proposals and six self-build proposals; APS also used an RFP process to select the contractor for the OMP. (Ex. APS-7 at 7.) The OMP was the lowest cost project

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[194] The OMP CTs can be started and stopped multiple times each day and have fast-ramping capabilities, with the ability to provide power to the grid within six minutes and to be at full capacity in under 10 minutes. (Ex. APS-7 at 5.) Mr. Albert stated that this flexibility is needed to help APS manage its load shape. (*Id.* at 8-9.) Because the OMP units can be stopped and restarted during the day, APS avoids overgeneration that would need to be sold to the market, potentially with negative pricing, to avoid a reliability risk. (*Id.* at 10.) Mr. Albert reported that negative pricing occurred 6,840 times in the five-minute market at the Palo Verde hub during the TY, occurring primarily in the middle of the day and during the months of March through May 2019. (*Id.* at 10-11.)

[195] There was a need for new generating capacity due to customer growth and more than 2,000 MW of expiring purchase power contracts. (Ex. APS-7 at 8.)

[196] MLSC is the maximum load that can be served inside a load pocket with all local generation producing at full output and transmission imports at their limit. (Ex. APS-7 at 5.) Mr. Albert stated that the Phoenix Area MLSC needs to be maintained at a level greater than the maximum Phoenix Area load plus planning reserves and that in the event of a 500 kV line outage, OMP increases the Phoenix Area MLSC and provides important reliability benefits. (*Id.*)

that met the RFP requirements, with a budgeted cost of $530.490 million[197] and a targeted in-service date of spring 2019, and was completed on schedule and on budget and went into service in May 2019. (*Id.*) According to Mr. Albert, the cost of the OMP as of September 30, 2019, was approximately $524 million. (*Id.*)

Mr. Albert testified that between June 1 and August 31, 2019, the OMP units were started 360 times and provided 232,000 MWhs to the grid at an average capacity factor of 20.6%. (Ex. APS-7 at 14.) Mr. Albert stated that the OMP units were used to serve customers on the peak day of August 5, 2019. (*Id.*) Additionally, the OMP units were used to provide regulation and off-line reserves needed to meet NERC reliability requirements and to enhance system reliability when other units had outages. (*Id.*) Mr. Albert further testified that all five units of the OMP played an integral role in APS's providing reliable service to customers during the "heat storm" in mid-August 2020 that resulted in desert southwest utilities declaring energy supply emergencies or issuing rolling blackouts. (Ex. APS-8 at 38.)

In addition to approving the OMP deferral in the 2016 Rate Case, the Commission approved a Certificate of Environmental Compatibility ("CEC") for the OMP (in Decision No. 74812 (November 13, 2014)[198]) and acknowledged APS's 2014 IRP that included the OMP (in Decision No. 75068 (May 8, 2015)[199]). (Ex. APS-7 at 12-13.)

As of the end of the TY, the OMP deferral regulatory asset totaled $9.5 million, with the cost-of-debt return comprising $5.3 million. (Ex. FEA-5 at 6 (citing APS workpaper).) By June 30, 2020, the OMP deferral regulatory asset totaled $56.1 million, with the cost-of-debt return comprising $27.8 million. (*Id.*) As of December 31, 2020, the OMP deferral regulatory asset was estimated to total $95.1 million, with the cost-of-debt return comprising $46.4 million. (*Id.*) As stated above, APS proposed to include $64.397 million in rate base for the OMP deferral regulatory asset, which it asserted included amortization of the OMP deferral through September 30, 2020, and estimated amortization through December 31, 2020. (LFE APS-87 at sched. B-2.) APS also proposed a corresponding

[197] As of September 30, 2019, the total OMP project costs were approximately $524 million, including direct cost plus overhead but not including Allowance for Funds Using During Construction ("AFUDC"). (Ex. APS-7 at 7.)
[198] Official notice is taken of this decision.
[199] Official notice is taken of this decision.

depreciation and amortization expense of $9.507 million. (LFE APS-87 at sched. C-2.)

2. Other Parties' Positions

a. FEA

FEA did not contest the prudency or used and usefulness of the OMP, but did contest APS's request to recover the OMP deferred costs in rates. (FEA RBr. at 1.) FEA argued that APS has failed to meet its burden of demonstrating that inclusion of the OMP deferral in rates is justified and, further, that by deferring the costs, APS is effectively seeking increased compensation from its customers. (FEA Br. at 3, 5.) FEA also asserted that the Commission only approved deferral of the OMP costs in the 2016 Rate Case decision, not recovery of the costs. (FEA RBr. at 2.) FEA argued that the 2016 Rate Case decision's language concerning "possible later recovery through rates" would be meaningless if the Commission did not require APS to demonstrate whether the revenues it collected during the deferral period were sufficient to provide APS full compensation for the OMP non-fuel costs incurred during the deferral period. (FEA RBr. at 2.)

Mr. Gorman testified that APS has not justified including the OMP deferred costs in rates. (Ex. FEA-1 at 4.) Mr. Gorman asserted that APS's earnings during the deferral period were stronger than normal due to increased revenue from customer sales growth and operating expense and depreciation savings associated with retiring the old Ocotillo units. (*Id.* at 10-11.) According to Mr. Gorman, because APS's revenues during the deferral period were more than adequate for APS to expense the deferrals during that time, APS has been fairly compensated for its full cost of service, including the post-in-service costs associated with the OMP, even though the OMP costs were not explicitly included in the development of APS's cost of service in the 2016 Rate Case. (*Id.* at 4, 9-10.) Mr. Gorman further stated that APS's earning of a 9.7% ROE during the TY, when it was authorized a 10.0% ROE, alone does not demonstrate that APS's revenue during the deferral period was inadequate for APS to recover the full OMP deferred costs. (Ex. FEA-5 at 5.) Mr. Gorman showed that APS only deferred approximately $9.5 million of OMP costs during the TY, with the bulk being deferred between July 1, 2019, and December 31, 2020. (Ex. FEA-5 at 5-6.) Mr. Gorman acknowledged that expensing the deferred cost during the TY would have reduced APS's earned ROE for the TY, but asserted that APS has not demonstrated that the lower earned ROE would not have provided APS fair compensation

based on the prevailing market COE during the period. (Ex. FEA-1 at 10; Ex. FEA-5 at 6.) Mr. Gorman added that the ROE authorized for APS in the 2016 Rate Case is well above market COE, as Mr. Walters demonstrated in his testimony. (Ex. FEA-5 at 6-7.) Mr. Gorman also criticized APS for not reflecting any avoided fixed O&M and depreciation expense offsets against the post-in-service deferred OMP costs. (Ex. FEA-1 at 10; Ex. FEA-5 at 4.) Mr. Gorman recommended that the OMP costs be disallowed, which he asserted would reduce APS's TY revenue requirement by approximately $15.7 million based on FEA's adjusted FVROR. (*Id.* at 4, 10-12; Ex. FEA-5 at 2, 9.)

Mr. Gorman proposed as a compromise position that if the Commission were to allow the OMP deferral costs, they should be recovered on a levelized basis over a 10-year period with a carrying charge set at APS's embedded cost of debt (rather than the WACC), which would result in a TY cost of $11.2 million for 10 years and would reduce APS's proposed revenue requirement by $4.5 million. (Ex. FEA-1 at 4-5, 11-12; Ex. FEA-5 at 3, 9.) Mr. Gorman disagreed with APS's criticism of the recommendation for cost-of-debt recovery, asserting that using a cost-of-debt return is not contrary to normal regulatory asset treatment for abandoned plant assets. (Ex. FEA-5 at 8.) Mr. Gorman asserted that when a facility is no longer used and useful and has a fair value below its original cost, allowing recovery of costs incurred when the facility was used and useful through amortization of the abandoned plant costs with a reduced carrying charge "strikes a reasonable balance." (*Id.* at 8.) Mr. Gorman added that APS's "proposal to defer costs that should be recovered currently is contrary to normal accounting practices for ongoing cost of service" and characterized both APS's proposal and his own compromise proposal as "extraordinary regulatory treatment for non-traditional abandoned plant costs." (*Id.*)

In response to Staff's support for recovery of the OMP deferrals through rates, FEA argued that neither APS nor Staff provided any evidence that it would be just and reasonable to include the deferred non-fuel OMP costs in APS's rates. (FEA RBr. at 2.) FEA also criticized Staff for suggesting that FEA's position was inconsistent with the Settlement Agreement and decision in the 2016 Rate Case, arguing that it is actually Staff's position that fails to follow the clear language of the Settlement Agreement and decision by disregarding the language about "possible later recovery through rates." (FEA RBr. at 2-4.) FEA also called Staff's characterization of Mr. Gorman's analysis as creating an

earnings test overly simplistic and noted that Staff's argument did not address Staff's failure to assess whether the deferred costs should be recovered through rates. (*Id.* at 3.) According to FEA, the only evidence of record concerning whether it is reasonable and justified to allow APS to recover the OMP cost deferrals through rates is that from Mr. Gorman, which showed that APS collected adequate revenue from customers to allow it to recover the deferred costs and earn a market compensatory return. (*Id.* at 3.) FEA also noted that APS's cost of debt is the same interest rate the Commission approved for carrying the deferrals during the deferral period. (*Id.* at 4.)

b. Other Intervenors

Aside from his average-of-period adjustments to all existing plant in rate base and to recent requested deferrals (including the OMP deferral), Mr. Higgins for AECC/Freeport did not make adjustments to remove the OMP or OMP deferral from rate base. (See Ex. AECC-1 at ex. KCH-1, ex. KCH-4, ex. KCH-6; Ex. AECC-3 at ex. KCH-1-S, ex. KCH-4-S, ex. KCH-6-S; AECC-Final Sched. at ex. KCH-1, ex. KCH-4-S, ex. KCH-6-S.)

RUCO included both the OMP and the OMP deferrals in rate base. (Ex. RUCO-1 at ex. FWR-2 at sched. B-2; Ex. RUCO-3 at ex. FWR-32 at sched. B-2; RUCO-Final Sched. at sched. B-2.)

The IBEW Locals also supported inclusion of the OMP and OMP deferral costs in rate base, citing the benefits described in Mr. Albert's testimony. (IBEW Locals Br. at 9-10.)

Mr. Gayer opposed having APS customers pay for the OMP, asserting that it would be "shocking" to have APS customers pay $100 million[200] for the OMP when the Ocotillo plant is a natural gas plant, a "legacy technology." (Ex. Gayer-4 at 4.)

c. Staff

On surrebuttal, Staff accepted APS's rebuttal adjustments for the OMP. (Ex. S-15 at 16, sched. B-15, sched. C-22.) At hearing, Mr. Smith testified that the OMP should be included in rate base because it was in service and useful during the TY and continued to be in service and appeared to be a very valuable resource to APS for reliability. (Tr. at 5052-5053.) Mr. Smith added that the OMP had reduced pollution and water usage. (Tr. at 5053.) Mr. Smith also testified that the OMP deferrals were

[200] In response to a data request, APS attributed $100 million of its requested $184 million revenue increase to the OMP. (Ex. Gayer-1 (response to Gayer 1.5).)

included because they were part of the Settlement Agreement in the 2016 Rate Case.[201] (Tr. at 5053.) Mr. Smith also confirmed that he had conducted an economic analysis of the OMP, although he also relied in part on analyses done in previous proceedings. (Tr. at 5101.)

In its brief, Staff supported inclusion of the OMP plant and deferrals in rate base, citing the testimony of Mr. Albert regarding the benefits of the OMP. (Staff Br. at 35.) Staff asserted that only FEA had raised concerns about the OMP deferrals and that the concerns addressed in Mr. Gorman's testimony "appear to be at odds with the Settlement Agreement approved by the Commission which FEA signed." (*Id.*) Staff asserted that Mr. Gorman's suggestion for "some sort of earnings test" before allowing the costs and for use of levelized cost recovery using the cost of debt as the carrying charge "appear to be inconsistent with the provisions in the Settlement Agreement." (*Id.* at 35-36.) Staff supported increasing APS's rate base by $82.009 million to reflect the projected amount of the OMP deferral through December 31, 2020. (*Id.* at 36.) Staff also supported APS's proposal for deferral of OMP costs from January 1, 2021 (APS's originally anticipated new rates effective date for this case), to the actual rate effective date for rates approved in this case and APS's proposal to address the deferral in its next rate case. (Staff Br. at 36; Ex. S-15 at 42.)

3. APS Response

APS argued that the OMP and the OMP deferral costs should be included in rate base because the Commission authorized a deferral order in the 2016 Rate Case, and the OMP is necessary, used and useful, and prudent. (APS Br. at 6-9.) APS asserted that because the OMP itself is prudent, recovery of the deferral is also prudent. (APS RBr. at 3.) APS asserted that FEA's "after-the-fact earnings test" for the OMP deferral is inconsistent with the 2016 Rate Case Decision, which did not include an earnings test. (*Id.* at 3.) APS further argued that it has met its burden by demonstrating that the OMP investment and expenses were prudent and that APS has earned below its authorized ROR since the 2016 Rate Case. (*Id.* at 3.) APS argued that disallowance or reduction of the deferral would effectively prevent APS from recovering its prudent costs for a used and useful asset. (*Id.* at 3.) Additionally, APS asserted that the deferral is to continue until the effective date for the rates established in this case

[201] Mr. Smith appeared to believe that the Commission had agreed in the 2016 Rate Case to include the OMP deferral in rate base in this rate case. (*See* Tr. at 5053.)

and that any trailing cost not included in rates in this case will be trued up in the next rate case. (*Id.* at 4.)

4. Resolution

In the Settlement Agreement approved in the 2016 Rate Case, APS was authorized to defer all non-fuel costs of owning, operating, and maintaining the OMP and retiring the existing steam generation at Ocotillo. APS was also authorized to accrue interest at the cost-of-debt approved in the 2016 Rate Case (5.13%). (Ex. APS-70 at 22, ex. A at 13.) APS was not guaranteed recovery of the deferred costs and was not guaranteed recovery of the deferred costs with any specified rate of return. (Ex. APS-70 at ex. A at 13.)

It is uncontroverted that the OMP is used and useful and that the OMP costs were prudently incurred. Additionally, it is apparent that the OMP provides environmental benefits and enhances the flexibility of APS's system, both of which benefit customers. There is no question that it is appropriate to include the OMP in PIS and in rate base. The only question is whether it is also appropriate to include the deferred regulatory asset in rate base and allow it to earn a rate of return set at the WACC approved herein.

Due to the approval of the Settlement Agreement in the 2016 Rate Case, which authorized the OMP deferral and the cost-of-debt carrying charge on the OMP deferral, the issue of whether the extraordinary and non-traditional relief afforded by an accounting order was appropriate is not before the Commission in this case.[202] Nonetheless, we note that the $524 million cost of the OMP is approximately 4.25% of APS's asserted FVRB and that the proposed $9.507 million depreciation and amortization expense is approximately 0.34% of APS's proposed TY operating expenses. We further note that in the 2016 Rate Case, authorization of the OMP deferral and carrying cost was but one aspect of a multi-faceted Settlement Agreement that had the support of the majority of parties to the case and thus that the issues addressed in the Settlement Agreement were not fully litigated.

The issue before the Commission in this case is whether the OMP deferral should be recognized

[202] The Commission recently found that an accounting order was not appropriate for SW Gas to defer the costs of a $96 million jurisdictional investment, which the Commission concluded were not significant or material relative to SW Gas's size and did not warrant extraordinary ratemaking treatment. (Decision No. 77918 (April 1, 2021), which is officially noticed herein.) The Commission also concluded that SW Gas's credit rating would not be negatively impacted by denial of the accounting order.

in rate base and, if so, with what amortization period and rate of return. Because the Commission authorized the deferral in the 2016 Rate Case, APS has demonstrated that the OMP was completed efficiently and within projected costs, and the OMP is used and useful and providing benefits to APS and its customers, it is just and reasonable to allow recovery of the OMP deferred costs. However, in light of the non-traditional ratemaking treatment that has already been authorized, and the carrying costs that have already been accrued on the deferred costs, it is just and reasonable to adopt FEA's position and allow recovery of the OMP deferred costs on a levelized basis over a 10-year period with a carrying charge set at APS's embedded cost of debt. In making this determination, we are mindful that without the extraordinary ratemaking treatment that was authorized in the 2016 Rate Case, APS would not have been able to obtain recovery of any of the deferred costs. Allowing for recovery of the OMP deferral (which includes the accrued carrying charges), with a return set at the 4.10% embedded cost of debt, provides APS recovery for its investment while balancing APS's interests with those of its customers and is expected to decrease APS's annual revenue requirement by approximately $4.5 million. (Ex. FEA-5 at att. MPG-1SR.)

D. PTYP

1. APS Recovery Request

APS's application included 12 months of PTYP in its OCRB, with gross jurisdictional PTYP totaling $756.329 million and net jurisdictional PTYP totaling $190.766 million. (Ex. APS-39 at sched. B-2.) The PTYP projects were broken down by function area (fossil generation, nuclear generation, distribution and information technology/facilities, technology innovation, and renewables). (*Id.*) APS witness Barbara Lockwood provided the breakdown of the PTYP projects and testified as to the need for the various PTYP projects. (Ex. APS-1 at 15-20, att. BDL-1DR, att. BDL-2DR, att. BDL-3DR, att. BDL-4DR, att. BDL-5DR.) Because the application was filed on October 31, 2019, the PTYP figures included projections for the projects that had not yet been completed. (Ex. APS-1 at 15; Ex. APS-12 at 20-21.) APS asserted that it had removed all revenue producing plant from its PTYP request and that it had rolled forward TY accumulated depreciation to reduce the amount of net PTYP. (*Id.*)

In its rebuttal case and final schedules, APS used updated PTYP amounts to reflect actual figures through June 30, 2020, and revised depreciation rates and accepted a Staff adjustment to remove

the cost of Automatic Metering Infrastructure ("AMI") meters that were related to growth. (Ex. APS-13 at 9-10.) As a result, APS included a net OCRB increase of $125.101 million, based on an increase in gross PIS of $717.732 million for PTYP, offset by depreciation and amortization and other deductions. (See Ex. APS-40 at sched. B-2; Ex. APS-39 at sched. B-2; LFE APS-87 at sched. B-2.)

The 12 months of PTYP was in service by June 30, 2020;[203] is used and useful and serving customers; and does not include any new revenue-producing plant. (Ex. APS-2 at 4; Ex. APS-10 at 6; Ex. APS-13 at 10; Ex. APS-14 at 2.) All of the PTYP adjustments reflect the actual depreciation, interest expense, property taxes, and reduced income tax expenses associated with the PTYP additions. (Ex. APS-14 at 3; Ex. S-12 at 10-11, 17; *see* Ex. APS-41 at 5.) APS's PTYP proposal reflects accumulated depreciation, 12 months of annualized depreciation expense using the TY PIS, and APS's proposed depreciation rates and does not include depreciation on PTYP during the PTY period. (Ex. APS-14 at 3.) APS used an end-of-period measurement for its PTYP.

APS asserts that allowing PTYP benefits customers by reducing rate case frequency, aligning investments for customers with rate recovery from customers, and encouraging timely investments made to serve customers. (Ex. APS-14 at 2.)

2. Average-of-Period vs. End-of-Period Measurement

a. AECC/Freeport

AECC/Freeport witness Kevin Higgins asserted that because of APS's pro forma adjustments to its TY, APS's TY only "nominally" ended on June 30, 2019, and effectively reflected the period of July 1, 2019, through June 30, 2020. (Ex. AECC-1 at 8-10.) Mr. Higgins asserted that if APS is allowed to recognize rate base and expense adjustments extending a full 12 months beyond the TY, then those adjustments should be made using average-of-period values rather than end-of-period values, as the justification for using end-of-period values is that it mitigates regulatory lag. (*Id.* at 10-11.) According to Mr. Higgins, allowing APS to combine a projected measurement period and an end-of-period rate base "doubl[es] up . . . regulatory lag mitigation" and is "unreasonably aggressive." (*Id.* at 11.) Mr. Higgins stated that with average-of-period rate base, PTYP would be valued using the average monthly

[203] Staff was able to verify that PTYP was in service through descriptions and photographic evidence of randomly chosen projects. (Ex. APS-10 at 6.)

value of the new plant as it was projected to be added over the course of the 12-month PTY period,[204] which is more appropriate with a projected test period because the value of rate base changes each month as new plant is added and existing plant depreciates. (*Id.* at 11-12.)

Mr. Higgins's adjustment to convert PTYP to an average-of-period value reduced gross PTYP by $410.079 million on a jurisdictional basis. (AECC Final Sched. at ex. KCH-1-S at 4, ex. KCH-2-S.) AECC/Freeport estimated that this PTYP adjustment would reduce APS's revenue requirement by approximately $40 million. (AECC Final Sched. at ex. KCH-2-S.)

Mr. Higgins asserted that it would be appropriate for the Commission to adopt a policy of using average-of-period rate base for PTYP in all of its rate cases, as it is consistent with the way PTYP is treated in other jurisdictions, and the main justification for using end-of-period rate base is that using a strict historical test period results in too much regulatory lag if an end-of period measurement is not used. (Tr. at 4691-92.) AECC/Freeport argued that both the Wyoming Public Service Commission and the Colorado Public Service Commission have determined that using average-of-period rate base is the "best means for measuring rate base when a utility attempts to include *projected* capital additions in rate base during a rate case" because it "best adheres to the matching principle of aligning cost-causation with cost recovery." (AECC Br. at 8.) Mr. Higgins conceded that no other party had supported the use of average-of-period rate base for PTYP. (Tr. at 4638.)

Mr. Higgins acknowledged that he had not made the same recommendation for average-of-period PTYP for TEP in Docket No. E-01933A-19-0028 ("TEP Rate Case"), stating that it was because TEP had proposed to include only six months of PTYP measured at end-of-period, which Mr. Higgins stated has approximately the same result as using average-of-period rate base with a 12-month PTY period. (AECC Br. at 9; Tr. at 4640, 4725.)

b. Other Parties

No other party supported AECC/Freeport's average-of-period adjustments to PTYP.

c. APS Response

Ms. Blankenship disagreed with Mr. Higgins's average-of-period adjustments to PTYP,

[204] At hearing, Mr. Higgins explained that average-of-period rate base is actually calculated using the end-of-month balance each month for a 13-month period. (Tr. at 4710-4711.)

asserting that PTYP is a known and measurable change to the TY, that is has historically been used to mitigate regulatory lag to the benefit of both APS and its customers, that "[w]atering down" PTYP adjustments using averages would be contrary to well-established PTYP practices, and that PTYP should be measured at a point in time. (Ex. APS-14 at 1-2.) Likewise, Mr. Snook asserted that because the PTYP represents prudent, known and measurable changes to TY rate base, the PTYP should be fully recoverable. (Ex. APS-29 at 5.)

Ms. Blankenship asserted that the Commission should not accept new PTYP practices in this rate case because doing so could impact APS as well as other regulated utilities and their customers. (Ex. APS-14 at 2.) Ms. Blankenship further asserted that PTYP benefits customers by reducing rate case frequency, aligning investments for customers to rate recovery from customers, and encouraging timely investments to serve customers. (Ex. APS-14 at 2.)

d. Resolution

A.A.C. R14-2-103(A)(3)(h) defines OCRB as "the depreciated original cost, prudently invested, of the property (exclusive of contributions and/or advances in aid of construction) *at the end of the test year*, used or useful, plus a proper allowance for working capital and including all applicable pro forma adjustments."[205] The Commission has for years allowed PTYP adjustments to rate base using end-of-TY amounts. Indeed, it appears that whether it is appropriate to use average-of-period valuation for PTYP for purposes of ratemaking is an issue of first impression for the Commission.[206]

When considering the appropriateness of using the average-of-period rate base for PTYP, it is important to consider the purpose of allowing PTYP, which is to minimize regulatory lag by allowing a utility to begin recovery for capital investments via rates within a shorter time period than would occur if the utility were prohibited from making pro forma adjustments to its rate base to reflect PTYP. This not only helps to minimize the amount of its capital investment that a utility will not be able to recover; it also helps to delay the need for the utility's next rate case and the resource expenditures that necessarily come with it.

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[205] Emphasis was added.

[206] Although Mr. Higgins raised the issue for AECC in the 2016 Rate Case, he did not perform an analysis of the impacts of using average-of-period rate base for PTYP in that case, and the issue was not specifically addressed in the Settlement Agreement approved in Decision No. 76295. (*See* Ex. APS-79 at 10-13; Ex. APS-70.)

It appears that the Wyoming and Colorado cases cited by AECC/Freeport involved projected plant. (See Ex. AECC-3 at 11-13.) This case does not involve projected plant. All of the APS PTYP in question is currently in service and used and useful and has been since at least June 30, 2020. That fact clearly distinguishes the cited cases from the instant case and mitigates against adopting AECC/Freeport's position, as does the fact that no other party supported the position (not even RUCO, which recommended different modifications to PTYP). If the practice were as well accepted as AECC/Freeport suggests, it would be reasonable to expect another party to support the idea.

At this time, the Commission has a docket open specifically for the purpose of evaluating Commission policy on PTYP, Docket No. AU-00000A-19-0080 ("PTYP Docket"). On April 29, 2021, Chairwoman Marquez Peterson filed a letter to the PTYP Docket requesting that Staff, RUCO, utilities, and all interested stakeholders provide answers to specific questions by June 4, 2021, and responses to each other's filings by July 2, 2021.[207] One of the concerns expressed by the Chairwoman is that Commission decisions regarding allowance for PTYP have been inconsistent, which she asserted increases uncertainty and thus cost of capital. If AECC/Freeport believes that the Commission should adopt a policy requiring that PTYP be valued on an average-of-period basis rather than an end-of-period basis, AECC/Freeport should advocate for that policy in the open PTYP Docket, in which the Commission should be able to scrutinize the issue fully with additional input from a more diverse group of interested persons.

Based on the evidence in this matter and the Commission's usual practice, the Commission will allow for valuation of PTYP on an end-of-period basis.

3. Amount of PTYP

a. RUCO

RUCO asserted that APS's requested PTYP of $773.3 million (total company basis) should be reduced to $608 million.[208] (RUCO Br. at 25; Ex. RUCO-3 at 15.) To accomplish this reduction, RUCO started with APS's proposed 12 months of PTYP but removed all PTYP projects with total

[207] Official notice is taken of this filing made in Docket No. AU-00000A-19-0080.

[208] As of its final schedules, on a total company basis, APS proposes gross PTYP of $733.921 million and net PTYP of $129.942 million. (LFE APS-87 at sched. B-2.) On a jurisdictional basis, APS proposes gross PTYP of $717.732 million and net PTYP of $125.101 million. (LFE APS-87 at sched. B-2.)

costs lower than $5 million[209] that were completed after December 31, 2019,[210] asserting that these projects were inconsequential to APS relative to its overall annual construction budget of nearly $1 billion and that disallowing them would not impair APS's financial health. (Ex. RUCO-1 at 9; Ex. RUCO-3 at 15-17; Tr. at 4289.) In his testimony, Mr. Radigan discussed the PTYP Docket and six criteria he stated are to be examined therein for inclusion of PTYP in rate base. (Ex. RUCO-1 at 7; Ex. RUCO-3 at 16.) Mr. Radigan concluded that the potential criteria did not support allowance of APS's PTYP. (Ex. RUCO-3 at 16-17.) RUCO argued that its position is supported by Decision No. 71410 (December 8, 2009), in which the Commission repeated Staff's position at that time that PTYP should be allowed in rate base only in special and unusual situations—one requiring that the magnitude of the investment be such that not including it would jeopardize the utility's financial health, and the other requiring, *inter alia*, that the cost of the PTYP be significant or substantial.[211] In Decision No. 71410, the Commission adopted Staff's exclusions of PTYP because the utility "ha[d] not demonstrated special or unusual circumstances to justify inclusion of" the PTYP at issue. (Decision No. 71410 at 21.)

RUCO argued that allowing PTYP in rate base violates the matching principle, which Staff relied on for its disallowance of PTYP in Decision No. 71410. (RUCO Br. at 26.) RUCO argued that

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[209] Mr. Radigan used $5 million because he believed a project that small would not require upper management approval but instead would be handled through a blanket work order or middle management. (Ex. RUCO-1 at 10.)

[210] If a PTYP project was completed by December 31, 2019, RUCO allowed it regardless of its cost. (Ex. RUCO-1 at 9.)

[211] In pertinent part, RUCO quoted this language from Decision No. 71410:

> As Staff explains, Commission rules require the end of the test-year, which is the one-year historical period used in determining rate base, operating income and rate of return, to be the most recent practical date available prior to the filing. A utility has the freedom to choose a test-year that includes all major rate base and operating income items needed to support its rate application, and to include pro forma adjustments to its chosen test-year. Matching is a fundamental principle of accounting and ratemaking, and the absence of matching distorts the meaning of, and reduces the usefulness of, operating income and rate of return for measuring the fairness and reasonableness of rates. Staff contends that the matching principle is the reason that the Commission has allowed inclusion of post test-year plant in rate base only in special and unusual situations that warranted the recognition of post test-year plant. Staff states that it has traditionally recognized two scenarios in which Staff believes recognition of post test-year plant is appropriate: (1) when the magnitude of the investment relative to the utility's total investment is such that not including the post test year plant in the cost of service would jeopardize the utility's financial health; and (2) when certain conditions exist as follows: (a) the cost of the post test year plant is significant and substantial, (b) the net impact on revenue and expenses for the post test-year plant is known and insignificant or is revenue neutral, and (c) the post test year plant is prudent and necessary for the provision of services and reflects appropriate, efficient, effective, and timely decision-making.

(Decision No. 71410 at 19-20 (footnotes omitted).) Official notice is taken of this decision.

the "matching principle . . . has been cast aside" in the past 10 years, resulting in utilities expecting 12 months of PTYP and essentially a 24-month TY. (RUCO Br. at 26.) RUCO asserted that it has advocated for policy clarity on PTYP. (*Id.*) RUCO acknowledged APS's adjustment to roll forward TY accumulated depreciation balance for one year as an offset to PTYP, and its exclusion of revenue-producing plant, and stated that RUCO believed APS was trying to strike a balance between its needs and those of its ratepayers. (Ex. RUCO-1 at 8.) Mr. Radigan testified that while the rolling forward of TY depreciation did not resolve the matching issues, it did mitigate the "inherent unfairness" of PTYP and the harm of regulatory lag from the ratepayers' perspective. (Ex. RUCO-1 at 9.) Mr. Radigan did not question Mr. Tetlow's characterization of some of the RUCO-excluded PTYP as important construction projects that had already been completed. (Ex. RUCO-3 at 16-17.) But, RUCO argued, there is nothing special or unusual about APS's PTYP projects, the PTYP projects increase APS's rate base only minimally, and APS would not be financially harmed if they were all excluded. (RUCO Br. at 27.) Mr. Radigan asserted that the PTYP projects excluded by RUCO were "just normal run-of-the-mill projects that you meet in operating utilities." (Tr. at 4210.) RUCO acknowledged that the smaller projects are used and useful and did not question their prudency, but asserted that Arizona uses a historical TY and that its exclusions of PTYP are no more arbitrary than are APS's inclusions of PTYP. (RUCO RBr. at 4-5.)

b. AECC/Freeport

Mr. Higgins asserted that if APS is going to have PTYP, it also needs to adjust depreciation reserve and accumulated deferred income taxes ("ADIT") consistent with the PTYP. (AECC Br. at 8-9; Tr. at 4635.) According to Mr. Higgins, APS should have adjusted its depreciation reserve for PTYP to match the depreciation expense that APS proposed to recover on the PTYP.[212] (Tr. at 4636.) Mr. Higgins stated that APS had taken "significant steps toward matching," however, by adjusting to include additional accumulated depreciation on its TY plant. (AECC Br. at 9, 10; Tr. at 4636.)

. . .

[212] Mr. Higgins increased accumulated depreciation by $5.197 million and decreased ADIT by $6.045 million to reflect his PTYP recommendation. (AECC Br. at ex. KCH-2-S at 1.) For operating expenses, Mr. Higgins made a combined downward adjustment to depreciation expense and taxes associated with PTYP of $17.324 million. (AECC Br. at ex. KCH-1-S at 6.)

c. Other Intervenors

No other intervenor challenged APS's inclusion of 12 months of PTYP or recommended disallowance of specific PTYP projects. The IBEW Locals expressed support for APS's position and criticized RUCO's position on PTYP. (IBEW Br. at 8-9; IBEW RBr. at 6-7.)

d. Staff

In its direct case, Staff recommended allowance in rate base of APS's actual PTYP placed in service by June 30, 2020, with the exception of the excluded AMI meters. (Ex. S-12 at 10-11, 17-18, 31-32.) Staff's Engineer determined that all of these PTYP projects had been prudently procured and were used and useful in the provision of service. (Ex. S-7 at 75.) According to Staff, the benefits of recognizing PTYP in rate base are that it gives rate recognition and commences cost recovery for non-growth-related plant that has been placed in service within a defined period after the TY, which can address regulatory lag. (Ex. S-12 at 19.)

Mr. Smith stated that the potential disadvantages of recognizing PTYP in rate base are that it can create a TY mismatch and overstate the increase in net utility plant if corresponding changes are not made for accumulated depreciation. (Ex. S-12 at 19.) Mr. Smith stated that APS's inclusion of an additional 12 months of annualized depreciation expense based on end-of-TY plant resulted in proper matching. (Ex. S-12 at 22-23; Tr. at 5152-5157.) Mr. Smith acknowledged that Staff had not previously recommended including an additional 12 months of depreciation expense on end-of-TY plant, but stated that he believed APS's adjustment for depreciation was "methodologically sound." (Tr. at 5153-5154.)

Staff's final schedules show that Staff agrees with APS's calculation of gross and net jurisdictional PTYP and recommends that it be allowed in rate base. (Staff-Final Sched. at sched. B-1 through sched. B-7.)

e. APS Response

APS argued that RUCO's exclusion of PTYP projects under $5 million for months 6-12 of the PTY period is arbitrary and inappropriate, as the Commission has reached no formal conclusions or policy as a result of the PTYP Docket, and RUCO has provided only its own opinions to justify the exclusion. (Ex. APS-10 at 6-7; Ex. APS-11 at 7.) Mr. Tetlow testified that contrary to RUCO's

assertions, projects under $5 million are important and necessary to APS's efficient and safe utility operations and, when prudent, should be included in rate base. (Ex. APS-10 at 7; Ex. APS-11 at 7.) Mr. Tetlow pointed out that Mr. Radigan did not contest that the PTYP projects have been completed, were prudent and timely, can be verified to be in service, and do not generate or support system growth or new customers. (Ex. APS-11 at 7.) As examples of PTYP excluded by RUCO but critical to APS, Mr. Tetlow cited proactive wood pole replacements, made to reduce distribution outages and mitigate public hazards due to downed poles; upgrades to the Buckeye 12 kV Substation, which improved the voltage and reactive power support from the Buckeye to Gila Bend substations; upgrades to Yucca controls on combustion turbines ("CTs") 1, 2, and 4, to replace obsolete control systems and reduce repeated outages; and overhaul of the Sundance CT 7 hot section (the part of the CT that experiences the highest temperatures and pressures), as part of routine reliability maintenance. (Ex. APS-10 at 7-9.) According to Mr. Tetlow, RUCO's exclusion of projects smaller than $5 million would reduce APS's PTYP by more than 20%, representing a reduction to rate base of $165 million; is inconsistent with the Commission's past PTYP practices; and could detrimentally impact future decisions to maintain systems proactively and to make prudent investments that help control costs. (Ex. APS-10 at 7, 9.)

APS also disagreed with the position that TY accumulated depreciation should be adjusted to reflect depreciation on PTYP during the PTY period, asserting that APS's approach (including as part of PTYP accumulated depreciation and 12 months of annualized depreciation expense computed using the TY plant balance and proposed depreciation rates) fairly represents ongoing accumulated depreciation in PTYP and has been accepted in prior rate cases. (Ex. APS-14 at 3; APS Br. at 21-22.) Ms. Blankenship did not cite the source for this position, which she attributed to RUCO, and it is not apparent that any RUCO testimony supports this position. It is possible that this reflects APS's understanding of a position taken by AECC/Freeport as to depreciation on PTYP.

f. Resolution

The PTYP proposed for inclusion in rate base by APS is in service and used and useful, and Staff has determined that it was prudent. The PTYP no longer includes plant associated with growth. APS's current customers are benefiting from the existence of the PTYP. Further, APS has reduced the

rate impact from the PTYP by offsetting it with a year of accumulated depreciation based on its end-of-TY plant. Adopting RUCO's exclusion of selected PTYP based on project cost and timing, which disregards the used and useful and prudent nature of the PTYP and the importance of specific projects in providing safe and reliable service to APS's customers, is not in the public interest in this case. However, if RUCO believes that the Commission should adopt a policy requiring that PTYP projects completed more than six months after the end-of-TY be excluded unless the projects have costs exceeding a designated threshold, RUCO should advocate for that policy in the open PTYP Docket, in which the Commission should be able to scrutinize the issue fully with additional input from a more diverse group of interested persons.

Allowing APS's proposed PTYP in rate base in this rate case will provide APS more timely recovery for its capital investments, will support APS's credit rating based on regulatory environment (thereby lowering or maintaining its already low cost of capital), and should contribute to APS's ability to delay filing another rate application (thereby conserving the resources that would be used to prepare and litigate the rate application and the resulting rate change for customers). Based on the evidence herein, and consistent with Staff's recommendation, we adopt APS's proposed jurisdictional gross and net PTYP.

4. Property Tax on PTYP

a. APS Recovery Request

APS has included approximately $11 million[213] in property tax expense associated with its 12 months of PTYP. (Ex. RUCO-1 at 17; Ex. S-12 at att. RCS-2 at 30.)

b. RUCO

RUCO argues that the property tax expense associated with PTYP should be excluded because the lag time between the plant's placement into service and APS's obligation to pay property taxes on the plant is two years. (RUCO Br. at 27; Ex. RUCO-1 at 17; Ex. RUCO-3 at 17-18.) Mr. Radigan asserted that APS's arguments for including the property taxes were unpersuasive because APS does not dispute that there is a two-year lag between when plant is placed into service and the utility must

[213] Mr. Radigan identified the amount as $11.06 million and then $11.1 million, and Mr. Smith identified the amount as $11.368 million, but in a context that suggested it was for the total company rather than APS. (*See* Ex. RUCO-1 at 17; Ex. RUCO-3 at 17; Ex. S-12 at att. RCS-2 at 30.)

pay property taxes on the plant; the decisions cited by APS as supporting inclusion of such property taxes were all resolved through settlements that have no precedential value; and the property taxes were not incurred by June 30, 2020, the date by which the PTYP was all in place. (Ex. RUCO-3 at 18-19.) Mr. Radigan testified that in the 2016 Rate Case, APS appropriately excluded property taxes in the Ocotillo pro forma adjustment because they would not be due for two years. (Tr. at 4217-4218.) Mr. Radigan was unaware whether the two-year property tax lag was factored into APS's lead-lag study for cash working capital. (Tr. at 4218.) Mr. Radigan acknowledged and did not express disagreement with Ms. Blankenship's argument that a property tax disallowance would require APS's cash working capital allowance, and thus its rate base, to be increased accordingly. (Ex. RUCO-3 at 18.)

c. Staff

Staff did not object to APS's inclusion of property tax expense for PTYP, based on effective property tax rates and actual amounts of PTYP. (Ex. S-12 at 18, 44, att. RCS-2 at 30.)

d. APS Response

Ms. Blankenship testified that the property taxes on PTYP represent known and measurable amounts and reflect the ongoing anticipated expenses between the effective date of the rates set in this case and APS's next rate case. (Ex. APS-13 at 11.) Ms. Blankenship further asserted that if the property taxes are not allowed, APS will have no method to recover for the property tax expenses that will be incurred in the first full year the new rates are in effect. (*Id.*) Ms. Blankenship testified that APS had met with Staff and RUCO in September 2019 and discussed APS's plan to include property taxes for PTYP. (*Id.*) According to Ms. Blankenship, including property tax on PTYP additions is consistent with the decisions in the 2008 Rate Case, the 2011 Rate Case, and the 2016 Rate Case and with other utilities and public utility commission decisions. (Ex. APS-13 at 11.) Additionally, Ms. Blankenship asserted, including the property taxes gives customers the benefit of the lag between the assessment and payment of property taxes in the cash working capital lead/lag study and has the effect of reducing rate base, and disallowing the property taxes would necessitate an increase in cash working capital and rate base. (Ex. APS-13 at 11.)

e. Resolution

We consider the property tax expenses on the PTYP included in rate base herein to be known

and measurable expenses, and we will allow for their recovery.

E. Coal-Impacted Community Transition

1. Background

a. The APS-Owned Coal-Fired Plants

APS partially owns three coal-fired power plants: the 4CPP, located in northwestern New Mexico; the Navajo Generating Station ("NGS"), located near Page in northern Arizona; and the Cholla Power Plant ("Cholla"), located just south of the Nation in north-central Arizona. (Ex. CG-1 at 5-6.)

The 4CPP began operating in 1963, and both it and the Navajo Mine that supplies its coal are located on land leased from the Nation in northwestern New Mexico. (Ex. CG-1 at 5-6, 15.) As described in more detail above, the 4CPP is now scheduled to close in 2031, although a number of parties believe that it will close sooner. (E.g., Ex. CG-3 at 8-9; Ex. CG-6 at 2.)

NGS is also located on land leased from the Nation. (Ex. CG-1 at 5-6.) NGS began operating in 1974 and, before it closed in November 2019, was the largest coal-fired power plant in the western U.S. (Ex. CG-1 at 6-7; Ex. APS-29 at 5-6; Ex. AECC-1 at 33.) The 2019 closure was 25 years earlier than the originally planned retirement date of 2044. (Ex. Navajo-1 at 11.) When operating at full-scale, NGS burned approximately 8 million tons of coal per year, which was obtained from Peabody Energy's Kayenta Coal Mine ("Kayenta Mine")[214] located on Black Mesa, Nation land approximately 90 miles east of NGS in northeastern Arizona. (Ex. CG-1 at 6.) NGS received some coal mined from a "joint use area" to which the Tribe has rights. (Tr. at 3980, 4008, 4013, 4016.) NGS is owned by SRP (43%), the U.S. Bureau of Reclamation ("USBoR") (24%), APS (14%), NV Energy (11%), and TEP (7.5%). (Ex. CG-1 at 6-7.) NGS provided power to California, Arizona, and Nevada, and the USBoR's share of NGS's output was used to power Central Arizona Project ("CAP") pumps moving approximately 1.5 million acre-feet per year ("AFY") of water from the Colorado River to central and southern parts of Arizona for residential, agricultural, and industrial uses. (Ex. CG-1 at 6.)

Cholla began operating in 1962. (CG Br. at 6.) APS is the majority owner and operator of Cholla, wholly owning Units 1-3, while Unit 4 is wholly owned by PacifiCorp. (Ex. CG-1 at 7.) Per

[214] APS also is responsible for a portion of the closure and reclamation costs for the Kayenta Mine. (Ex. CG-1 at 7.)

a settlement agreement with the EPA, APS retired Unit 2 in 2015 to reduce pollution and agreed to retire Units 1 and 3 by April 2025. (Ex. CG-1 at 7-8; Ex. APS-3 at att. BDL-02RJ.) PacifiCorp announced early in 2020 that it would close Unit 4 within the year because it was no longer economical compared to other resources. (Ex. CG-1 at 7-8.) Cholla originally had a planned retirement date of 2035. (Ex. Navajo-1 at 11.)

b. The Area and its People

The Nation comprises one vast and several much smaller isolated parcels of land, more than 27,000 square miles altogether, with the largest parcel straddling the borders of Arizona, Utah, and New Mexico, in the Four Corners region where their borders meet with the southwestern Colorado border. (See Ex. Hopi-15; Tr. at 3410.) The largest portion of the Nation is located in Arizona. (See Ex. Hopi-15.) Approximately 350,000 individuals identify as Navajo, and 175,000 live on the Nation. (Tr. at 3410.)

The Hopi reservation is comprised of two separate parcels of land, one large and one much smaller, both surrounded on all sides by the Navajo reservation in Arizona. (See Ex. Hopi-15.) The Hopi reservation is approximately one-tenth the size of the Navajo reservation. (See Ex. Hopi-15.) The Tribe has total enrollment of approximately 14,400, and approximately 7,000 live on the Hopi reservation. (Ex. Hopi-12; Tr. at 3589.)

The residents of the Nation and of the Hopi reservation generally fare worse economically than others in the southwest. The Nation's median household income ($27,389[215]) is approximately half that of the Arizona median ($51,310); the Nation's rates of unemployment, families below the FPL, and households receiving food stamps are more than twice those of Arizona; and the Nation's percentage of people without health insurance is twice that of Arizona. (Ex. CG-1 at 17; Ex. Navajo-5 at 31, 33, 36, 38.) In the 2010 Census, 38% of Nation members were classified as "severely poor." (Ex. Navajo-5 at 38.) The Tribe's median annual household income was $34,016, slightly lower than that for Navajo County and 33.7% lower than that for the state as a whole. (Ex. Hopi-11.) The Tribe also has a disproportionately large percentage of families living at or near the FPL, with approximately

[215] Income figures provided are as of the 2010 Census. (*See* Ex. Navajo-5 at 36.)

35% classified as "severely poor" and approximately 28% receiving food stamps per the 2010 Census. (Ex. Hopi-6 at 2; Ex. Hopi-11.) These financial circumstances for Hopi members were expected to worsen due to the NGS closure. (Ex. Hopi-6 at 2; Ex. Hopi-11.)

It has been said that the Nation is 50 years behind the rest of the U.S. in developing water infrastructure, with approximately 30-40% of Nation members not having running water in their homes, and it has been estimated that approximately $500 million in infrastructure would be needed to provide them running water. (Ex. Navajo-1 at 22; Ex. CG-3 at 15; Ex. CG-2 at 14.) Most of the residents of the Nation receive their electric service from the Navajo Tribal Utility Authority, which is fully owned by the Navajo people. (Tr. at 3401.) The Nation has been working on an initiative called "Light Up Navajo" to electrify all Nation homes and has found that a number of its members are unable to afford the cost to connect their homes to the grid even within 1,000 feet of power line. (Tr. at 3401-3402.)

Approximately 35% of homes on the Hopi reservation do not have electricity. (Ex. Hopi-14.) The Hopi reservation receives its electrical service from APS[216] and has a history of unreliable service, with an outdated distribution system and complete or partial power outages occurring routinely, sometimes for several days at a time.[217] (See Ex. Hopi-4; Ex. Hopi-6 at 3; Ex. Hopi-8 at 6; Ex. Hopi-14; Tr. at 3589.) The Hopi reservation is served by two distribution feeders known as Keams Canyon 3 and 5, approximately a 41-mile transmission line, and approximately 100 miles of distribution wires. (Tr. at 1319-1320; Ex. APS-82.) Over the past five years, APS has invested approximately $1.6 million in system improvements for the Hopi reservation system, and reliability has improved. (Tr. at 1320.) There were fewer outages in 2020 than there had been previously, although they continued to occur.[218] (Tr. at 3581, 3588.) Many Hopi APS customers have generators to ensure service for powered water service or for healthcare and communications. (Ex. Hopi-6 at 3; Ex. Hopi-14.) A number of Hopi

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[216] APS has approximately 2,000 customers on the Hopi reservation. (Tr. at 1319.) There are also Hopi members who are APS customers in Tuba City. (*See* Tr. at 1321.)

[217] The Hopi village of Bacovi, for example, is located at the end of an APS delivery path and experiences numerous outages, which the Hopi believe could be remedied by APS paying for a microgrid in the location. (Ex. Hopi-8 at 5.) As of 2018, APS was working with the Hopi to address the brownouts. (Ex. Hopi-14.)

[218] Outage data for Keams Canyon Feeders 3 and 5 shows the following outages per year: 2015 – 54, 2016 – 52, 2017 – 40, 2018 – 49, 2019 – 34, 2020 – 29. (Ex. APS-82.) APS stated that the increase in 2018 outages was due to the failure of residential transformers, which have since been replaced, and that the number of customers interrupted and duration of the 2018 outages were significantly lower than in prior years. (Ex. APS-82.)

homes that do not have access to electricity relied on coal from the Kayenta Mine for heat, and they no longer have access to that coal since the Kayenta Mine closed. (Ex. Hopi-9.)

c. Pollution & Water Impacts

The 4CPP historically has served as the largest source of NOx pollution and one of the largest sources for CO_2 and mercury pollution in the U.S. (Ex. CG-3 at 11-12.) During its operation, approximately 33.5 million tons of coal combustion waste have been disposed of in on-site surface impoundments (lined and unlined), and contaminants have leached into the groundwater, migrating toward the Chaco River, which flows into the San Juan River. (Ex. CG-3 at 13.) Since 1977, APS has used intercept trenches and pump-back wells to minimize the migration of contaminants. (Ex. CG-3 at 13.) High levels of mercury have been found in fish from lakes downwind of the 4CPP. (Ex. CG-3 at 13-14.)

The 4CPP has an allocation to withdraw 51,600 AFY of water from the San Juan River and on average pumps approximately 27,500 AFY. (Ex. CG-3 at 14.) The San Juan River's average discharge declined to less than 1 million AFY between 2000 and 2016, a long-term drying trend is anticipated due to reduced snowpack and streamflow, and the adverse impacts on the Nation and the Navajo people from this drying trend are expected to increase. (Ex. CG-3 at 14.)

NGS was one of the largest sources of pollution in the southwest, annually emitting more than 500 million tons of CO_2 into the atmosphere and releasing millions of tons of additional harmful pollutants into the air.[219] (Ex. CG-1 at 6.) NGS annually released pounds of hazardous chemicals such as arsenic, mercury, and chromium into the environment; released thousands of tons of particulate matter ("PM") into the air (PM 10 and PM 2.5); and generated millions of tons of coal-ash waste that was disposed of on-site. (Ex. CG-1 at 11.) A new aquifer was unintentionally formed from NGS-polluted water on site at NGS, and the aquifer must be pumped continually to keep it from contaminating other groundwater sources because its water contains heavy metals, sulfate, and total dissolved solids ("TDS"), some exceeding federal water quality standards. (Ex. CG-1 at 12.) The N Aquifer, the source of drinking water for Black Mesa, is at risk of contamination from the NGS aquifer

[219] In 2018, NGS emitted more than 14 million tons of CO_2, more than 3,500 tons of SO_2, and more than 12,000 tons of NOx into the air. (Ex. CG-1 at 10.)

and from migration of leached NGS coal-ash waste chemicals through geologic fractures. (Ex. CG-1 at 7, 12-13.)

The N Aquifer was materially damaged by groundwater pumping for coal operations, which exceeded natural recharge. (Ex. CG-1 at 14.) The Colorado River Compact authorized NGS to use up to 34,100 AFY of the 50,000 AFY allocated for use in Arizona's portion of the Upper Colorado River Basin, which is mostly Nation land. (Ex. CG-1 at 6.) A 1968 Navajo Council Resolution that approved use of the water for NGS provided that use and control of the NGS water would be returned to the Nation for the Navajo's exclusive use and benefit once the plant retired. (Ex. CG-1 at 6.) The Kayenta Mine also used approximately 1,250 AFY of groundwater drawn from the N Aquifer. (Ex. CG-1 at 7.)

In 2018, Cholla emitted 4.2 million tons of CO_2, 1,809 tons of SO_2, and 4,030 tons of NOx into the air. (Ex. CG-1 at 11.) At least four of Cholla's seven on-site surface impoundments, used for disposal of wastewater and coal ash, have caused significant groundwater contamination with levels of toxic chemicals such as arsenic, sulfate, radium, and chromium exceeding regulatory limits. (Ex. CG-1 at 14.)

d. Economic Impacts

The Nation and the Tribe both have received direct economic support from coal operations in the form of royalties and other taxes and fees; the Nation has also received lease payments. (Ex. CG-1 at 15.) In 2018, the 4CPP and NGS combined contributed approximately $70 million of the Nation's $220 million annual gross budget. (Ex. CG-1 at 15.) For fiscal year ("FY") 2021, due to the closure of the NGS and Kayenta Mine, the Nation's projected revenue was expected to be $40 million lower than its FY2020 budget of $172 million. (Ex. CG-1 at 16.) For FY2010-FY2019, the Tribe received from Peabody Western Coal Company annual revenue averaging $15.4 million in the form royalties and bonus payments (collectively "royalties") as well as generation performance payments from Peabody and SRP, which were $1.4 million in 2015.[220] (See Ex. Hopi-7; Ex. Hopi-16; Ex. Hopi-3.) When unpredictable and non-recurring amounts are excluded from general fund revenues, the royalties constituted approximately 87.86% of the Tribe's general fund revenue for FY1996-FY2009 and

[220] Because NGS does not occupy Hopi land, the Hopi receive no lease revenue. (Ex. CG-1 at 16.) In large part, the royalties are derived from coal mining that has occurred at the joint use area. (Tr. at 4008-4009, 4013.)

approximately 60.23% of the Tribe's general fund revenue for FY2010-FY2019. (See Ex. Hopi-7; Ex. Hopi-16.) Beginning in 2021, the Tribe no longer receives royalties. (Ex. Hopi-7; Ex. Hopi-16.) The Tribe has already been significantly impacted by this loss of funding and at the time of hearing was working on a reduction in force for government positions. (Tr. at 3956-3958.) The Tribe Chairman is concerned that the lack of funding will result in reduced critical community services, including behavioral health, social services, and law enforcement in the years ahead. (Tr. at 3956-3958.) As of the hearing, the Tribe did not have any energy-related revenue substitutes. (Tr. at 3958.)

The coal industry has been and remains one of the largest employers in the Four Corners region.[221] (Ex. CG-3 at 7-8.) The average annual wages of power plant employees in the southwest are approximately $100,000, plus health and retirement benefits, and jobs of this quality are scarce on the Nation. (Ex. CG-1 at 15; Ex. Navajo-1 at 12.) In 2018, approximately 80% of the workforce for the 4CPP and Navajo Mine (approximately 640 of 800 combined workers) were Navajo. (Ex. CG-1 at 15; Ex. Navajo-1 at 12.) NGS and the Kayenta Mine were the two largest non-governmental employers on the Navajo reservation, and approximately 86% of their workforce (approximately 600 of 700 combined workers) were Navajo. (Ex. Navajo-1 at 12; *see* Ex. CG-1 at 15.) It is unknown what percentage of the 200 workers at Cholla are Navajo, but 23 workers identify as Native American. (Ex. CG-1 at 18; Ex. Navajo-1 at 9.)

When 4CPP Units 1-3 were retired, an estimated 150 jobs at the 4CPP and 180 jobs at the Navajo Mine were lost. (Ex. CG-1 at 19.) When NGS closed, SRP offered a redeployment program for NGS employees who desired to stay with SRP, but Peabody Energy did not, and the Kayenta Mine's entire workforce was laid off. (Ex. CG-1 at 16.) In 2020, when APS announced the 2031 retirement of the 4CPP, APS estimated that the 4CPP and Navajo Mine generated direct annual payroll of nearly $100 million to approximately 700 workers (mostly Navajo); that operations at the 4CPP and Navajo Mine provided $100 million annually to local, state, tribal, and federal entities through taxes, fees, and coal royalties; and that the 4CPP and Navajo Mine had an annual indirect economic impact exceeding $200 million. (Ex. CG-3 at 8.) The Nation estimated that the 4CPP and Navajo Mine provide $98

[221] The Four Corners region is the southwestern corner of Colorado, the southeastern corner of Utah, the northeastern corner of Arizona, and the northwestern corner of New Mexico. (Ex. CG-3 at 7.) The region includes Native American nations such as the Navajo Nation, New Mexico's San Juan County, and the city of Farmington, New Mexico. (*Id.*)

million in annual wages and benefits, 2,560 jobs directly and indirectly, and $225 million in total annual economic activity. (Ex. Navajo-1 at 13, app. A.) The Nation estimated that NGS and the Kayenta Mine provided $236.6 million in annual wages and benefits, 2,963 jobs directly and indirectly, and $517.6 million in total annual economic activity. (Ex. Navajo-1 at 13, app. A.) The Nation estimated that Cholla provides $20.5 million in annual wages and benefits, 485 jobs directly and indirectly, and $38 million in total annual economic activity. (Ex. Navajo-1 at 13, app. A.)

In 2010, it was estimated that the decreased annual revenue to the Tribe resulting from NGS closure would result in the direct loss of 544 Tribal government and village government jobs, in the indirect loss of between 816 and 1,360 Hopi jobs, and in a loss in total payroll and benefits of $8 million[222] for the Tribe. (Ex. Hopi-1; Ex. Hopi-3; Ex. Hopi-13.)

e. Health Impacts

The Navajo and Hopi people in the Four Corners area have "borne the brunt of public health impacts associated with 50- to 60-year lives of coal plants in their backyards." (Tr. at 3634.) Anecdotal evidence supports that the emissions from NGS have detrimentally impacted people of the Navajo Nation, increasing rates of asthma and other pulmonary problems, heart disease, and cancer. (Ex. CG-1 at 8-9.) Residents of the Nation have approximately twice as much asthma (at 20%) as the national average. (Ex. CG-1 at 9.) A 2018 analysis performed by the Clean Air Task Force concluded that pollution from NGS resulted in an estimated 26 deaths, 15 heart attacks, 184 asthma attacks, 16 hospital admissions or emergency department visits, 6 cases of chronic bronchitis, and 1,345 lost work days annually, and that pollution from Cholla resulted in an estimated 6 deaths, 3 heart attacks, 40 asthma attacks, 4 hospital admissions or emergency department visits, and 296 lost work days annually. (Ex. CG-1 at 10.) It has been suggested that some forms of cancer became more common in the Nation after NGS began operating, particularly in communities downwind from NGS. (Ex. CG-1 at 9.) However, neither federal and state authorities nor the owners of NGS have performed comprehensive health/epidemiological studies regarding the health impacts. (Ex. CG-1 at 9-10.)

[222] This was based on 2009 dollars. (Ex. Hopi-13.)

The Commission previously has recognized that NOx (a precursor to ground-level ozone), SO_2 (a precursor to PM2.5), and primary PM2.5 particulates produced by the burning of fossil fuels can cause adverse health impacts to humans. (Decision No. 78041 (June 16, 2021)[223] at 64.) For example, the Commission has noted that ground-level ozone causes respiratory symptoms such as coughing and shortness of breath; decreases lung function; and inflames airways, which increases the risk of respiratory infection. (Decision No. 78041 at 64 n.34.) The Commission also has noted that higher daily ozone concentrations are associated with increased asthma attacks, worsened chronic obstructive pulmonary disease, early death, damage to the central nervous system, and reproductive and developmental harm and that both short- and long-term PM2.5 exposures have been determined likely to cause adverse respiratory effects and have been determined to cause adverse cardiovascular effects and to increase nonaccidental mortality. (Decision No. 78041 at 64 n.34.)

f. Rationale

The following quote from the Citizen Groups explains why utilities such as APS have been called upon to assist coal-impacted communities to transition away from a coal-based economy:

> [O]perations at the coal plants co-owned by APS began more than 50 years ago. These three plants have historically provided a reliable, inexpensive supply of electricity for APS and its customers, making the Company and its shareholders many millions of dollars in profits. For decades, APS and its customers have benefited greatly from the Navajo, Hopi, and non-tribal communities in both Arizona and New Mexico that have provided the labor and resources for these plants to operate, while the local communities have suffered environmental and public impacts resulting from coal plant operations and coal mining.[224]

APS asserts that its proposed Coal Community Transition plan ("CCT") "is intended to provide financial support, energy infrastructure resources, and other economic development tools to facilitate the transition of these affected communities towards an economic foundation that does not rely upon coal-fired power plant operations." (APS Br. at 101.) The Commission recognized in Decision No. 78856 that "action must be taken, and soon, to mitigate the negative impacts of plant closures on tribal lands and elsewhere." (Ex. Navajo-9 at 171.)

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[223] Official notice is taken of this decision.
[224] CG Br. at 7-8.

2. APS Recovery Request

On rebuttal, APS proposed for the first time a CCT that would provide the Nation cash and non-cash benefits and would provide cash benefits to Navajo County Communities and the Tribe in anticipation of APS's transition away from coal-fired generation by 2031 and the affected communities' need to transition away from coal-based economies. (Ex. APS-2 at 19-23; Ex. APS-5 at 8-10.) The discussions that led to the CCT occurred between APS and the Nation and concerned transition assistance suggestions made by the Nation and Citizens Groups in their direct testimony. (Ex. APS-2 at 19-20; Ex. APS-5 at 9.) The discussions that led to the CCT proposal did not involve the Tribe, and the Tribe was not solicited for input on the CCT before it was publicly revealed. (Tr. at 3958-3959, 3975-3976.)

On rejoinder, APS provided a copy of a "Non-Binding Memorandum of Understanding Between the Nation and Arizona Public Service Company Regarding Coal Community Transition Planning" ("CCT MOU"), dated November 5, 2020, and signed by the Attorney General for the Nation and Mr. Guldner for APS. (Ex. APS-3 at att. BDL-02RJ.)

In pertinent part, the CCT MOU includes the following provisions:[225]

- APS and the Nation will engage in good faith discussions and intend to develop a binding and final agreement providing support for the Nation to "transition away from economic drivers that are solely reliant upon coal-fired electricity generation" ("CCT Agreement"), which must address (1) opportunities for development of renewable energy resources on the Nation or land owned by the Nation or an affiliated entity for the benefit of the Nation; (2) commitments from APS to provide financial support for CCT-related programs within the Nation; (3) economic development within the Nation, (4) expansion of electric infrastructure within the Nation, and (5) the Nation's pursuit of additional water resources. [recitals]
- APS intends to make the following commitments in the CCT Agreement:
  - "CCT Financial Commitments"—APS will, over a period of 10 years, pay to the Nation

[225] Ex. APS-3 at att. BDL-02RJ. Subsequent citations for this document will be to the "CCT MOU." Bracketed citations with the locations of each provision in the CCT MOU are included at the end of each item in the bulleted list.

$100 million, provided that the Commission approves and authorizes APS to recover this amount from its retail customers through a dedicated cost-recovery mechanism. To the extent that the Commission does not approve such a mechanism or cost-recovery from retail customers, the $100 million will be reduced or eliminated, but APS will continue to work with the Nation in good faith to secure full funding through a cost-recovery mechanism in future proceedings, a different Commission-approved cost recovery method, or securitization. [§ 1(a)]

- "Tribal Electrification" Commitments—In this matter, APS must propose to modify its distribution line extension policy for Nation lands so that distribution lines can be extended up to 2,000 feet at no cost to Navajo applicants. If it is determined that a line extension policy providing more than 2,000 free feet would have a greater impact on the ability to electrify homes, APS must work with the Nation to identify and must advocate for Commission approval of that longer footage amount, in this matter or in a future matter. [§ 1(b)] Additionally, APS must:
  - Within one year after execution of the CCT Agreement, conduct or pay for a census of unelectrified homes and businesses in the APS service territory within the Nation; [§ 1(b)(i)]
  - Prepare an assessment regarding the effectiveness of the 2,000 feet extension policy; [§ 1(b)(ii)] and
  - Commit an additional $10 million (to be covered 50% by APS shareholders and 50% by APS customers through the dedicated cost-recovery mechanism) to be used toward additional home and business electrification projects within the Nation. [§ 1(b)(iii)]
- "Tribal Renewable Energy" Commitments—To the extent authorized by the Commission, APS must (1) within the 24 months after the CCT Agreement is executed, seek to procure at least 250 MW of renewable electricity generation capacity to be

constructed within the Nation to deliver electricity to APS customers;[226] and (2) within 12 months after the 4CPP's retirement, seek to have at least 350 MW of renewable electricity generation capacity constructed within the Nation or neighboring communities to deliver electricity to APS customers. [§ 1(c)] Additionally, the following conditions apply:

- APS must give preference to proposals associated with renewable energy projects located within the geographic vicinity of the 4CPP or NGS. [§ 1(c)(i)]
- APS must contribute $2.5 million per year to the Nation, to be funded by shareholders, from the retirement of the 4CPP (or 2032, whichever is earlier) to the end of 2038, for transmission line development. [§ 1(c)(ii)]
- If APS procures renewable electricity generation capacity located within the Nation or neighboring communities to serve APS native load, APS must preserve its transmission service reservation as needed to deliver that procured generation capacity to APS native load. [§ 1(c)(iii)]

- "Tribal Economic Development" Commitment—In each of the two years before permanent closure of the 4CPP, and in each of the three years thereafter, APS must provide an annual payment of $250,000, funded by shareholders, to a Nation economic development organization designated by the Nation, for a total contribution of $1.25 million. [§ 1(d)]
- "Tribal Water Rights" Commitment—APS must support the Nation's pursuit of water rights from the San Juan River that are currently associated with the 4CPP and San Juan Generating Station and owned by BHP Billiton ("BHP"), by making appropriate introductions, providing background information, and encouraging BHP to engage with the Nation on the issue. [§ 1(e)]
- Funding from Other Sources—Upon request, APS must support the Nation, and other coalitions that develop, in seeking federal, state, or other funding for CCT assistance,

[226] There is a renewable energy company called Navajo Power that is not affiliated with or controlled by the Nation's government but is owned by Navajo members. (Tr. at 3433-3434, 3455.)

and APS must support and encourage the other 4CPP owners to make similar CCT support commitments, although any additional funds received will be in addition to the funds described in the CCT MOU. [§ 1(f)]

- Job Redeployment—APS must, at least six months before each plant closes, prepare and provide job redeployment offers, within APS's organization, for all APS employees at Cholla and the 4CPP. [§ 1(g)]

- *Inter alia*, the Nation intends to make the following commitments in the CCT Agreement:
  - Nation must support APS's position in this matter regarding cost recovery for 4CPP investments, including the SCRs. [§ 2(a)]
  - The Nation must support before the Commission APS's requests for cost recovery for APS's CCT-related commitments. [§ 2(d)]
  - The Nation must support before the Commission APS's proposal for an "advanced energy" or "clean energy" cost-recovery surcharge for APS clean energy generation investments. [§ 2(e)]
- APS and the Nation agree to use practicable efforts to settle this matter in whole or in part and to use best efforts to obtain other parties' support for §§ 1 and 2 of the CCT MOU. APS and the Nation also agree that the CCT Agreement must prohibit each of them from entering into a settlement or stipulation for this matter that does not include §§ 1 and 2 of the CCT MOU. [§ 8.]

Although not included in the CCT MOU, APS also proposes the following as part of the CCT:[227]

- Regarding those impacted by the closure of Cholla:
  - APS proposes to pay $12 million to the Navajo County Communities,[228] over five years, with $10.9 million of that to be recovered through the proposed Advanced Energy Mechanism ("AEM") and $1.1 million to be funded by shareholders.
  - APS will provide job redeployment offers, within the APS organizations, to all APS

[227] Ex. APS-2 at 23; Ex. APS-3 at 19.

[228] APS identified the Navajo County Communities as primarily including the Navajo County General Fund, Northland Pioneer College, and Joseph City Unified School District. (Ex. APS-2 at 23.) APS identified them as taxing districts that have received direct economic benefits from Cholla. (Ex. APS-3 at 19.)

employees at least six months before Cholla closes.

- Regarding those impacted by the closure of NGS:
  - APS proposes to pay $3.7 million to the Tribe, to be paid over five years, with $3.35 million of that to be recovered through APS's proposed AEM and $0.35 million to be funded by shareholders.

APS is requesting Commission approval to recover through the AEM that portion of the CCT funding to be paid by ratepayers ($119.25 million[229]) and to modify its Service Schedule 3 to allow for the free distribution line extensions for Navajo applicants located within APS's service territory within the Nation. (Ex. APS-2 at 20.) APS acknowledges that it does not need approval to expend the funds proposed to be paid by shareholders (approximately $27.7 million[230]).

APS asserts that it selected for CCT support the governmental bodies that have received direct economic benefits as a result of operations of coal-fired power plants that APS owns or operates. (Ex. APS-3 at 19.) To determine the amount of support, APS considered the direct testimony of Nation President Jonathan Nez; input from stakeholder advocates; the amount of taxes, lease payments, and royalties the entities received; whether APS was the operating agent for the plant at issue; and the extent of APS's ownership in each plant at issue.[231] (Ex. APS-3 at 19-20.) Ms. Lockwood testified that the CCT is structured to provide financial support equivalent to approximately the direct financial support the entity would have received over two years through continued operation of the plant at issue. (Ex. APS-3 at 20, 24-25.) The scheduling of funding was based on the retirement status or timing for the plant at issue as well as an effort to minimize bill impacts. (Ex. APS-3 at 20.) APS was also influenced by community transition arrangements proposed in other jurisdictions, noting that PNM proposed for its customers to pay $40 million for its exit from San Juan Generating Station, with no

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[229] Ratepayers would pay $100 million, $5 million, $10.9 million, and $3.35 million, for a total of $119.25 million. (CCT MOU at §§ 1(a), (b)(iii); Ex. APS-2 at 23.)

[230] Shareholders would pay $5 million, approximately $20 million, $1.25 million, $1.1 million, and $0.35 million, for a total of approximately $27.7 million. (CCT MOU at §§ 1(b)(iii), (c)(ii), (d); Ex. APS-2 at 23.)

[231] The formulaic approach APS used is described in detail in an attachment to Ms. Lockwood's rejoinder testimony. (*See* Ex. APS-3 at att. BDL-01RJ.) A very significant difference in the aid proposed for the Nation and Navajo County Communities versus the Tribe is attributed to APS being the operating agent of the 4CPP and Cholla, which APS stated results in the "primary responsibility to participate in and support local community affairs," as opposed to being a non-operating agent and only a 14% owner in NGS. (*Id.*) APS also noted that it had no relationship with Peabody Energy or the Kayenta Mine. (*Id.*)

shareholder funding; that Pacific Gas and Electric proposed for its customers to pay $85 million for its exit from Diablo Canyon,[232] with no shareholder funding; and that Puget Sound Energy and Avista proposed to pay a combined $13 million to exit Colstrip Steam Electric Station, with 50/50 funding from customers and shareholders. (Ex. APS-3 at 21-22.) APS believes that having shareholders fund approximately 17% of the CCT is reasonable. (Ex. APS-3 at 21.) APS asserts that its customers should pay the majority of CCT funding because providing CCT funding is similar to site reclamation or power plant decommissioning costs that APS customers pay,[233] the economy in Arizona's service territory has benefitted from the electricity generated in the coal-impacted communities, providing CCT funding is the right thing to do, and the proposed CCT funding reflects the costs of doing business for a transition to clean energy. (Ex. APS-3 at 23-24.) Mr. Guldner acknowledged at hearing that both shareholders and customers benefited from the 4CPP and continue to benefit from the 4CPP, because shareholders benefit from any equity investment in plant that earns a return, but asserted that shareholders are indifferent to where plant is located, whereas customers benefited from having the 4CPP located near the mine and away from Metro Phoenix. (Tr. at 926-927.) Mr. Guldner testified that unlike customers, shareholders did not benefit from the lower costs associated with the 4CPP's location because the profit margin is regulated, although he acknowledged that shareholders can benefit from lower O&M costs between rate cases. (Tr. at 927-931.) Mr. Guldner further opined that due to the capital-intensive nature of coal-fired plants, any such benefit would likely be offset by capital additions that would not yet be represented in rates. (Tr. at 930-931.)

APS asserts that the Commission must approve the CCT without delay because the coal-impacted communities have been dependent on the operation of the coal plants for their livelihood, have "dire and immediate needs," and will otherwise be devastated by coal plant closures. (APS Br. at 105-106.) APS asserts that even though Cholla and the 4CPP are not due to retire for another four and 10 years, the CCT assistance cannot be delayed because the impacted communities need to start

[232] Mr. Smith noted that this is a nuclear plant, not a coal plant. (Tr. at 5074.)

[233] During the hearing, APS clarified that APS does not have a trust account or any other type of account where funds are being collected in anticipation of the decommissioning of the 4CPP and Cholla. (Tr. at 1596-1598.) When APS determines that a plant is to be retired, it commissions a study to assess how much decommissioning will cost and records the decommissioning obligation as an asset retirement obligation ("ARO"). (Tr. at 1598-1599.) Those ARO costs are recorded as part of depreciation reserves. (Tr. at 1599.)

planning and building to replace their coal-based economies immediately. (APS Br. at 105.) APS asserts that there is no need to delay the CCT approval to allow for participation from APS's coal plant co-owners because among them the Commission only has jurisdiction over TEP, the Commission has already ordered TEP to address its obligations in a second phase of its rate case, and the CCT is only intended to cover APS's obligations. (APS Br, at 107 (citing Ex. Navajo-9; Ex. APS-3 at 2; Tr. at 3530-3531, 5032-5033).) Additionally, APS asserts, approval of the CCT should not be delayed in anticipation of federal or state government policy on transition assistance because the CCT is not intended to supplant any transition assistance that may come from the state or federal government, and there is no guarantee that such assistance will be forthcoming. (APS Br. at 107-108.) APS adds that per the decision in the TEP Rate Case, the Commission expects APS's transition obligations to be determined in this case and to serve as guidance in determining TEP's and other utilities' transition obligations. (APS Br. at 108 (citing Ex. Navajo-9).) Additionally, APS asserts, unlike the TEP Rate Case, this case has a "fulsome CCT-related record" upon which it is possible for the Commission to reach its determination without waiting for the outcome of the transition docket opened as required by the decision in the TEP Rate Case ("Generic Transition Docket"[234]). (APS Br. at 108-110.)

APS supports the Commission's evaluation of additional transition-related matters in a generic docket, stating that the "CCT is not intended to function as a replacement for economic output," but instead is a tool to build the foundation for economic output and is only a portion of what the communities will need for successful transition. (APS Br. at 106.) APS asserts that the Generic Transition Docket can be used to identify the other actions needed to build upon the CCT. (APS Br. at 106 (citing Tr. at 280-282, 684-686, 3640-3641).)

Additionally, APS argues that the Commission should approve APS's proposed revision to its Schedule 3 line extension policy as part of the CCT approval in this case, to authorize APS to extend distribution lines within the Nation up to 2,000 feet at no cost to Navajo applicants, as described in the CCT MOU. (APS Br. at 110.) APS asserts that no intervening party objected to this revision and that it would implement the change through a compliance filing in this docket. (APS Br. at 110.)

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[234] Docket No. E-00000A-21-0010, opened on January 12, 2021, is a generic docket "In the Matter of Impact of the Closures of Fossil-Based Generation Plant on Impacted Communities."

3. Supporting Parties

a. The Nation

In his direct testimony, Nation President Jonathan Nez asserted that utilities and regulators have an obligation to account for coal-impacted communities when making plant retirement decisions and proposed three principles for just transition:[235]

- Arizona utility coal plant closures should be governed by an established, Commission-regulated process that allows the Nation and other coal-impacted communities a long time to prepare for closure, and utilities should be required to report formally to coal-impacted communities any plans to close individual units or change to seasonal operations.
- Utilities and the Commission should provide sustained financial and in-kind transition support to the Nation and other coal-impacted communities.
- The Commission, utilities, and the Nation and other coal-impacted communities should partner so that the coal-impacted communities have a say in how transition aid is allocated for local economic diversification projects.

President Nez also made the following more specific recommendations for transition assistance:[236]

1. APS should provide at least $193.2 million in initial direct financial transition assistance to Nation communities (based on $100,000 per MW), a Just Transition Council[237] should be formed to decide on transition plans and assistance, and securitization should be considered as a tool to provide additional transition assistance (a portion of the cost savings could be earmarked for coal community transition assistance).
2. In this case, the Commission should create notification and plant shutdown rules and facilitate formation of a Just Transition Council to oversee economic diversification efforts or, alternatively, should order APS to provide initial aid and a transition plan consistent with President Nez's testimony and then open another docket to address future planning.

[235] Ex. Navajo-1 at 13-14.
[236] Ex. Navajo-1 at 14-23.
[237] The Just Transition Council would be composed primarily of elected officials from the Nation, but would also include officials from other coal-impacted communities, and would receive technical assistance from APS and the Commission. (Ex. Navajo-1 at 17.)

The Commission's rules should, *inter alia*, require utilities to provide notice of plant closure at least five years in advance, or as soon as the operator decides to close the plant, whichever occurs first, and require utilities to pay for studies evaluating the likely economic and social impacts of closure to local communities and identifying opportunities for mitigation.

3. The Commission, APS, and the Nation should work together to develop renewable energy projects on the Nation: APS should work with the Nation to develop an RFP for projects sited on the Nation and should use local economic impact as a key factor in evaluating bids, APS should allocate to the Nation a portion of the capacity on the 345 kV and 500 kV transmission lines from the 4CPP and Cholla to APS's service area and should not ever charge the Nation any transmission fees associated with this capacity,[238] the Commission should require Arizona utilities to meet a gradually increasing portion of their annual renewable energy generation requirements from facilities sited on the Nation or benefitting the Nation (up to 25% of annual requirements by 2040), and a significant long-term market should be created for renewable energy from the Nation.
4. APS should significantly increase electrification assistance to the Nation by conducting a census of and extending electric service to unelectrified buildings in the western Nation service area and should invest in local water access by working to ensure that water from the San Juan River used for the 4CPP is given to the Nation after plant closure, contributing $5.32 to $7.7 million in funds toward financing of a water delivery pipeline to LeChee and areas around NGS, and contributing at least $7.56 million toward the extension of the Navajo-Gallup Water Supply project to Shiprock, New Mexico.

The Nation now urges the Commission to approve the CCT[239] in this matter, without delay, asserting that it is in the public interest, that the record in this case has been sufficiently developed to approve the CCT for the Nation, and that the Nation would be harmed if additional delay occurred. (Nation Br. at 3, 6, 10-11; Nation RBr. at 6, 12.) The Nation asserts that the non-cash benefits from the CCT are in the public interest, as they will result in improved electricity access on the Nation, jobs

[238] President Nez testified that the Nation has hosted the transmission lines associated with the 4CPP but has not benefited from them. (Ex. Navajo-1 at 20.)
[239] Our understanding is that the Nation seeks approval of the CCT MOU.

for Nation members who are employed at the 4CPP, aid in acquiring water rights for the Nation, economic development support, and promotion of renewable development on and near the Nation, all of which are good public policy. (Nation Br. at 5.) The Nation requests express Commission approval of the non-cash benefits because Commission approval would formally memorialize the CCT, mitigating the potential for future disputes and making the CCT more accessible to the public. (Nation Br. at 6.) The Nation also committed that it would not return to the Commission for additional transition assistance from APS if the CCT is approved and entirely fulfilled by APS. (Ex. Navajo-1 at 8.)

The Nation refutes as unsupported by RUCO and essentially not worthy of consideration RUCO's concerns about the CCT representing "ratepayer largess" or a "public relations" effort by APS, and RUCO's speculation that the Nation might not effectively provide aid to the Navajo people if the cash benefits went to the Nation, because RUCO openly opposes any ratepayer-supported transition assistance. (See Nation Br. at 7-8 (citing Tr. at 4075, 4131; Ex. RUCO-3 at 6; Ex. RUCO-8 at 14), 14; Nation RBr. at 6-7.) In response to RUCO's testimony that it wanted to "flesh out" the just transition issues, the Nation criticized RUCO for not issuing discovery on the CCT and not contacting the Nation or APS about the CCT and suggested that the "Commission should be concerned by the precedent that rewarding an aggressive strategy of information avoidance might set." (Nation Br. at 12 (citing Tr. at 4128), 13.) The Nation also added that its rights should not be impaired or delayed by RUCO's lack of a permanent director who could take a position on the CCT.[240] (Nation Br. at 13-14.)

The Nation asserts that it and APS would propose exactly the same CCT terms in a generic docket. (Nation Br. at 12-13.) The Nation points out that if the Commission were to adopt RUCO's recommendation for a generic docket proceeding on just transition, that generic docket would provide the Commission no means to change rates or tariffs to effectuate any transition assistance, and

[240] At the time of the hearing, RUCO's Interim Director testified that "RUCO does not believe that ratepayers should be responsible for the implementation or payment for APS's moral or ethical principles" and referred to the AEM as "objectionable with or without the CCT proposal." (Tr. at 4043, 4050.) The Interim Director also testified: "RUCO does not support the concept of just transition funds as proposed by APS in this matter." (Tr. at 4050.) On a second day of testimony, the Interim Director stated that she could not agree that RUCO would never agree to cost recovery from ratepayers to support just transition, because RUCO's future position would be decided by the permanent RUCO Director who had not yet been appointed, but that RUCO did not support the CCT based on the evidence in this docket. (Tr. at 4540-4541.)

implementation would have to wait for the next APS rate case, which could be years away. (Nation Br. at 8, 11; Nation RBr. at 3-4.) The Nation also argues that moving consideration of the CCT to the Generic Transition Docket would be "tantamount to denying the Nation's right for the [CCT] to be considered in a timely manner" and would result in a denial of due process. (Nation RBr. at 4-5.) The Nation argues that the generic docket would not allow for the Nation to be heard "at a meaningful time," due to the lack of a schedule, and would not allow for the Nation to be heard "in a meaningful manner" because generic dockets do not allow for testimony, cross-examination, and the admission of other evidence. (Nation RBr. at 5.) The Nation also argues that the generic proceeding would not improve the Commission's ability to receive comments, because hundreds of comments have been filed in this docket already from a diverse group of people, and the comments regarding transition assistance have been overwhelmingly supportive. (Nation RBr. at 5.)

According to the Nation, the Commission has already expressed its support and expectation for just transition to be addressed in this matter through the SCRs ROO,[241] Decision No. 77856,[242] and Decision No. 77763[243] (October 2, 2020). The Nation states that parties that do not regularly participate in Commission proceedings, including the Nation, intervened in this matter because the issue was expected to be addressed herein and, further, that it "strains credulity" for a party to each of

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[241] The SCRs ROO found that a transition plan proposed by the Citizen Groups was outside the scope of the SCRs Phase but that it was reasonable to require APS to begin establishing a transition plan for the 4CPP and impacted communities and to require APS to file a proposed initial transition plan for Commission consideration in its next rate case; the SCRs ROO ordered APS to include a transition plan. (SCRs ROO at 23, 25.)

[242] Decision No. 77856, issued in the TEP Rate Case, was admitted herein as Exhibit Navajo-9. In the Decision, the Commission declined to approve a transition plan proposed by the Citizen Groups, directed Staff to open a generic docket on just transition, and held open the TEP Rate Case for a second phase to receive additional evidence regarding the outcome of the generic docket, and stated the following:

> We expect that the generic docket that we require here will run concurrently with the prosecution of APS' rate case. We also expect that the findings, conclusions, and recommendations from the generic docket will be completed close in time to the issuance of a Decision in the APS matter, such that it will be feasible to begin a Phase Two proceeding in the [TEP Rate Case] docket not long after the completion of both APS and the generic docket. Thus, we direct the Hearing Division to hold a procedural conference within 45 days of the issuance of a Decision in the APS rate case to establish a timeline for the filing of evidence and testimony, and conducting a hearing in Phase Two of [the TEP] rate case.

(Ex. Navajo-9 at 172.) The Decision ordered for these things to occur. (Ex. Navajo-9 at 202.)

[243] An excerpt of Decision No. 77763 was admitted herein as Exhibit RUCO-11. In the Decision, the Commission ordered APS, "as part of its corporate obligations to support a just and equitable transition of communities impacted by early power plant closure," to develop and file for review and approval a Tribal Energy Efficiency Program proposal and budget to implement energy efficiency projects with the Nation and Hopi communities. (Ex. RUCO-11 at 38.)

those proceedings[244] to complain that it did not know the issue would be addressed in this case. (Nation Br. at 9.) The Nation characterizes as "spurious" arguments about just transition not having been addressed early enough in this case, pointing out that other disputed issues were resolved by agreement between parties during the case. (Nation Br. at 9-10.) Per the Nation, because the Commission has already made the policy decision that "action must be taken and soon, to mitigate the negative impacts of plant closures on tribal lands and elsewhere," the fact-finding process in this docket has been more than adequate, and the opposition has amounted to "speculat[ion]"[245] or "name calling,"[246] there is no need to delay a decision to wait for other opinions. (Nation RBr. at 8 (quoting Ex. Navajo-9 at 171), 9-10.) Additionally, the Nation asserts, because the Commission has exclusive and plenary authority over ratemaking, there is no need for legislative action related to the CCT. (Nation RBr. at 8-9.)

In response to the Tribe's request for additional proceedings to address its just transition, the Nation states that the CCT MOU is a fully negotiated settlement that does not impact the Tribe and should be ruled on by the Commission. (Nation Br. at 14.) The Nation states that because it and the Tribe are separate sovereign nations that have separate, independent transition issues to address, the Nation's and the Tribe's transitions do not need to be resolved at the same time. (Nation Br. at 14-15.) The Nation also states that it should not be prejudiced because the Tribe decided to file its own testimony late. (Nation Br. at 15.) If a Phase 2 is held to address just transition in this docket, the Nation says, it should be brief and limited in scope, lasting no longer than five months. (Nation Br. at 18-19.)

The Nation emphasizes the economic harm that will result to the Nation if the 4CPP is closed without just transition support, asserting that the coal plants and mines provide thousands of direct and indirect jobs across the 4CPP region and have contributed more than $1 billion per year in total regional economic activity, that APS pays significant taxes related to coal generation (the NGS closure resulted in $40 million of lost tax revenue), that the Nation depends on revenues related to the 4CPP to pay for essential public safety services, and that the Nation depends on the 4CPP for jobs that pay well. (Nation Br. at 16.) The Nation asserts that the CCT, consistent with the Commission's decision in the TEP

[244] We understand this to be a reference to RUCO.
[245] Citing Staff Br. at 42; Tr. at 5082.
[246] Citing Ex. RUCO-3; Ex. RUCO-8; RUCO Br. at 16.

Rate Case,[247] is not just a reimbursement tool to replace the direct revenues that will be lost and that its benefits will be greatest if it is implemented to support transition before the 4CPP closes because the economic development the CCT brings will mitigate the local impacts of the closure. (Nation Br. at 10; Nation RBr. at 11-12.) The Nation also argues that delay would result in reduced benefits. (Nation Br. at 12.)

According to the Nation, because no party has offered an alternate method to compute the CCT cash benefits for the Nation, the record supports the method proposed in the CCT. (Nation Br. at 6-7.) The Nation argues that it would be "nonsensical" to weight the need for transition assistance based on number of meters, miles of distribution line, or energy load, because those do not measure the effects of the 4CPP and other coal plants, and using them as an indicator of need would result in the "absurd" result that Phoenix would need the most assistance. (Nation Br. at 16-18.)

The Nation criticizes RUCO and Staff for ignoring the fact that the Nation's prefiled direct testimony proposed transition assistance, including monetary amounts, that the Nation believed APS should provide and making it sound like the subject of transition assistance first was raised in APS's rebuttal testimony. (Nation RBr. at 2.) The Nation argues that because the Nation proposed transition assistance at its first opportunity in this case, RUCO's and Staff's arguments, if accepted, would mean that the Nation could not have done anything to obtain approval of transition assistance in this case. (Nation RBr. at 2-3.) The Nation also argues that RUCO's and Staff's refusal to acknowledge the Nation's testimony "infringes on the Nation's basic due process rights as an intervenor."[248] (Nation RBr. at 3.) Further, the Nation criticizes both Staff and RUCO for recommending that the CCT be addressed in a Phase 2 of this docket, because the Commission established a schedule in the TEP Rate Case that called for this docket and the Generic Transition Docket to be resolved "close in time."

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[247] In Decision No. 77856, the Commission defined "impacted communities," for purposes of that decision and the Generic Transition Docket, as follows:

> [T]he term "impacted communities" means cities, towns, counties, communities, tribes, census designated areas, and non-incorporated geographic areas that will be negatively affected, financially or socially, by the closure of fossil-based generation plant or mining facilities associated with fossil-based generation plant, located in or near their jurisdictions, that have been a source of economic income and employment for the communities[.]

(Ex. Navajo-9 at 172.)

[248] To be clear, the Commission does not consider a party's due process rights to be infringed if another party fails to recognize the party's evidence in the manner desired. The Commission has admitted the Nation's evidence, and the Nation had an opportunity to brief that was identical to that of Staff and every other party.

(Nation RBr. at 10 (quoting Ex. Navajo-9 at 172).)

The Nation also criticizes RUCO's position that the CCT is "not a cost of service," asserting that it is inconsistent with RUCO's advocacy for the Commission not to allow approval for the SCRs in this case and for the Commission to consider customer emotions and polling in setting APS's cost of capital. (Nation RBr. at 12-13.) The Nation argues that because the CCT has a clear and direct relationship to APS's fossil-based generation capacity, and is akin to decommissioning costs (for which no one challenges recoverability), the CCT is directly related to cost of service and appropriate to address through APS's rates and tariffs. (Nation RBr. at 13.)

The Nation urges the Commission to approve the AEM along with the CCT, but also urges the Commission to stay open to securitization of the CCT and SCRs costs as a lower cost option for APS customers, including those in the Nation. (Nation Br. at 19.)

When NGS closed, the Nation received 500 MW of transmission capacity for its own use, which President Nez testified would be used toward replacing the revenue stream that came to the Nation from NGS. (Tr. at 3353-3358; Ex. RUCO-19.)

b. Citizen Groups

The Citizen Groups are community organizations based in the Four Corners region that have ties to the Navajo Nation and that are, in the broadest strokes, focused on obtaining and protecting a cleaner environment and achieving more sustainable use of the land. (Ex. CG-1 at 2-3.) Although they believe that the CCT cash benefits are less than what is needed for a just and equitable transition,[249] because the Nation supports the CCT, the Citizen Groups urge the Commission to approve the CCT without delay. (Ex. CG-2 at 15; CG Br. at 3.) The Citizen Groups call meritless the arguments made to wait and rule on transition assistance either in the Generic Transition Docket or a Phase 2 in this docket, arguing that the Commission contemplated that resolution would come in this docket and, further, that it is unclear whether anything will ever happen in the Generic Transition Docket. (CG Br. at 18.)

[249] On direct, the Citizen Groups recommended that APS be required to contribute funding of $100,000 per MW of peak ownership of the retiring plants, which amounted to $114.5 million for the 4CPP, $33.726 million for NGS, and $61.5 million for Cholla (totaling $209.726 million). (Ex. CG-1 at 29.) The Citizen Groups assert that this is consistent with what the Navajo and Hopi advocated for in the TEP Rate Case. (Ex. CG-1 at 28-29.) The Citizen Groups also made specific recommendations for the forms of transition assistance to be provided. (Ex. CG-1 at 27-42.)

The Citizen Groups describe APS's CCT proposal as a "concrete and meaningful first step" and assert that the Commission's decision in this matter will lay the foundation both for the other owners of the three coal plants to recognize their own obligations to support transition and for efforts to secure additional financial support at the federal level. (CG Br. at 17.) The Citizen Groups would have liked to see transition support come before the NGS plant closed, as the plant owners knew by February 2017 that retirement was coming, because the delay has caused unnecessary economic hardship for the Nation, the Tribe, and other coal-impacted communities and has put them two years behind where they should be.[250] (Ex. CG-2 at 13.) The Citizen Groups remind the Commission that they have been advocating for transition assistance before the Commission for years, in resource planning dockets and previous rate cases (including the 2016 Rate Case). (CG RBr. at 3.)

The Citizen Groups assert that they will hold APS to its promise to support their efforts to secure transition assistance from other entities, including the federal government and the 4CPP and NGS owners, and express concern that it may take years to determine whether and what such aid will be forthcoming. (Ex. CG-2 at 13-14; CG RBr. at 4.) The Citizen Groups also desire to work with APS to ensure that APS's 2031 exit from the 4CPP results in its closure rather than continued operation by another entity and, further, that any transmission capacity made available by the closure is dedicated to clean energy and does not allow for coal power, as continued operation of coal plants means continued use of the Nation's water for industrial use. (Ex. CG-2 at 15.)

The Citizen Groups are sympathetic to the Tribe's objection to the amount of transition assistance proposed by APS, which the Citizen Groups consider inequitable and inadequate, and support the Tribe's efforts to negotiate for more funding. (CG Br. at 17; CG RBr. at 7.) The Citizen Groups maintain, however, that "[p]erfect should not be the enemy of good" and that the Tribe's treatment in the CCT does not warrant denial of the CCT proposal in this docket. (CG RBr. at 8.) Rather, the Citizen Groups assert, negotiations between the Tribe and APS can and should continue because there are components of the CCT that do not require Commission approval, such as

[250] The Citizen Groups attributed the delay to SRP's entertaining offers from other entities to buy and operate NGS after the retirement announcement in 2017. (Ex. CG-2 at 14.)

commitment to develop clean energy projects with the Tribe, electrification of homes, and use of shareholder funds. (CG RBr. at 8.)

The Citizen Groups assert that because ratepayers have benefited from inexpensive and reliable electricity generated on or near tribal lands, using tribal employees, land, and natural resources, ratepayers share a responsibility for just and equitable transition. (CG Br. at 16; CG RBr. at 5.) The Citizen Groups disagree with RUCO's assertions that transition assistance is "not a necessary cost of service" and that ratepayers will not benefit from it, countering that ratepayers will benefit from the transition, because it will result in new, less expensive, and more reliable sources of electricity generation for the future. (CG Br. at 16; CG RBr. at 5.) The Citizen Groups also point out that ratepayers will not be required to pay the entire amount immediately, as most of the ratepayer funding under the CCT will be collected over 10 years. (CG RBr. at 5.)

The Citizen Groups also dispute Staff's reasoning that APS ratepayers should not be required to pay for the CCT because they are already paying for land leases, royalties, and property taxes in connection with the 4CPP and Cholla. (CG RBr. at 5-6.) According to the Citizen Groups, the uncontroverted evidence establishes the need for the transition funds because the Nation is already consuming its current revenues for essential health, social, and public safety services. (CG RBr. at 6.) The Citizen Groups also dispute Staff's argument that the CCT should not be approved in this case because the CCT MOU is nonbinding and not the final agreement between APS and the Nation, observing that this is because APS could not commit to providing the Nation ratepayer dollars for transition assistance without Commission approval. (CG RBr. at 6.) The Citizen Groups further assert that "if the Commission orders APS to provide this support, it must do so under the terms of [the CCT] MOU"[251] and observe that the Commission will be able to enforce its decision should APS fail to comply. (CG RBr. at 6-7.)

The Citizen Groups support the AEM as the means for APS to obtain ratepayer funding for the CCT, which they likened to use of the DSMAC to obtain ratepayer funding for the Tribal Energy

[251] To the extent that this suggests the Commission is bound by the CCT MOU in its ability to order APS to provide transition assistance that falls within the Commission's jurisdictional authority, we disagree with it. The Commission is not a party to the CCT MOU and is not bound by its provisions. The Commission will reach its conclusions based on the evidence and the public interest, not based on the confines of the CCT MOU.

Efficiency Program. (Ex. CG-2 at 16.) The Citizen Groups note that a 2019 statewide poll directed by the Arizona PIRG Education Fund ("PIRG"), which included respondents of different political leanings, found that more than 83% of respondents indicated it is very or somewhat important for the NGS owners to provide financial assistance and support such as job training to coal-impacted communities and that 73% of respondents indicated that it was very or somewhat important even if electric bills would increase slightly. (Ex. CG-2 at 16-17.) Nonetheless, the Citizen Groups assert, APS must strive to minimize the economic impact on its customers,[252] and the Citizen Groups hope that securitization will become an option in Arizona to lessen that impact. (Ex. CG-2 at 16.)

c. Sierra Club

Sierra Club strongly recommends approval of the CCT in this case, noting that the Commission has already recognized its importance and found that it is within the Commission's jurisdiction to approve such funding. (SC Br. at 30-31.) Sierra Club asserts that the evidence presented by the Nation, the Tribe, and the Citizen Groups establishes that transition funding is urgently needed now because essential services like healthcare, education, and housing are already jeopardized by the loss of coal-related revenue, and the process of planning for and rebuilding local economies will take years. (SC Br. at 30-32.) Sierra Club also asserts that although the CCT offered by APS is "far from comprehensive," it is "an excellent first step," just, reasonable, and in the public interest. (SC Br. at 30.)

Sierra Club further argues that it is just, reasonable, and in the public interest to require ratepayers to pay for the majority of CCT assistance because APS ratepayers have significantly benefitted for decades from the operations of the 4CPP, NGS, and Cholla—by receiving cheap electricity (made cheaper due to lower land costs), having the sources of air pollution removed from more densely populated areas, not having to compete with power plants for groundwater resources, and not experiencing the negative externalities that those in the Four Corners region have. (SC Br. at 32-33.) Additionally, Sierra Club asserts, supporting coal-community transition is "simply part of plant closure for which ratepayers are responsible." (SC Br. at 34.)

[252] On direct, the Citizen Groups recommended that the majority of any funding for transition assistance come from shareholders, not customers, suggesting that customers should be required to cover no more than half. (Ex. CG-1 at 29.)

The Sierra Club advocates for the Commission to approve the CCT in this matter and also allow the Generic Transition Docket to move forward as an opportunity for additional transition assistance to be provided. (SC Br. at 30, 34.) Sierra Club points out that the CCT proposal only involves APS, not other coal facility owners, and asserts that the CCT proposal provides far less financial assistance than the coal-impacted communities will need to make successful transitions to non-coal economies. (SC Br. at 34.) According to the Sierra Club, the Commission should direct other utilities to provide transition support, either through the Generic Transition Docket or another mechanism. (SC Br. at 35.)

Sierra Club supports the Tribe's request to receive additional cash and non-cash benefits from APS, including distribution line extensions, assistance in developing renewable energy, and support to build microgrids to resolve excessive outages. (SC Br. at 35.) Sierra Club observes that APS has offered to negotiate with the Tribe and encourages the Commission to approve the cash assistance APS offers herein to the Tribe while also directing APS to work with the Tribe on an expanded proposal. (SC Br. at 35; SC RBr. at 16.) In its responsive brief, Sierra Club goes further and asserts that the Commission should direct APS to engage in good faith negotiations with the Tribe and should establish a clear schedule for negotiations and presentation of a supplemental transition plan for approval in the Generic Transition Docket. (SC RBr. at 18.)

Sierra Club opposes RUCO's and Staff's positions that the CCT should be considered in the Generic Transition Docket rather than in this case, arguing that the Generic Transition Docket is "likely to cause years rather than months of delay" and that neither Staff nor RUCO has actively worked to move the Generic Transition Docket forward (in spite of the requirement for a recommendation from Staff by May 29, 2021, pursuant to Decision No. 77856). (SC Br. at 35-36.) In its responsive brief, Sierra Club noted that Staff had recently requested a 60-day extension to make its recommendation in the Generic Transition Docket.[253] (SC RBr. at 18.)

Sierra Club supports funding of the CCT in this case either through the AEM or a narrower adjustor specific to CCT expense as Staff suggested. (SC Br. at 36.) If the Commission chooses to approve use of the AEM, however, Sierra Club has a number of recommendations to improve the AEM

[253] Official notice is taken of Decision No. 78016 (May 18, 2021), issued in the TEP Rate Case, which granted Staff an extension of the deadline for its recommendations from May 29, 2021, to July 28, 2021.

POA. (SC Br. at 36-39.)

In the alternative, Sierra Club advocates for APS to retire the 4CPP promptly and use the resulting savings to offset the CCT costs, arguing that the total CCT proposal would amount to less than 20% of the total savings from retiring the 4CPP. (SC RBr. at 17.) Sierra Club adds that approval of the CCT would facilitate retirement of the 4CPP because the transition costs would be resolved and would not impede closure negotiations and related decisions. (SC RBr. at 17.)

4. Opposing Parties

a. The Tribe

The Tribe had no notice from APS or discussions with APS (beyond a "heads-up" phone call) prior to APS making its CCT proposal herein, and the Tribe flatly rejects its treatment in APS's proposed CCT. (Ex. APS-6 at 3; Tr. at 3958-3959, 3975-3976.) The Tribe also objects to APS's not having provided notice that it would address the transition assistance issue until its rebuttal testimony, because the Tribe had not previously felt compelled to intervene in this case. (Hopi Br. at 1-2.) The Tribe asserts that its later intervention put it at a disadvantage and made it impossible to pursue funds for, or to obtain, expert assistance for this case. (Hopi Br. at 1-2.) According to the Tribe, approving the CCT herein would be unjust and "would legitimize and enable future gaps in needed notice." (Hopi Br. at 2.)

The Tribe supports use of the Generic Transition Docket rather than this docket to address transition assistance because it was not involved in the discussions that led to the CCT, does not want to be left waiting for some unspecified later action by APS, and wants to ensure that the assistance received by the Tribe comports with what is provided to the Nation. (Tr. at 3962-3963; Hopi Br. at 5.) The Tribe points out that it is inconsistent for APS to assert that the Tribe should wait for further transition assistance in the future, while also arguing that providing assistance to impacted communities is urgent and should not be delayed. (Hopi Br. at 5.) The Tribe also points out that APS has not provided any future funding disbursement plan and has not identified any alternate future process through which the Tribe would obtain additional assistance. (Hopi Br. at 6.) The Tribe argues that if the CCT is approved, the Tribe will have no assurance of equitable assistance, and that "a proper and truly equitable result" can only be obtained if assistance to both the Nation and the Tribe are resolved

at the same time. (See Hopi Br. at 6; Tr. at 3962.)

According to the Tribe, the CCT disproportionately favors the Nation while inequitably underfunding the Tribe, and APS has not provided sufficient explanation or justification for this disparity or any explanation of how APS determined the non-cash assistance amounts or recipients. (Hopi Br. at 1-2.) The Tribe adds that because APS serves far more Hopi customers than Navajo customers, APS should have offered the Tribe non-cash transition assistance. (Ex. Hopi-8 at 4.) The Tribe also argues that because the coal-related revenues to the Tribe amounted to so much more of its general fund revenues (stated alternately as 80%[254] and "even more than 95%"[255] for the Tribe, as compared to 25% and "less than 30%" for the Nation), the Tribe needs significantly more financial assistance than the Nation does. (Ex. Hopi-6 at 5; Hopi Br. at 3-4.) The Tribe asserts that its inability to fund an expert for this case only highlights its economic disadvantage in comparison to the Nation. (Hopi Br. at 2-3.) The Tribe appears to believe that the lack of such an expert left it unable to analyze and advocate effectively for its own needs in this case. (See Hopi Br. at 3.)

The Tribe also objects to APS considering the Nation's interests to be determinative, as evidenced by Ms. Lockwood's testimony that the CCT is a "complete and appropriate package that is supported by the community" and that "there is no reason to delay moving forward" with it. (Hopi Br. at 4 (citing Tr. at 195).)

Further, the Tribe criticizes the CCT because it would require Hopi APS customers to pay the costs for the Tribe's and the Nation's transition assistance, which the Tribe asserts would contradict the concept of assistance, would be fundamentally unjust, and would not happen to the Nation's members because far fewer Nation members are APS customers. (Hopi Br. at 4-5; Ex. Hopi-6 at 5; Ex. Hopi-8 at 4-5.) According to the Tribe, it and its members cannot afford to pay the assistance costs in light of the drastic reductions to the Tribe's revenue stream. (Hopi Br. at 5.) Additionally, the Tribe says, because it does not have a tribal electric utility, while the Nation does, the Tribe is not able to manage the impacts from APS rate increases in the way that the Nation can. (Hopi Br. at 5.)

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[254] This number is misleading. While the average for FY1996-FY2019 was 80.3%, the average for FY2010-FY2019 was 60.2%. (*See* Ex. Hopi-7.)

[255] This number is even more misleading, because in the period from FY1996 to FY2020, the Tribe only received more than 90% of its net general fund revenues from royalties in FY1997-FY2002 and in FY2006. (*See* Ex. Hopi-16.) Also, since FY2010, the percentage has not exceeded 77.2%, which is quite significant, but not in excess of 95%. (*See id.*)

In testimony, Chairman Nuvangyaoma asserted that $100,000 per MW of nameplate capacity would be a fair and reasonable measure of the transition assistance that APS should pay the Tribe, which would result in APS paying the Tribe at least $31.5 million based on APS's share of the NGS capacity. (Ex. Hopi-6 at 4.) Mr. Lomayestewa also suggested that the Tribe would accept transition assistance that included:[256]

- $15 million in cash assistance;
- Hopi customers' exemption from paying for the CCT costs;[257]
- Reliability upgrades;
- Technical assistance to further its own electrification goals (operational assistance to a new Tribal utility; a load profile assessment, existing system service performance profile, and limitation analysis (to include additional usage allowance projections) for the Hopi reservation; an electrification survey of the Hopi reservation; and a survey/inventory of existing infrastructure on the Hopi reservation);[258]
- Transmission access for the Tribe similar to that made available to the Nation; and
- Support for Hopi renewable energy generation through APS purchase guarantees.[259]

Chairman Nuvangyaoma also supported the $15 million figure, although he stated that the Tribe would need to engage further with APS to determine what is just and equitable. (Tr. at 3961.) Ultimately, the Tribe argues that because APS participated in the decision to close NGS earlier than planned, and it only profited from its investments in coal-fired generation, APS must provide truly equitable relief to the coal-impacted communities and take into account that the Tribe is "the most severely impacted." (Hopi Br. at 7.)

In addition to its positions taken specific to the CCT, the Tribe asserts that any rate approved in this matter must require a commitment from APS to improve the reliability of service to underserved areas such as the Tribe, because APS's service reliability for the Nation and the Tribe is "third quartile,"

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[256] Ex Hopi-8 at 6.
[257] The Hopi are concerned because, as APS customers, they would be required to pay for both their own transition assistance and the Nation's CCT. (Tr. at 3591.)
[258] The Hopi desire eventually to have Hopi Utilities Corporation provide water, wastewater, and electric service to Hopi residents. (Tr. at 4007-4008.)
[259] Hopi-8 at 6.

which is undesirable and indicates operational shortcomings. (Hopi Br. at 6.) The Tribe asserts that APS should be expected to bring its reliability performance up to the first quartile, although the Nation also expressed skepticism that this will occur. (Hopi Br. at 6.)

b. AECC/Freeport

On brief, AECC/Freeport states that while it does not take a position on the substantive issue of whether APS customer funding for the CCT is warranted at this time, AECC/Freeport considers approval of the CCT in this docket to be premature because the Commission and interested stakeholders have not had an opportunity to analyze the transition assistance issue and how it should be applied to the communities adversely affected by early coal plant retirements. (AECC Br. at 43.) AECC/Freeport argues that because only APS and the Nation were involved in creation of the CCT, there are no details regarding the administration of APS customer funds paid to the Nation, and the future development goals and transition activities are vague, the Commission should address the CCT in the Generic Transition Docket rather than this case. (AECC Br. at 44.) AECC/Freeport argues that approval of the CCT in this docket may be deemed arbitrary and capricious, suggesting that the Commission does not have sufficient evidence herein that the policy goals of transition assistance serve the public interest. (AECC Br. at 44.) AECC/Freeport further suggests that bypassing the Generic Transition Docket and approving the CCT in this case might not sufficiently protect APS's customers and might result in rates that are not considered to be "just and reasonable." (AECC Br. at 44.)

c. RUCO

RUCO opposes the CCT both because APS proposes to have customers pay far more than shareholders and because RUCO believes that CCT assistance it is not a necessary cost of service. (RUCO Br. at 16.) RUCO argues that customers' payments of over $100 million in CCT costs will not result in improved service and that the CCT discussions should have involved not only APS and the Nation, but also the Tribe and RUCO (because customers are proposed to shoulder most of the financial burden). (RUCO Br. at 16-17.) RUCO calls out President Nez for testifying that APS represented both ratepayers and shareholders during the negotiations and for referring to the CCT as a "great start" when asked if the CCT represents the total commitment to transition costs for the Nation that APS's customers will be asked to make. (RUCO Br. at 17 (citing Tr. at 3330, 3486).) RUCO

asserts that because there is so much money at stake, and the transition issue is a policy issue (as opposed to being a cost of service issue), the CCT should be addressed in the Generic Transition Docket so that it can be thoroughly examined. (RUCO Br. at 18.) RUCO objects to the CCT as a "one-off proposal" that resulted from a process with insufficient stakeholder involvement, that the Tribe has rejected, and that raises more questions and concerns than it resolves. (RUCO Br. at 18.)

Nonetheless, RUCO would not object to having this docket remain open for a Phase 2 transition assistance proceeding, as is being done in the TEP Rate Case. (RUCO Br. at 18.)

d. Staff

Staff opposes approval of the CCT in this matter and asserts that the issue instead should be addressed in the Generic Transition Docket and through a Phase 2 implementation stage in this docket. (Staff Br. at 41-42; Staff RBr. at 5-6, 8.) Staff expresses concern because inclusion of the CCT MOU in Ms. Lockwood's rejoinder testimony provided no opportunity for parties to file written testimony on the CCT MOU; the CCT MOU is a non-binding document that will be superseded by a finalized document with provisions that are not currently available; the CCT proposal would require ratepayers to fund $10.5 million in CCT payments to the Nation for 10 years while ratepayers are already paying approximately $52.57 million per year on property taxes, royalties, and leases for the 4CPP; and the CCT would require ratepayers to pay another $2.18 million and $670,000 per year over the next five years to the Navajo County Communities and the Tribe, although there is no binding agreement related to those payments, and ratepayers are already paying $5.46 million per year for property taxes for Cholla. (Staff Br. at 39-42; Staff RBr. at 7.) Staff also asserts that efforts are underway at the federal level to provide support and assistance to the impacted communities and disagrees with APS's position that approval of the CCT in this docket would not supplant any role that the state or federal governments may play in providing support to the coal-impacted communities. (Staff RBr. at 7.)

Staff also notes the Tribe's disagreement with the CCT assistance APS has proposed for it. (Staff Br. at 41.)

Noting that the Commission directed Staff to solicit comments regarding transition assistance in the Generic Transition Docket from impacted communities, the Governor's Office, the state legislature, regulated and unregulated entities, state and federal agencies, and public utility

commissions in neighboring states, Staff asserts that the Generic Transition Docket will allow for input from a wider range of participants than this matter. (Staff Br. at 42 (citing Decision No. 77856).)

Further, Staff recommends that any ratepayer funding approved as a result of the Generic Transition Docket and a Phase 2 of this matter be recovered through a specific surcharge mechanism created for the purpose, the Coal Community Transition Charge ("CCTC"), to provide transparency. (Staff Br. at 42-43.)

5. APS Response

APS agrees with the Nation that it is "critical" for the Commission to provide express approval of the CCT's non-financial assistance elements in addition to the financial assistance elements APS seeks to have funded by customers. (APS RBr. at 75.) APS supports collection of ratepayers' CCT assistance funds through the AEM, inclusion in base rates, or another defined mechanism (such as Staff's proposed CCTC). (APS RBr. at 75.) APS argues that the Commission's signal of policy support will ensure the success of the CCT and will develop momentum for additional support mechanisms. (APS RBr. at 75.) APS also asserts that no party has opposed the non-financial assistance elements of the CCT; points out that the Nation, Citizen Groups, and Sierra Club all support the CCT; and asserts that only Staff, RUCO, and AECC/Freeport oppose the CCT financial assistance elements.[260] (APS RBr. at 76.)

APS disputes RUCO's arguments that the CCT represents ratepayer "largess" unrelated to the costs of APS's electricity service and will not result in improved service or any change in service for APS customers, arguing that RUCO's position ignores that the coal-impacted rural and tribal communities have provided inexpensive and reliable electricity that has created economic vitality across Arizona, that APS's customers have benefitted specifically from the locations of the power plants near coal supplies and from their inexpensive power, and that electrification will be expanded within APS's service area in the Nation. (APS RBr. at 76-77.) APS likens the CCT to end-of-plant-life decommissioning, remediation, or reclamation, which is a cost of doing business funded by

[260] APS appears to have forgotten about the Tribe's position, which at least questions whether the financial assistance to the Nation is equitable in light of the proposed financial assistance to the Tribe. The Tribe's position can fairly be described as desiring for the Nation not to receive a piece of the CCT pie until it is determined how big the much CCT pie the Tribe will receive.

customers. (APS RBr. at 77.) APS asserts that the record establishes the CCT is equitable, firmly rooted in APS's cost of service, and in the public interest. (APS RBr. at 78.)

APS further argues that RUCO's assertion that there is no analysis to support the breakdown of CCT funding between shareholders and customers is false, stating that the breakdown "reflects a reasonable attribution of responsibility when compared to CCT precedents in other jurisdictions." (APS RBr. at 79 (citing Ex. APS-3 at 21).) Additionally, APS points out that no other party offered an alternate breakdown. (APS RBr. at 79.)

APS criticizes Staff for apparently considering the CCT financial assistance to be a direct replacement of the taxes, royalties, and lease payments. (APS RBr. at 78.) APS argues that Staff's view is not supported by the record because the evidence shows that transition assistance is needed right away to allow the communities to plan and prepare for the upcoming closures and the time when those payments will cease, not to replace the lease, tax, and royalty payments, which currently are fully allocated to support essential public services. (APS RBr. at 78.)

Regarding the total amount of CCT assistance proposed, APS touts its supporting analysis, set forth by Ms. Lockwood, which was designed to provide each affected community approximately two years' worth of the annual direct economic contribution APS has been providing to it. (APS RBr. at 79-80.) APS notes that the Citizen Groups and Nation originally suggested assistance of $100,000 per MW of plant capacity owned by APS and that the Nation ultimately agreed upon the amounts supported by the APS analysis. (APS RBr. at 79-80.) APS asserts that no party has objected to, questioned, or otherwise expressed concern about the reasonableness of the methodology.[261] (APS RBr. at 80.)

APS takes issue with Staff's position that the CCT should be addressed in the Generic Transition Docket because the CCT was not provided until APS's rebuttal testimony. (APS RBr. at 82.) APS points out that the CCT proposal was made in direct response to the Nation's and Citizen Groups' direct testimony, that the issue of transition assistance has been recognized by the Commission in numerous proceedings during the past few years, and that the CCT proposal has been thoroughly examined in this case. (APS RBr. at 82.) APS adds that there is no guarantee that transition assistance

[261] APS again appears to be forgetting about the Tribe, which definitely questioned the fairness of the methodology as applied to the Tribe.

from state or federal government sources will ever arise but that, if it does, that assistance can supplement the CCT assistance provided by APS, which is not enough to address fully the impacted communities' needs. (APS RBr. at 82-83.)

APS likewise dismisses claims by AECC/Freeport and RUCO that they have not had an adequate opportunity to evaluate the CCT proposal and that its details are lacking, pointing out that neither of them participated in discovery regarding the CCT and that both of them had an opportunity to cross-examine witnesses who supported the CCT. (APS RBr. at 80.) APS reiterates that the situation with the CCT in this case is different than the situation regarding transition assistance in the TEP Rate Case, because APS's CCT proposal is supported by substantial evidence and has been thoroughly evaluated through both testimony and a hearing. (APS RBr. at 79-80.) APS further asserts that this case is "the exact venue" for a decision on the CCT proposal because the CCT proposal has been extensively evaluated by numerous parties with diverse perspectives, and this case provides an opportunity for the Commission to take immediate action on the CCT through APS's rates and tariffs. (APS RBr. at 81-82.)

While APS argues that the CCT proposal should be resolved in this case, APS also asserts that the aspects of the CCT proposal solely addressing the Tribe "could potentially benefit from further proceedings within a generic docket that is directly connected to a potential second phase of APS's rate case." (APS RBr. at 81.) APS asserts that because the Tribe clearly supports and needs CCT assistance and is only concerned about the level of support proposed for itself, additional proceedings may be useful to determine whether and how much additional assistance should be provided. (APS RBr. at 81-83.) APS supports the Commission approving the CCT proposal in its entirety and holding open this case for a Phase 2 to address solely whether additional support to the Tribe is warranted. (APS RBr. at 83.) APS asserts that it would commit to advancing consideration of additional CCT assistance for the Tribe through the Generic Transition Docket and would support an aggressive timeline to resolve any Phase 2 proceedings, such as the five-month timeline proposed by the Nation. (APS RBr. at 83-84.)

APS disagrees with the Tribe's assertion that approval of the CCT should be delayed until the Tribe's concerns are addressed, calling it "counterproductive" and pointing out that there is no reason

the Commission cannot consider additional support in a subsequent proceeding. (APS RBr. at 84.) APS reiterates that APS proposes different levels of CCT assistance for the Nation and the Tribe "based upon the vastly different levels of direct economic contributions" made to them related to APS's ownership of coal-fired power plants, pointing out that APS owns 63% of the 4CPP but only 14% of the NGS and asserting that the amount of direct economic contributions APS has made to the Tribe were only 3.2% of the direct economic contributions APS provides to the Nation. (APS RBr. at 84-85.) APS also questions the Tribe's assertions that coal-related revenues comprise the vast majority of the Tribe's general revenue funds, pointing out that the average for the past 10 years was much lower than 80% to 95%. (APS RBr. at 85.) APS argues that there is no merit to the Tribe's argument that it did not have adequate notice of this case or any of the individual contested issues in this case, asserting that because transition assistance has been an issue before the Commission since at least 2018, a reasonable person would have expected the issue to be addressed in this case. (APS RBr. at 85-86 (citing Decision No. 77763; Decision No. 77829;[262] SCRs ROO).) APS further asserts that for the same reasons that all APS customers should be required to provide funding for CCT, all APS customers within the Hopi reservation should be required to provide funding for CCT. (APS RBr. at 86.)

Finally, APS asserts that APS's service to its customers within the Hopi reservation has improved each year since 2015, that it has invested approximately $1.6 million in transmission and distribution system improvements in that time, and that its 2020 outage rates within the Hopi reservation have improved by 37% since 2015 and continue to improve. (APS RBr. at 86 (citing Tr. at 1320-1321, 1396; Ex. APS-82).) APS acknowledges that the performance of its system within the Hopi reservation and Nation are within the third quartile of APS's 125 distribution system feeders in the Northeast Division, but asserts that this situation does not support providing a greater amount of CCT assistance to the Tribe. (APS RBr. at 86 (citing Tr. at 1396-1398).)

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[262] Official notice is taken of Decision No. 77829 (November 23, 2020), issued in Docket No. RU-00000A-18-0284 ("Energy Rules Docket"), in which the Commission approved going forward with a formal Notice of Proposed Rulemaking for proposed Energy Rules that included a requirement for an electric utility in choosing resources for its IRP to give preferential treatment to renewable and clean energy resources sited or deployed in "impacted communities," which was defined to mean "cities, towns, counties, communities, tribes, census designated areas, and non-incorporated geographic areas that will be negatively affected, financially or socially, by the closure of Conventional Energy Resources or mining facilities, located in or near their jurisdictions, that have been a source of economic income and employment. (Decision No. 77829 at ex. A at 51, 63.)

6. Resolution

The Commission has determined that APS has a corporate obligation to support a just and equitable transition away from coal-based economies for communities impacted by early power plant closures.[263] The Commission has also indicated that it expects the issue to be addressed for APS in this case.[264] To address that obligation, and in response to testimony from the Nation and the Citizen Groups, APS has created the CCT proposal. The CCT proposal would provide the Nation with considerable financial and non-financial assistance over the next 10 years while providing the Navajo County Communities notably less financial assistance over a five-year period and a job redeployment commitment for Cholla employees and providing the Tribe strikingly less financial assistance over a five-year period and no non-financial assistance whatsoever. APS proposes for APS customers to pay through rates (specifically through the AEM) for approximately 80% of the financial assistance to the Nation and approximately 91% of the financial assistance to the Navajo County Communities and the Tribe.[265]

While APS set forth in detail the formulaic process, based on objective data, through which it determined the financial assistance amounts it offered to the Nation, the Navajo County Communities, and the Tribe, APS did not elucidate the manner in which it determined the financial assistance burden that should be shouldered by APS customers versus shareholders (i.e., PNW). APS described several transition packages provided or offered in other jurisdictions as support, but this information established no clear trend. APS also asserted that customers should pay more because providing transition assistance is like paying site reclamation or power plant decommissioning costs and is the cost of transitioning to clean energy. While it may be accurate to characterize the transition assistance costs as end-of-plant-life costs, we must observe that customers have already been paying the decommissioning and site restoration costs for the 4CPP and the decommissioning costs for Cholla[266]

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[263] Decision No. 77763 at 38.

[264] *See* Decision No. 77856 at 172.

[265] For the Nation, customers would pay $105 million out of the approximately $131.25 million provided. (*See* CCT MOU.) For the Navajo County Communities, customers would pay $10.9 million out of the $12 million provided. (*See id.*) For the Tribe, customers would pay $3.35 million of the $3.7 million provided. (*See id.*)

[266] Customers have been paying the costs of decommissioning the 4CPP and Cholla through depreciation expenses included in rates over the depreciable life of the plants, which will continue until plant retirement. (Ex. APS-49.) APS will not be requesting special funding for decommissioning in a future rate case. (*Id.*) Presumably, APS treated the decommissioning costs for NGS is the same or a substantially similar manner.

and will also be asked to pay the costs of replacing the generation that is/will no longer be produced by NGS, Cholla, and the 4CPP.

The proponents of the CCT argue that because customers for many years have been purchasing inexpensive electricity generated by the three coal plants, it is fair to have customers shoulder the vast majority of the burden. Assuming that APS's customers have been purchasing inexpensive electricity generated by the three coal plants,[267] that would not establish customers as the exclusive or even principal beneficiaries of the generation provided over the decades these coal plants have operated. Whether or not the savings in O&M costs at the three plants have accrued to the benefit of APS's sole shareholder during specific years due to regulatory lag, APS has been profitable, profitable enough to pay PNW a dividend that has allowed PNW to have "a track record of consistently paying and annually increasing the PNW common stock dividend," making it possible for APS and PNW to raise capital from financial markets on a continual basis.[268] It would be disingenuous to say that APS (as opposed to its customers) and PNW have not benefitted from this. Additionally, and importantly, it was APS, not APS's customers, that chose to invest in the coal-fired plants, which have, throughout their decades of operation, produced electricity for APS to sell and APS's customers to buy, economic benefits for the impacted communities, and severe negative externalities that have disproportionately impacted the Four Corners region and its inhabitants, including those in the Nation, those on the Hopi reservation, and those not located on either but impacted by Cholla. In light of the negative externalities that have impacted these communities, and the economic devastation that has come or is coming with closure of the coal-fired plants, it is just and reasonable for APS customers and shareholders to share the burden of transition assistance costs. Thus, we will require APS to make payments, and authorize APS to collect from customers, amounts equal to 50% of the customer-funded assistance identified in the CCT MOU. For the Tribe, we will require the payment to be made within 60 days after the effective date of this decision, so that it can help address the financial decline that has already resulted from the NGS

[267] Especially in recent years, some might quibble over the "inexpensive" label, which we acknowledge is relative and upon which we make no determination.

[268] Ex. Gayer-1 (response to Gayer 6.2). In 2018, PNW paid dividends of approximately $318 million; in 2019, PNW paid dividends of $330 million; for the period from January through September 1, 2020, PNW had paid dividends of $173 million and declared an additional dividend of $86 million. (Ex. Gayer-1 (responses to Gayer 4.1-4.3).) Additionally, PNW had declared that it expected consolidated earnings for 2020 to be $4.75 to $4.95 per diluted share, which is significantly higher than the dividend payments of $2.8825 per share in 2018 and $2.995 per share in 2019. (Ex. Gayer-4 at 3.)

closure.

Additionally, we will require APS to provide to the Tribe the same electrification assistance APS has offered for the Nation. No reason has been presented to exclude the Tribe from the non-financial assistance that would improve electrification, and logically, it makes more sense to provide electrification assistance to the Tribe than to the Nation. The Hopi reservation is essentially an island within the Nation and is served entirely by APS, whereas the Nation has its own electric utility providing service to most Nation residents.

Based on the record herein and for the reasons described above, the Commission cannot approve the CCT MOU as proposed. Rather, the Commission can and will approve the following:

- APS shall, in equal payments over a period of 10 years, pay to the Nation a total of $50 million, which shall be recoverable from its retail customers through an adjustor clause as set forth in Section (V)(R)(15) below.
- APS shall, through a single payment made within 60 days after the effective date of this decision, pay to the Tribe $1.675 million, which shall be recoverable from its retail customers through an adjustor clause as set forth in Section (V)(R)(15) below.
- APS shall, in equal payments over a period of 5 years, pay to the Navajo County Communities[269] a total of $5 million, which shall be recoverable from its retail customers through an adjustor clause as set forth in Section (V)(R)(15) below.
- APS shall provide job redeployment offers, within the APS organizations, to all impacted APS employees at least six months before Cholla closes, at least six months before the 4CPP moves to seasonal operations, and at least six months before the 4CPP closes. Job redeployment offers may require employee relocation.
- APS shall modify the distribution line extension policy in its Service Schedule 3, as applicable only to residential and commercial buildings on the Nation and the Hopi reservation, so that distribution lines can be extended up to 2,000 feet at no cost to Navajo and Hopi applicants.

[269] APS identified the Navajo County Communities as primarily including the Navajo County General Fund, Northland Pioneer College, and Joseph City Unified School District. (Ex. APS-2 at 23.) APS identified them as taxing districts that have received direct economic benefits from Cholla. (Ex. APS-3 at 19.)

- APS shall, within 12 months after the effective date of this decision, perform or pay for a census of unelectrified buildings in the Nation and may spend up to $1.25 million toward other home and business electrification projects within the Nation, which shall be recoverable from its retail customers through an adjustor clause as set forth in Section (V)(R)(15) below.
- APS shall, within 12 months after the effective date of this decision, perform or pay for a census of unelectrified buildings in the Hopi reservation and may spend up to $1.25 million toward other home and business electrification projects within the Hopi reservation, which shall be recoverable from its retail customers through an adjustor clause as set forth in Section (V)(R)(15) below.

APS is not required to obtain Commission approval of financial assistance for which it does not seek customer recovery through rates and, unless a tariff change is involved or there is another legal issue, also is not required to obtain Commission approval of non-financial assistance to be provided. Thus, the Commission makes no determinations as to the appropriateness of the remaining provisions of the CCT MOU.

The Commission's approval of the assistance set forth above is not intended to establish, and shall not be interpreted as establishing, the entirety of APS's transition assistance obligation to the Nation, the Tribe, or the Navajo County Communities. Nor should it be interpreted as definitively establishing the limits of the transition assistance for which APS may ultimately obtain recovery from customers. The Commission considers the Generic Transition Docket to be an appropriate venue to flesh out additional information concerning APS's and other utilities' equitable obligations to coal-impacted communities and the extent to which those obligations should be covered by customer as opposed to shareholder funds. The Commission encourages APS, the Nation, and the Tribe to participate fully in the Generic Transition Docket. If the Generic Transition Docket identifies additional transition assistance that should be provided to the Nation or the Tribe, and APS desires authorization to recover from its customers the costs of this transition assistance, APS shall file an application, in this docket, requesting such recovery. The Commission will hold open this docket for a period of 12 months after the effective date of the decision herein for APS to file such a request. If

no such request is filed within that time, APS may raise the issue in its next rate case.

F. Pension & Other Post-Employment Benefits ("OPEB")

1. APS Recovery Request

APS included in rate base the following pension and OPEB items as of the end of TY:[270]

Description ($ in Millions)	Total Company	Jurisdictional
Pension Regulatory Asset **(a)**	$712.9	$658.0
OPEB Regulatory Liability	($143.0)	($131.8)
Pension Liability (underfunded) **(b)**	($305.2)	($280.2)
OPEB Asset (overfunded)	$52.6	$48.3
Net Deferred Tax Liability	($123.3)	($122.80)
Net Rate Base	**$194.0**	**$171.50**
Prepaid Pension Asset = (a)-(b)	**$407.70**	**$377.80**

2. AECC/Freeport

AECC/Freeport advocated for the Commission to disallow APS's inclusion of pension and other post-employment benefits ("OPEB") items in rate base and asserted that the Commission has not previously vetted the issue for APS. (Ex. AECC-1 at 17, 25-26.) According to Mr. Higgins, APS recovers its pension and OPEB costs based on the net periodic benefit cost included in its revenue requirement, which is comprised of TY pension and OPEB expenses and capitalized pension and OPEB costs, and while the net periodic benefit cost may be different than APS's actual contributions in a given year, the pension and OPEB employer contributions and cumulative net periodic benefit costs will be the same over time. (Ex. AECC-1 at 15-16.) Mr. Higgins asserted that the cumulative adjustments to the value of pension or OPEB plan assets and liabilities that have not yet been reflected in earnings through the net periodic benefit cost are unrecognized actuarial losses and gains, which can generally be reflected as increases or decreases to "other comprehensive income" and excluded from net income. (Ex. AECC-1 at 18.) Further, Mr. Higgins stated, a portion of the net gain or loss must be amortized and included in net period benefit cost once a "'corridor' of materiality" is exceeded, to smooth out recognition of gains and losses over a long period of time. (Ex. AECC-1 at 18-19.) Mr. Higgins asserted that APS included approximately $24.7 million in rate base as a regulatory asset for amortization of net losses in 2019 pension costs even though the unrecognized actuarial losses do not

[270] APS RBr. at 20; Ex. APS-14 at 5.

represent a cash expense for APS, only a change in valuation of APS's pension plan assets or liabilities that have not yet been reflected in net periodic benefit costs. (Ex. AECC-1 at 19-20.) APS informed Mr. Higgins that the unrecognized actuarial losses could permissibly be included in a regulatory asset under FAS No 71. (Ex. AECC-1 at 20.) Additionally, Mr. Higgins noted that PNW's 2019 10-K asserted that the regulatory asset would be charged to other comprehensive income if the regulatory asset is disallowed by the Commission. (Ex. AECC-1 at 20.)

Mr. Higgins agreed with APS that the unrecognized actuarial losses should be recoverable through rates, but asserted that the regulatory asset should not be included in rate base because customers should not be required to pay a carrying charge on these non-cash outlays. (Ex. AECC-1 at 20-21.) In response to APS's contention that prior Commission Decisions[271] had allowed inclusion of pension and OPEB assets in rate base, Mr. Higgins observed that the topic had not been specifically addressed in the decisions and, further, that APS had not submitted testimony on the topic in those cases. (*Id.* at 21.)

According to Mr. Higgins, APS similarly included in rate base a regulatory liability associated with its OPEB plan, including an unamortized prior service credit[272] and unrecognized actuarial losses, and Mr. Higgins likewise recommended that the unamortized OPEB prior service credit and actuarial losses be excluded from rate base. (Ex. AECC-1 at 21-22.)

Mr. Higgins stated that APS has also included in rate base the balances associated with the funded status of its pension and OPEB plans. (Ex. AECC-1 at 23.) According to Mr. Higgins, APS's pension plan is underfunded, and its OPEB plan is overfunded, and GAAP requires an employer to recognize the funded status of its pension and OPEB plans on its balance sheet, with underfunding recognized as a liability and overfunding recognized as an asset. (Ex. AECC-1 at 23.) APS included in rate base a liability of $280.2 million for the underfunded pension plan and an asset of $48.3 million for the overfunded OPEB plan, although, according to Mr. Higgins, GAAP does not require that the balances be included in rate base. (Ex. AECC-1 at 23-24.) According to Mr. Higgins, the net balance

[271] APS cited Decision Nos. 69663, 71448, 73183, and 76295. (Ex. AECC-1 at 21.)

[272] Mr. Higgins stated that a prior service credit results when a plan amendment retroactively reduces employee benefits and that a prior service credit should be netted against any prior service costs and the net balance amortized gradually as a component of net periodic benefit cost. (Ex. AECC-1 at 22.)

of the pension plan's funded status and the unrecognized net actuarial loss is a prepaid pension asset. (Ex. AECC-1 at 24.) Likewise, Mr. Higgins stated, the sum of the overfunded OPEB plan and the unamortized prior service credit and actuarial loss represents an accrued OPEB liability. (Ex. AECC-1 at 24.)

In a discovery response, APS informed Mr. Higgins that APS does not have a prepaid pension asset/liability or a prepaid OPEB asset/liability, that the regulatory assets/liabilities related to the funded status of its pension plan have been included in rate base since at least Decision No. 67744, and that the prior Commission Decisions' lack of discussion regarding a pension asset/liability shows that APS's treatment of pension expense is accepted ratemaking practice. (Ex. AECC-1 at 25.) Mr. Higgins disagreed, asserting that the Commission has not fully evaluated whether including these pension-related items in rate base is in the public interest. (Ex. AECC-1 at 25.) Mr. Higgins asserted that there is no reasonable basis for customers to be required to pay APS a return on a prepaid pension asset and, further, that the accrued OPEB liability also should not be included in rate base. (Ex. AECC-1 at 25-26.) Mr. Higgins acknowledged that some jurisdictions allow prepaid pension assets to be included in rate base, but stated that others do not or place limitations on the allowed return. (Ex. AECC-1 at 26.) Finally, Mr. Higgins asserted that if a prepaid pension asset is to be included in rate base, there must be consideration of what return should be allowed. (Ex. AECC-1 at 26.)

On surrebuttal, Mr. Higgins stated that the issue is not whether APS's customers fully fund APS's pension costs—they do—but who should bear the risk of the timing differences between cumulative contributions and cumulative expenses, which are what cause prepaid pension assets and liabilities. (Ex. AECC-3 at 18.) Mr. Higgins asserted that the risk should rest with APS, which is responsible for managing the timing differences appropriately, and not be shifted to customers. (Ex. AECC-3 at 18.)

AECC/Freeport's adjustment resulted in a net rate base reduction of $233.852 million, comprised of adjustments to remove from rate base end-of-TY balances for the pension unrecognized actuarial loss asset, the OPEB prior service credit/unrecognized loss liability, the underfunded pension liability, the overfunded OPEB asset, and net deferred tax liability. (Ex. AECC-1 at 27, ex. KCH-1; Ex. AECC-3 at ex. KCH-1-S.) AECC/Freeport estimated that the adjustment would reduce APS's

revenue requirement by $22.863 million. (Ex. AECC-3 at ex. KCH-7-S.)

In the event the Commission does not remove the prepaid pension asset and OPEB liability from rate base as AECC/Freeport recommended, Mr. Higgins asserted that the Commission should authorize a rate of return on the prepaid pension asset equal to the Expected Return on Assets ("EROA") for APS's pension plan, which was 5.75% for 2020, without a tax gross-up. (Ex. AECC-3 at 18-19.) Likewise, Mr. Higgins recommended that the Commission authorize a rate of return on the accrued OPEB liability at the 2020 EROA for the OPEB plan, which is 4.85%, without a tax gross-up. (Ex. AECC-3 at 19.) Mr. Higgins asserted that at APS's proposed rate of return, customers otherwise would be required to pay APS a pre-tax return of 9.16% on the prepaid pension asset, although the funds invested in the pension plan earn an EROA of only 5.75%, "obviously . . . not a good proposition for customers." (Ex. AECC-3 at 19.)

3. FEA

Like Mr. Higgins, Mr. Gorman recommended that the Commission disallow APS's pension regulatory asset in rate base, stating that the jurisdictional allocation of the TY pension asset was $654.4 million, that there is no Commission precedent allowing the inclusion of a pension asset as a regulatory asset in rate base (as three of the decisions cited by APS were resolved through settlement agreements and the fourth did not address including a pension asset in rate base), and that the pension asset is merely the result of accounting mechanisms used by APS to avoid recording an OCI adjustment to its common equity capital and not the result of costs incurred by APS or the use of investor funding to make capital investments. (Ex. FEA-1 at 12-15.) Mr. Gorman added that using the pension asset instead of the OCI adjustment increases APS's rate of return and revenue requirement because it results in a higher common equity balance and ratio and related income tax expense. (Ex. FEA-1 at 15.) Mr. Gorman estimated that the adjustment increased APS's revenue requirement by $1.2 million. (Ex. FEA-1 at 15.) Mr. Gorman asserted that because APS experiences no carrying charge on the pension asset, APS should not be allowed to recover a carrying charge from its customers. (Ex. FEA-1 at 16.) Mr. Gorman added that APS's calculation of annual pension expense already includes amortization of actuarial gains and losses, showing that APS's net periodic pension costs in 2016 through 2020 included amortization of actuarial gains/losses ranging between $26.108 million and $42.613 million.

(Ex. FEA-1 at 16, att. MPG-2DR at 8.) Thus, Mr. Gorman stated, allowing the pension asset in rate base as a regulatory asset would be inappropriate double-counting. (Ex. FEA-1 at 16.) Mr. Gorman estimated that FEA's adjustment to remove the pension asset would lower APS's claimed revenue deficiency by $42.4 million. (Ex. FEA-1 at 16.)

In response to APS's changed position on rebuttal and rejoinder that its pension asset is a "prepaid pension asset," Mr. Gorman responded that it is not. (Ex. FEA-5 at 12.) Mr. Gorman stated that the pension regulatory asset "is simply an accounting change by [APS] . . . not a 'prepaid' pension asset," because a prepaid pension asset represents funding into the pension trust in excess of the pension expense, increasing the pension trust assets, whereas the pension regulatory asset did not increase the amount of pension trust fund assets. (Ex. FEA-5 at 12.) Mr. Gorman asserted that APS had not shown that creation of the pension asset had reduced TY pension expense in any way or resulted in customer savings or benefits. (Ex. FEA-5 at 11.) Mr. Gorman further asserted that APS's argument that a regulatory pension asset should be included in rate base regardless of how it is funded directly contradicts the standard ratemaking principle that a utility should not be permitted to include in rate base and should not be permitted to earn a return on an asset funded by customers rather than investor capital. (Ex. FEA-5 at 10.) Mr. Gorman stated that excluding the pension asset from rate base but allowing the accounting change to avoid OCI would provide APS reasonable compensation. (Ex. FEA-5 at 12.)

In its brief, FEA asserted that APS's pension asset should be removed from rate base and cost of service, regardless of whether it is a pension regulatory asset or a prepaid pension asset. (FEA Br. at 7-8.) FEA disagreed with Ms. Blankenship's rejoinder testimony that APS recovers its GAAP-recorded pension expense from its customers, that a prepaid pension asset is recorded when APS's cash contributions exceed its GAAP pension expense, and that the recorded prepaid pension asset can only be funded by shareholders because it is based on the difference between pension trust contribution and GAAP pension expense. (FEA Br. at 9.) FEA asserts that Ms. Blankenship's argument erroneously fails to recognize that within the regulated industry, the amount of pension expense built into rates and recovered from customers in cost of service is based on TY pension expense, not the annually adjusted GAAP pension expense. (FEA Br. at 9.) According to FEA, because APS has not established in this

case whether the prepaid pension asset was funded by investors or customers, and APS has the burden of proving that the asset should be included in rate base, APS is not entitled to a return on this expense. (FEA Br. at 9-11.) FEA also disagreed with Ms. Blankenship's assertion on rejoinder that Mr. Gorman may have misconstrued APS's adjustment to OCI, which she stated was related to the Supplemental Employee Retirement Benefit Plan ("SERBP"), and asserted that Ms. Blankenship was incorrect that the OCI adjustment did not increase APS's cost of service, pointing out that APS's OCI-related adjustments had increased common equity and the common equity ratio. (FEA Br. at 11-12.) FEA concluded that because APS has failed to meet its burden of demonstrating that the inclusion of the asset in rate base is fair to customers and is a just and reasonable addition to the cost of service, the pension asset should be removed from rate base and cost of service. (FEA Br. at 12-13.)

4. Other Parties

No other party challenged APS's inclusion of the pension and OPEB amounts in rate base.

5. APS Response

On rebuttal and rejoinder, Ms. Blankenship asserted that because APS has contributed more to its qualified pension plan than it has recognized in actuarially calculated pension expense, APS has a regulatory asset balance or "prepaid pension asset," and because it has contributed less than the actuarially calculated expense to its retiree medical and post-employment benefits fund, APS also has an OPEB regulatory liability. (Ex. APS-13 at 13; Ex. APS-14 at 4.) Ms. Blankenship asserted that APS has historically included both the prepaid pension asset (addition to OCRB) and the OPEB liability (reduction to OCRB) in rate base and that the rate base amounts are offset by corresponding accumulated deferred income taxes ("ADIT"). (Ex. APS-13 at 13; Ex. APS-14 at 4.) Ms. Blankenship asserted that the net rate base increase was $194.0 million as of June 30, 2019,[273] and that it represents shareholder capital being used to benefit customers. (Ex. APS-13 at 13-14; Ex. APS-14 at 4-5.)

Ms. Blankenship disagreed with Mr. Higgins and Mr. Gorman's arguments that the rate base items should be removed, arguing that it is customary to include prepayments in rate base, with prepayments made by the utility recognized as increases to OCRB and prepayments by customers

[273] The amount of the prepaid pension asset was $407.7 million. (Ex. APS-13 at 14; Ex. APS-14 at 5.)

recognized as reductions to OCRB. (Ex. APS-13 at 14; Ex. APS-14 at 6-7.) Ms. Blankenship further stated that it is appropriate to allow APS to earn a return on the prepaid pension asset because customers earn a return on it as a result of the annual pension cost being decreased by the amount of EROA and a reduction in Pension Benefit Guarantee Corporation Variable Rate Premiums.[274] (Ex. APS-13 at 14; Ex. APS-14 at 7.) Ms. Blankenship stated that the decrease for EROA is calculated using the EROA percentage and the value of all assets in the pension trust, meaning that customers benefit from any amount prepaid by the company. (Ex. APS-13 at 15; Ex. APS-14 at 8-9.) Ms. Blankenship added that no party has ever questioned the rate base treatment of these regulatory assets and liabilities before. (Ex. APS-13 at 15.)

Ms. Blankenship stated that Mr. Gorman was wrong in characterizing the pension regulatory asset as an accounting change rather than a prepaid pension asset and in asserting that it does not benefit customers. (Ex. APS-14 at 5.) Further, Ms. Blankenship stated, Mr. Gorman was wrong in suggesting that APS is double-earning a return on the pension asset, because APS's adjustment to OCI and thus common equity is to remove SERBP OCI and thus unrelated to the pension regulatory asset. (See Ex. APS-14 at 6.) Ms. Blankenship also asserted that "Mr. Gorman's characterization of the prepaid pension asset [as] being fully funded by . . . customers is inappropriate and an oversimplification of the financial realities." (Ex. APS-14 at 7.) Ms. Blankenship stated that it is GAAP expenses that are collected from customers as pension expenses, that the prepaid pension asset is the cumulative excess of contributions over GAAP expenses, and that this means the prepaid pension asset represents shareholder-funded prepayments. (Ex. APS-14 at 7.) Additionally, Ms. Blankenship stated that Mr. Gorman was wrong in stating that the prepaid pension asset does not reduce expense, due to the pension expense reductions realized as a result of the prepaid pension asset as well as EROA on it. (Ex. APS-14 at 8-9.)

Ms. Blankenship also disagreed with Mr. Higgins's position that the allowed rate of return on the prepaid pension asset, if included in rate base, should be set at the EROA rather than the WACC. (Ex. APS-14 at 10.) Ms. Blankenship asserted that this would be inconsistent with prior Commission

[274] According to Ms. Blankenship, the premiums paid to PBGC are calculated as a percentage of unfunded liability and were 4.5% for 2020. (Ex. APS-14 at 9.)

decisions and, further, that it would not align with standard ratemaking principles or how WACC and EROA are applied, as WACC is applied to net rate base, and EROA is applied to gross pension and OPEB rate base assets. (Ex. APS-14 at 10.) According to Ms. Blankenship, it would be inequitable and unreasonable to deny APS a WACC return on the prepaid pension asset because customers are receiving greater benefits from the prepaid pension asset than APS is requesting from its inclusion in rate base. (Ex. APS-14 at 10.)

At hearing, Ms. Blankenship testified that the pension plan includes approximately $129 million in EROA. (Tr. at 1628-29.) In its brief, APS argued that if the net pension asset is excluded from OCRB, current pension expenses should be raised by $129 million, the EROA benefit should be excluded from future cost of service, and an adjustment should be made for the net OPEB liability, which collectively would increase APS's revenue requirement by $100 million. (APS Br. at 27.) APS additionally argued that if the pension regulatory asset and OPEB regulatory liability are excluded from rate base, they must be accounted for in OCI,[275] which would result in increased common equity, WACC, and revenue requirement (without any customer benefit). (APS Br. at 27; Ex. APS-14 at 6.)

6. Resolution

Accounting and ratemaking treatment of pension and OPEB costs is complicated and requires a comprehensive methodology that recognizes both current operating expense and rate base investments and liabilities. Pension expense must be recognized as accounted for under GAAP as an operating expense, and plan assets, pension benefit obligations ("PBO"), and the pension components of OCI must be included in rate base to recognize the time value of money invested in pension plans. While the Commission does not fully agree with APS's arguments and description of its treatment of the pension and OPEB costs, and APS's use of "prepaid pension asset" to reflect the combination of plan assets, PBOs, and OCI caused some confusion, APS's approach is comprehensive and results in the unrecognized actuarial gains/losses in the plan assets and PBO offsetting the unrecognized gains/losses in the OCI. APS's reclassification of its OCI balance to a regulatory asset, although

[275] In a response to an AECC/Freeport data request, Ms. Blankenship explained that APS has included the amounts in a regulatory asset rather than in OCI since it adopted Accounting Standards Codification ("ASC") 715: Compensation – Retirement Benefits on December 31, 2006. (Ex. AECC-1 at ex. KCH-15 at 4.) Further, Ms. Blankenship stated that FAS 71 allows a regulated utility to establish a regulatory asset/liability to record the offset to the funded status adjustments instead of OCI. (*Id.*)

unusual, does not change the impact to rates. In contrast, the AECC/Freeport and FEA positions are piecemeal and incomplete and lack balance rather than providing a comprehensive methodology due to omission of rate base assets and liabilities, making their adoption inappropriate.

APS's proposed inclusion of pension and OPEB assets and liabilities in rate base is appropriate. However, APS's prepaid pension asset, net of changes in SERBP liability, is significantly higher for the TY than in preceding years (2015-2018), as shown below (all $ in millions).[276]

Year	Prepaid Pension Asset	Changes in SERBP Liability	Net
2015	$192.6	$16.5	$176.1
2016	$256.4	$2.5	$253.9
2017	$308.0	($4.1)	$312.1
2018	$341.8	($0.4)	$342.2
TY	$407.7	($2.0)	$409.7
		Average:	$298.8
		Rate Base Adjustment:	($110.9)

Thus, it is appropriate to normalize the net prepaid pension asset to represent the typical level of investment in pension costs by APS. Averaging the year-end figures for 2015 through 2018 plus June 2019 results in $298.9 million and a reduction to rate base of $110.9 million.

Additionally, because there is no compelling reason to depart from the normal treatment of the return allowed on assets that are appropriately included in rate base, the Commission declines to adopt a separate rate of return for these rate base items.

G. Compensation Issues

APS's executive compensation includes three components: base salary, annual cash incentives under APS's Annual Incentive Award Program ("AIAP"), and long-term stock incentives.[277] (Tr. at 561, 817-818; *see also* Ex. S-12 at 49.) Non-executive, non-unionized APS employees also are generally eligible to receive annual cash incentives under the AIAP, which provides cash incentives to individual employees based on the achievement of performance goals set at the company, the business unit, and the employee level. (Ex. AECC-1 at 29; Tr. at 864-865.) If APS does not meet a threshold company performance goal based on annual earnings, no cash incentive payments are made under the

[276] *See* Ex. APS-31.

[277] APS is not requesting recovery of the costs of executives' long-term stock incentives from ratepayers. (Ex. APS-12 at 26.)

AIAP, regardless of achievement of the other performance goals. (Ex. APS-14 at 12; Ex. S-12 at 51.)

At hearing, Mr. Guldner testified that customer satisfaction should play a role in executive compensation and that APS is moving toward designing its incentives to be more focused on customer satisfaction, with APS planning to add a J.D. Power performance goal[278] to its long-term incentive plan. (Tr. at 764-765, 1016-1017.)

1. Annual Cash Incentives under AIAP

a. APS Recovery Request

APS has included in its adjusted TY operating expenses a normalized amount of $32.789 million for cash incentive payments to employees under the AIAP, determined by averaging the cash incentive compensation expenses for calendar years 2017 and 2018 and the TY. (Ex. AECC-1 at 29; APS Br. at 38; Ex. APS-12 at 27, att. EAB-13DR; Ex. APS-39 at sched. C-2 at 13.) APS's pro forma adjustment increases TY operating expenses by $5.606 million. (APS Br. at 38; Ex. APS-12 at 27, att. EAB-13DR.) At hearing, Ms. Blankenship acknowledged that the financial and shareholder value portions of the AIAP constituted approximately 54% for the TY. (Tr. at 1517-1518, 1550.) Ms. Blankenship attributed the idea for the three-year normalization to a Staff proposal adopted by the Commission in Decision No. 71448. (Ex. APS-12 at 27.)

b. AECC/Freeport

AECC/Freeport asserts that the portion of the cash incentive plan based on financial performance and shareholder value should be paid by shareholders and not recoverable from customers. (AECC Br. at 4; Ex. AECC-1 at 29.) According to Mr. Higgins, it can be appropriate to allow recovery from ratepayers of annual cash incentives if the amounts are not excessive and the goals of the plans are focused on customer satisfaction, operating efficiency, and safety, not on the utility's financial performance. (Ex. AECC-1 at 29.) Mr. Higgins did not dispute that it may be appropriate to reward employees for financial performance, but asserted that shareholders, as the primary beneficiaries of meeting or exceeding financial targets, should cover those costs. (Ex. AECC-1 at 29-30.) According to Mr. Higgins, approximately 39% of the normalized TY total average cash incentive expense was

[278] Mr. Guldner acknowledged that APS was ranked in the fourth quartile by J.D. Power, that the fourth quartile ranking is "not okay," and that APS is working to move out of that fourth quartile. (Tr. at 765, 1016-1017.)

based on APS's financial performance, and another 15% was based on "Shareholder Value." (Ex. AECC-1 at 30; *see* Ex. AECC-1 at ex. KCH-15 at 1-2, 11-12.) Mr. Higgins thus recommended that $20.363 million of the cash incentive expense be disallowed because it was related to financial performance. (Ex. AECC-1 at ex. KCH-10 at 1; Ex. AECC-3 at 2, ex. KCH-10-S at 1.)

Mr. Higgins testified that while the AIAP supports efficiency gains and cost reductions, those only benefit customers if they are reflected in a TY because only shareholders benefit from the efficiency gains and cost savings occurring between TYs. (Ex. AECC-3 at 21-22.) Mr. Higgins also noted that the Utah Public Service Commission ("Utah PSC") for years has disallowed recovery through rates of incentive compensation tied to financial performance, on the basis that financial goals may be achieved at the expense of customer service and only incentive compensation plans with customer service goals as their primary objective should be recoverable in rates. (Ex. AECC-3 at 22-23 (citing *In re US West Commc'ns, Inc.,* Utah PSC Docket No 95-049-05 (November 6, 1995).)

c. RUCO

RUCO asserts that the Commission should reject the proposed normalization of the cash incentive amount (as having no basis) and disallow $22.574 million of the actual cash incentives APS paid employees in the TY. (Ex. RUCO-3 at ex. FWR-32 at 15-16 (sched. C-2); but cf. RUCO-1 at 19-20, ex. FWR-16; RUCO Br. at 28.) In its schedules, RUCO describes this as a 75% disallowance of the cash incentive expenses. (Ex. RUCO-3 at ex. FWR-32 at 15-16.) RUCO takes the position that because the financial performance portion of the incentive compensation was approximately 54% for the TY, the portion of the cash incentive compensation that is tied directly to the benefit of shareholders should be paid for by shareholders, and the remaining portion that benefits both shareholders and customers should be allocated equally between them. (RUCO Br. at 29 (citing Tr. at 1550).)

Mr. Radigan pointed out that the decision cited by Ms. Blankenship as supporting the normalized cash incentive cost recovery should not be used as precedent because it approved a settlement agreement in which incentive compensation was not even discussed. (Ex. RUCO-1 at 18.) Mr. Radigan also noted that in the 2016 Rate Case, Staff rejected this type of normalization adjustment, proposed that the AIAP costs be shared 50/50 between shareholders and customers, and cited a number of decisions that supported Staff's position for 50/50 sharing. (Ex. RUCO-1 at 18 (citing Decision No.

70011 (November 27, 2007), involving UNS Gas, Inc.; Decision No. 70360 (May 27, 2008), involving UNS Electric, Inc.; Decision No. 68487 (February 23, 2006), involving Southwest Gas Corporation ("SW Gas"); Decision No. 70665 (December 24, 2008), involving SW Gas; Decision No. 71623 (April 14, 2010), involving UNS Gas, Inc.; and Decision No. 71914 (September 30, 2010), involving UNS Electric, Inc.[279]).) Mr. Radigan also clarified that he does not dispute that the TY cash incentives were a valid cost and that the amount paid was reasonable, but asserted that there is no assurance that the award levels will be repeated in future years. (Ex. RUCO-3 at 13-14.) According to Mr. Radigan, his adjustment merely allocates the portion of the cash incentives benefiting shareholders and ratepayers between them equally, to provide an appropriate balance. (Ex. RUCO-3 at 13-14.)

Mr. Radigan also asserted that a portion of the cash incentive compensation gets capitalized each year, that $9.1 million was capitalized in 2018, and that approximately $8.0 million was capitalized in 2019. (Ex. RUCO-1 at 20.) Mr. Radigan testified both that the $8.0 million capitalized in 2019 should be removed from rate base and that 75% of the 2019 amount should be removed from rate base because it should be allocated to shareholders rather than customers. (Ex. RUCO-1 at 20.) RUCO's schedules showed a reduction to rate base of $8.031 million, which is the jurisdictional amount. (See Ex. RUCO-1 at ex. FWR-2 at sched. B-2 at 3.) This adjustment was retained in RUCO's surrebuttal schedules and final schedules herein. (Ex. RUCO-3 at ex. FWR-32 at sched. B-2 at 3; RUCO-Final Sched. B-2 at 2.)

d. Staff

In keeping with its position in the 2008 Rate Case, 2011 Rate Case, and 2016 Rate Case,[280] Staff recommends that the cash incentive compensation costs be shared 50/50 by shareholders and customers because the AIAP benefits both. (Staff Br. at 26.) Mr. Smith testified that removing 50% of the normalized level of annual incentive compensation expense, $18.709 million on a jurisdictional basis, will provide an appropriate balance between the benefits attained by shareholders and customers from the AIAP. (Ex. S-12 at 48, 55, att. RCS-2 at 33 (sched. C-8).)

Because the AIAP requires APS to exceed a specified threshold earnings level for any cash

[279] Official notice is taken of these decisions.

[280] Mr. Smith acknowledged that only the 2008 Rate Case incorporated Staff's recommendation into the development of the allowed revenue requirement, as the 2011 Rate Case and the 2016 Rate Case ended in settlements. (Ex. S-12 at 52.)

incentives to be paid for the year, Mr. Smith concluded that the primary purpose of the company performance portion of the AIAP is to emphasize APS's earnings. (Ex. S-12 at 51.) However, Mr. Smith determined that the AIAP business unit goals include both shareholder value-oriented goals and customer satisfaction goals, leading him to conclude that achievement of those AIAP goals benefits both shareholders and customers. (Ex. S-12 at 51.) Mr. Smith noted that the Commission has required 50/50 sharing of cash incentive costs in a number of prior decisions, citing the same decisions as referenced by RUCO. (Ex. S-12 at 52-55.) Mr. Smith further noted that there is no assurance that the normalized expense (either as proposed by APS or Staff) will actually be incurred in future years. (Ex. S-12 at 48.)

e. APS Response

Ms. Blankenship testified that the cash incentive is a validly incurred cost and an identified portion of APS employee compensation provided as a reward for meeting goals that align APS's success with the interests of its customers. (Ex. APS-13 at 18; Ex. APS-14 at 12.) According to Ms. Blankenship, the AIAP is an important component of the overall rewards and compensation package for employees and supports APS's efforts to attract and retain top talent. (Ex. APS-14 at 12.) Ms. Blankenship characterized the proposed adjustments to reduce APS's employee compensation as arbitrary disallowances of prudent costs that benefit customers, asserting that no party has alleged or provided evidence showing that APS's overall employee compensation is excessive or unreasonable. (Ex. APS-13 at 18; Ex. APS-14 at 12.) Ms. Blankenship disagreed with Mr. Higgins's opinion that shareholders are the primary beneficiaries of the financial performance targets and goals in the AIAP and that the associated incentives should not be recovered through utility rates, asserting that customers directly benefit from the financial targets and goals through cost reductions and reduced rates. (Ex. APS-13 at 18; Ex. APS-14 at 12-13.) Ms. Blankenship acknowledged, however, that if APS does not meet the earnings threshold identified in the incentive plan, no incentive is paid regardless of business unit performance. (Ex. APS-14 at 12.) Ms. Blankenship also agreed with Mr. Higgins that an incentive plan should include goals for customer satisfaction, operating efficiency, and safety. (Ex. APS-14 at 12.)

According to Ms. Lockwood, customers, employees, and shareholders all benefit from the

AIAP incentives because the only way for employees to be rewarded for the financial performance metric is through identifying cost efficiencies. (Ex. APS-2 at 12-13; Ex. APS-3 at 7.) Ms. Lockwood testified that the efficiency gains and cost reductions supported through the AIAP improve APS's earnings and are "given back to customers through rates." (Ex. APS-2 at 12-13.) Ms. Lockwood criticized what she viewed as AECC/Freeport's, RUCO's and Staff's positions that a financially healthy utility that is able to provide earnings to its investors is contrary to the interests of its customers, asserting that APS's ability to earn a reasonable return on its investments causes APS to be able to attract the capital investments necessary to provide service on reasonable terms and thus is not in conflict with its customers' interests. (Ex. APS-2 at 13.) Ms. Lockwood further asserted that no party had provided any evidence to support a finding that any portion of the AIAP incentives are excessive or imprudent. (Ex. APS-3 at 7.)

f. Resolution

Although Staff accepts normalization of the cash incentive amounts under the AIAP, we are not persuaded that the normalization should occur, as it results in an increase from actual TY operating expenses for an expense that, while incurred in 2017, 2018, and the TY, is not guaranteed to occur in future years. Cash incentives may be made under the AIAP, or they may not, and that alone is a valid reason not to make a pro forma adjustment to increase the expense over the actuals incurred in the TY through normalization.

As to the portion of the cash incentive payments that should be recoverable from customers, we observe that no cash incentives are paid under the AIAP unless APS meets a threshold earnings level and that APS's earnings level criterion is also heavily weighted in determining what the incentives will be if the threshold is met. Additionally, the evidence shows that the AIAP business unit performance goals give significant weight to shareholder interests while expressly considering customer-related goals less frequently. (See Ex. S-13.) Yet we acknowledge that business units' operational goals related to reliability and safety provide customers benefits. Thus, we conclude that it is just and reasonable to include in operating expenses to be recovered through rates 50% of the actual TY costs of the AIAP cash incentives. This results in a reduction from TY operating expenses of $15.0493 million. Additionally, it is just and reasonable to allow in rate base 50% of the AIAP cash incentives

cost, which results in a reduction from rate base of $4.0155 million.

We also note that we are encouraged by Mr. Guldner's commitment to amending the long-term stock incentive performance goals and his testimony generally about making APS more customer-focused, and we encourage Mr. Guldner to amend the AIAP performance goals to place greater emphasis on customer satisfaction and customer interests. We also encourage Mr. Guldner's team to develop a set of performance goals that will allow APS's employees to be eligible to receive incentives (whether cash or otherwise) for providing stellar customer-oriented performance, even if APS does not meet its overall earnings performance goal under the AIAP for a given year.

2. Executive Compensation

a. APS Recovery Request

APS has requested recovery of the portion of executives' base salaries that are allocated to and paid by APS (as opposed to being allocated to and paid by the other owners of generating stations that APS operates). (Ex. APS-6 at 6.) APS is not requesting recovery for its long-term stock-based compensation or for SERBP.[281] (Ex. APS-6 at 6.)

Additionally, although APS had proposed recovery of a total of $242,448 in TY operating expenses paid for executive housing allowance, retention bonuses, financial planning, and physicals,[282] Mr. Guldner agreed with Staff during the hearing that those expenses were unusual and should not be charged to ratepayers.[283] (Tr. at 1021-1022.) APS has removed those expenses in its final schedules. (LFE APS-87 at sched. C-2 at 17.)

b. RUCO

RUCO asserts that 50% of APS executives' base salaries should be disallowed, resulting in a disallowance of $12.173 million in operating expenses on a jurisdictional basis. (Ex. RUCO-3 at ex. FWR-32 at sched. C-2 at 16.) Mr. Radigan based this adjustment on an APS letter dated October 9,

[281] SERBP is a means for executives to be provided retirement benefits exceeding the amounts permitted in qualified retirement plans by the Internal Revenue Service, and the Commission has previously disallowed SERBP costs in a number of Class A utility rate cases, including for APS. (Ex. S-12 at 37-40 (citing Decision No. 68487, Decision No. 71623, Decision No. 71914, Decision No. 69663).)

[282] Ex. S-12 at 56-57, att. RCS-2 at 34 (sched. C-9).

[283] Staff had asserted that the costs should be disallowed because they do not provide any benefit to ratepayers and are not necessary for the provision of safe and reliable electrical service to APS customers. (Ex. S-15 at 26.)

2020,[284] filed in response to Chairman Burns's September 1, 2020, letter asking APS, RUCO, and Staff to respond to specific questions regarding executive compensation. (Ex. RUCO-3 at 2.) Mr. Radigan asserted that APS had 22 executives at vice president and above who earned on average $1,117,321 per year in 2019, for a total of $24.6 million, and that the Chairman and President of APS earned a base salary of $1.3 million, which he added to reach a total base salary figure for executive officers of $25.9 million. (Ex. RUCO-3 at 2.)

Mr. Radigan acknowledged that the executive compensation paid may be reasonable and appropriate, as asserted by Mr. Guldner. (Ex. RUCO-3 at 3.) Mr. Radigan also acknowledged that PNW's expressed approach to setting salaries is to provide the compensation needed to attract, engage, and retain an experienced management team with the skills to succeed in its complex operating environment and who are able to provide consistently strong operating and financial results. (Ex. RUCO-3 at 3.) Mr. Radigan also acknowledged that ratepayers should pay their fair share of executive compensation when they receive service from a well-operated utility that provides affordable, efficient, and reliable electricity service as a result of prudent decision-making. (Ex. RUCO-3 at 3.) Yet, Mr. Radigan asserted, there are serious questions about whether APS has met that standard with its customer service, resource planning, and proposed dates to retire existing generation assets. (Ex. RUCO-3 at 3.) Mr. Radigan asserted that shareholders should also be willing to pay compensation for executives whose work results in good financial performance compared to peer companies, because that performance benefits shareholders. (Ex. RUCO-3 at 3.) Mr. Radigan also opined that the Commission has a practice of dividing the responsibility for expense items that benefit both shareholders and ratepayers 50/50 when there is not a study showing a precise and proper allocation. (Ex. RUCO-3 at 4.) Thus, Mr. Radigan concluded, 50% of the 2019 base salaries should be disallowed for recovery from ratepayers. (Ex. RUCO-3 at 4.) During the hearing, Mr. Radigan acknowledged

[284] Official notice is taken of this letter, which showed that APS's average vice president compensation as of September 1, 2020, was at market median at all levels (executive vice president, senior vice president, and vice president) but that executive vice president compensation as of December 31, 2019, was above median (while the others were at median). APS asserted that the above median placement was appropriate because APS's executive vice presidents in 2019 were "significantly tenured and highly experienced." The letter also showed that executive vice president and senior vice president compensation had been above median at end of year 2015 and 2010. For purposes of the letter, APS included in compensation base salary, annual incentives at target, long-term incentives at target, special payments, and executive benefits (car allowance, financial planning, and executive physicals).

that his analysis had used incorrect figures and would need to be reevaluated and corrected. (Tr. at 4212-4217.) RUCO's brief acknowledges the incorrect figures but RUCO's final schedules do not correct the figures because RUCO was unable to find data to revise its recommendation. (RUCO Br. at 31 n.12; RUCO Final-Sched. at sched. C-2 at 13-14.)

c. Staff

Staff did not advocate for disallowance of any portion of executives' base salaries.

d. APS Response

APS argues that RUCO's disallowance has no factual or legal basis. (APS Br. at 37-38.) Mr. Guldner expressed confidence that APS's compensation philosophy is prudent and that its executive compensation levels are reasonable and appropriate. (Ex. APS-5 at 11.) According to Mr. Guldner, the individuals on APS's executive team are highly qualified and experienced; they provide leadership to deliver clean, reliable, and affordable electric service to 1.3 million customers in a complex operating and regulatory environment that includes the largest nuclear power plant in the U.S.; they are responsible stewards of both shareholder and customer money; and they provide leadership and services within their communities. (Ex. APS-5 at 10.) Mr. Guldner testified that APS annually has an independent compensation consulting firm review and evaluate its executive compensation to ensure that it remains competitive with that of other regulated and non-regulated companies. (Ex. APS-5 at 10.) Mr. Guldner also explained that a portion of APS's executive compensation is allocated to and paid by the other co-owners of generating stations operated by APS. (Ex. APS-5 at 10-11.)

APS also characterizes RUCO's recommended disallowance as arbitrary and asserts that RUCO "attempts to insert a fictional wedge in between the benefits and goals of APS and its customers," when their interests are actually aligned. (APS Br. at 37-38.) Per Ms. Blankenship, customers also benefit from the executive compensation because they are prudent costs necessary to attract and retain qualified directors and officers. (Ex. APS-13 at 19.) Additionally, APS points out that RUCO has not challenged the reasonableness of the executive compensation and that RUCO used incorrect numbers in its analysis. (APS Br. at 37-38.)

e. Resolution

Admittedly, RUCO's disallowance adjustment does not accurately reflect half of the base

executive salaries for which APS has requested recovery in this matter. Additionally, RUCO has not provided a basis for disallowance of the executive base salaries other than that both shareholders and customers benefit from the executives' performance, and there may have been some shortcomings in APS's performance in certain areas. RUCO does not argue, and the evidence does not establish, that the executive salaries are excessive in comparison to the executive salaries for other utilities or that APS has not actually incurred the salary costs for which recovery is sought. Nor does the evidence establish that APS's executives are focusing primarily on shareholder interests to the detriment of customers or that customers do not benefit from having competent and experienced executives work for APS. RUCO's disallowance is not adequately supported and will not be adopted.

3. Union Wage Increase

APS currently employs approximately 1,350 members of IBEW Local 387 and since 1945 has had a series of collective bargaining agreements with IBEW Local 387 governing pay/wages and other terms and conditions of employment. (Ex. IBEW-1 at 3.) There is a shortage in the labor market for linemen, substation electricians, and generation workers, and APS must offer a highly competitive employment package to compete for these skilled union workers. (Ex. IBEW-1 at 5.) Additionally, a significant portion of APS's union workforce is approaching retirement age.[285] (Ex. IBEW-1 at 6.)

a. APS Recovery Request

APS annualized payroll expenses for union employees to reflect the union rate increase for 2020 that was to occur in April 2020 pursuant to the collective bargaining agreement between APS and its unionized workforce. (Ex. APS-12 at att. EAB-8DR; Ex. APS-14 at 1.) The pro forma adjustment was an increase of $1,711,970 to reflect the anticipated 2020 increase in payroll expenses (2.5%) for the union workers. (Ex. AECC-1 at ex. KCH-15 at 3 (response to AECC 8.7); but cf. Ex. IBEW-1 at 11, att. B (response to IBEW 1.2).)

b. Other Parties' Positions

AECC/Freeport asserts that because the union wage increase was to occur on April 1, 2020, conformance to the matching principle would require that only three months of the wage increase be

[285] APS projected that 30% of its employees would be eligible to retire by the end of 2020,

allowed in adjusted TY expenses, representing what was incurred during the "effective test period" that ended 12 months after the TY. (AECC Br. at 3-4, 13-14.) AECC/Freeport asserts that this adjustment is reasonable, reducing APS's retail revenue requirement by only $1.458 million and striking an appropriate balance between APS and its customers. (AECC Br. at 14; Ex. AECC-1 at 28-29; Tr. at 4650-4651.)

The IBEW Locals wholeheartedly support inclusion of the union pay increase in TY payroll expenses, asserting that it is required by the collective bargaining agreement, is necessary to maintain an amicable relationship between APS and its union employees, and if addressed proactively will minimize the impact of future rate increases because the IBEW Locals will be less likely to intervene. (Ex. IBEW-2 at 4; Ex. IBEW-1 at 10.) Additionally, the IBEW Locals argue that federal law encourages collective bargaining and grants such agreements special status, that state law requires that a utility be permitted to recover known and measurable changes that are reliable and certain, and that APS's mature and stable relationship with IBEW Local 387 has positively impacted APS's credit rating. (IBEW Br. at 5-6 (citing 29 U.S.C. § 151; 29 U.S.C. § 185; *Scates v. Arizona Corp. Comm'n*, 118 Ariz. 531, 533-534 (Ariz. Ct. App. 1978) ("*Scates*");[286] Tr. at 173-174, 961-963).)

No other parties oppose the pro forma adjustment to include the entire 2020 union payroll increase.

c. APS Response

APS characterizes AECC/Freeport's adjustment as "arbitrary, punitive[,] and inconsistent" with Commission practice regarding normalization and annualization of expenses. (APS Br. at 41.) Ms. Blankenship asserted that the union wage increase, required by the collective bargaining agreement, has already occurred and thus is a known and measurable change. (Ex. APS-14 at 14.) Additionally, Ms. Blankenship stated, because APS intends to continue employing a unionized workforce and to comply with the collective bargaining agreement, the increased cost is also prudent and thus should be fully included in APS's cost of service. (Ex. APS-14 at 14.) APS argues that AECC/Freeport's disallowance should be rejected because it improperly excludes known and measurable costs that APS

[286] The IBEW Locals also cited an unpublished opinion of the Arizona Court of Appeals.

is contractually committed to pay and has paid. (APS RBr. at 33.)

d. Resolution

Because there is no sign that APS will cease to employ union workers, the wage increase is contractually required, and no evidence has been presented showing that the amount of the increase is unreasonable or imprudent, the union wage increase is a known and measurable change that should be allowed in TY expenses.

4. Directors & Officers ("D&O") Insurance

a. APS Recovery Request

APS included in its TY operating expenses $720,860 paid during the TY for D&O insurance and stated that it does not capitalize D&O insurance costs, although they are a component of prepayments in working capital, with the balance of D&O insurance in prepayments at approximately $306,697 on a total company basis as of the end of TY.[287] (Ex. RUCO-1 at 23, ex. FWR-20; Ex. S-12 at att. RCS-2 at 32, att. RCS-3 at 41-42.) D&O insurance protects a corporation's directors and officers from liability for claims based on decisions they make as directors and officers of the corporation. (Ex. RUCO-1 at 22; *see* Ex. S-12 at 45.) APS asserts that the D&O insurance expenses are customary and necessary to attract and retain qualified directors and officers. (Ex. RUCO-1 at ex. FWR-20.)

b. RUCO

According to Mr. Radigan, shareholders benefit from D&O insurance because the insurance pays for litigation costs and liabilities resulting from a claim made against APS, and customers benefit from the insurance because having it helps to attract and retain qualified directors and officers. (Ex. RUCO-1 at 23.) Mr. Radigan testified that because both shareholders and ratepayers benefit from D&O insurance protection, the D&O insurance costs should be shared 50/50 between shareholders and ratepayers (Ex. RUCO-1 at 23.) Thus, RUCO made a downward adjustment to operating expenses of approximately $376,000 (50% of the total company expense) to reflect this sharing. (RUCO Br. at 31; RUCO-Final Sched. at sched. C-2 at 13; Ex. RUCO-1 at 23, ex. FWR-2 at sched. C-2 at 15; Ex. RUCO-3 at ex. FWR-32 at sched. C-2 at 16.)

[287] Insurance policies over $50,000 that cover one year or longer are recorded in prepaid expense and straight-line amortized monthly throughout the policy coverage period. (Ex. S-12 at att. RCS-3 at 41.) As of December 31, 2019, the balance of D&O insurance payment in prepayments was down to $0. (Ex. S-12 at att. RCS-3 at 42.)

c. Staff

Like Mr. Radigan, and for the same reason, Mr. Smith recommends disallowance of 50% of the D&O insurance expense, resulting in a reduction to TY operating expenses of $360,430 on a jurisdictional basis. (Ex. S-12 at 45, att. RCS-2 at 9; Ex. S-15 at 23-24.) Mr. Smith acknowledged that this disallowance was not made in the 2008 Rate Case and that it was not expressly addressed in the settlements adopted in the 2011 Rate Case and 2016 Rate Case, although Staff made the recommendation in the 2011 Rate Case and 2016 Rate Case. (Ex. S-12 at 45-46.) Mr. Smith asserted that Staff recommended a similar adjustment in Southwest Gas's 2010 Arizona rate case, which was incorporated into the settlement approved in that case, and added that such an adjustment was also adopted by the Nevada Public Service Commission ("Nevada PSC") in a 2009 order in a Southwest Gas rate case. (Ex. S-12 at 46 (citing Nevada PSC Docket No. 09-04003).) Mr. Smith further stated that the public utility commissions in Arkansas and California have required 50/50 sharing and that Connecticut and Florida have also required some sharing of these expenses. (Ex. S-12 at 47.)

In addition to the TY operating expense adjustment, Mr. Smith removed 50% of the D&O insurance prepayments amount from the working capital component of rate base, for a reduction of $145,000. (Ex. S-12 at 47, att. RCS-2 at 6; Ex. S-15 at att. RCS-9 at 21.)

d. APS Response

Ms. Blankenship testified that D&O insurance protects APS and its directors and officers from claims brought against them for good faith decisions made in their capacities on the board or as management and is critical to recruiting and retaining qualified officers and directors. (Ex. APS-14 at 13.) According to Ms. Blankenship, customers benefit from a well-managed company, and officers and directors expect D&O insurance coverage. (Ex. APS-14 at 13.) Ms. Blankenship also testified that not having D&O insurance would increase APS's risk, which could impact its financial stability and ability to provide affordable and reliable service to its customers. (Ex. APS-14 at 13.) Ms. Blankenship asserted that the TY D&O insurance costs should be fully recovered because they were reasonably and prudently incurred. (Ex. APS-14 at 13.)

e. Resolution

In two recent Class A rate cases, the Commission has taken different positions on the issue of

recovery for D&O insurance costs. In Decision No. 77850 (December 17, 2020),[288] involving SW Gas, the Commission adopted Staff and RUCO's position that D&O insurance costs (expensed and capitalized) should be shared 50/50 because shareholders and ratepayers benefit equally from the insurance. (Decision No. 77850 at 33, 40.) In Decision No. 77856, issued two weeks later and involving TEP, the Commission rejected RUCO's position and allowed TEP full recovery of its D&O insurance expense. (Ex. Navajo-9 at 79.)

Looking back further, the Commission has been inconsistent in allowing recovery for D&O insurance costs, sometimes allowing full recovery (*see, e.g.,* Decision No. 59951 (January 3, 1997); Decision No. 60172 (May 7, 1997)) and sometimes requiring a 50/50 sharing of the costs between shareholders and ratepayers (*see, e.g.,* Decision No. 58664 (June 16, 1994)).[289] We are persuaded by APS's testimony in this case that D&O insurance is necessary to attract and retain qualified officers and directors, which is important for everyone's benefit. Because we consider D&O insurance to be a necessary cost of doing business that does not disproportionately benefit shareholders over ratepayers, we will allow full recovery of these costs in TY operating expenses and in the working capital component of rate base.

H. Industry Association Dues

1. APS Recovery Request

APS requests recovery for $3.582 million in industry association dues payments made during the TY to a total of 24 organizations. (Ex. RUCO-1 at ex. FWR-18 (Response to SEIA 1.2), ex. FWR-19.) APS asserts that it has excluded from its recovery request all dues expenses related to lobbying. (Ex. RUCO-1 at ex. FWR-18 (Responses to Vote Solar 1.36, SEIA 1.2).) Mr. Snook clarified that APS has removed specifically the expenses attributable to legislative or regulatory advocacy by the Edison Electric Institute ("EEI").[290] (Ex. APS-29 at 9-10; Ex. APS-30 at 16; Tr. at 2549.)

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[288] Official notice is take of this decision.

[289] Official notice is taken of these decisions.

[290] APS's brief asserts that APS also removed the expenses attributable to advocacy by the Electric Power Research institute ("EPRI"). (APS Br. at 42.) This does not appear to be supported by Mr. Snook's testimony cited in the brief or by the other evidence of record. APS showed that it removed a total of $334,604 in EEI dues below the line because they represented EEI donations or lobbying expenses. (Ex. S-12 at att. RCS-3 at 58.) Additionally, APS removed EEI dues attributable to its TY memberships in Utility Air Regulatory Group ("UARG") and Utility Solid Waste Activities Group ("USWAG"), as recommended by Staff, because APS is no longer a member of UARG or USWAG as of January 1, 2020.

2. RUCO

Mr. Radigan asserts that the industry association dues benefit both shareholders and ratepayers, that the Commission has previously approved a 50/50 sharing of industry association dues in prior rate cases, and that APS's TY industry association dues expenses likewise should be divided 50/50, which Mr. Radigan stated would reduce O&M expense by $1,791,178. (Ex. RUCO-1 at 21-22 (citing Decision No. 71914, Decision No. 70360[291]).) Mr. Radigan did not question that the association dues were prudent expenses or that the amounts for which APS requests recovery exclude amounts directly related to legislative and regulatory advocacy. (Ex. RUCO-3 at 14-15.)

3. APS Response

APS considers RUCO's recommended disallowance to be erroneous, arbitrary, and punitive, arguing that the cases cited by RUCO only disallowed portions of dues that were related to legislative and regulatory advocacy, which APS has not sought to recover in this case, and that adopting RUCO's disallowance would be contrary to law. (APS Br. at 42; APS RBr. at 34.) Mr. Snook testified that RUCO's disallowance should be rejected because the dues paid were prudent costs, and the disallowance sends the wrong message—essentially telling APS that it should not participate in those organizations. (Tr. at 2550.) Mr. Snook added that if the expenses are not recovered, APS is faced with not being a member of the organizations, so as to manage costs. (Tr. at 2550.)

4. Resolution

APS has removed from its request significant portions of association dues that are attributable to legislative and regulatory advocacy, specifically for EEI. We have previously disallowed portions of EEI dues attributable to legislative and regulatory advocacy, advertising, marketing, and public relations. (Decision No. 71914 at 25; Decision No. 70360 at 26.) We do not believe that APS has removed from its requested association dues expense all advocacy-related expenses (for example, AriSEIA engages in advocacy activities[292]). However, by removing the EEI dues attributable to

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(Ex. S-12 at 42, att. RCS-2 at 28, att. RCS-3 at 56-59.) Mr. Snook did testify that it was important for APS to maintain its membership in EPRI so it could stay abreast of changes in the electric industry. (Ex. APS-29 at 9-10.)

[291] Although Mr. Radigan mistakenly cited Decision No. 70860 in his testimony, we understand it to have been intended as a citation of Decision No. 70360.

[292] Based on past experience at the Commission, some of those advocacy efforts may run counter to APS's interests. We also note that the AriSEIA dues, $10,000, are among the lower dues paid by APS. (Ex. RUCO-1 at ex. FWR-18.)

advocacy efforts, APS has acted in keeping with our prior decisions on this issue. It is essential for APS to remain current concerning developments in the energy industry, and its membership in the various associations provides it access to research and other information that it otherwise would not be able to obtain. We conclude that it is just and reasonable to allow recovery of the $3.582 million in association dues requested.

I. Injuries & Damages Expense

1. APS Recovery Request

APS has included in TY operating expenses approximately $8.96 million reflecting its actual jurisdictional TY expenses for injuries and damages. (See Ex. S-12 at att. RCS-2 at 27, att. RCS-3 at 55.)

2. Staff

Mr. Smith determined that APS's injuries and damages expenses fluctuate annually and thus recommends that APS's injuries and damages expenses be normalized using the four-year period of 2016-2019, which results in normalized jurisdictional TY expenses for injuries and damages of approximately $9.15 million. (Ex. S-12 at 42, att. RCS-2 at 27; Staff Br. at 25.) Staff recommends an upward adjustment of approximately $187,000 to APS's TY operating expenses. (Ex. S-12 at att. RCS-2 at 27.)

3. Other Parties

No other party has advocated for or apparently adopted Staff's position.

4. APS Response

APS did not adopt Staff's normalization adjustment and did not address the adjustment in its briefs. (See LFE APS-87; APS Br.; APS RBr.)

5. Resolution

While Staff is correct that APS's injuries and damages expenses have fluctuated somewhat, the fluctuation in jurisdictional amounts for 2016-2019 ranged from a low of approximately $7.95 million to a high of approximately $10.09 million. The mean of those is $9.02 million, which is only $60,000 more than APS has included in its TY operating expenses and, in light of the scale of APS's operations, is insignificant. We conclude that Staff's normalization adjustment is unnecessary and will not adopt

it.

J. Accelerated Amortization of Regulatory Assets

1. APS Recovery Request

APS has included in rate base more than $1.3 billion in TY regulatory assets, as shown below:[293]

Asset	TY Amortization	End-of-TY Value (Jurisdictional)	Amortization Period
Pension regulatory asset	-	$654.442 million	N/A
Deferred income taxes on AFUDC	($4.966 million)	$132.296 million	2003-2049
Unrecovered power plant costs for NGS	($9.606 million)	$82.833 million	2017-2026
Unrecovered power plant costs for Cholla	($16.103 million)	$81.063 million	2017-2033 proposed
Property tax deferral	($9.464 million)	$68.239 million	2017-2027
4CPP deferral	($8.038 million)	$44.054 million	2017-2024
SCR debt deferral	-	$81.645 million	2021-2031 proposed
Investment tax credit basis adjustment	($0.664 million)	$26.123 million	2017-2047
Navajo coal reclamation	($1.068 million)	$17.797 million	2010-2026
Regulatory treatment of CIAC on Mead-Phoenix Transmission Line	($0.331 million)	$10.180 million	2005-2050
Unrecovered power plant costs for West Phoenix	-	$9.982 million	2021-2031 proposed
OMP deferral	-	$91.458 million	2021-2031 proposed
Unrecovered power plant costs for Saguaro	($2.266 million)	$7.426 million	2017-2022
OPEB subsidy PPACA	($1.113 million)	$6.432 million	2010-2024
AG-X deferral	($2.888 million)	$6.864 million	2017-2022
Other		$12.365 million	
Total		**$1,333.199 million**	

2. RUCO

Mr. Radigan expressed concern about the amount of TY regulatory assets that APS has included in rate base for full cost recovery at the WACC rate of return, particularly the stranded costs for NGS,

[293] Ex. AECC-2 at ex. KCH-22 at 2 (APS response to AECC 17.3); *see also* Ex. RUCO-1 at ex. FWR-21 (APS response to AECC 2.5).

the liability for the Navajo coal mine reclamation, the balance for the retired Cholla units, the stranded costs for Saguaro, and the stranded costs for West Phoenix, which combined totaled $199.1 million. (Ex. RUCO-1 at 25; *see* Tr. at 4188-4189.) Mr. Radigan asserted that the stranded asset list will grow with the Clean Energy Commitment, leaving ratepayers to fund a return of and on assets that are not used and useful, and that stranded costs should be eliminated as soon as "practically possible." (Ex. RUCO-1 at 25.) According to Mr. Radigan, RUCO's recommended exclusion of the 4CPP SCRs from rate recovery in this case would reduce APS's requested revenue requirement by approximately $73 million and thus leave sufficient cash flow to accelerate the elimination of stranded costs. (Ex. RUCO-1 at 25.) To that end, RUCO recommends a pro forma adjustment to increase depreciation and amortization expense by $80 million per year to accelerate the reduction of stranded costs by providing APS additional cash to write off its regulatory assets. (Ex. RUCO-1 at 25, sched. C-2 at 11; Ex. RUCO-3 at sched. C-2 at 11; Tr. at 4188-4189, 4192, 4255.) Mr. Radigan stated that this would allow for elimination of the stranded production plant costs by the end of 2020,[294] after which time the additional cash flow could be returned to ratepayers through an adjustor mechanism, refunded, or retained to use for other future production-related stranded costs. (Ex. RUCO-1 at 25-26.)

3. AARP

AARP supports RUCO's proposal. (AARP RBr. at 4-5.)

4. Other Parties

No other parties adopted RUCO's position or expressed opposition to APS's proposal.

5. APS Response

APS does not appear to have addressed RUCO's recommendation for a $80 million pro forma adjustment to depreciation and amortization expense explicitly in testimony or its briefs. Because APS has not adopted the $80 million pro forma adjustment, however, we infer that APS does not support it. (See LFE APS-87 at sched. C-2.)

6. Resolution

As we understand it, RUCO's proposed pro forma adjustment to increase TY depreciation and

[294] We understand this to mean within a year or two after the effective date of the rates approved herein.

amortization expense by $80 million is intended to allow APS to eliminate current stranded asset balances quickly and to serve as a means of funding either the elimination of future stranded assets as they arise or customer refunds. RUCO's proposed adjustment would accomplish this by increasing APS's annual revenue requirement by $80 million. The Commission does not believe that it would be reasonable to require customers to fund elimination of the current stranded assets in such a short time or to create ongoing funding for an undesignated purpose. Additionally, it is premature at this time to prescribe treatment of costs that are not yet stranded. RUCO's $80 million adjustment to increase depreciation and amortization expense for regulatory assets will not be adopted.

K. Navajo Generating Station Regulatory Asset

1. APS Recovery Request

APS seeks to recover the remaining book value of NGS ($73.227 million at the end of TY) through a regulatory asset to be depreciated over the original life of the plant (until 2026) and with a return set at the WACC established in this case. (Ex. APS-29 at 5-6.)

2. AECC/Freeport

APS's depreciation rates for NGS were designed to recover APS's capital investment through 2026, although NGS was retired in late 2019. (Ex. AECC-1 at 33.) As a result, APS has on its books a large undepreciated balance for NGS ($82.8 million as of June 30, 2019), which APS transferred into a regulatory asset that it proposed to amortize through 2026. (Ex. AECC-1 at 33.) APS also proposed to offset the regulatory asset with a deferred tax liability of $20.5 million. (Ex. AECC-1 at 33.)

Mr. Higgins recommended that APS be permitted to include the NGS regulatory asset in rate base, but that the rate of return for the regulatory asset be set at APS's cost of long-term debt rather than the WACC. (Ex. AECC-1 at 34.) Mr. Higgins asserted that "there must be a reasonable nexus between the costs customers pay and the used and usefulness of the facilities for which customers are charged" and that the "full burden of plant obsolescence should not fall entirely on customers." (Ex. AECC-1 at 34.) Mr. Higgins stated that NGS was closed because APS and the other owners determined that continuing to operate NGS was not cost effective. (Ex. AECC-1 at 34.) Further, Mr. Higgins stated, if APS were a competitive company, the remaining investment in NGS would be written off (charged to shareholders). (Ex. AECC-1 at 34.) Mr. Higgins did not advocate for disallowance,

however, because that could disincentivize a utility from taking action to shut down facilities that are no longer cost effective. (Ex. AECC-1 at 34.) Mr. Higgins asserted that AECC/Freeport's position provides a proper balance by allowing APS to recover its remaining investment in NGS through 2026, while not requiring customers (who will be paying a full return on plant that replaces NGS) to pay a full return on obsolete plant. (Ex. AECC-1 at 34.) Mr. Higgins asserted that the adjustment reduces APS's revenue deficiency by approximately $2.581 million, based on a WACC established using an ROE of 9.75%. (Ex. AECC-1 at 35, ex. KCH-13; Ex. AECC-3 at 24, ex. KCH13-S.)

In response to APS's opposition to AECC/Freeport's position, Mr. Higgins reiterated that customers should not incur the full burden of the obsolete NGS regulatory asset while also paying a full return on replacement plant. (Ex. AECC-3 at 24.) While Mr. Higgins agreed that a complete disallowance might be a disincentive to retirement of an uneconomic plant, he stated that his recommended disallowance, between $2 and $3 million per year for APS, would not be a sufficient disincentive for a utility to fail to retire such a plant. (Tr. at 4667.)

3. Other Parties

No other party adopted AECC/Freeport's position or, except for RUCO,[295] opposed APS's treatment to recover the book value of NGS.

4. APS Response

Mr. Snook asserted that when depreciation rates and salvage costs do not result in a value close to zero at the end of plant life, a regulatory asset or liability is created, representing a "mismatch in timing." (Ex. APS-29 at 5-6.) According to Mr. Snook, the NGS regulatory asset should receive a WACC return, i.e., "normal regulatory asset treatment," because it reflects prudently incurred costs over the life of NGS. (Ex. APS-29 at 6.) Mr. Snook added that APS has not proposed accelerated recovery of the NGS regulatory asset to more closely match the 2019 closure date, thus preventing potential rate pressure. (Ex. APS-29 at 6.) Mr. Snook also characterized AECC/Freeport's debt-only return recommendation as a partial disallowance of the prudently incurred costs of the NGS, which were funded with both debt and equity, and punishment for APS's decision to retire NGS. (Ex. APS-

[295] As described in the previous section, RUCO took a different position as to the treatment of regulatory assets for stranded costs.

29 at 6.)

The SEC Form 10-Q for Q2 2018 for PNW and APS stated that APS would seek recovery for the book value of NGS plus a return as well as other costs related to retirement and closure, believed that it would be allowed such recovery, and would write off all or a portion of the regulatory asset if the Commission were to deny full recovery of the remaining net book value. (Ex. APS-39 at sched. E-9 at 31.) The Form 10-Q further stated that APS's net income, cash flows, and financial position would be negatively impacted if the Commission were to deny full recovery. (*Id.*)

According to APS, the remaining book value of NGS on June 30, 2019, was $73,226,933. (APS Br. at 23.) APS argued that no party disputed that NGS was a prudent investment, objected to creation of the NGS regulatory asset, disagreed with the amount of the NGS regulatory asset, argued against amortization of the NGS regulatory asset through 2026, argued against APS earning a return on the NGS regulatory asset during the amortization period, or disputed that NGS was financed with both equity and debt capital. (APS Br. at 23-24.) APS further argued that AECC/Freeport has cited no precedent for its position and that there is no basis for removing the equity portion of WACC for the NGS regulatory asset rate of return. (APS Br. at 24.) APS also characterized AECC/Freeport's position as "egregious" because AECC/Freeport has recognized that the early closure of NGS benefited customers. (APS Br. at 24 (citing Tr. at 4664-4666).) APS argued that adopting AECC/Freeport's position would disincentivize utilities' exercise of prudent judgment for the benefit of their customers, would be inconsistent with sound ratemaking principles, and would set a dangerous precedent. (APS Br. at 25.)

5. Resolution

The Commission was recently faced with this issue in the TEP Rate Case, in which both AECC/Freeport and RUCO advocated for TEP to be allowed a debt-only rate of return on the remaining book balances permitted in rate base for the NGS. (Decision No. 77856 at 93-95.) The Commission determined that while it was appropriate under the circumstances not to allow full recovery of the regulatory asset, allowing a cost-of-debt rate of return would be "unnecessarily complex from tracking, recording and functional perspectives[,] causing complications for processing future rate cases over the next decade." (*Id.* at 95.) The Commission determined that it was more appropriate to direct TEP to

record 15% of the annual amortization for the NGS below the line as non-operating expenses, as it would provide a similar, but simpler economic disallowance. (*Id.*)

The solution adopted in the TEP Rate Case is equally just and reasonable under the circumstances in this case, and it will be adopted.

L. Depreciation & Amortization Expense

1. APS Recovery Request

APS proposes adjusted TY depreciation and amortization expense of $616,026,000, which includes adjusted depreciation expense of $452,074,936, representing a composite accrual rate of 2.89% (LFE APS-87 at sched. C-1 at 2; Ex. APS-16 at 13; Tr. at 1639.) APS's depreciation rates and expense were determined by Dr. White using a 2019 depreciation study completed by Foster Associates that produced an annualized depreciation expense of $478,728,736 and resulted in a composite accrual rate of 3.07%. (Ex. APS-15 at 11, att. REW-2DR.) Except where specific amortization accounting has been approved by the Commission, APS uses a straight-line method, vintage group procedure, and remaining life technique for depreciation. (Ex. S-12 at 79.)

Both APS's originally requested and finally requested depreciation expense represent an increase from APS's current composite depreciation rate of 2.74%, which would have resulted in annualized depreciation expense of $428,124,772. (Ex. APS-15 at 11.) A portion of the change is attributable to amortization of a $490,198,766 reserve imbalance. (Ex. APS-15 at 11.) The remainder of the change is attributable to adjustments in service life and net salvage statistics recommended in the 2019 depreciation study as well as direction from APS (after the 2019 depreciation study and Dr. White's direct testimony) to extend the life-span of nine non-legacy solar power stations from 30 years to 40 years and to reduce the amortization period of the Palo Verde depreciation reserve excess from nine to six years.[296] (Ex. APS-15 at 11; Ex. APS-16 at 13; Tr. at 1639.)

APS's depreciation expense assumes a 2038 projected retirement date for the 4CPP; that was

[296] Dr. White opined that the changes made to depreciation expense after his direct testimony and at APS request were made to mitigate the rate increase impact on customers but also based on engineering considerations. (Tr. at 1639, 1646.) Dr. White testified that the depreciation rate for life span accounts is based on an estimated year of final retirement, and he relied on APS to provide that information. (Tr. at 1644-1646.) Dr. White also testified that selection of an amortization period, such as for the Palo Verde excess depreciation reserve, does not require a study. (Tr. at 1646-1647.) The Palo Verde excess depreciation reserve has a current balance of $343.5 million. (Tr. at 1647.) Nine-year amortization resulted in $38.2 million per year, while six-year amortization results in $57.25 million per year. (Tr. at 1647-1648.)

the date used in the 2019 depreciation study, because APS had not yet announced an earlier closure date. (Tr. at 1648.) Dr. White did not know why APS chose to maintain the 2038 retirement date for depreciation purposes, but stated that using 2031 would significantly increase depreciation expense. (Tr. at 1649.)

Dr. White did not recommend abandonment of the straight-line depreciation method, testifying that APS's current system will remain appropriate with periodic depreciation studies and routine adjustment of parameters to reflect changing operating conditions. (Ex. APS-15 at 10.) Dr. White also opined that APS's current amortization accounting for select general support asset accounts is consistent with the goals and objectives of depreciation accounting and remains appropriate. (Ex. APS-15 at 10.)

2. RUCO

Mr. Radigan recommended that Dr. White's 2019 depreciation study and proposed depreciation rates be adopted, but with modifications to the average service lives for 10 plant accounts[297] and changes to net salvage for two plant accounts,[298] which combined reduced APS's adjusted TY depreciation expense by $27.9 million. (Ex. RUCO-1 at 27-43.) Mr. Radigan's average-service life modifications were all based on his own mathematical and curve-fitting analyses, and all resulted in longer average service lives than proposed by APS. (Ex. RUCO-1 at 34-41, ex. FWR-22, ex. FWR-23, ex. FWR-24, ex. FWR-25, ex. FWR-26, ex. FWR-27, ex. FWR-28, ex. FWR-29, ex. FWR-30.) For the net salvage accounts, Mr. Radigan's modifications were based on his analyses of the historic data, which he found not to support APS's proposed changes to the accounts, as well as his determination that APS had not explained its proposed changes. (Ex. RUCO-1 at 42, ex. FWR-31.) Aside from these modifications, Mr. Radigan found the 2019 depreciation study to be "complete and comprehensive." (Ex. RUCO-1 at 43.)

Mr. Radigan testified that, contrary to assertions by Dr. White, he had performed an actuarial

[297] Specifically, Mr. Radigan recommends different average service lives for Accounts 361 (Station Equipment), 362 (Station Equipment), 364.02 (Poles, Towers, and Fixtures – Steel), 365 (Overhead Conductors and Devices), 366 (Underground Conduit), 367 (Underground Conductors and Devices), 369 (Services), 370.03 (Meters – AMI), 371 (Installations on Customers Premises), and 373 (Street Lighting and Signal Systems). (Ex. RUCO-1 at 34-41.)

[298] Specifically, Mr. Radigan recommends that APS's proposals to increase net salvage from -10% to -20% for Account 365 and to change net salvage for Account 367 be rejected as unsupported by historic data. (Ex. RUCO-1 at 42.)

analysis, not just a visual curve fitting, for each account for which he recommended a different average service life. (Ex. RUCO-3 at 19-20.) Additionally, he questioned Dr. White's assertions that Mr. Radigan's calculations were "flawed" because Dr. White did not indicate the monetary value of the flaws. (Ex. RUCO-3 at 20.) Mr. Radigan attributed most of the differences between his position and that of Dr. White to "judgment and not substance" and found no reason to change his recommendations. (Ex. RUCO-3 at 20-21.) RUCO argues that while its depreciation analyses includes the details, reasons, and facts to support its recommendations (including the best-fitting Iowa curves), APS's depreciation study does not indicate why its results are reasonable and should be adopted. (RUCO RBr. at 6.)

3. Staff

For the plant investment component of depreciation rates, Staff recommends use of the depreciation lives, curves, and rates proposed by APS, which Mr. Smith testified were developed in a manner consistent with the Commission's rules on depreciation and are a reasonable approach to updating APS's currently approved depreciation rates. (Ex. S-12 at 95.) For the cost of removal component of depreciation rates, however, Mr. Smith recommends that the Commission use a method similar to the FAS 143 "Present Value Method" now being used by the Maryland and District of Columbia ("DC") public utility commissions ("PUCs"). (Ex. S-12 at 81, 95.) Mr. Smith asserts that Dr. White has used the Present Value Methodology in his presentations before the Maryland and DC PUCs for the net salvage (cost of removal) component of depreciation accruals. (Ex. S-12 at 84-86.) Mr. Smith acknowledged that the DC PUC required use of the FAS 143 method in calculating cost of removal and that Dr. White advocated for the DC PUC not to adopt the FAS 143 method. (Ex. S-12 at 85, 89.) Mr. Smith observed that the DC PUC determined that the FAS 143 approach was a better method to use for the cost of removal component because it avoids the "intergenerational inequity" that results from requiring current customers to pay more in "'real' dollars" than future customers must pay, which results from current customers being charged for future inflation. (Ex. S-12 at 87; Ex. S-15 at 33-34.) Mr. Smith acknowledged that he is not aware of the Present Value Method's having been used by Arizona utilities regulated by the Commission, but stated that it is not uncommon for regulatory treatments to evolve when additional information becomes available. (Ex. S-12 at 91.) Mr. Smith also

acknowledged that it is always challenging to achieve the right balance between costs assessed to current ratepayers and costs assessed to future ratepayers, but the Maryland and DC PUCs have determined that the Present Value Method achieves that balance. (Ex. S-12 at 93-94.)

Mr. Smith's analysis, made using APS's calculations for the FAS 143 Present Value Method for cost of removal[299] and an accretion rate of 3.78%, resulted in Staff's recommendation to reduce APS's depreciation expense by $12.134 million. (Ex. S-12 at 90, 96; Ex. S-15 at 35.) Mr. Smith testified that using the FAS 143 method is equitable and reasonable. (Ex. S-15 at 30.) Additionally, Mr. Smith asserted, using the FAS 143 method in this case could benefit both APS and its customers by allowing higher levels of costs related to the 4CPP to be subject to securitization, because the decreased depreciation expense would result in a larger amount of remaining cost for negative net salvage/cost of removal in 2031. (Ex. S-15 at 30-31.) Staff argues that using the FAS 143 method will fairly allocate the estimated future costs of removal/negative net salvage to customers across generations and that having lower depreciation expense will result in a slower build-up of accumulated depreciation for APS's fossil fueled generation assets. (Staff RBr. at 2.)

Concerning RUCO's recommendations, Mr. Smith testified that his own testimony should not be construed as opposing Mr. Radigan's depreciation rate recommendations. (Ex. S-15 at 36.) Mr. Radigan also criticized APS and Dr. White for not providing Mr. Radigan a spreadsheet that Mr. Radigan asserted was necessary to modify Dr. White's recommended depreciation rates appropriately and that Dr. White stated was a work product of Foster Associates. (Ex. S-15 at 36.) Mr. Smith testified that the development of a regulated utility's depreciation rates should be transparent and that it is unacceptable not to provide spreadsheets with sufficient detail to support proposed depreciation rates and that can be used to analyze and modify those rates. (Ex. S-15 at 36.) Mr. Smith recommended that the Commission "require full transparency from its regulated utilities in supporting and providing workpaper details for the depreciation rates that the utility is requesting the Commission to approve." (Ex. S-15 at 36.)

. . .

[299] In the 2016 Rate Case, APS was required to include this information in its next rate case.

4. APS Response

Dr. White urged the Commission to reject RUCO's accrual rates, testifying that RUCO used a curve-fitting technique that was significantly different from that employed by Dr. White and also used incorrect average service lives, remaining lives, and net salvage rates in developing its accrual rates. (Tr. at 1640.)

Dr. White also urged the Commission to reject Staff's position that the straight-line method should be abandoned and the FAS 143 present value formulation instead be adopted for net salvage accrual rates. (Tr. at 1640, 1651.) According to APS, the FAS 143 method was not developed for use in determining depreciation expenses in utility rate cases but as a financial accounting standard to be used for determining the amount of an asset retirement obligation included on a corporation's balance sheet. (APS Br. at 43; Tr. at 5018-5019.) Dr. White testified that the FAS 143 method would reduce current accruals and increase future accruals, which he described as "kicking the can down the road" because the lower current accruals are made up at the end, and the time-period over which plant costs are charged to operations is the same for straight-line and FAS 143. (Tr. at 1641, 1651-1652; Ex. APS-17 at 3.) Dr. White showed that using the FAS 143 method (as opposed to the straight-line method) for 4CPP Units 4 and 5 and Common dismantlement costs would result in lower accruals in 2019 (by approximately $1 million) through 2027, when the FAS 143 accruals would begin to exceed the straight-line accruals, ultimately resulting in the FAS 143 accruals exceeding the straight-line accruals by approximately $2 million in 2038.[300] (See Ex. APS-16 at 11-12.) In Dr. White's opinion, "[t]he simplicity of the straight-line method far outweighs the complexity of attempting to shift the timing of net salvage accruals to achieve a reduction in current depreciation expense, increase future expense and potentially increase the marginal cost of external financing." (Ex. APS-16 at 12; Ex. APS-17 at 4-5.)

In response to Mr. Smith's testimony concerning transparency, Dr. White testified that he had provided spreadsheets with formulas intact for direct testimony to Mr. Radigan as well as workpapers and had provided Mr. Smith workpapers with formulas intact for rebuttal testimony, with all provided

[300] As the name implies, the straight-line method would result in a straight line at $6 million, while the FAS 143 method would result in a diagonal line increasing from approximately $5 million to approximately $8 million over the period from 2019 to 2038; the lines intersect at 2027. (*See* Ex. APS-16 at 11.)

in response to data requests and in a timely manner as per the Procedural Order in this case. (Ex. APS-17 at 5.) Dr. White clarified that his concern about providing workpapers and spreadsheets created by Foster Associates was that witnesses modified those spreadsheets and presented them as their own independent work product without creating their own spreadsheets. (Ex. APS-17 at 5.)

5. Resolution

We are not persuaded that it is necessary at this time to modify the average service lives and depreciation rates for the 10 plant accounts identified by Mr. Radigan or the changes to net salvage for the two plant accounts identified by Mr. Radigan. While Mr. Radigan presented extensive information supporting his analyses, including somewhat compelling curve-fitting graphs, he did not adequately respond to Dr. White's concerns about his use of incorrect average service lives, remaining lives, and net salvage rates in his analyses.

We also are not persuaded that it would be in the public interest to use the FAS 143 method rather than the straight-line method for net salvage accrual rates. We are concerned that Staff's proposal may be based more on current and short-term outcome than sound analysis, believe that the increased costs imposed on future customers would be anachronistic as they will have benefited less from the retired plants, and consider the possible future availability of securitization too speculative to justify the switch to this more complicated method.

APS's depreciation study was conducted in a manner previously approved by the Commission, and its depreciation rates were developed consistent with that depreciation study. The depreciation study is 186 pages long; devotes more than two pages of single-spaced text to describing Foster Associates' Life Analysis and Estimation methodology alone; and includes an example of the supporting schedules developed for each account, which were made available in work papers provided to the other parties and include an abundance of data concerning the plant in the specific account as well as curve-fitting graphs.[301] We find that APS's proposed depreciation rates have been fully supported and that it is just and reasonable to adopt APS's proposed depreciation rates and its proposed depreciation and amortization expense (with the necessary modifications for disallowances of plant as

[301] Ex. APS-15 at att. REW-2DR.

described herein).

M. Proposals to Change Manner of Recovering Specific Costs

1. Collecting EE Costs in Base Rates & with Regulatory Asset

a. APS Recovery Request

Currently, APS collects $20 million for EE costs through base rates as expenses and the remainder through the DSMAC. (Ex. APS-29 at 16; Tr. at 2436, 2552.) In the TY, APS had a total DSM/EE budget between $40 and $50 million. (Tr. at 2435.) APS has not proposed to change that arrangement in this case, but has expressed an openness to having a fixed budget for EE collected through base rates or a fluctuating budget for EE that would allow for deferral of EE costs above/below the amount collected through base rates, to be recovered/refunded in a future rate case. (Ex. APS-29 at 16-17; Tr. at 418, 523.)

Additionally, APS initially suggested that EE costs as well as the costs currently collected through the REAC and the LFCR could be collected together through the newly proposed AEM, which is discussed more fully below. (Tr. at 417.) In its final position, APS no longer proposed to move these costs into the AEM in this case. (Tr. at 2501-2502.)

b. WRA/SWEEP

WRA/SWEEP assert that the Commission should order APS to recover $65 million of EE program costs through base rates, arguing that it would benefit all APS customers, the electric system, the economy, and the environment because EE is reliable and less expensive than other available resources, reduces load growth and peak demand and thus defers the need for additional infrastructure and reduces costs, enhances the reliability of the grid, reduces the amount of water used for power generation, reduces air pollution, creates jobs that cannot be outsourced, drives local economic growth, helps to relieve system constraints in load pockets, mitigates customer exposure to fuel price increases because it does not rely on any fuel. (WRA/SWEEP Br. at 17-18; Ex. WRA-1 at 41.) WRA/SWEEP assert that APS's EE programs from 2011 through 2019 have provided more than 43.7 million MWh of lifetime electric savings; produced over 1,000 MW of peak demand savings; saved more than 13.6 billion gallons of water; significantly reduced harmful emissions of CO_2, SO_2, and NOx; generated more than $1.9 billion in benefits to Arizona residents and businesses; and created more than 40,000

Arizona jobs, with 28,000 of those jobs in Phoenix.[302] (Ex. WRA-1 at 42.)

WRA/SWEEP assert that to ensure adequate investment in EE by APS, the Commission should allow APS to recover at least $65 million of EE program funding through base rates, with the DSMAC adjustor mechanism used solely to true up for actual costs, allowing for refunds to customers if the entire $65 million is not spent and allowing APS to collect for additional authorized EE expenditures. (Ex. WRA-1 at 43.) WRA/SWEEP assert that the $65 million is "slightly more" than the $51.9 million budget the Commission approved in APS's 2020 DSM Plan and that APS has collected $66.6 million in previous years. (Ex. WRA-1 at 43.) Mr. Baatz added that for 2020-2030, APS should commit to delivering at least 1.3% net annual savings from EE each year. (Ex. WRA-1 at 44.)

WRA/SWEEP additionally assert that the Commission should allow APS to include its EE program costs in rate base as a regulatory asset that earns a return at the Commission approved ROR, to be amortized over a seven-year period. (Ex. WRA-1 at 44.) Mr. Baatz testified that allowing APS to earn a return on its EE program costs would provide APS with greater certainty that its EE/DSM budget is stable, make EE investments as attractive as other capital investments, and reduce rate impacts. (Ex. WRA-1 at 45.) Additionally, Mr. Baatz asserted, allowing APS a return on its capitalized EE costs would not be a replacement for the performance incentive that APS currently earns for its EE investments,[303] unless the authorized return on the capitalized investments were adjustable based on APS's performance in delivering EE savings, something that Mr. Baatz believes fits into the larger topic of a performance-based ratemaking mechanism for APS. (Ex. WRA-1 at 45, 47.) Mr. Baatz acknowledged that capitalization of EE costs could incentivize APS to inflate its EE budgets to increase its spending, and asserted that the Commission would need to review EE filings in a timely fashion to avoid wasteful spending and ensure that APS's and its customers' interests are balanced. (Ex. WRA-1 at 45.) Mr. Baatz asserts that there is substantial nationwide benchmarking data for the Commission to use in its reviews. (Ex. WRA-1 at 45-46.) Mr. Baatz noted that New Jersey, Maryland, Illinois, Utah, and Colorado allow utilities to earn a return on EE program investments, with varying

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[302] Mr. Baatz noted that APS was highlighted as one of 14 leading utilities for EE in a 2016 national report by the American Council for an Energy Efficient Economy. (Ex. WRA-1 at 42.)

[303] Mr. Baatz asserted that the performance incentive is not guaranteed, is calculated based on the programs' net benefits, is paid only after investment, and is still useful to motivate APS to meet EE policy goals. (Ex. WRA-1 at 45.)

amortization periods used. (Ex. WRA-1 at 46.) Mr. Baatz further noted that the Salt River Project ("SRP") has moved to funding and recovering its EE program costs in base rates instead of through an adjustor. (Ex. WRA-1 at 47.) Mr. Baatz denied that capitalization of EE program costs would reduce transparency as to those costs, stating that EE costs should be treated like other resources, which do not have their costs expressly identified on customer bills. (Ex. WRA-1 at 47.)

c. Other Parties

Although AARP did not brief the issue, Mr. Rubin testified that APS's DSM expenditures should not be capitalized unless they involve purchase of a long-lived asset of significant magnitude that it can be depreciated because capitalizing some or all of the costs would increase rates to customers, improperly benefit APS's shareholders, and create intergenerational inequities among customers. (Ex. AARP-2 at ii, 9-10.)

Vote Solar also did not brief the issue, but Mr. Sandoval opined that WRA/SWEEP's proposal would offer potential benefits to all customers while managing rate impacts and providing APS an additional incentive to invest in EE and, further, asserted that the idea of capitalizing DSM investments "could benefit from stakeholder engagement within a dedicated regulatory docket" to consider the implications and ensure safeguards. (Ex. VS-2 at 6-7.)

d. APS Response

APS's primary position is that the current collection arrangement should be maintained. (Tr. at 2437.) However, APS proposes that any increase in the amount of EE/DSM program costs recovered through base rates be done in a revenue neutral manner, so that the increased amount would not exceed the TY amount collected through the DSMAC. (Ex. APS-29 at 17; Tr. at 2437.)

APS is "interested" in WRA/SWEEP's recommendation for EE/DSM costs to be capitalized using a regulatory asset, amortized over a 7-year period, and allowed to earn a return at the after-tax COC on the unamortized balance. (Ex. APS-29 at 17-18; Tr. at 2552.) Mr. Snook testified that as Arizona shifts its EE focus to peak management, capitalization of EE/DSM costs would align with the general proposition that EE should be treated like supply-side resources. (Ex. APS-29 at 18.) Additionally, Mr. Snook stated, capitalization would better align the resource costs with the timing of benefits, would protect customers by ensuring DSM costs are apportioned across a period of time closer

to the 10-year average measure life of the DSM portfolio, and would put DSM investments on a more level playing field with other investments and encourage demand-side resource investments. (Ex. APS-29 at 17.) Mr. Snook also noted, however, that capitalization would increase the cost of demand-side resources and could limit future spending on new programs because of the carrying costs. (Ex. APS-29 at 17; Tr. at 2553.) Mr. Snook asserted that with a move to capitalization, there would also need to be provisions made to establish how the amortized costs would be recovered if the Commission were to revert to an operating expense approach in the future. (Ex. APS-29 at 17-18.) Additionally, Mr. Snook stated, any capitalization plan would need to address the unique risks associated with deferring DSM costs as a regulatory asset when the asset would have no value outside of the regulatory construct, so that there would be reasonable assurance of future cost recovery. (Ex. APS-29 at 18.) APS has determined on balance that at this point in time, capitalization of these costs is "probably not the right path to go down."[304] (Tr. at 2553.)

e. Resolution

Although the Commission desires for APS to increase its DSM/EE expenditures, it is important that those expenditures be made for DSM/EE programs that have the greatest net benefit to APS and its customers. At this time, the overall cost of those cost-effective DSM/EE programs in a given year is speculative, and including an additional $45 million in base rates (so that this amount must be paid by customers each year) would not adequately protect customers. Even though WRA/SWEEP recommend that the DSMAC continue to be used for true-up purposes, including the additional $45 million in base rates could act as a disincentive for APS to invest in only the most cost-effective DSM/EE programs, minimizing the likelihood that customers would receive refunds through the DSMAC in any given year. Additionally, removing those costs from the DSMAC reduces the transparency of APS's DSM/EE expenditures. Finally, we note that treating DSM/EE program costs as other resource costs (assuming that it is an APS-owned supply-side generation resource) means that APS would need to wait until its next rate case to have the costs included in base rates (as plant in

[304] Mr. Snook explained that the capitalization approach is often being used now in jurisdictions where there is a dramatic increase in EE spending, because capitalization decreases costs in the beginning because they are instead financed over time. (Tr. at 2553, 2555.) In the end, however, ratepayers would end up spending more than if the same costs were expensed. (Tr. at 2554, 2556-2557.)

service added to rate base); it does not mean that APS would receive up-front funding for those costs through base rates. We conclude that it is not in the public interest to add $45 million to APS's revenue requirement to fund DSM/EE programs at this time.

WRA/SWEEP's capitalization idea for DSM/EE program costs is intriguing but has not been fleshed out sufficiently to address the shortcomings identified by Mr. Snook (increasing the costs of DSM/EE programs for customers, creating regulatory assets with no inherent value, and creating the need for transition protocols should a future Commission determine that DSM/EE program costs should again be treated as expenses rather than capitalized). Additionally, the Commission does not have sufficient data to determine whether the proposed seven-year amortization period for a DSM/EE regulatory asset would appropriately align the timing of the benefits of the DSM/EE program with the customers who are required to pay for the asset. We conclude that it is not in the public interest at this time to capitalize APS's DSM/EE program costs as regulatory assets rather than maintaining the current treatment as operating expenses.

2. Removing DSM Costs from Base Rates

a. APS Recovery Request

With the exception of the $20 million included in base rates since the 2016 Rate Case, APS currently collects the costs for its DSM/EE programs through the DSMAC. (Ex. APS-29 at 16; Tr. at 2436, 2552.)

b. AECC/Freeport

AECC/Freeport asserts that the Commission should remove the $20 million included in base rates for DSM program costs and require that all DSM costs be recovered through the DSMAC, to provide greater transparency to customers about the true costs of DSM/EE programs. (AECC Br. at 36; Ex. AECC-1 at 35; AECC-2 at 13.) AECC/Freeport asserts that because customers would have no way of knowing that $20 million is included in base rates unless they read the rate case order, they may mistakenly believe that all DSM costs are included in the DSMAC. (AECC Br. at 36; Ex. AECC-2 at 13.) AECC/Freeport denies that its proposal is based on Freeport's being exempted from the DSMAC

at its Bagdad mine site,[305] agreeing that Freeport is required to fund DSM/EE programs that it is no longer eligible to participate in, but asserting that its proposal is grounded in its belief that greater transparency benefits customers and public policy should err on the side of disclosure and transparency. (AECC Br. at 37; Ex. AECC-2 at 13.)

c. Other Parties

No other parties adopted AECC/Freeport's proposal.

d. APS Response

APS does not support AECC/Freeport's proposal that no DSM program costs should be recovered through base rates. (Ex. APS-29 at 16.)

e. Resolution

Although AECC/Freeport asserts that its desire to have $20 million in DSM costs currently recovered through base rates instead collected through the DSMAC, from which its Bagdad mine is exempted, is due to a desire for APS's customers to be able to see more easily how much APS's DSM programs actually cost, that assertion rings hollow. AECC/Freeport's proposal is nothing more than a shell game that could give APS's customers other than Freeport the false impression of cost savings. We conclude that it is not in the public interest to adopt AECC/Freeport's proposal.

3. Retaining LFCR Costs in LFCR; Modification to LFCR

a. APS Recovery Request

APS proposes to recalculate the rates under which new lost fixed costs would be tracked in the LFCR, but not to move the revenue related to lost fixed cost MWhs from January 2016 through June 2019 ($39.792 million) into base rates. (Ex. APS-28 at 3, 22.) APS proposes this to help ensure that the bill impacts customers experience on the effective date of rates set in this matter are consistent with the estimated bill impacts provided to customers for this rate case. (Ex. APS-28 at 3.) According to Mr. Snook, the transfer of the LFCR revenue into base rates in the 2016 Rate Case "led to some confusion about the characterization of the customer bill impacts that would occur on the initial reset

[305] In Decision No. 74813 (November 13, 2014), the Commission granted a Freeport request to be exempted from paying the DSMAC, for the Bagdad mine only, based on Freeport's having its own active DSM program at the Bagdad mine for which it historically budgeted approximately $10 million annually. (AECC/Freeport Br. at 36.) Official notice is taken of this decision.

of base rates," and APS wants to avoid a recurrence of that. (Ex. APS-28 at 21-22.) APS does not propose to make changes to the LFCR as currently approved.

b. WRA/SWEEP

WRA/SWEEP assert that APS should be required to zero out the LFCR because it is standard practice to zero out this type of mechanism in every rate case, and customer confusion is not a valid reason to avoid resetting the mechanism. (Ex. WRA-1 at 48.) Mr. Baatz testified that resetting a lost fixed cost recovery mechanism to zero in a rate case is standard practice and eliminates the potential for over recovery of authorized fixed costs because the billing determinants are also reset in the rate case. (Ex. WRA-1 at 48.) Mr. Baatz explained his rationale for requiring that the LFCR be reset to zero as follows: "The test year period of this rate case includes the fixed costs that are also included in the LFCR. Allowing cost recovery to continue on the LFCR while also setting rates based on a test year which includes lost sales from [DG] and [EE] is a scenario ripe for over recovery of costs." (Ex. WRA-2 at 20.) Mr. Baatz further stated that the issue was because rates are set in a rate case based on billing determinants from the TY, which includes the reduced sales from EE and DG for the TY, meaning that "the assumed 'lost revenues' are included in new rates." (Ex. WRA-1 at 49.) Mr. Baatz characterized APS's rationale for keeping revenues in the LFCR as "concern[] about a messaging issue" and suggested that APS should instead be concerned about "avoiding potential double recovery of costs." (Ex. WRA-1 at 49.)

WRA/SWEEP recommend that the Commission require an "earnings test" for the LFCR to continue,[306] so that APS would be required to submit documentation of "actual versus authorized revenues for the year in question" and would be precluded from recovering any LFCR revenues unless it showed that its revenues were deficient. (Ex. WRA-1 at 49.) Mr. Baatz asserted that this "would protect APS ratepayers from over recovery of revenues, which has been an issue in recent years." (Ex. WRA-1 at 49.) Mr. Baatz added that New Jersey Natural Gas is subject to an annual earnings test to recover its lost revenues that requires it to show that it did not earn more than its ROE in order to recover lost revenues from EE. (Ex. WRA-1 at 49.) Mr. Baatz dismissed APS's argument that an

[306] WRA/SWEEP also expressed a preference for a full revenue decoupling mechanism, characterizing the LFCR as "an inferior policy," and noted that SWEEP has advocated for full decoupling in APS's last few rate cases. (Ex. WRA-1 at 48.)

earnings test would undermine the intent of the LFCR, reasoning that the earnings test would not eliminate APS's ability to recover lost revenues but would set a limit on recovery by allowing APS to earn up to its authorized ROE. (Ex. WRA-2 at 21.) Mr. Baatz further asserted that the current LFCR gives APS an incentive to continue promoting higher usage while also allowing it to recover lost revenues from EE and DG, whereas the addition of an earnings test would discourage this. (Ex. WRA-2 at 21.) According to Mr. Baatz, the earnings test is a "customer protection mechanism." (Ex. WRA-2 at 21.)

c. Staff

Staff agrees with APS's proposal not to transfer the balance in the LFCR adjustor into base rates. (Ex. S-12 at 109; Ex. S-15 at 52-53.) Mr. Smith acknowledged the concerns raised after the 2016 Rate Case relating to the delayed reset of the LFCR and agreed that leaving the $39.792 million within the LFCR rather than transferring it into base rates should make it clearer what customers should expect to see when rates become effective and should help avoid confusion about bill impacts that occurred after the 2016 Rate Case. (Ex. S-12 at 109; Ex. S-15 at 52-53.)

d. Other Parties

Mr. Gayer asserts that the adjustor transfer never occurred in APS's 2016 Rate Case. (Ex. Gayer-4 at 1.)

e. APS Response

Mr. Snook testified that APS does not have a theoretical objection to transferring all of the unrecovered fixed costs in the LFCR to base rates, essentially zeroing out the LFCR as of the effective date of the rates approved in this matter, but that the mechanics are complicated, and the resulting bill impact would be difficult to explain to customers. (Ex. APS-28 at 13.) Mr. Snook opined that zeroing out the LFCR caused controversy in the 2016 Rate Case because the LFCR collects after the fact, and it caused confusion. (Tr. at 2434-2435.)

Mr. Snook testified that the LFCR recovers a portion of lost fixed costs[307] determined using actual observed reduced sales resulting from EE and DG programs and is intended to eliminate the

[307] Mr. Snook testified that the LFCR recovers 30-40% of lost fixed costs. (Tr. at 2440.)

disincentive that APS would otherwise have to engage in and support EE and DG, especially rooftop solar. (Ex. APS-28 at 13-14; Tr. at 2438-2439.) The LFCR was approved for APS in lieu of a full revenue decoupling mechanism that APS requested. (Tr. at 2438.) Additionally, Mr. Snook stated, there is already significant scrutiny of the proposed lost fixed costs, to ensure their validity, through a separate proceeding and evaluation concerning the LFCR. (Tr. at 2440.) Thus, he stated, adding an earnings test to the LFCR would undermine the intent behind it. (Ex. APS-28 at 14; Tr. at 2439-2440, 2443.) Mr. Snook maintained that the LFCR should not be subjected to an earnings test even under circumstances when APS was earning significantly more than its authorized ROE (12% versus an approved ROE of 10%). (Tr. at 2649-2651.) Under those circumstances, Mr. Snook stated, the Commission would have reason to require APS to come in for a rate case. (Tr. at 2650.) When asked how the Commission would know that APS was earning more than its authorized ROE, Mr. Snook stated that there could be a compliance filing and that if the AEM is approved, the earnings test proposed for the AEM would show the earnings level. (Tr. at 2650-2651.) Mr. Snook acknowledged that APS's annual reports would not provide all of the information needed to determine the earnings level, in part because APS provides total company information as well as jurisdictional APS information. (Tr. at 2651.)

In response to Mr. Gayer, Mr. Snook asserted that Decision No. 77292 expressly found that the adjustor transfer occurred in the 2016 Rate Case in accordance with the normal functioning of the adjustor mechanisms.[308] (Ex. APS-28 at 14.)

f. Resolution

The LFCR is a special ratemaking treatment that was created to minimize APS's disincentive to supporting EE programs and DG solar. Although the usual ratemaking treatment for adjustor mechanisms is to zero them out by including their revenues in the adjusted TY and resetting them to begin afresh with the effective date of new rates, APS and Staff have expressed concern that doing so

[308] Decision No. 77292 did not make any findings of fact or conclusions of law expressly addressing APS's transfer of revenue collection from adjustor mechanisms to base rates. Rather, the Commission found that "Ms. Champion and the Intervenors have not proven by a preponderance of the evidence that APS has not properly implemented the rates and charged approved in Decision No. 76295." (Decision No. 77292 at 88.) The Commission also concluded that "[t]he evidentiary record . . . does not establish by a preponderance of the evidence that APS has charged customers for service other than as authorized in Decision No. 76295. (*Id.* at 91.)

for the LFCR in this case could create customer consternation that the notice provided at the commencement of this rate case did not accurately portray the actual bill impacts. We note that the form of notice provided was caused by APS's decision, in its application, not to sweep the revenues from the LFCR into its TY revenues. Had APS followed the typical procedure and zeroed out the LFCR, there would be no cause for concern about resetting of the LFCR from a customer notice perspective. However, if the reset had been proposed by APS, it is likely that customers would have been even more concerned about APS's proposed rate increase than they have expressed in this rate case.

Recent history demonstrates that customer confusion and distress as a result of a bill increase is a valid concern, as customers hit with a significant adjustor increase (and additional rate increase) months after the initial rate increase established in the 2016 Rate Case voiced concerns that APS was overbilling them and generally did not understand the origin of the increases. We will discuss this further below, in relation to APS's adjustor mechanisms generally, but believe that such a reaction is not surprising because APS's customers can potentially experience rate increases every month from January 1 through June 1 due to its suite of adjustors.

Although WRA/SWEEP propose to have the amount currently in the LFCR swept into base rates, the record in this case elucidates neither the mechanics for doing this nor the impacts to APS's revenue requirement and bill impacts of doing this. What is certain, however, is that sweeping the LFCR revenues into base rates would result in an increased revenue requirement that would continue to exist until the conclusion of APS's next rate case, whenever that occurs. Because that additional revenue would not impact the calculations for the LFCR, without modifying the LFCR POA in an as-yet-unidentified manner, the sweep into base rates would not be in the best interest of ratepayers and will not be adopted.

However, because it is currently possible for APS to collect for lost fixed costs under the LFCR even when it is earning more than its authorized ROE, and the Commission would have no way of knowing that APS was earning more than its authorized ROE, we conclude that it is in the public interest to add an earnings test to the LFCR. For this purpose, we will adopt an earnings test similar to

the earnings test APS has included in its proposed AEM POA,[309] as follows:

- The requested increase to the LFCR adjustor rate will be dependent on an earnings test, which will compare the previous year's rate of return, unadjusted, with a threshold rate of return.
- The threshold rate of return will be the ROE authorized in the most recent rate case with an updated capital structure and cost of debt, consistent with the actual numbers from the previous year.
- The earnings test will be based on APS's FERC Form 1, using the previous year's costs, revenues, and other financial information, with certain pro forma adjustments made as appropriate based on APS's most recent rate case.[310]
- If the previous year's rate of return is higher than the threshold rate of return, the LFCR rate for the coming year will be set at zero.

4. REST and AZ Sun Costs in System Benefits Charge ("SBC")

a. APS Recovery Request

APS proposes to recover $6.0 million in REST costs and approximately $65.6 million in AZ Sun solar plant ("AZ Sun") costs through its SBC.[311] (Ex. APS-29 at 36; Ex. AECC-2 at 11-12.) The

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[309] *See* AEM POA at 3-4.

[310] This means that if a pro forma adjustment proposed by APS in its most recent rate case was not adopted by the Commission, the adjustment shall not be included in this calculation.

[311] The Commission provided the following background on the System Benefits Charge in Decision No. 75121 (June 25, 2015), of which official notice is taken:

> The System Benefits charges ("SBC") are a product of the Commission's attempts in the late 1990's to move toward retail electric competition and deregulation of certain portions of traditional electric service. The SBC is designed to be a charge paid by all electric service customers within a public utility corporation's service territory, regardless of whether the customer actually receives electric energy from the incumbent utility. The SBC is defined in A.A.C. Rl4-2-1601(41) as: "…Commission-approved utility low income, demand side management, Consumer Education, environmental, renewables, long-term public benefit research and development, and nuclear fuel disposal and nuclear power plant decommissioning programs, and other programs that may be approved by the Commission from time to time." The associated dollar amounts are allocated to each program but are collected from ratepayers through the SBC as a part of base rates, not as a separate surcharge. The allocation of costs to be collected through the SBC was established in APS's most recent rate case which was approved by the Commission in Decision No. 73183 (May 24, 2012).

Decision No. 75121 at 1-2.

The Commission further explained the costs included in APS's SBC as follows:

> APS's SBC is comprised of the following categories of costs: demand-side management (only the amount included in base rates, not the amount collected through the Demandside Management surcharge); Four Corners & Navajo Coal Reclamation; low-income discounts (related to Rate Schedules E-3 and E-4), renewable energy (only the amount included in

AZ Sun solar plant assets are APS-owned grid-scale solar facilities installed as part of approved renewable programs to achieve REST targets. (Ex. APS-29 at 36.) According to Mr. Snook, the AZ Sun assets were transferred to base rates "and were just categorized incorrectly" in the 2016 Rate Case. (Ex. APS-29 at 36.) APS proposes to correct this error in this case by moving those costs out of base rates and including them in its SBC. (Ex. APS-29 at 36.)

b. AECC/Freeport

Mr. Higgins testified that the $6.0 million in REST costs and $65.6 million in AZ Sun solar plant costs should be recovered through non-SBC generation base rates and not through the System Benefits cost category. (Ex. AECC-2 at 12; Ex. AECC-3 at 37.) Mr. Higgins asserted that these costs are related to generation and should be reflected in APS's unbundled generation charge, which should reflect APS's costs of providing generation service, rather than in the non-bypassable SBC. (Ex. AECC-3 at 37.) Mr. Higgins disagreed with APS's assertion that the AZ Sun solar plant costs were categorized incorrectly when they were transferred to base rates after the 2016 Rate Case. (Ex. AECC-3 at 37-38.) According to AECC/Freeport, allowing recovery of these costs through the SBC would "obfuscate[] the functionalization, allocation and recovery of these costs" and would undermine the Commission's policy of expanding buy-through programs (adopted in Decision No. 77043 (January 16, 2019)[312]) because buy-through customers cannot avoid paying the SBC, even though they do not purchase generation from APS. (AECC Br. at 38.) Mr. Higgins asserted that the recalculated SBC, with the DSM, REST, and AZ Sun components removed, would be reduced to $0.00131/kWh if calculated using the median ROE of 9.75% used by AECC/Freeport and that it would need to be changed further to reflect the COE approved in this matter. (Ex. AECC-2 at 15.)

c. Other Parties

No other party expressly adopted or opposed either APS's movement of the AZ Sun costs into the SBC or AECC/Freeport's arguments against it.

. . .

> base rates, not the amount collected through the Renewable Energy Standard Tariff), Palo Verde Nuclear Generating Station ("PVNGS") Decommissioning, and PVNGS Independent Spent Fuel Storage.

Decision No. 75121 at 2.

[312] Decision No. 77043 was admitted herein as Exhibit CS-3.

d. APS Response

Mr. Snook testified that all customers should pay for the AZ Sun assets, even if they do not purchase generation from APS.[313] (Ex. APS-29 at 36; Tr. at 2518.) He further opined that the reason AECC/Freeport disagrees is because AG-X customers must pay the SBC but not the unbundled generation charge. (Ex. APS-29 at 36; Tr. at 2526-2526.) Mr. Snook testified that the concept of system benefits is that every customer should contribute, as the costs included are related to public policy requirements. (Tr. at 2527-2528.)

e. Resolution

Created in the Commission's Retail Electric Competition rules, the SBC was designed expressly to recover from all customers, regardless of energy usage, the costs resulting from specific public policy-related decisions made by the Commission (e.g., approval of limited income programs, DSM programs, and renewables). The AZ Sun costs, incurred to meet REST requirements, fall within the purview of the SBC and are appropriately collected through the SBC. AECC/Freeport's position will not be adopted.

N. Property Tax Deferral

a. APS Recovery Request

In the 2011 Rate Case, APS obtained approval for a property tax expense deferral, and the deferral was permitted to continue in the 2016 Rate Case. (Ex. AECC-1 at 39; Tr. at 1515.) APS proposes in this matter for the deferral to be continued to allow future recovery/credit of 100% of all changes to Arizona property tax expense above or below the adjusted TY level of $177 million to the extent that the changes are caused by changes in the applicable Arizona composite property tax rate (as opposed to changes in the assessed value of APS's property). (Ex. APS-12 at 28, 42.) The 2016 Rate Case approved settlement agreement required that the property tax deferral not accrue interest during the deferral period, unless the balance was negative, in which case interest would accrue at APS's short-term debt rate. (Ex. APS-12 at 28.) The settlement agreement further provided that beginning with the effective date of the Commission's decision in APS's next general rate case, any positive

[313] Mr. Snook believes that AG-X customers do purchase generation capacity from APS to ensure resource adequacy. (Tr. at 2518.)

balance would be recovered over 10 years, with a return at APS's short-term debt rate and also with a return on any unrefunded negative balance at the same short-term debt rate. (Ex. APS-12 at 28.) APS asserts that the deferral will be done in accordance with the provisions of Accounting Standards Codification ("ASC") 980, formerly known as FAS No. 71. (Ex. APS-12 at 42.) APS intends to track and record for the deferral as it does for the deferral approved in the 2016 Rate Case and, in its next rate case, to request recovery of any positive balance from customers over 10 years and to refund any negative balance to customers over three years. (Ex. APS-12 at 42.) In this matter, APS included a reduction to TY rate base of $6.1 million for the property tax amounts deferred from July 1, 2019, through December 31, 2020, along with a corresponding decrease to operating expenses of $4.2 million, and indicated that the deferred amount would be amortized over three years as a refund to customers. (Ex. APS-13 at 19, att. EAB-3RB, att. EAB-4RB.)

b. AECC/Freeport

AECC/Freeport asserts that APS's request for a deferral mechanism for property tax expense is "unwarranted single-issue ratemaking" and should be rejected because it was produced as a result of the many tradeoffs represented in settlement agreements and "does not warrant adoption on its own merit." (Ex. AECC-1 at 38-39; AECC Br. at 38-39; Ex. AECC-3 at 38.) According to Mr. Higgins, the property tax deferral is single-issue ratemaking because it allows for deferral for a change in a single cost item considered in isolation, without consideration of the many other factors that influence rates and that could move APS's rates in the opposite direction. (Ex. AECC-1 at 38.) Mr. Higgins asserts that single-issue ratemaking generally is not sound regulatory practice unless there is a compelling public interest, and that "[r]atemaking is not intended to be a simple exercise in expense reimbursement." (Ex. AECC-1 at 39.) Mr. Higgins asserts that APS should be able to handle normal business risks and economic forces and should not be insulated from those through this deferral. (Ex. AECC-1 at 39.)

Additionally, AECC/Freeport agrees with Mr. Smith's testimony that APS has not provided sufficient evidence to warrant continuing the property tax deferral mechanism, which was approved through settlement. (AECC Br. at 39.)

. . .

c. Staff

Staff recommends denial of the property tax deferral in this case,. (Ex. S-12 at 103; Ex. S-15 at 43-44.) Mr. Smith testified that the prior property tax deferrals were the result of settlement agreements and that APS has not demonstrated that continuing the deferral is necessary. (Ex. S-15 at 44.)

d. Other Parties

Other parties did not expressly take a position on APS's request for continuation of its property tax deferral mechanism.

e. APS Response

Ms. Blankenship testified that property taxes can fluctuate significantly from year to year and are outside of APS's control, making it necessary to have a mechanism to allow for future recovery/refund when property tax rates change. (Ex. APS-13 at 19.) Ms. Blankenship stated that allowing the deferral does not impact rates in this case and does not guarantee recovery in a future rate case; it just preserves APS's ability to recover/refund the costs if the Commission finds them to be reasonable and prudent in the future rate case. (Ex. APS-13 at 19-20; Tr. at 1476.) Additionally, Ms. Blankenship stated, discontinuation of the property tax deferral could negatively impact customers because APS would not be able to refund customers savings from decreased property tax rates, as it is able to do in this case. (Ex. APS-14 at 15.) Ms. Blankenship estimated that APS was refunding approximately $10.5 million to customers through its rate base reduction, when interest at APS's short-term debt rate is included. (Ex. APS-14 at 15.) Under normal ratemaking, in the absence of the deferral mechanism, APS would have retained the savings from the reduced property tax rates occurring outside of a TY. (Tr. at 1556-1557.) Ms. Blankenship acknowledged that APS would not have earned any return on property tax expense that is not deferred, as it would simply be treated as an operating expense. (Tr. at 1557-1558.)

APS does not agree that the property tax deferral mechanism represents single-issue ratemaking. (Tr. at 1516.)

f. Resolution

No evidence has been presented demonstrating that property tax rates are expected to fluctuate

greatly in the foreseeable future, in either direction. Nor has evidence been presented that they have fluctuated greatly in the past. In the absence of demonstrated volatility in property tax rates, there is no justification for the special ratemaking treatment that a continued deferral represents. The record does not establish that continuation of the property tax deferral mechanism is in the public interest, and it will be denied.

O. Cost of Service – Allocation of Costs

Mr. Snook testified that APS conducted an embedded cost of service study ("COSS") using data from the TY by grouping the expense and rate base items that comprise APS's costs into major categories (such as PIS or O&M expense); functionalizing each cost to production, transmission,[314] distribution, or customer service; classifying each cost as energy, demand, or customer, based on what drives the magnitude of the cost (amount of kWh consumed, the rate at which energy is consumed/kW capacity, or the number of customers taking service, respectively); and allocating the functionalized and classified costs to particular jurisdictions, customer classes, and rate schedules or subclasses using allocation factors such as class coincident peak ("CP"), class non-coincident peak ("NCP"), the sum of individual peaks, energy, or number of customers. (Ex. APS-28 at 7-10.)

The COSS allocates only the base rate portion of the cost to serve, not the revenues and expenses from adjustors. (Ex. APS-28 at 13.) Additionally, because APS makes some sales to parties that are not traditional retail customers, and those sales exceed the incremental costs of the service provided, APS allocates the revenues from those transactions to all customers through a revenue credit that lowers the amount of retail customers' overall revenue requirements. (Ex. APS-28 at 12.)

According to APS, its COSS demonstrated that APS's rates recovered 94% of APS's jurisdictional costs as a whole and had a relative rate of return ("RROR")[315] for the TY of 1.1. (Ex. APS-28 at 14, att. LRS-3DR). The COSS further showed that the classes/subclasses below had the

[314] APS directly assigned transmission costs to the non-ACC jurisdictional portion of the COSS but then brought back a portion of transmission costs to offset the revenues from the Open Access Transmission Tariff, which Mr. Snook stated ensures that there is no double-counting of transmission costs and that each customer class pays toward transmission service costs. (Ex. APS-28 at 11-12.) To address the "mismatch" between the transmission costs solar and non-solar residential customers pay on their bills, however, APS reallocated the direct assigned cost responsibility to residential customers using each residential subclass's 4CP. (Ex. APS-28 at 12 n.2.)

[315] The RROR standardizes class-specific RORs to the overall system average ROR. (Ex. S-5 at 24.) A RROR of 1.0 signifies that a customer class is producing revenues matching its cost of service, while a lower or higher RROR signifies under-production or over-production of revenue, respectively. (*Id.* at 25.)

following RRORs for the TY:[316]

Residential						
Group	**Total Residential Class**	**R-XS**	**R-Basic**	**R-Basic Large**	**TOU-E**	**R-2 & R-3 (Combined)**
TY	0.65	0.51	0.39	0.61	1.06	0.83

Residential Solar				
Group	**Legacy Solar (Energy)**	**Legacy Solar (Demand)**	**R-Solar TOU**	**R-Solar (Demand)**
TY	(0.87)	0.52	0.6	0.9

General Service						
Group	**Total General Service**	**E-20 (Church Rate)**	**E-32 TOU XS**	**E-32 TOU S**	**E-32 TOU M**	**E-32 TOU L**
TY	1.66	(0.14)	3.00	3.27	2.57	1.37
General Service						
Group	**E-30 & E-32 XS (Combined)**	**E-32 S**	**E-32 M**	**E-32 L**	**AG-X**	**GS-Schools M & L (Combined)**
TY	2.29	2.03	1.94	0.94	0.79	1.24

1. Allocation of Production Costs

a. APS Position

Per Mr. Snook, because most production-related assets are designed and built to enable APS to meet its system peak load, APS allocates these costs to each jurisdiction based on the average of system peak demands occurring in the four summer months (June, July, August, and September) (i.e., "4CP"). (Ex. APS-28 at 10.) Mr. Snook testified that this is consistent with the requirements for allocation of production costs in FERC rate cases, has been accepted by the Commission for many years, and ensures that the right proportion of costs is allocated to each jurisdiction. (Ex. APS-28 at 10.)

For the COSS, APS allocated production costs to jurisdictional customer classes using the

[316] Ex. S-5 at ex. DED-3; *see* Ex. APS-28 at 14, att. LRS-3DR. The COSS includes additional subclasses. APS provided three revised COSS models during discovery, and the numbers reflected here, other than for R-Solar, are understood to have come from one of APS's revised COSS models. (*See* Ex. AECC-2 at 5-7.) The revised COSS models were not offered as exhibits.

Average and Excess Demand ("A&E") method, the use of which was required by the Commission in Decision No. 69663. (Ex. APS-28 at 11.) The A&E uses two measures of demand: (1) Average Demand, which is derived from a class's average hourly demand for each hour of the year; and (2) Excess Demand, which is derived from the amount of a class's NCP demand that exceeds the class's Average Demand. (Ex. APS-29 at 28.) Mr. Snook stated that Average Demand is considered to show the base level of demand driving the costs for baseload power plants, and Excess Demand is considered to show what is driving the costs for peaking power plants. (Ex. APS-29 at 28.) Under the A&E method, costs are allocated to each class based on its proportionate share of the sum of NCP Excess Demands. (Ex. APS-28 at 11.) For the residential class, APS reallocated the total residential costs for production demand to subclasses based on the subclasses' contributions to the system coincident peak over the 4CP (as contemplated by § 12.2 of the Settlement Agreement approved in the 2016 Rate Case). (Ex. APS-28 at 11.)

b. AECC/Freeport

AECC/Freeport supports APS's use of the 4CP method to allocate jurisdictional production demand costs because APS's maximum system demands are driven by summer usage, and APS uses the 4CP method in its FERC rate cases. (Ex. AECC-2 at 9.)

AECC/Freeport also supports APS's use of the A&E method to allocate production demand costs across its retail customer classes. (Ex. AECC-2 at 9.) Mr. Higgins noted that APS used the A&E method for that purpose in its last three rate cases and that it was adopted in response to Commission direction in Decision No. 69663. (Ex. AECC-2 at 9.) Further, Mr. Higgins observed, the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual (January 1992) ("NARUC Manual") states that the A&E method "effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor." (Ex. AECC-2 at 10 (quoting NARUC Manual at 49).) Mr. Higgins added that the A&E method properly allocates the incremental production plant needed to meet loads above average demand to the classes who create the need for the additional capacity. (Ex. AECC-2 at 10.)

AECC/Freeport opposes Staff's position that the Average and Peak ("A&P") method should be

used to allocate production costs, asserting both that the Commission rejected the A&P method in the 2005 Rate Case and that, as performed by Dr. Dismukes, the A&P method is biased against customers with higher load factors and inconsistent with the NARUC Manual. (Ex. AECC-3 at 40-42, 44-46.) Mr. Higgins noted Staff's support for the A&E method to allocate production costs in the 2011 Rate Case, the 2016 Rate Case, and multiple rate cases involving other utilities. (Ex. AECC-3 at 42-43.) According to Mr. Higgins, Dr. Dismukes's A&P method is inconsistent with the NARUC Manual because neither of the two A&P variants included in the NARUC Manual weights the energy component in the manner that Dr. Dismukes did, and both variants would result in less of a cost shift from classes with lower load factors to classes with higher load factors than Dr. Dismukes's method did. (Ex. AECC-3 at 44-46.) Mr. Higgins stated that Dr. Dismukes's method used an inappropriate "mix and match" of the energy and demand weightings between the A&E and A&P methods. (Ex. AECC-3 at 46.)

Mr. Higgins compared use of the A&E method and Dr. Dismukes's A&P method using a hypothetical utility with two customer classes that have the same average demand—one that has flat class usage all year, and one that has peaky usage, increasing significantly in April-May and September-October, increasing further in June and August, and peaking in July. (Ex. AECC-3 at 47.) Mr. Higgins stated that the A&P method allocates each class 50% of the responsibility for the energy (average demand) portion of costs and then allocates the costs for the incremental capacity (above system average demand) proportionately based on each class's share of total demand during the peak month of July. (Ex. AECC-3 at 47-48.) According to Mr. Higgins, this is inappropriate and represents a double-weighting of the average demand because the average demand has already been fully allocated in the first allocation. (Ex. AECC-3 at 48.) Mr. Higgins asserted that other state utility regulators have rejected the A&P method and instead approved use of the A&E method based on their conclusions that the A&P method results in double-weighting of average usage.[317] (See Ex. AECC-3 at 49-50.) Mr. Higgins dismissed as "flawed" Dr. Dismukes's position that the double-weighting arguments are faulty, asserting that the A&E method considers the average demand of all classes, not just high-load factor

[317] Mr. Higgins cited a 2011 rate case for Interstate Power and Light Company before the Iowa Department of Commerce Utilities Board and a 2010 rate case for AmerenUE before the Missouri Public Service Commission. (Ex. AECC-3 at 49-50.)

classes, and that both the A&E method and A&P method assign each customer class a consistent percentage of production plant costs for all baseload and peaking plants. (Ex. AECC-3 at 50-52.) Mr. Higgins also stated that "Dr. Dismukes conflates the assignment of fixed production plant with the assignment of variable production O&M costs, which includes the cost of fuel," because APS used the A&E method to allocate production plant but used energy allocators to allocate fuel costs. (Ex. AECC-3 at 52.) Further, Mr. Higgins disagreed with Dr. Dismukes's testimony that the A&E method uses the NCP to measure excess demand to avoid a known computational problem, asserting that the A&E uses the NCP by design to ensure that no class is a "free rider" when it comes to sharing cost responsibility for production plant, which could occur if 1CP were used instead. (Ex. AECC-3 at 53.)

Mr. Higgins generally agreed with Mr. Snook's justification for using the A&E method, but disagreed with Mr. Snook's statement that using the A&E versus the A&P 4CP is insignificant, pointing out that Dr. Dismukes reported that his A&P 4CP method would shift $58.7 million of the revenue requirement to the general service classes. (Ex. AECC-3 at 54-55.)

c. ASBA/AASBO

ASBA/AASBO disagreed with APS's use of the A&E method to allocate production demand costs, asserting that it was "disproportionately disadvantageous" to the schools class because the method has no weighting for customer class contribution to APS system peaks. (Ex. ASBA-3 at 8.) Mr. Sarver compared the class CP demand to the A&E allocated demand and the class NCP to the A&E allocated demand for the general service classes and determined that while the A&E allocated demand and the class NCP were tightly correlated across the board, and the A&E allocated demand and the class CP were nearly as highly correlated for the other general service classes, the correlations were not high for the School TOU class and the E-20 Church class.[318] (Ex. ASBA-3 at 8-10.) According to Mr. Sarver, this shows that most of the general service classes peak around the same time as the system peak, but that the School TOU class and the Church class contribute significantly less to the system peak. (Ex. ASBA-3 at 11.) The problem with the allocation method based on NCP, Mr. Sarver stated, is that it treats class peak demand the same regardless of when the peak occurs, weighing

[318] The data also showed that the three general service classes with the least correlation were also the classes that had the lowest NCP load factors. (*See* Ex. ASBA-3 at 10.)

equally a customer class that peaks at 2 p.m. on a Monday afternoon or at 8 a.m. on a Sunday morning with a customer class that peaks at the system peak. (Ex. ASBA-3 at 11.) Mr. Sarver asserted that as a result, APS has allocated production demand costs for the School TOU class and Church class 40% higher than their actual class demands during system peak. (Ex. ASBA-3 at 11-12.) Mr. Sarver asserted that this is unfair and that Dr. Dismukes's A&P 4CP allocation method would more accurately allocate costs to the classes who contribute to system peak without penalizing classes that avoid peaking during system peak. (Ex. ASBA-3 at 12.) Mr. Sarver testified that if the A&P 4CP method were adopted, the Schools TOU class would have a lower production demand revenue requirement in the COSS and a lower target revenue, and that the lower target revenue should be used to reduce the School TOU energy and demand rates and to replace the shoulder period rates with off-peak rates. (Ex. ASBA-3 at 12-13.)

d. FEA

FEA agrees with and recommends approval of APS's use of the A&E 1 NCP method for allocating retail fixed production costs, asserting that it appropriately allocates the additional capacity requirements on the system, as measured by system excess, in proportion to the "peakiness" of customer classes because customer classes with greater maximum demand impose greater costs on APS's system. (Ex. FEA-3 at 6-8.) Ms. Alderson testified that fixed plant production costs (those that do not vary with changes in energy output during a period, such as initial capital outlay for construction, return on investment cost, depreciation expense, taxes, purchased capacity costs, and some O&M) should be allocated primarily on the basis of class contribution to peak demands, while variable production costs (those that fluctuate based on the amount of energy generated or purchased during a period, such as fuel expense, purchased power expense, most O&M expenses, and emissions control expenses) should be allocated on the basis of class energy consumption over the TY period. (Ex. FEA-3 at 8-9.)

Ms. Alderson disagreed with APS's allocation of certain purchased power costs solely on the basis of energy consumption and recommended adjusting the COSS to allocate them using the A&E 1CP method. (Ex. FEA-3 at 9-10.) Specifically, Ms. Alderson stated, APS had a total of $323.2 million in PPA expense for the TY (not including market purchases passed through to AG-X customers), $67.8

million of which represented fixed capacity payments for non-renewable purchased capacity. (Ex. FEA-3 at 10.) Ms. Alderson asserted that because these costs were incurred to meet peak demand, they should be allocated using the A&E 1 NCP method just like other fixed production costs. (Ex. FEA-3 at 10.) Ms. Alderson asserted that APS also included $172.0 million in TY purchased power expense for 500 MW (nameplate) of renewable power and capacity, a portion of which should also be classified and allocated on a demand basis because it is used to meet peak demand and reserve capacity needs. (Ex. FEA-3 at 2, 10.) Because APS counted 397 MW of the 500 MW renewable capacity toward its 2019 capital reserve margin, Ms. Alderson asserted, that portion was used to meet peak demand. (Ex. FEA-3 at 10-13.) Ms. Alderson estimated the total value for the 397 MW (on a revenue requirement basis) at $57 million using the avoided cost of building new market capacity and recommended that the $57 million be allocated using the A&E 1 NCP method, like other production demand costs, rather than allocated like fuel and purchased power energy needed to meet system energy load. (Ex. FEA-3 at 2-3, 9-13.) Ms. Alderson modified APS's COSS to show the impact of the $57 million allocation and concluded, *inter alia*, that the residential class was covering 84.4% of its costs while the general service class was covering 108.2% of its costs, that the residential class should have a 17.8% rate increase, and that the general service class should have an 8.4% rate decrease. (Ex. FEA-3 at 14, att. AMA-2DR.)

Ms. Alderson agreed with Mr. Snook's statement that Staff has not provided sufficient support in this case to justify moving away from the longstanding and widely approved A&E allocation methodology, which the Commission has approved without objection in the last three APS rate cases and for both TEP and UNSE. (Ex. FEA-4 at 8.) Ms. Alderson asserted that there is insufficient evidence of record to justify the Commission's finding that the A&P method is more reasonable than the A&E method, pointing out that it has rejected the A&P method in the past, and further asserted that Staff's A&P proposal should be rejected because Staff has not justified the discrepancy between its position in this case and its recent contrary positions in other cases. (Ex. FEA-4 at 5-6, att. AMA-1SR.)

. . .

. . .

e. Kroger

Kroger[319] asserted that APS's use of the A&E method to allocate production demand costs to retail classes was reasonable, although it would have been more appropriate for APS to use the same 4CP demand allocation method that APS used to allocate jurisdictional production demand costs. (Ex. Kroger-1 at 12.)

f. Staff

Staff disagrees with APS's use of the A&E NCP method to allocate production plant costs, asserting that APS should instead use an A&P-4CP allocation method. (Ex. S-5 at 18.) Dr. Dismukes testified that the largest controversy over cost of service often arises concerning whether costs are to be recovered based on the relative size of a customer class and the peak load contributions of a customer class and how the approach should consider the use of customer, peak, and off-peak usage. (Ex. S-5 at 7.) Dr. Dismukes stated that methods that skew heavily toward customer and peak considerations tend to shift costs "more than proportionally" to lower load-factor customers and "can fail to capture the service being provided by the utility . . . and how the value of that service varies by the amount purchased by different customer classes." (Ex. S-5 at 7-8.)

Dr. Dismukes stated that the A&P and A&E cost allocation methods both involve developing an energy and demand component and then combining them using a weighted average based on system load factor, meaning that both are intended to reflect both the energy and demand functions of production plant. (Ex. S-5 at 12.) But, Dr. Dismukes asserted, the A&E method places more emphasis on a rate class's demand contribution and less emphasis on the rate class's energy usage, because the A&E method values a class's peak demand ("excess") relative to the class's average demand, which exaggerates the effect of the class's load factor. (Ex. S-5 at 12.) Thus, Dr. Dismukes stated, high load factor customers typically prefer the A&E method while residential and small commercial customers typically prefer the A&P method. (Ex. S-5 at 12.)

Dr. Dismukes stated that the arguments about double-weighting of the energy component with the A&P "are incorrect because they conflate the concepts of energy and demand and the roles each of

[319] Kroger has 49 stores in APS's service area that operate under the "Fry's" name and consume more than 100 million kWh per year. (Ex. Kroger-1 at 5.) Kroger takes service on E-32 M and E-32 L and is a major participant in AG-X. (Ex. Kroger-1 at 6.)

these play in utility system planning." (Ex. S-5 at 13.) Further, Dr. Dismukes stated, they are "faulty since they effectively presume that utilities design systems to first meet the needs of baseload customers and only later develop resources dedicated to customers that have peaking requirements[, whereas in] reality, demand and energy reflect separate and differing utility planning parameters." (Ex. S-5 at 13.) Dr. Dismukes testified that a utility needs to ensure both that it has enough generating capacity to meet its system peak and that the nature of the generation resources are such that it can "ensure least-cost dispatch." (Ex. S-5 at 14.) Dr. Dismukes stated that the "logical error" of the A&E method can be seen with a customer class that has a 100% load factor, because it would be assigned an excess demand component of zero, meaning that it would be considered to have no peak demand requirements even though it was using system resources at all times, including during peak system demand periods. (Ex. S-5 at 14.) The A&P method would assign the 100% load factor customer class some peak demand requirement, to reflect that such a customer class consumes electricity during system peak load periods, "correctly view[ing] all customers as having both energy and demand requirements." (Ex. S-5 at 14.)

Dr. Dismukes also expressed concern about the A&E method because if it is used with a CP measure rather than an NCP measure, its results are the same as the results from a general 1 CP allocation factor, which Dr. Dismukes stated negates the hybrid demand-energy nature of the A&E method.[320] (Ex. S-5 at 14-15.) Dr. Dismukes stated that the NARUC Manual suggests using the NCP to allocate excess demands to fix this issue with the A&E method and acknowledged that APS did use NCP for its demand measure. (Ex. S-5 at 15.) Dr. Dismukes asserted, however, that it is inappropriate to use the NCP as a measure of peak demand to allocate costs for production plant because the NCP assumes a low level of load diversity and thus amplifies customer peak demand requirements. (Ex. S-5 at 16.) Dr. Dismukes stated that it is appropriate to use NCP for distribution plant allocation, because distribution facilities serve isolated segments of a system, but not to allocate electric generation units that serve regional system demands with high load diversity. (Ex. S-5 at 16.) Dr. Dismukes opined that APS has high load diversity on its system, based upon a 2016 load profile analysis of residential

[320] Dr. Dismukes referred to this as an "observed computational problem inherent in the A&E method" and suggested that using the NCP in the A&E method "represents an attempt to work around a known computational problem by using an inappropriate measure of demand that is inconsistent with the capacity concerns [electric generation units] are designed and operated to address." (Ex. S-5 at 16.)

customers that found five separate generalized load profiles, with one ("Weekday Evening Peakers") representing a plurality of residential customers, but 58% of residential customers not falling into that load profile, and the presence of DG systems also has an impact on customers' load profiles. (Ex. S-5 at 17-18.) According to Dr. Dismukes, plant designed to meet broader system-wide peak demands should be allocated using CP-based measures, while plant designed to meet localized peak demand should be allocated using NCP demand measures. (Ex. S-5 at 18.)

Dr. Dismukes recommended that the Commission adopt an A&P-4CP allocation method for allocation of APS's production plant costs, which he stated would result in a "fair and reasonable approximation of the relative COS." (Ex. S-5 at 18.) Dr. Dismukes's recalculation of class revenue responsibilities using the A&P-4CP method for production plant costs resulted in a determination that residential customers are covering more of their costs, and general service customers are covering less of their costs, than reflected in APS's COSS. (See Ex. S-5 at 18-19, ex. DED-1; Ex. APS-28 at att. LRS-3DR.)

g. APS Response

While Mr. Snook conceded that there is often more than one valid cost-allocation method that could be used, he stated that the allocation methods APS uses are valid, widely used in the industry, and have historically been accepted by the Commission. (Ex. APS-29 at 27.) Further, he opined that cost allocation methods should not be changed absent a compelling reason because using the same methods over time supports consistent rate design and customer impacts. (Ex. APS-29 at 27.)

Mr. Snook acknowledged the validity of Ms. Alderson's position that some production demand costs are embedded in PPAs and thus allocated as energy costs in the COSS and should instead be reclassified as production demand-related costs and allocated using the A&E method, but stated that it was "perhaps largely theoretical" because there are minimal capacity costs inherent in purchased power costs. (Ex. APS-29 at 30.) Mr. Snook urged the Commission to direct APS to evaluate this in the COSS for its next rate case, both because APS has recommended a proportional allocation of revenue increase in this case (and thus is not truly using its COSS results to set rates) and because the change would result in only a $5-6 million difference in this case. (Ex. APS-29 at 30; Tr. at 2337.)

Mr. Snook disagreed with Dr. Dismukes's recommendation to use an Average and Peak

("A&P") method with four coincident peak months (June-September) ("A&P-4CP") rather than the A&E method, stating that Staff has never before raised the issue and that AECC/Freeport, FEA, and Kroger all support use of the A&E method. (Ex. APS-29 at 28.) He also noted that the A&E method has been used without objection in the last three APS rate cases and is currently used by TEP/UNSE and asserted that using the A&P-4CP method would not result in significantly different COSS results. (Ex. APS-29 at 29-30.) In response to Dr. Dismukes's criticism of APS's A&E method because it uses NCP information rather than CP information to allocate Excess Demand costs, Mr. Snook stated that the class NCP must be used to allocate the Excess Demand component because if class CP information is used instead, the allocator becomes purely a 1 CP allocator and does not reflect both demand and energy information. (Ex. APS-29 at 29.)

h. Resolution

APS is a summer-peaking utility, and a large portion of its production costs are attributable to peak demand. Accordingly, an equitable method of allocating production costs will recognize causation of the peak demand. Both the A&E and A&P methods are reasonable alternatives for allocation of peak demand costs. However, based on the evidence presented in this case, we find that the A&P method more equitably allocates peak production costs due to its emphasis on CP compared to the focus of the A&E method on NCP. We find that the A&E method disproportionately allocates production costs to customers with lower load profiles, as the NCPs of lower load profile customer classes do not approach the system peak demand capacity during CP. The A&E method overstates costs for Church customers and School customers and likely overstates costs for residential customers (to the extent their class NCPs do not occur during the CP). Thus, we find that the A&E method used by APS to allocate production costs does not reflect the most equitable method for sharing of peak production costs. We conclude that Staff's recommended A&P-4CP allocation method for production costs more appropriately reflects the actual contributions each class of customers makes to system peak demand and should be used instead of APS's A&E method. We recognize that it is a departure from prior Commission decisions but believe that the change is justified because APS's production needs are largely driven by its summertime system peaks, and it is incontrovertible that customers with high load factors consume a significant amount of energy during system peak hours and contribute

significantly to peak demand.

Additionally, we conclude that Ms. Alderson's issue about the classification of PPA costs wholly as energy-related costs is valid and that APS shall, for its next rate case, determine the extent to which production demand costs are embedded in its PPAs and reclassify that portion of the PPA cost as production demand-related rather than energy-related.

2. Allocation of Distribution Costs

Distribution costs include cost components associated with construction, maintenance, and operation of the local power grid, including substations, the primary lines delivering power from substations to customer transformers, and secondary equipment that includes customer transformers and the service drop to the home as well as certain other point-of-delivery equipment (not including meters). (Ex. APS-29 at 31, 34.)

a. APS Position

Because distribution plant is generally designed to meet a customer class's peak load, APS allocated the costs related to distribution substations and primary distribution lines based on NCP loads. (Ex. APS-28 at 12.) Because APS sizes secondary distribution equipment based on the kW power demands of a home or a group of homes, APS allocated those costs using the sum of individual peak loads or demand of all customers within a customer class (Sum of Individual Max or "SIM")). (Ex. APS-28 at 12; Ex. APS-29 at 34.) The SIM allocator adds the individual peak demands for each customer each month, regardless of the date and time they occur. (Ex. APS-29 at 34.) Per Mr. Snook, APS has used these allocation methods for many years, and they have been accepted by the Commission. (Ex. APS-28 at 12.)

b. AECC/Freeport

AECC/Freeport supports APS's use of the SIM allocator for secondary distribution costs. Mr. Higgins disagreed with Dr. Dismukes's position that secondary distribution equipment costs should be allocated using the NCP allocator rather than the SIM allocator, asserting that this would "exacerbate" the existing bias in APS's COSS that shifts costs away from customer classes with high numbers of

customers and that exists because no portion of distribution plant accounts 364 through 368[321] are allocated as customer related, although a significant portion of the investment in these accounts is primarily related to customer numbers. (Ex. AECC-3 at 39, 56, 58.) Mr. Higgins agreed with Mr. Snook's response to Dr. Dismukes's argument, asserting that diversity is not a valid reason to use the NCP allocator for secondary distribution costs because while diversity reduces the combined costs for substation and primary distribution equipment, it does not reduce the costs of secondary distribution equipment, which is sized to serve individual homes and cannot be shared despite load diversity. (Ex. AECC-3 at 55-56.) Mr. Higgins also supported the positions of FEA and APS that APS should be required to perform a comprehensive assessment of customer-related distribution costs in its next rate case, suggesting that the assessment could include either a Minimum Distribution System study as proposed by Ms. Alderson or an alternative investigation as proposed by Mr. Snook. (Ex. AECC-2 at 39; Ex. AECC-3 at 56-57.)

c. ASBA/AASBO

ASBA/AASBO supports APS's determination and allocation of both primary and secondary distribution costs as reasonable. (Ex. ASBA-3 at 8.)

d. FEA

FEA disagrees with APS's classification of all distribution-related equipment other than meters as 100% demand-related. (Ex. FEA-3 at 14.) Ms. Alderson asserted that classifying all retail distribution-related equipment based only on demand is flawed because certain distribution plant assets ("the minimum system") should be classified as customer-related. (Ex. FEA-3 at 3, 14-15-17.) According to Ms. Alderson, the minimum system is that portion of total distribution cost that a utility must incur to render service to customers, irrespective of those customers' demands. (Ex. FEA-3 at 17.) Ms. Alderson pointed out that the NARUC Manual clearly shows that the distribution assets in FERC accounts 360, 361, and 364 through 368 are properly classified as both customer- and demand-related costs. (Ex. FEA-3 at 15-16 (citing NARUC Manual at Table 6-1).) Because APS has not performed a Minimum Distribution Study or Zero-Intercept Method analysis to determine what

[321] These accounts are for poles and towers, underground and overhead lines, and transformers. (Ex. AECC-3 at 56.)

distribution-related equipment should be classified as customer-related and did not provide sufficient data for FEA to determine it either, Ms. Alderson recommended that the Commission require at least 30% of the distribution plant costs in FERC Accounts 364-368[322] to be classified as customer-related, based on Ms. Alderson's analysis of the average allocations used by other utilities. (Ex. FEA-3 at 3, 18-20, att. AMA-3DR.) Ms. Alderson further recommended that APS be required to conduct a Minimum Distribution Study or similar analysis and, in its next base rate case, to file a COSS that uses the resulting customer classification.[323] (Ex. FEA-3 at 19.) Ms. Alderson modified APS's COSS to show this 30% customer-related classification and concluded, *inter alia*, that the residential class was covering 83.9% of its costs while the general service class was covering 109.2% of its costs and that the residential class should have an 18.5% rate increase while the general service class should have a 9.3% rate decrease. (Ex. FEA-3 at 20-21, att. AMA-4DR.) Ms. Alderson further modified APS's COSS to reflect her recommendations for both production costs and distribution costs and concluded that the residential class was covering 83.4% of its costs while the general service class was covering 110.1% of its costs and that the residential class should have a 19.1% rate increase while the general service class should have a 10% rate decrease. (Ex. FEA-2 at 22, att. AMA-5DR.) Ms. Alderson's modified COSS, reflecting all of FEA's recommendations, produced the following RRORs for APS and the residential and general service classes:[324]

Group	Total ACC Jurisdiction	Total Residential	Total General Service
TY	1.1	0.7	2.0

e. WRA/SWEEP

WRA/SWEEP do not agree with APS's customer-related cost allocation, asserting that APS has used too broad a definition of customer-related costs, based on WRA/SWEEP's concern that APS's

[322] These FERC Accounts include the costs of poles and towers, underground and overhead lines, and transformers. (Alderson Dir. at 15)

[323] Ms. Alderson specified that APS should be required to present the results of the study in a manner that would allow intervenors to review the inputs, outputs, and study methods used and to use the data in any adjustments to the COSS. (Ex. FEA-3 at 19.)

[324] Ex. FEA-3 at att. AMA-5DR. Ms. Alderson also included figures for Total Water Rates, Total Street Lighting, and Total Dusk to Dawn. (*Id.*)

proposed basic service charges were inflated. (Ex. WRA-1 at 28.) Mr. Baatz testified that customer-related costs typically include the meter, service drop, and billing/collection costs—"operating and capital costs found to vary with the number of customers regardless, or almost regardless, of power consumption." (Ex. WRA-1 at 28 (quoting Bonbright at 347).) Mr. Baatz testified that although APS agreed with Mr. Baatz's view on what constitute customer-related costs, APS allocated additional costs, most likely distribution plant costs, as customer-related, and also included additional expenses "substantially higher" than Mr. Baatz's calculation. (Ex. WRA-1 at 28-29.) Mr. Baatz disagreed with APS's inclusion of distribution plant beyond the cost of meters (FERC account 370) and services (FERC account 369), stating that the costs of shared infrastructure like poles, wires, and transformers do not vary directly with the number of customers on the system and thus are not appropriately classified as customer related. (Ex. WRA-1 at 29.)

In response to APS's rebuttal testimony that some fixed distribution plant costs are appropriately allocated to customer-related costs, Mr. Baatz asserted that Mr. Snook was attempting to redefine customer-related costs to include costs that are incurred to meet demand or energy needs and that, using Mr. Snook's logic, "nearly every cost on the entire utility system could be considered a customer related cost." (Ex. WRA-2 at 17.)

f. Staff

Dr. Dismukes recommended that secondary distribution costs be allocated using the NCP method rather than the SIM method APS used in the COSS. (Ex. S-5 at 20.) Dr. Dismukes testified that APS's use of the SIM allocator, which adds customers' individual peak demands, "implies a hyper-undiversified system wherein secondary-voltage distribution systems serve customer loads that effectively peak simultaneously." (Ex. S-5 at 20.) Per Dr. Dismukes, this is problematic because APS's 2016 analysis determined that APS's residential customers are heterogeneous, with a wide diversity of load profiles within individual customer classes. (Ex. S-5 at 20.) Dr. Dismukes asserted that "end-use load diversity should be aligned with cost allocation, and APS's high load diversity . . . is not aligned" with the SIM cost allocator. (Ex. S-5 at 20.) Dr. Dismukes recommended a 100% class NCP cost allocation methodology for allocation of secondary-voltage distribution plant costs, which he stated would provide a "fair and reasonable approximation of the relative COS" while being aligned

with APS's load diversity. (Ex. S-5 at 20.) When Dr. Dismukes recalculated class cost responsibilities using the 100% NCP method, residential customers' allocated costs were lower, and general service customers' allocated costs were higher. (Ex. S-5 at 20, ex. DED-2.)

Dr. Dismukes also recalculated the COSS using his adjustments for both production plant and secondary distribution plant allocation, concluding that APS's allocation methods had "skew[ed] the allocation of costs and revenue responsibilities away from larger customers and onto residential and small commercial customers." (Ex. S-5 at 21.) Additionally, Dr. Dismukes asserted, his COSS recommendations, unlike APS's, aligned with APS's load analysis of its customer classes. (Ex. S-5 at 21.) Dr. Dismukes's COSS showed that the classes/subclasses below had the following RRORs, shown in comparison to the results of APS's COSS:[325]

Residential						
Group	**Total Residential Class**	**R-XS**	**R-Basic**	**R-Basic Large**	**TOU-E**	**R-2 & R-3 (Combined)**
APS	0.65	0.51	0.39	0.61	1.06	0.83
Staff	0.75	0.63	0.52	0.71	1.18	0.89

Residential Solar				
Group	**Legacy Solar (Energy)**	**Legacy Solar (Demand)**	**R-Solar TOU**	**R-Solar (Demand)**
APS	(0.87)	0.52	0.6	0.9
Staff	(0.85)	0.59	N/A	N/A

General Service						
Group	**Total General Service**	**E-20 (Church Rate)**	**E-32 TOU XS**	**E-32 TOU S**	**E-32 TOU M**	**E-32 TOU L**
APS	1.66	(0.14)	3.00	3.27	2.57	1.37
Staff	1.40	0.47	3.97	2.99	1.85	1.00
General Service						
Group	**E-30 & E-32 XS (Combined)**	**E-32 S**	**E-32 M**	**E-32 L**	**AG-X**	**GS-Schools M & L (Combined)**
APS	2.29	2.03	1.94	0.94	0.79	1.24
Staff	2.30	1.96	1.62	0.61	0.36	1.79

[325] Ex. S-50 at ex. DED-3.

g. APS Response

In response to FEA's argument, Mr. Snook agreed that a portion of primary and secondary distribution costs could reasonably be reclassified to customer-related costs, because they do not vary based on a customer's monthly peak demand or monthly energy usage and because any excess capacity from one customer or a small customer group cannot be shared with or used to serve another customer. (Ex. APS-29 at 32.) Mr. Snook cited customer line transformers and secondary service drops to homes, as well as common overhead costs to operate the grid (such as for communication and control equipment or cybersecurity) as examples of fixed distribution costs that could appropriately be included in customer-related costs. (Ex. APS-29 at 32.) Mr. Snook testified that APS had proposed reclassification of some costs as customer costs in the 2016 Rate Case to support a proposed increase in basic service charges for residential and commercial customers, but had not proposed such reclassification in this case primarily because it is not proposing to increase the basic service charges and is not proposing to allocate revenues disproportionately to classes based on the COSS. (Ex. APS-29 at 33.) APS does not agree with either FEA's position that the COSS in this case should be recomputed with some distribution costs reclassified as customer-related or FEA's proposal for APS's next rate case to require investigation of the issue using two specific methods. (Ex. APS-29 at 33.) APS proposed that the Commission direct it to evaluate this issue in its COSS for the next rate case instead. (Ex. APS-29 at 33.)

Regarding Staff's position, Mr. Snook asserted that using the total class NCP demand allocator would be inconsistent with the cost drivers for secondary distribution costs, which serve individual customers or small groups of customers, not an entire class such that a reduction in load in one area allows capacity to be used by another customer in a different area. (Ex. APS-29 at 35.) Mr. Snook agreed that load diversity among the members of a class reduces the combined costs for substation and primary distribution equipment for the class, but stated that the same is not true for secondary distribution equipment. (Ex. APS-29 at 35.) APS urged the Commission to reject Staff's position and reaffirm the use of APS's current SIM allocator method for secondary distribution costs as the method most reflective of cost drivers. (Ex. APS-29 at 36.)

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h. Resolution

We find persuasive FEA's position that APS should allocate as both demand-related and customer-related the costs of the distribution accounts identified by Ms. Alderson (FERC accounts 360, 361, and 364 through 368), because the NARUC Manual identifies them as appropriately allocated as demand-related and customer-related, and it is logical that there is a minimum distribution system that must exist to serve customers irrespective of the customers' consumption.

Secondary distribution equipment is location specific and sized based on the kW power demands of the location for which it is installed. Because secondary distribution equipment cannot be used except for the location for which it is installed, unlike substation and primary distribution equipment, load diversity does not impact the necessary sizing of the equipment. Thus, we are not persuaded that APS needs to change its SIM allocation method for secondary distribution costs as advocated by Staff. The evidence in this case supports use of individual customer peaks as more reflective of the secondary distribution equipment necessary to serve the individual customers than would be the class NCPs.

3. Allocation of Costs for DG Solar Customers

a. APS

Rather than simply analyzing the cost of service to the entire residential class as a whole in the COSS, APS divided the residential class into nine subclasses, including four solar subclasses (two legacy and two non-legacy). (Ex. APS-28 at att. LRS-3DR at 2.) Mr. Snook testified that it was appropriate to create separate residential solar subclasses because the peak demand (CP, NCP, and SIM) and energy characteristics of the solar customers are very different from those of non-solar customers. (Ex. APS-29 at 39.) Mr. Snook testified that APS had nearly 76,000 grandfathered residential solar customers and more than 15,000 non-grandfathered residential solar customers[326] at the end of the TY and, further, that the average residential solar customer used approximately 74% of the capacity and 37% of the energy during the TY that they had used before adopting solar. (Ex. APS-29 at 39.) After dividing the solar customers into groups based on whether they were served under

[326] Non-grandfathered residential solar customers are on the RCP rate for exports rather than on net metering. (Ex. APS-29 at 39.)

energy rates or demand rates, APS used data for the residential solar customers' entire load (both that served by APS and that served by the DG solar system) as the starting point for cost allocation to develop the CP, NCP, and SIM demand allocations and the energy allocations. (Ex. APS-29 at 39.) APS then credited the solar customers for the following:[327]

- Self-provided production capacity, using the four summer subclass CPs and NCPs;
- Total energy production, including what was consumed on site and what was delivered to the grid;
- Avoided transmission costs, based on a comparison to the APS-delivered customer load at the four summer CPs;
- Avoided primary distribution costs, based on a comparison to APS-delivered customer load at the time of the four summer subclass NCPs; and
- Avoided secondary distribution costs, based on a comparison to APS-delivered customer load at the time of the four summer subclass SIMs.

According to Mr. Snook, this process resulted in the COSS allocating to residential solar customers only the capacity and energy costs based on what APS must provide them, while also capturing the cost of providing grid services for export and backup services (such as support for the starting of an air conditioning unit ("inrush current"[328]), which cannot be met by a solar array). (Ex. APS-29 at 41.)

b. SEIA/AriSEIA

SEIA/AriSEIA argues that APS's COSS methodology for DG customers is "fundamentally flawed and should be rejected" because, *inter alia*, "APS discriminates against DG customers" by assigning them costs for energy and services that APS does not provide them. (SEIA Br. at 19.) Specifically, Mr. Lucas asserted that APS was wrong to use site energy data rather than delivered

[327] Ex. APS-29 at 40.

[328] Mr. Snook described inrush current as "the oomph behind the electricity . . . that basically kickstarts the motor," explaining that air conditioners have starting capacitators that require additional capacity instantaneously (approximately two or three times the device's nameplate rating) to start the motor. (Tr. at 2656-2657.) It is the inrush current (basically a spike in demand) that sometimes causes lights to flicker when an air conditioner starts up. (Tr. at 2657-2658.) Solar systems that are 100% off grid lack the capacity to provide that inrush current, making it necessary either to buy special, more expensive, appliances that do not need inrush current to start or to install sufficient storage to provide that capacity. (Tr. at 2656-2658.)

energy data in the COSS, because of the "fundamental principle that customers should be able to take any action – as long as it is safe and legal – to alter the amount of energy and power they purchase from APS." (Ex. SEIA-1 at 17.) Mr. Lucas compared the installation of DG solar to installing energy efficient appliances or gas appliances, stating that "what happens behind the meter should stay behind the meter." (Ex. SEIA-1 at 17.) According to Mr. Lucas, it is absurd to allocate DG customers costs based on total site load, regardless of how much of the site load was served by self-generation, because it is like allocating costs to a customer for the energy that would have been consumed if not for their energy efficient windows, or their kids' having gone off to college, or their being only seasonal residents. (Ex. SEIA-1 at 17.) Mr. Lucas asserted that customers should only be charged based on their actual usage, which for DG solar customers is their delivered load. (Ex. SEIA-1 at 18.) According to Mr. Lucas, the Commission subscribed to this idea in Docket No. E-00000J-14-0023, in the Matter of the Commission's Investigation of Value and Cost of Distributed Generation ("Value of Solar Docket"), when it decided that DG solar customers should be compensated for exported energy rather than having a monetary value assigned to their site load. (Ex. SEIA-1 at 18 (quoting Decision No. 75859 (January 3, 2017)[329] at 147).) Mr. Lucas conceded that the issue was slightly different in the Value of Solar Docket, but stated that the idea of looking behind the meter, which is necessary when using site load, directly conflicts with the Commission's conclusion. (Ex. SEIA-1 at 18.) Mr. Lucas disputed APS's assertion that Decision No. 75859 established that DG solar customers should be treated as a separate class in the COSS because they are partial requirements customers that export power to the grid, arguing that Decision No. 75859 made that determination expressly "for purposes of rate design," not for determining cost of service, and rate design is a separate process. (Ex. SEIA-1 at 18-19 (quoting Decision No. 75859 at 146).)

Mr. Lucas asserted that solar customers should not be treated differently than other residential customers in the COSS because there is so much variation in load characteristics among all residential customers that using differences in load characteristics as justification for separate treatment of DG solar customers is unwarranted. (Ex. SEIA-1 at 20-21.) Mr. Lucas quoted testimony provided in the

[329] This decision was admitted herein as Exhibit APS-64.

2016 Rate Case to the effect that although there are other distinct groups of customers larger than the group of DG solar customers with highly varying load shapes that could impact cost recovery, it is only DG solar customers that APS has singled out for different treatment. (Ex. SEIA-1 at 21 (quoting Briana Kobor's direct testimony).)

Mr. Lucas also testified that although APS has repeatedly referenced the additional costs needed to serve DG solar customers as "grid services costs," APS has never quantified those costs. (Ex. SEIA-1 at 21-22.) Additionally, Mr. Lucas stated, APS has acknowledged that the costs for "inrush current" and to maintain distribution voltage within required operating limits are included in generation and distribution costs, respectively; that it does not track costs in a manner allowing it to identify specific upgrades or additions made to accommodate solar customers; and that it has not added new feeders, new capacitor banks, or new voltage regulators and has not reconductored lines to accommodate residential PV customers. (Ex. SEIA-1 at 21-22.) Thus, Mr. Lucas asserted, the cost to serve DG solar customers' load is already reflected in the costs of generation, transmission, and distribution assets that serve the delivered load of any customer, and there is no justification for treating DG solar customers differently. (Ex. SEIA-1 at 22-23.)

Mr. Lucas dismissed APS's assertions that it serves DG solar customers on a higher level of demand than just for delivered load for capacity (generation, transmission, distribution primary, and distribution secondary), stating that APS will not admit that it is only responsible for serving delivered load and calling APS "evasive." (Ex. SEIA-1 at 23.) Mr. Lucas asserted that because APS plans its system with an assumption of load diversity, not an assumption that every customer will max out their capacity at the same time, and assumes that customers will pull significantly less than their potential power,[330] delivered load is the right value to use to capture a customer's behavior and to allocate costs. (Ex. SEIA-1 at 24.) Mr. Lucas suggested that APS may be confusing the service it must provide to DG solar customers with resource planning concepts, but pointed out that APS routinely handles the variability in solar generation and can forecast solar generation much more accurately than all or nothing as its position would suggest. (Ex. SEIA-1 at 25.) Additionally, Mr. Lucas pointed out that if

[330] APS assumes that a customer with a 200-amp service drop, which could theoretically pull 38.4 kW, will have a peak demand of only 12.23 kW. (Ex. SEIA-1 at 24, att. KL-43.)

APS were to send a household's full capacity of power (for example, 10 kW) when its net load was lower (such as 6 kW, the 10 kW in use minus 4kW of solar generation), it would cause "massive electrical issues." (Ex. SEIA-1 at 25-26.) Mr. Lucas analogized the power grid to a bathtub, with the water flowing through the bathtub faucet representing generated and purchased power from APS, the water flowing down the drain representing customer load, and the water flowing into the bathtub from a hose connected to the bathroom sink representing rooftop solar. (Ex. SEIA-1 at 26.) If the hose from the sink is turned on and providing water to the bathtub, APS must react by turning down the bathtub faucet to avoid an overflow because if APS were not to turn down the bathtub faucet (based on APS's "conceit that it serves a solar customer's site load"), the bathtub would overflow. (Ex. SEIA-1 at 26.)

Mr. Lucas also asserted that APS's load research reports ("LRRs") prepared for the COSS do not support the idea that solar DG customers represent a demand reflective of site load, because the LRRs' "Total Residential" load is equal to the sum of the "Residential No Solar" and the "Residential Solar Delivered" rather than the sum of the "Residential No Solar" and "Residential Solar Site." (Ex. SEIA-1 at 15, 26-27.) Additionally, Mr. Lucas asserted, APS's load forecasts are based entirely on delivered load. (Ex. SEIA-1 at 27, att. KL-14.)

Based on APS's LLRs, Mr. Lucas estimated that using the site load instead of delivered load caused an increase in costs of 40-80% for allocation of production costs and transmission costs and of 15-30% for allocation of distribution-related expenses. (Ex. SEIA-1 at 27-28.) Mr. Lucas also estimated that using site energy rather than delivered energy resulted in the entire residential class (solar and non-solar) being assigned approximately $20.6 million more in costs than would have been assigned if delivered energy allocators were used for the solar subclasses. (Ex. SEIA-1 at 29-30.) Mr. Lucas opined that the solar credit does not adjust for this, although he was unable to produce the results expected when he changed the allocators to delivered load and removed the solar credit, instead producing an increase in costs to both solar and non-solar residential customers. (Ex. SEIA-1 at 30, 34-35.)

For the COSS, the solar credit was $53.1 million, $28.5 of which was covered by non-solar residential customers and $24.6 million of which was covered by non-residential customers. (Ex. SEIA-1 at 31.) Mr. Lucas criticized APS for calculating the solar credit in an imported file rather than

within the COSS and further for not using the same allocators to calculate the solar credit as were used to allocate costs, estimating that the production demand solar credit alone would have been increased by $6.2 million if the proper A&E method were used. (Ex. SEIA-1 at 31-33.) Mr. Lucas also criticized APS for applying the solar credit (and revenue from other classes necessary to provide the solar credit) as a debit/credit to O&M expenses, because including it in O&M expenses impacts income tax allocation, pro forma adjustments, and system benefits allocations between the classes. (Ex. SEIA-1 at 33-34.)

Mr. Lucas also asserted that APS did not follow the Commission's directive, made in a UNSE rate case, that distribution costs should be allocated based on the combined maximum demand of the DG and non-DG classes because using a separate class NCP allocator does not attribute distribution system costs proportionately to the cost causation between the DG and non-DG classes. (Ex. SEIA-1 at 39-40 (quoting Decision No. 76900 (September 20, 2018)[331] at 83-85).) Per Mr. Lucas, APS instead

[331] Official notice of this decision was taken at hearing, upon SEIA/AriSEIA's request. Specifically, the Commission stated:

> Cost causation is the primary consideration for allocating costs. The cost driver for the distribution system is capacity. Distribution circuit capacity is required for both delivery of energy to the customer and export of energy from the customer. Therefore distribution circuits must be built to accommodate the combined maximum demand capacity for delivery and export usage. If DG export production occurs during the combined DG and non-DG NCP, it is appropriate and reasonable to include that usage of the grid for export or import in the allocation of costs because it impacts distribution system capacity. . . .
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> . . .
>
> The Companies utilized the class NCP method which determined the NCP for the non-DG and DG classes separately to allocate the distribution costs between DG and non-DG customers. However, usage of the grid during times other than the net combined NCP of the DG and non-DG classes should not be factored into the allocation of the distribution costs as it does not drive distribution capacity costs. Since the combined NCP for the DG and non-DG customer classes occurs in the summer, the DG class NCP, based on exports in April, does not impact the cost of the distribution circuit as there is plenty of excess capacity at that time.
>
> . . .
>
> We agree with the Companies that both load demand and export energy production have the potential to be the constraining factor on the demand capacity of a distribution circuit. Accordingly, depending on the circumstances, either may be the appropriate factor for allocating distribution costs between the DG and non-DG customer classes. However, the Companies' use of the separate class NCP demands instead of the relative demands each class places on the distribution system at the time of their combined maximum demand, does not attribute the cost of the distribution system in proportion to cost causation between the DG and non-DG classes, and thus, it is inequitable. The potential impact could be, and likely is, significant, but we cannot know the full effect until the Companies revise their CCOSSs to reflect a more equitable allocation based on the relative demands of each class at the time of their combined maximum demand.

(Decision No. 76900 at 82-84.)

calculated its class NCP based on the maximum hour of site energy of the solar subclasses and the delivered energy of the non-solar subclasses, regardless of whether the peaks coincided with the total residential class peak. (Ex. SEIA-1 at 40.) Mr. Lucas noted that none of the independent subclass peaks occurred during the total residential Class NCP of August 5, 2018, between 5 and 6 p.m. (Ex. SEIA-1 at 41.) When Mr. Lucas revised the analysis based on the actual hour of the total residential class peak, and using delivered energy, the differences were significant, with non-legacy solar subclasses seeing their delivered Class NCP demand fall by 76-84% and legacy solar subclasses seeing their Class NCP demand fall by 30-33%. (Ex. SEIA-1 at 41.)

Mr. Lucas also criticized APS for allocating much higher customer costs to the solar subclasses than to the non-solar subclasses in the COSS, attributing the bulk of the difference to meter costs, for which APS allocated approximately $18 per month to each solar customer, based on APS's requirement for solar customers to have two meters (a bidirectional meter to measure usage and exports and a production meter to measure the solar system's generation), the significantly higher cost of the bidirectional meters ($310 versus $106), and APS's much higher "shop cost" to test and validate the bidirectional meters (reported to be more than eight times as expensive). (Ex. SEIA-1 at 49-51.) Mr. Lucas stated that APS acknowledged that the production meters are not needed for billing, but asserted that it uses the data from the production meters for performance-based incentives for solar customers, to study and monitor the grid impacts of DG solar, to calculate the LFCR, to calculate cost of service, and to track compliance with regulatory mandates and, additionally, to comply with a Commission requirement for production meters to be used. (Ex. SEIA-1 at 52 (citing Decision No. 72737 (January 18, 2012).[332]) Mr. Lucas testified that APS has no need to use production meters because it has never offered production-based incentives to residential customers, could and should use delivered load (which would not require a production meter) rather than site load for its COSS, and could use PV system modeling rather than production meter data for its LFCR. (Ex. SEIA-1 at 52.) According to Mr. Lucas, if APS were to treat solar customers like non-solar residential customers for metering, their

[332] Official notice is taken of this decision, issued in Docket No. E-01345A-11-0264, which approved APS's 2012 REST Plan. In Decision No. 72737, the Commission agreed with an APS plan to install production meters for previously installed and new residential and non-residential grid-tied PV systems so that data would be available on whether Up-Front Incentives ("UFI") systems performed as expected and APS could use actual production data in its compliance reporting for UFI systems. (Decision No. 72737 at 9.)

cost for metering would be just over $8.1 million, as opposed to the $26.8 million included in the COSS for the 86,646 solar customers. (Ex. SEIA-1 at 53.) Per Mr. Lucas, the $26.8 million represents $17.76/MWh in incremental metering expenses for solar outflow, equivalent to approximately two-thirds of the energy value of solar production of $28.95/MWh.[333] (Ex. SEIA-1 at 53, att. KL-24, att. KL-15.)

Even with the outsized metering costs, however, Mr. Lucas argued, the total cost to serve solar customers is roughly equivalent to the cost to serve non-solar customers for similarly sized customer subgroups because, for example, the cost to serve legacy solar demand customers ($2,545) is almost the same as the cost to serve non-solar residential demand customers ($2,534). (Ex. SEIA-1 at 54.) Additionally, Mr. Lucas argued, when metering costs are removed and cost to serve is reviewed on a per kWh basis, the cost to serve the solar subclasses ($0.1231/kWh to $0.1402/kWh) is in keeping with the costs to serve the non-solar subclasses ($0.1063/kWh to $0.1410/kWh). (Ex. SEIA-1 at 55.)

Aside from his concerns about the specific allocations made in APS's COSS, Mr. Lucas also criticized APS for creating its COSS using a traditional approach established from authorities published nearly 30 to nearly 60 years ago[334] when DG was virtually nonexistent and centralized power plants in vertically integrated markets were the norm. (Ex. SEIA-1 at 12-13.) Mr. Lucas asserted that the Regulatory Assistance Project's ("RAP's") *Electric Cost Allocation for a New Era: A Manual* (2020) ("RAP Manual") updated traditional cost allocation and rate design approaches based on modern conditions and should be reviewed in this and future rate cases because it addresses allocation of renewable generation and smart meters more fairly by recognizing the benefits that each provides. (See Ex. SEIA-1 at 13-14, 32.)

Mr. Lucas also criticized APS's COSS workpapers for being "full of unlinked files, hardcoded values, and inscrutable formulas" and APS's "refusal to provide access to files that were directly imported into the [COSS]," both of which he said made performance of his own analysis more difficult. (Ex. SEIA-1 at 9, 35-37.) Mr. Lucas stated that APS's COSS may have been an improvement from

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[333] APS stated that the solar credit represents the energy value of solar production, which is credited against the allocated cost-of-service for the site load. (Ex. SEIA-1 at att. KL-15 (response to SEIA 4.3).)

[334] The authorities referenced included, *inter alia*, James Bonbright's *Principles of Public Utility Rates* (1st ed. 1961, 2nd ed. 1988) ("Bonbright") and the NARUC Manual. (Ex. SEIA-1 at 13.)

previous cases, but that it still did not comply with Commission requirements for transparency, accessibility, and flexibility. (Ex. SEIA-1 at 9.) Mr. Lucas asserted that in the Value of Solar Docket, the issue of APS's use of a proprietary "black box" COSS model was discussed extensively, and the Commission determined that it did not have a sufficient record to support a specific COSS methodology. (Ex. SEIA-1 at 37 (quoting Decision No. 75859 at 144).) Thus, the Commission directed utilities to submit COSSs based on transparent, accessible, and flexible models with spreadsheets containing links between inputs and outputs available to parties. (Ex. SEIA-1 at 37-38 (quoting Decision No. 75859 at 174-175).)

Mr. Lucas also identified a number of errors that he found in APS's COSS workpapers, including use of the wrong meter costs for solar customers (overstating the total meter costs by 23%, or approximately $9.5 million) and use of incorrect customer counts in the LRRs for many residential customer groupings. (Ex. SEIA-1 at 42.) Mr. Lucas also criticized APS's use of "demand adjustors" to conform billing data peak demand to total system peak reported on APS's FERC Form 1 because APS used them for the delivered load of customer groups but not the site load of solar customers and because APS did not make corresponding adjustments to energy levels. (Ex. SEIA-1 at 43.) Because APS did not adjust its COSS to show the growth/shrinkage in customer subclasses during the TY, Mr. Lucas asserted, subclasses with customer growth (such as solar subclasses) were over-allocated customer costs while subclasses with customer attrition were under-allocated customer costs. (Ex. SEIA-1 at 45-46.) Mr. Lucas suggested that APS could address this issue in its COSS by using fewer subclasses or by developing a load shape based on per-capita load rather than absolute load and multiplying it by the average number of customers. (Ex. SEIA-1 at 46.)

Mr. Lucas produced a modified COSS that addressed the issues he identified in his testimony, which showed that the cost to serve the solar subclasses (collectively) was approximately $6.1 million lower than had been shown in APS's COSS and that costs of service were lower for the solar subclasses other than legacy solar demand.[335] (Ex. SEIA-1 at 46-48.)

. . .

[335] Legacy solar demand's cost of service increased by $1.1 million. (Ex. SEIA-1 at 48.) Costs also increased for the R-XS, R-TOU No Solar, and R-Demand No Solar subclasses. (*Id.*)

Mr. Lucas recommended the following:[336]

- That the Commission require APS to use delivered load for DG solar customers in its COSS;
- That if APS in the future identifies, quantifies, and justifies additional costs that are explicitly related to providing service to DG solar customers (beyond the costs of providing their delivered power and energy), those costs be included in APS's COSS;
- That the Commission require APS to use in its COSS delivered load with no solar credit, for simplicity and transparency, or, if the Commission were to prefer the site load and solar credit method, that the Commission require APS to use the proper A&E allocator for production demand costs rather than the average of 4CP and Class NCP as it did in its COSS;
- That in future rate cases, APS be required to provide more detail about how it establishes its load shapes;
- That the Commission require APS to demonstrate why using delivered load allocators in the COSS resulted in a higher total residential revenue requirement than APS's site load/solar credit method, even though the delivered load method resulted in a smaller sum of allocators;
- That the Commission direct APS to investigate ways of reducing metering expenses for solar customers, such as through modeling software, which has improved greatly since the Commission required the production meters in 2012;
- That the Commission require APS, in its COSSs for future rate cases, to reflect properly the mix of meters used rather than assuming that each customer has the most expensive meter installed, because APS has been installing bidirectional meters that are much less expensive than those included in the COSS; and
- That the Commission reject APS's method using independent Class NCP hours for its various subclasses and instead require an updated COSS that aligns subclass/class NCPs with the combined total residential class peak.

On surrebuttal, Mr. Lucas noted "Mr. Snook's obvious and unwarranted hostility" toward SEIA/AriSEIA and asserted that Mr. Snook's rebuttal should be disregarded essentially because it

[336] Ex. SEIA-1 at 27, 35, 41-43, 48-49, 53, att. KL-24 (response to SEIA 31.1).

presented no new information, misinterpreted some of Mr. Lucas's testimony, and was inappropriately dismissive concerning the information presented in Mr. Lucas's direct testimony. (See Ex. SEIA-2 at 24-30.) Additionally, Mr. Lucas disputed Mr. Snook's characterization of RAP, asserting that it is "a well-respected organization that works on regulatory issues throughout the world," with personnel comprised of former commissioners, environmental regulators, state consumer advocates, industry executives, and system operators and a board of directors that includes former commissioners, academics, and industry experts. (Ex. SEIA-2 at 30.)

c. Vote Solar

Vote Solar argues that APS's COSS is flawed and "vastly overstates" the costs to APS's system caused by solar customers. (VS Br. at 11.) Mr. Sandoval asserted that the production meter is only required because of APS's 2012 REST Plan and, further, that the Commission previously has rejected holding solar customers responsible for the production meter costs in a TEP rate case, determining that solar customers should only be responsible for the "incremental cost of a bidirectional meter that is necessary for DG customers to receive credit for their systems' production and to receive compensation for their excess production." (Ex. VS-1 at 16 (quoting Decision No. 75975 (February 24, 2017)[337] at 155).) Mr. Sandoval pointed out that in that TEP rate case decision, the Commission stated the following concerning production meter costs:

> The production meter supports REST compliance (and LFCR calculations). The REST Rules are for the benefit of all ratepayers, the Company, and society in general, and the cost of REST compliance should not be imposed only on the group of customers who contribute to meeting renewable goals. The bidirectional meters, however, do benefit the DG customers who receive compensation for their production, and it is appropriate on an interim basis that new DG customers are responsible for the additional costs of serving them.[338]

Mr. Sandoval also took issue with APS's allocation of distribution demand costs to DG customers, based on their loads in an hour that represents the NCP hour for the solar subclass rather than the NCP hour for the residential class, which effectively assumes that solar customers have their

[337] Official notice is taken of this decision, issued in Docket No. E-01933A-15-0239. The quoted text was included in the analysis and resolution of an issue concerning a DG Meter Fee.
[338] Decision No. 75975 at 155; Ex. VS-1 at 16.

own distribution system rather than recognizing that they are served by the same distribution system as other residential customers. (Ex. VS-1 at 17.) Mr. Sandoval asserted that this allocation also assumes that solar customers' separate NCP drives the peak load on the substations and feeders that serve them, which is not true because the much larger classes being served along with dispersed solar customers contribute to cumulative peak loads during the class-wide peak load hour. (Ex. VS-1 at 17-18.) Mr. Sandoval pointed out that APS has acknowledged "distribution assets are built to serve the areas of the grid that they serve" rather than to serve particular classes and, further, that the Commission has previously determined in a separate phase of the same TEP rate case that costs should not be allocated based on a solar-specific NCP but only on solar customers' net contribution to the class-wide NCP load. (Ex. VS-1 at 19, ex. VS-2 (citing Decision No. 76899 at 94-96).) Mr. Sandoval concluded that under a correct cost of service and revenue analysis, DG customers cover their costs to the same extent as other customers with similar load, without the Grid Access Charge. (Ex. VS-1 at 20.)

d. Other Parties

No other parties expressly adopted or objected to APS's allocation of costs for DG solar customers.

e. APS Response

Mr. Snook disagreed with Mr. Lucas's position on allocation of production costs, asserting that Mr. Lucas had offered no justification for it. (Ex. APS-29 at 46.) Mr. Snook asserted that use of the A&E method is necessary to reflect overall generation costs to serve the entire site load from APS's resource portfolio and that the second allocator is needed to assess appropriately the capacity cost savings from adding solar generation, based on the availability of the solar generation at the time of APS's system peaks. (Ex. APS-29 at 46-47.) Mr. Snook further asserted that APS uses the same type of two-method allocation approach for its general service partial requirements customers. (Ex. APS-29 at 47.)

Additionally, Mr. Snook asserted that Mr. Lucas is attempting to relitigate issues resolved in the Value of Solar Docket. (Ex. APS-29 at 37.) According to Mr. Snook, Decision No. 75859 found that residential solar customers should be treated as a separate class in a COSS, not as a part of the residential class. (Ex. APS-29 at 37.) Mr. Snook also asserted that APS provided significant testimony

both in the Value of Solar Docket and the 2016 Rate Case to justify why costs for rooftop solar customers should be allocated based on site load and then credited based on the costs the customers offset. (Ex. APS-29 at 37.) If delivered load were used instead, Mr. Snook stated, other costs would need to be added back in for services the rooftop solar customers receive but would no longer pay for in rates. (Ex. APS-29 at 37.) Additionally, Mr. Snook testified, APS must supply residential solar customers with backup and ancillary services that necessitate APS's building, operating, and maintaining the bulk of its fixed infrastructure required to serve residential solar customers because APS's maximum system peak in the summer months is near sunset, and its peak continues after sunset, when solar systems are no longer producing power. (Ex. APS-29 at 41-42.) Mr. Snook suggested that cost offsets for residential solar customers should be based on how well their solar systems offset APS's peak loads and actual avoided fuel costs. (Ex. APS-29 at 42.)

In response to Mr. Lucas's complaint that APS's COSS model was not transparent, Mr. Snook noted that it was a Microsoft Excel spreadsheet-based model, that APS had held a meeting to demonstrate it, and that only Mr. Lucas had raised a transparency concern. (Ex. APS-29 at 38.) Mr. Snook asserted that APS's independently audited financials are the source of all numbers in the model and that Mr. Lucas had access to APS's FERC Form 1 for 2018 and its 10-Qs for Q1 and Q2 2019. (Ex. APS-29 at 38.) Mr. Snook attributed Mr. Lucas's complaint to his desire to reallocate costs (incorrectly per Mr. Snook) to residential solar customers using delivered load, which was not possible using the model. (Ex. APS-29 at 38.) Mr. Snook also disagreed with Mr. Lucas's position that APS was bound by a finding in a UNSE decision regarding the use of a residential subclass NCP for cost allocation to rooftop solar customers, stating that the UNSE decision applies only to UNSE and, further, that APS's method is appropriate because APS has a much higher adoption rate for rooftop solar than UNSE does. (Ex. APS-29 at 38.)

Mr. Snook also disagreed with Mr. Lucas's advocacy for use of the RAP Manual, asserting that RAP is an advocacy group with a mission "dedicated to accelerating the transition to a clean, reliable, and efficient energy future," and thus not an unbiased source. (Ex. APS-29 at 43.) Mr. Snook rejected Mr. Lucas's criticism of APS's load research census and how the data is extrapolated to FERC Form 1 sales information, asserting that APS's load research is better than that for most utilities because APS

uses more than 1 million customers in its census sample while most utilities use approximately 2% of their customers and, further, that Mr. Lucas's criticism was based on his desire to obtain data on delivered load for solar customers. (Ex. APS-29 at 43.) Mr. Snook also refuted Mr. Lucas's characterization of a solar generator as just another appliance, observing that residential solar generators potentially export power to the grid and that special rate provisions are needed to compensate the customer for that power, provide backup service for the generator, and recover the costs of grid services provided by the utility. (Ex. APS-29 at 44-45.) Mr. Snook also disagreed with Mr. Lucas's assertion that cost evaluation for residential solar customers should be based on marginal costs, asserting that in a rate case, which is focused on recovery of average embedded costs for a historic TY, TY embedded cost information should be used.[339] (Ex. APS-29 at 45.)

On rejoinder, Mr. Snook emphasized that DG solar provides intermittent power that must be supplemented and backed up by APS's generation capacity, asserting that an investigation into the summer 2020 outages in California had reported that solar generation provided only approximately 20% qualifying capacity value to meet net system load during peak electricity demand, meaning that 80% of the solar rated capacity is not available during peak hours and needs to be backed up. (Ex. APS-30 at 6.) Mr. Snook asserted that the Commission has long recognized that partial requirements customers have standby, backup, and other costs to ensure continuous service and that APS's cost allocation method for DG customers recognizes these costs while Mr. Lucas's approach does not. (Ex. APS-30 at 6.) Regarding the UNSE rate case, Mr. Snook stated that unlike UNSE's residential solar class NCP in April, which did not align with the residential class NCP, APS's total residential solar class NCP and overall residential class NCP both occurred in August, and the NCPs for each residential subclass all occurred in June-August. (Ex. APS-30 at 7.)

APS did not respond to Mr. Sandoval's testimony.

f. Resolution

APS's COSS allocates to DG solar customers costs that appear to be in excess of the costs actually incurred to serve those customers, primarily through the use of the solar class NCP concept to

[339] Mr. Lucas denied that he had made an argument for marginal costs to be used. (Ex. SEIA-2 at 30.)

allocate distribution costs, but also through including overstated costs for meters (based both on inappropriate allocation of the cost of the production meters required by the Commission for REST compliance and on APS's current use of less expensive bidirectional meters than reflected in the COSS). While we are not convinced that APS does not provide additional services to DG solar customers that are not provided to non-solar customers, and we believe that Mr. Lucas's bathtub analogy supports that there are additional costs (because APS must actively monitor the hose's output to ensure the bathtub doesn't overflow and would need to fill the bathtub independently if the sink hose were to stop functioning), we believe that APS has not yet made sufficient efforts to quantify those costs and needs to quantify those costs so that the issue can be examined more thoroughly in APS's next rate case and resolved.

Because we do not have sufficient information in this record to determine the appropriate cost allocations to DG solar customers, and because the rates established herein are informed by but not based upon the results of the various COSS analyses from the different parties, we will not require APS to make any DG-customer-related changes to its COSS herein but will require APS to do the following related to the COSS for its next rate case:

- To complete an analysis to identify, quantify, and justify the additional costs ("extra costs") that APS incurs specifically to provide service to DG customers (beyond the costs of providing their delivered power and energy);
- To complete a COSS using delivered load for DG solar customers as well as a COSS using site load for DG solar customers, with the extra costs clearly included and identified within each;
- To complete a COSS including DG solar customers within the non-DG residential classes with which the DG solar customers' rates are most closely aligned (e.g., DG demand customers will be included with non-DG demand customers);
- To use in each COSS the actual costs for the bidirectional meters in use at the end of the TY;
- To omit from metering costs for DG customers in each COSS the production meters that APS is required to have for REST compliance and uses for LFCR computations;
- To align DG subclass/class NCPs with the combined total residential class peak in allocation of primary distribution costs in each COSS; and

- To make available to the other parties in the case all of the schedules, formulas, and backup data necessary to create each COSS.

4. Allocation of Costs for AG-X Customers

a. APS Position

APS treated AG-X customers as a separate customer class; allocated transmission, distribution, and production demand costs to them in the same manner as for other customer classes; and also allocated to them some components of production energy costs. (Ex. AECC-2 at 15-16.) APS asserted that for allocation of production-related costs, AG-X customers do not provide sufficient resource adequacy to be excluded as a resource planning obligation and "many legacy generation resources were initially constructed for serving these customers as part of the overall retail load." (Ex. APS-28 at 11.)

b. AECC/Freeport

AECC/Freeport agrees with APS's allocation of transmission and distribution costs to AG-X customers because AG-X customers are transmission and distribution customers for APS. (Ex. AECC-2 at 15.) But AECC/Freeport does not agree with APS's decision to allocate a full share of APS's fixed production costs to AG-X load in the COSS. (Ex. AECC-2 at 11.) Mr. Higgins asserted that because AG-X customers procure their own production supply from non-APS sources, AG-X load should be excluded from the allocation of most production demand costs. (Ex. AECC-2 at 11, 22.) Mr. Higgins further asserted that the AG-X class should generally be excluded from allocation of APS's production energy costs. (Ex. AECC-2 at 11, 22.)

According to Mr. Higgins, it does not make sense for AG-X customers to be allocated production demand costs in the same manner as other customer classes because AG-X customers have not relied on APS's production supply for more than seven years. (Ex. AECC-2 at 16.) According to Mr. Higgins, AG-X customers contribute to APS's ability to defer new capacity needs, as demonstrated by APS's 2020 IRP identifying 160 MW of AG-X capacity as an existing resource for each year of the planning period and, further, APS's determination that AG-X customers represent 200 MW of NCP demand and 160 MW of CP demand. (Ex. AECC-2 at 17-18, ex. KCH-22 at 17.) Mr. Higgins disagreed with Mr. Snook's testimony that AG-X does not provide sufficient resource adequacy for APS to exclude a portion of the AG-X load as a resource planning obligation, asserting that the AG-X

tariff requires a Generation Service Provider ("GSP") to provide "firm power," which is defined to mean generation resources identified in Western Power Pool Schedule C ("WPP Schedule C") or a reasonable equivalent determined by APS, and that this firm power provides more resource adequacy than the non-firm market wholesale purchases APS has included in its resource planning. (Ex. AECC-2 at 17-18.) Mr. Higgins conceded that IRP planning could indicate that AG-X provides less than a MW-for-MW reduction in long-term capacity needs because of reliability requirements, and that it would be reasonable to consider the extent to which AG-X load "has any genuine cost responsibility for reliability-related capacity," but asserted that the existing AG-X reserve capacity charge is an appropriate mechanism to compensate APS for any reliability-related generation required for AG-X load and, further, that AG-X GSPs should have the opportunity to meet APS's resource adequacy needs. (Ex. AECC-2 at 18-19.)

The reserve capacity charge is the generation demand charge for AG-X service and is set at $5.5398/kW/month, which is lower than the non-fuel generation charges paid by full-service customers. (Ex. AECC-2 at 19.) Mr. Higgins asserted that by charging a reserve capacity charge that is lower than the non-fuel generation charges paid by full-service customers and then allocating a full share of production demand costs to AG-X customers, APS creates the "misleading impression" that AG-X customers do not cover their full costs of service although, Mr. Higgins asserted, AG-X customers cover significantly more than their full costs of service. (Ex. AECC-2 at 19-20.) Mr. Higgins testified that by paying the reserve capacity charge for the seven years that the AG-X program (previously called AG-1) has existed, AG-X customers have already paid enough of the legacy generation costs referenced by Mr. Snook, noting that the Oregon PUC only required such payments for five years. (Ex. AECC-2 at 20 (citing Oregon PUC Order No. 12 500 (December 30, 2012) at 8-9).) Mr. Higgins noted that AG-X customers also pay transmission, distribution, and customer charges; the SBC; all surcharges applicable to their underlying rate schedules (except the PSA and EIS); and an administrative management fee of $0.0018/kWh/month. (Ex. AECC-2 at 22.)

Mr. Higgins performed his own cost-of-service analysis for AG-X customers and determined that AG-X customers are overpaying their costs of service and would need to receive a rate decrease of 28.5% or greater to achieve a 1.0 RROR. (Ex. AECC-2 at 25-29.) The variance in the amount of

decrease needed was based on Mr. Higgins's inclusion (or omission) of the impacts of his recommendations on REST and AZ Sun costs,[340] SBC, DSM costs, and the PSA, as well as whether he used APS's revenue requirement or AECC/Freeport's recommended revenue requirement. (Ex. AECC-2 at 25-30.)

c. Other Parties

No other party expressly adopted or opposed AECC/Freeport's arguments.

e. APS Response

Mr. Snook testified that generation capacity costs are allocated to AG-X customers based on their resource adequacy needs, because the WSPP Schedule C is insufficient to provide resource adequacy. (Tr. at 2517-2518.) Mr. Snook testified that the WSPP Schedule C contract provides a block of power that is "firm until it's not" because it can be curtailed. (Tr. at 2583.) Mr. Snook conceded that curtailment is infrequent, but stated that "whenever it does happen it's always at a time when the system needs something." (Tr. at 2583.) Mr. Snook recounted that there were curtailments for approximately half of the AG-X customers occurred during the heat storm in summer 2020, on critical days, when both the APS system and the regional system were "stressed," and APS had to provide generation capacity to fill the void. (Tr. at 2584.) Mr. Snook also noted that the cost allocation does not affect the rates AG-X customers pay because APS has not proposed to change the AG-X program design based on the COSS in this case. (Tr. at 2518.)

f. Resolution

Although the incidences of APS needing to fill the void left by curtailment for AG-X customers are infrequent, they do occur, and apparently at the most inopportune times, when power is the most expensive to obtain such as during the 2020 summer heat storm. Unless the AG-X program is modified in the future to make AG-X customers self-sufficient (either by having them accept curtailment or arrange in another way to obtain replacement power), APS will continue to incur generation capacity costs for AG-X customers. Thus, it is reasonable for APS to allocate generation costs to AG-X customers. AECC/Freeport's position will not be adopted.

[340] Mr. Higgins testified that base rate REST and AZ Sun costs should be functionalized as demand production and allocated using the A&E method. (Ex. AECC-2 at 14-15.)

P. Cost of Service – Allocation of Revenues

a. APS Position

APS proposes to distribute the revenue increase evenly across all rate classes so that the rate classes do not experience disparate impacts. (Ex. APS-26 at 4; Ex. APS-27 at 3.) Ms. Hobbick testified that there were some inconsistent impacts for rate classes from APS's proposal because the TEAM adjustor was transferred into base rates, and the TEAM refunded the lower income tax rates based on cents per kWh, although income taxes generally are allocated using class revenues. (Ex. APS-26 at 5.) Per Ms. Hobbick, this resulted in some classes receiving a disproportionate benefit of the tax credit through the TEAM as compared to what happens when the lower federal tax rate is directly reflected in rates. (Ex. APS-26 at 6.) To mitigate these differences, Ms. Hobbick made slight adjustments to rate design, resulting in a narrow range of net impacts and a near even distribution of revenue across classes, with the proposed increases ranging from 1.33% to 3.64% and the net increases (after adjustor transfers) ranging from 5.41% to 5.82%. (Ex. APS-26 at 6.)

b. AECC/Freeport

AECC/Freeport disagrees with APS's proposed revenue allocation. Based on his revised COSS, Mr. Higgins determined that the net revenue changes needed to achieve 1.0 RRORs would range from a decrease of 30% for AG-X customers to an increase of 57% for Church customers. (Ex. AECC-2 at 30-31.) Mr. Higgins recommended, however, that net revenue changes be made within a narrower range to support gradualism. (Ex. AECC-2 at 31.) To determine his recommended revenue allocations, Mr. Higgins grouped the rate classes other than AG-X into three groups based on each class's needed net revenue changes, with group 1 needing revenue changes greater than 5% below the system average (2%), group 2 needing revenue changes between 5% below and 5% above the system average, and group 3 needing revenue changes more than 5% above the system average. (Ex. AECC-2 at 31.) Mr. Higgins recommended a net increase of 1% for group 1, the system average net increase of 2% for group 2, and the remaining revenue requirement (other than the AG-X revenue contribution) to be collected from group 3 (resulting in 3.05%). (Ex. AECC-2 at 31.)

Mr. Higgins stated that because AG-X customers' standard rates are tied to the non-generation rates of their underlying rate schedules (E-32M, E-32L, E-34, or E-35), he determined the AG-X

revenue change by setting the reserve capacity charge at $2.7699/kW/month, setting the SBC to $0.00131/kWh, and decreasing the other AG-X rates by the non-fuel base revenue decreases for the underlying rate schedules. (Ex. AECC-2 at 31.) Mr. Higgins thus concluded that AG-X customers should have a net revenue decrease of 6.35%. (Ex. AECC-2 at 31.)

Mr. Higgins recommended that his basic approach for revenue allocation be used whether the Commission approves a lower or higher revenue requirement, specifically noting that the reserve capacity charge should be set at $2.7699/kW/month and that the SBC should be set at approximately $0.00131/kWh (which excludes DSM, REST, and AZ Sun costs). (Ex. AECC-2 at 32-33.)

c. FEA

FEA disagrees with APS's proposed revenue allocation, asserting that it is not in line with the COSS results and does not do enough to reduce subsidies between rate classes, instead exacerbating the subsidies already being paid by the general service class. (Ex. FEA-3 at 3, 23-25.) Ms. Alderson determined that the residential class requires the largest rate increase and that the Large and XL general service customers should receive a rate reduction to eliminate subsidies. (Ex. FEA-3 at 23-24) Ms. Alderson asserted that her "corrected COSS" and alternate spread of the proposed revenue increase would minimizes subsidies and brings classes closer to cost of service, while also mitigating impacts on residential customers, who are currently receiving the greatest subsidies, so as to avoid rate shock. (Ex. FEA-3 at 3.) According to Ms. Alderson, APS has not provided any justification for not attempting to rebalance rates and reduce subsidies. (Ex. FEA-3 at 25.)

Ms. Alderson recommended that her corrected COSS be used to spread the overall revenue increase approved by the Commission across the retail customer classes, that no class receive a net rate decrease, and that no class receive a net rate increase greater than two times the system average net rate increase. (Ex. FEA-3 at 21-22, 26.) If the Commission approves only a very small revenue increase for APS or approves a revenue decrease, however, Ms. Alderson believes that rate decreases should be provided to classes that are providing significant revenue subsidies. (Ex. FEA-3 at 26.) Ms. Alderson prepared a table showing FEA's recommended revenue spread, based on the $183.6 million revenue increase requested by APS and Ms. Alderson's corrected COSS. (Ex. FEA-3 at 26-27, att. AMA-6DR.) Ms. Alderson stated that this revenue spread would move each class closer to a 1.00 parity

ROR. (Ex. FEA-3 at 27.) Under FEA's recommended revenue spread, customers on Legacy Solar, R-Basic, Church, AG-X, and Street Lighting rates would receive the highest rate increases at 11.6% (two times the average increase); customers on R-Demand and R-Solar Demand would receive a 10.7% increase; customers on R-TOU and R-Solar TOU would receive a 5.7% increase; Water Pumping customers would receive a 5.0% increase; E-32 L customers would receive a 4.1% increase; and the remaining general service and classified customers would receive a 1.0% increase. (Ex. FEA-3 at att. AMA-6DR.)

d. Kroger

Kroger asserts that APS's rates need to be made more cost-based so that subsidies between rate classes can be reduced. (Ex. Kroger-1 at 6.) Mr. Baron determined that general service customers are paying more than $198 million in subsidies under APS's current rates. (Ex. Kroger-1 at 13-14.) Further, Mr. Baron determined that APS's proposed rates in this case (not including adjustors) would increase the subsidies paid by general service customers by $8.6 million, to a total of $203 million. (Ex. Kroger-1 at 15-16.) Mr. Baron recommended that if the Commission approves a base revenue increase lower than APS's requested $40.5 million increase, any reduction be applied to rate classes to reduce interclass subsidies. (Ex. Kroger-1 at 17; Kroger Br. at 2.) Specifically, Mr. Baron suggested that 50% of the difference between $40.5 million and the approved revenue increase amount be applied on a uniform percentage basis to reduce subsidies paid by general service customers[341] and that the remaining 50% of the difference be applied on a uniform percentage basis to all rate classes to reduce APS's proposed rate increases. (Ex. Kroger-1 at 17-18; Kroger Br. at 2-3.) Mr. Baron asserted that he had made the same recommendation in the recent TEP rate case. (Ex. Kroger-1 at 18.)

e. Vote Solar

Vote Solar vehemently opposes requiring DG solar customers to pay the Grid Access Charge, as discussed below in the Section related to residential rate design, but did not provide other arguments concerning the allocation of revenue proposed by APS. (See VS Brief.)

. . .

[341] The exception would be Church rate customers, as they are providing no subsidization. (Ex. Kroger-1 at 18.)

f. Walmart

Walmart does not oppose APS's revenue allocation. (Ex. Walmart-1 at 8; Ex. Walmart-2 at 5.) However, Walmart recommended that if the Commission were to approve a revenue requirement lower than what APS proposed, the revenue decrease be used to reduce current interclass subsidies by apportioning a portion of the reduction only to rate classes providing subsidies, and reducing the impact to all customers by apportioning the remainder to all classes. (Ex. Walmart-1 at 9.) Additionally, Mr. Chriss expressed support for Kroger's two-step allocation process for reductions in revenue requirement. (Ex. Walmart-1 at 9.) Mr. Chriss testified that Walmart would prefer that class subsidies be eliminated if a revenue decrease occurs in this case. (Tr. at 3032-3033.)

g. RUCO

RUCO supports APS's proposed revenue allocation, which RUCO asserted would result in a 0.63% rate decrease for every class. (Ex. RUCO-2 at 1; RUCO Br. at 38.) RUCO opposes the revenue allocations proposed by Staff and AECC/Freeport, because Staff would allocate to the residential class less than the average decrease in rates, and AECC/Freeport would allocate to the residential class more than the average increase in rates. (Ex. RUCO-2 at 21.) Mr. Radigan testified that RUCO supports the even revenue allocation proposed by APS because the "numerous and dramatic rate changes" made in the 2016 Rate Case produced "confusion, undue rate impacts, and anger" in customers, and because RUCO's recommended rate decrease is so small that an uneven allocation would have no meaningful impact. (Ex. RUCO-2 at 21-22.) Mr. Radigan testified that this case should address the "major rate design issues" caused by the 2016 Rate Case and that APS's next rate case should address interclass subsidies. (Ex. RUCO-2 at 22.)

h. Staff

Staff opposes APS's proposed revenue allocation, asserting that it is "inequitable and . . . not conditioned or influenced in any way by APS's CCOSS results." (Ex. S-5 at 25.) Dr. Dismukes asserted that APS's proposed base rate increase ranged from a 1% increase to a 3.6% rate increase, although APS proposed a revenue increase across customer classes of 2.1%. (Ex. S-5 at 25.) Additionally, Dr. Dismukes took issue with APS proposing to increase all residential base rates by 2.24% because APS's COSS showed that the largest residential subclass (TOU) has a RROR greater

than 1.0. (Ex. S-5 at 25-26.) Dr. Dismukes disagreed with APS's proposal not to base its revenue allocation on the results of its COSS, asserting that although regulators deviate from setting rates at full COS based on policy or equity reasons, it is widely accepted that reasonable rates should be informed by COS and that using the COS to set rates minimizes subsidization among classes and "promotes appropriate consumer rationing." (Ex. S-5 at 26.)

Dr. Dismukes recommended that, if the Commission approves a rate decrease for APS, the rates for rate classes that have RRORs lower than 1.0 be allocated a reduction at 50% of the overall system average decrease, and the remaining revenue classes (with RRORs of 1.0 or above) be allocated the remaining reduction equally. (Ex. S-5 at 26.) Using Staff's proposed revenue requirement, Dr. Dismukes estimated that Staff's proposed revenue allocation would result in decreases of between 0.38% and 1.03% for APS's customers. (Ex. S-5 at ex. DED-6 at 3-4.)

i. APS Response

Ms. Hobbick testified that significant progress was made in the 2016 Rate Case to improve revenue allocation consistent with cost causation, as demonstrated by the net impact to residential customers of 4.54% and the net impact to general service customers of 1.87%. (Ex. APS-26 at 4-5.) Because of this, APS asserted, the proposed increase should be distributed evenly. (Ex. APS-26 at 5.)

APS disagreed with the revenue allocation proposed by FEA because it would increase costs to residential customers to decrease costs for large business customers. (Ex. APS-26 at 6.) Ms. Hobbick testified that Ms. Alderson's recommendations would allocate more than $149 million of APS's originally requested $183.6 million revenue increase to residential customers. (Ex. APS-26 at 6.) APS also argued that FEA contradicted itself by criticizing APS for not proposing to spread its revenues based on COSS results while also acknowledging that COSS results are rarely strictly followed. (APS Br. at 54; Tr. at 3162-3163.)

APS also disagreed with Staff's proposed allocation, in part because it involves a revenue decrease, with half of the overall average decrease allocated to those rate classes with rates of return less than APS's average. (Ex. APS-26 at 7.) APS agrees with Dr. Dismukes's recommendations to use gradualism to protect customers from rate shock, to maintain rate continuity, and not to set rates solely based on COSS results. (Ex. APS-26 at 7.) On brief, APS criticized Staff's recommended

revenue allocation for benefiting commercial classes to the detriment of residential classes and for creating disparate rate impacts among residential classes. (APS Br. at 55.)

j. Resolution

As discussed above, the parties have disparate positions concerning the appropriate distribution of the change in revenues. More importantly, the Commission is not able to adopt any of the COSSs proposed in this matter in their entireties, and it has not been established that achieving a unity rate of return is an appropriate objective in this matter. Accordingly, cost of service provides only minimal direction for revenue allocation in this case. Nevertheless, a comparison of the COSS results obtained by APS and Staff revealed that the following subclasses likely are not fully covering their costs of service: R-XS, R-Basic, R-Basic L, Legacy Solar (Energy), Legacy Solar (Demand), Church, and E-32 L. It also seems likely that AG-X customers and R-2 and R-3 combined customers are not fully covering their COS. Likewise, it appears that the remaining classes are either fully covering their costs (TOU E (at least non-solar) and E-32 TOU L) or over-recovering their costs (E-32 TOU XS, E-32 TOU S, E-32 TOU M, E-30 and E-32 XS combined, and GS-Schools M and L combined). The Commission considers coverage of COS to be an important goal, so that subsidization between classes is appropriately managed to the extent reasonable in light of public policy goals and the public interest to promote efficient use of resources. Because the Commission does not have before it a COSS that it can rely upon as guidance in reasonably allocating the revenue requirement change to ameliorate subsidization to an appropriate extent, the Commission instead will adopt an even allocation of the change in revenue requirement, as proposed by APS. This will ensure gradualism and consistency in APS's rates and is appropriate in light of the extreme changes that were made in the 2016 Rate Case, from which many customers are still reeling.

Q. AG-X/AG-Y

The AG-X program, described above in section (III)(F)(2), allows AG-X customers to purchase generation from GSPs rather than from APS. The AG-X program has been fully subscribed since its inception, as was its predecessor program known as AG-1. (Ex. CSD-1 at 6.) Each program was the result of a rate case settlement—AG-X from the 2016 Rate Case and AG-1 from the 2012 Rate Case. (Ex. CSD-1 at 3-7.) A total of 115 customer accounts currently participate in AG-X, and more than a

dozen others have been turned away due to the program's 200 MW cap. (Ex. CSD-1 at 7.) No AG-1 or AG-X customer has returned to standard general service. (Ex. CSD-1 at 7.) AG-X customers include hospitals, universities, grocery stores, and retail stores. (Ex. APS-29 at 21.)

AG-Y would be a pilot; available to standard offer customers served under E-32 M, E-32 M TOU, E-32 L, E-32 L TOU, or E-32 L SP; and capped at 200 MW of customer load, although APS would be able to exceed the cap at its discretion upon notice to the Commission. (Ex. APS-53; Ex. APS-28 at att. LRS-5DR.) The POA for the AG-Y rider, as proposed by APS, is attached hereto and incorporated herein as Exhibit A. AG-Y customers would remain subject to the provisions, charges, and adjustments in their retail rate schedules, except that unbundled generation energy costs would be credited on the monthly bill at a rate of $0.03600/kWh, PSA charges would not apply, and the customer would pay generation energy costs based on hourly wholesale market prices per kWh posted on APS's website on a day-ahead basis. (Ex. APS-28 at att. LRS-5DR.) AG-Y customers would be required to enter into an electric supply agreement with APS, but would not be involved with any GSP other than APS. (Ex. APS-28 at 24-25, att. LRS-5DR.)

Parties to this case have made recommendations both for changes to the AG-X rider and for approval/denial/modification of the proposed AG-Y rider.

1. APS Position

APS proposes for AG-X to continue in its current form and size, but with the following modifications proposed by other parties:

- AG-X should allow customers that aggregate accounts to meet AG-X's 10 MW minimum load-size eligibility requirement to add accounts if their aggregate load falls below the 10 MW threshold because of participation in EE programs. (Ex. APS-29 at 25.)
- The AG-X scheduling procedure should be changed to allow for intra-day scheduling changes by GSPs. (Ex. APS-29 at 25.) The intra-day trading capabilities would need to be developed and integrated into APS's scheduling platform and protocols, and APS has committed to working with GSPs and customers to develop the intra-day scheduling capabilities. (*Id.*)

APS also proposes for the PSA mitigation mechanism to remain in place for AG-X.

APS proposes for the Commission to approve AG-Y as included in Exhibit A, asserting that

AG-Y was created to meet Decision No. 77043, the Commission's "Policy Statement Regarding AG-Y Alternative Generation/Buy-Through Program" ("AG-Y Policy"),[342] by providing medium and large commercial customers increased flexibility to manage their energy costs while not shifting costs to other customers (APS Br. at 86; Ex. APS-29 at 18-19; Ex. CS-3.) Mr. Snook testified that the AG-Y program would provide customers access to market energy prices without creating issues of resource adequacy or preferential transmission access or an increase in ancillary service costs to be shouldered by non-AG-Y customers. (Ex. APS-28 at 24.) Mr. Snook added that AG-Y would not create transmission delivery issues related to the Palo Verde hub and would not create ramping issues for APS's system like those that occur with GSP's hourly block schedules. (*Id.* at 25.)

2. AECC/Freeport

AECC/Freeport argues that because AG-X customers are already paying more than they should for the services they receive from APS, the reserve capacity charge should be reduced by 50% in this case and set at cost in APS's next rate case, and the PSA mitigation mechanism for AG-X service should be eliminated. (Ex. AECC-2 at 20-21; Ex. AECC-3 at 34.)

According to Mr. Higgins, unlike the reserve capacity charge adopted for AG-1, which at $1.04775/kW/month was set at 15% of the FERC cost-based generation rate and was truly for reserve capacity, the current reserve capacity charge (which is five times greater at $5.5398/kW/month) pays for more than reserve capacity, providing APS a continuous source of generation-related revenues and compensating APS for its legacy generation resources. (Ex. AECC-3 at 30.) Mr. Higgins testified that the reserve capacity charge was structured in its current form in the 2016 Rate Case settlement to allow APS to meet its revenue requirement because APS had proposed to eliminate AG-1 in that case, had thus allocated AG-1 customers a full share of generation costs, and needed to mitigate the perception that other classes would be subsidizing AG-X. (See Ex. AECC-3 at 30-31.) Per Mr. Higgins, because AG-X customers have paid reserve capacity charges for seven years, they have more than paid the legacy generation costs and stranded costs that the reserve capacity charge was intended to cover. (Ex. AECC-2 at 20-21; AECC Br. at 22.)

[342] The AG-Y Policy was admitted herein as Exhibit CS-3.

AECC/Freeport supports Calpine/Direct's position that APS's resource adequacy deficiency claims are flawed and unsupported by the evidence. (AECC RBr. at 10.) Mr. Higgins disputed APS's contention that the reserve capacity charge actually recovers the costs of APS's power plants still needed to serve AG-X customers because of the infirmities of the GSPs' power supplies. (Ex. AECC-3 at 31.) Mr. Higgins acknowledged that during the heat storm event on August 18, 2020, which lasted five hours, the AG-X supply shortfall ranged from 38 MW to 94 MW, and APS provided power so that power consumption by AG-X customers was not curtailed. (Ex. AECC-3 at 32.) Mr. Higgins suggested, however, that APS was adequately compensated for that because the GSPs subsequently paid APS liquidated damages totaling approximately $514,000, or nearly $1,733/MWh, all of which was credited to APS retail customers through the PSA. (Ex. AECC-3 at 32.) Additionally, Mr. Higgins questioned why the large reserve capacity charges paid by AG-X customers did not cover the costs of the back-up generation provided by APS, asserting that it is misleading to call it a reserve capacity charge when it "provided no financial protection to them against the [California Independent System Operator ("CAISO")] curtailment event and the associated market risk." (Ex. AECC-3 at 33.) Mr. Higgins further asserted that if APS's IRP planning process indicates that due to reliability issues, AG-X results in less than a MW-for-MW reduction in APS's long-term capacity, the Commission should investigate, with stakeholder involvement, whether and to what extent AG-X load has any genuine cost responsibility for reliability-related capacity and whether any sources other than APS (such as GSPs) can provide resource adequacy. (See Ex. AECC-3 at 33-34.)

Mr. Higgins testified that the $15 million PSA mitigation mechanism is the difference between what APS would have charged AG-X customers if APS supplied their generation service and what APS charges them through reserve capacity charges. (Tr. at 4672.) According to Mr. Higgins, the PSA mitigation mechanism for AG-X should be eliminated in this case because in its original application, APS designed its rates to recover its full revenue requirement without including the PSA mitigation mechanism. (Ex. AECC-3 at 34.) APS stated in response to a data request that the pro forma adjustment to include the PSA mitigation had been left out of the revenue requirement calculation by mistake and would be corrected. (Ex. AECC-3 at 34-35.) According to Mr. Higgins, APS in its rebuttal testimony then created a revenue shortfall that could be attributed to AG-X, as

justification to continue the PSA mitigation mechanism, meaning that any claimed revenue shortfall from AG-X is a "contrivance." (Ex. AECC-3 at 35.) Mr. Higgins conceded that it does not matter on a practical level whether the $15 million per year in revenues is collected through base rates or the PSA mitigation mechanism, but he argued that collecting the money through the PSA perpetuates the idea that AG-X results in cost shifts that must be mitigated, which he stated is misleading because the AG-X program is an integral part of APS's rates, and there is no revenue shortfall when rates are designed to recover the requested revenue requirement. (Ex. AECC-3 at 35-36.) AECC/Freeport argues that because AG-X provides the opportunity for continued and sustained economic development, which benefits the public, the costs for AG-X should be recovered through base rates as are the costs of other APS programs that benefit the public, and AG-X should not be "discriminated against and singled out" by having its costs recovered through the PSA mitigation mechanism. (AECC Br. at 26.) Mr. Higgins recommended that the Commission "sever any connection between the PSA mitigation mechanism and the AG-X program" because the mitigation is no longer needed as long as rates are designed to recover the approved revenue requirement. (Ex. AECC-3 at 36.) Alternatively, however, Mr. Higgins asserted that the PSA mitigation mechanism could be maintained to support the AG-Y program if the AG-Y program were structured as a buy-through program such as AG-X instead of in its APS-proposed form. (Ex. AECC-3 at 36.)

AECC/Freeport also recommends that the Commission modify AG-X to permit growth in existing AG-X load by up to 10% at existing locations (a proposal APS has accepted) and to allow for additional growth in AG-X load if it is delivered other than through the Palo Verde hub, asserting that this would foster economic development in Arizona without adversely impacting APS's ability to deliver power from Palo Verde to APS's non-AG-X customers. (AECC Br. at 26-27.) AECC/Freeport disagrees with APS's position that there are currently transmission constraints for deliveries from the Palo Verde hub,[343] although Mr. Higgins acknowledged that future transmission availability from Palo Verde to Phoenix (beyond 2025) is significantly constrained and that it is reasonable to limit growth

[343] APS has reserved 3,200 to 4,000 MW of transmission capacity from Palo Verde through 2025, and its current load imported from other suppliers through Palo Verde to serve non-AG-X retail customers is 1,711 MW. (Tr. at 1060-1061; AECC Br. at 26.) APS also has generating resources (owned and contracted), such as the Palo Verde nuclear plant, that are located at the Palo Verde hub and that APS also uses that 3,000-plus MW of transmission capacity to import into the Phoenix load pocket. (Tr. at 1061.)

for AG-X loads through Palo Verde to 10%. (AECC Br. at 26; Ex. AECC-2 at 38-39.)

Regarding the AG-Y proposal, AECC/Freeport urges the Commission not to approve the AG-Y program as proposed and instead to approve an AG-Y program that is comparable to AG-X—that at least allows AG-Y customers to contract with GSPs for power supplied through APS. (AECC Br. at 27.) AECC/Freeport argues that the AG-Y program proposed by APS is inconsistent with the AG-Y Policy because it "is simply a tariff pricing option in which customers can pay a daily market price for power without GSP involvement," not a buy-through program. (AECC Br. at 27.) Further, AECC/Freeport argues, the proposed AG-Y program has legal problems because the Arizona Constitution requires the Commission, rather than the market, to establish the "range of rates" to which customers are subject. (AECC Br. at 28.) Additionally, AECC/Freeport argues, the proposed AG-Y program would leave customers subject to hourly market-index pricing with no cap, meaning that only customers able to manage load requirements would be able to avoid occasional high price spikes that occur in the market. (AECC Br. at 28.) AECC/Freeport further argues that GSPs are better positioned to offer the products that will help AG-Y customers further their renewable energy goals and help them manage risk, noting that APS's AG-Y proposal would not allow a customer to choose the nature of its generation (e.g., renewables) and would not allow a customer to negotiate a long-term contract that would allow the customer a better ability to manage costs. (AECC Br. at 28.)

Mr. Higgins testified that if the AG-Y program were modeled after AG-X, there should be only minimal differences, such as allowing E-32 M and E-32 L customers, and customers with an aggregated peak load of 1,000 kW or greater, to participate. (Ex. AECC-2 at 35.) Mr. Higgins testified that a reserve capacity charge comparable to the current AG-X reserve capacity charge would be appropriate for a period of time, as the AG-Y program would be new, and that it could later be stepped down and then eliminated to the extent it exceeds resource adequacy costs. (Ex. AECC-2 at 35-36.) Mr. Higgins also stated that it would be appropriate for the AG-Y program to have a rate mitigation mechanism like AG-X has had through the PSA mitigation mechanism and that the PSA mitigation mechanism should be used to support the AG-Y program if it becomes a buy-through program. (Ex. AECC-2 at 36-37.) Based on APS's current transmission availability, Mr. Higgins urged the Commission to approve an AG-Y buy-through program for 200 MW of load, with a provision for AG-Y customers to be provided

must-run generation by APS at cost-based rates for any hours in which a portion of AG-Y load cannot be served from a market hub due to transmission constraints that would adversely affect other customers if the AG-Y load were to be served 100% from the market hub, and to direct APS to work collaboratively with stakeholders (customers and GSPs) to develop a protocol for AG-Y to be a buy-through program that allows customers to be served from market hubs. (Ex. AECC-2 at 39; AECC RBr. at 10.) AECC/Freeport argues that APS's claim that it would need to increase AG-X/AG-Y charges if AG-Y were a buy-through program should be rejected because APS has provided no empirical evidence demonstrating the projected costs to expand AG-X to incorporate AG-Y-eligible customers. (AECC RBr. at 9.) AECC/Freeport further calls APS's assertion that buy-through priority to deliver power at the Palo Verde hub would need to be eliminated for AG-Y "yet another red herring," arguing that there is sufficient transmission capacity from Palo Verde.[344] (AECC RBr. at 9.)

3. ASBA/AASBO

ASBA/AASBO urge the Commission to approve AG-Y and to require APS to provide a carveout in AG-Y to allow at least one school from each school district in APS's service territory[345] to participate, which Mr. Sarver estimated would add 20-30 MW to the 200 MW cap. (Ex. ASBA-3 at 4.) Mr. Sarver expressed concern that if the AG-Y program is popular, the 200 MW cap proposed by APS will prevent schools from participating because a lottery and waiting list will ensue as they have for AG-X. (Ex. ASBA-3 at 3.) In its brief, ASBA/AASBO emphasized that the 200 MW cap is an arbitrary limit imposed by APS and, further, that APS has conceded that it would have no concerns "if it was the desire of the Commission from a public policy standpoint in approving the AG-Y program to set aside 20 megawatts of the program for schools." (ASBA Br. at 9 (quoting Tr. at 2374).) Additionally, ASBA/AASBO pointed out Mr. Snook's agreement that schools' load characteristics "could be an ideal fit to maximize the benefit of the day-ahead pricing structure." (ASBA Br. at 9 (quoting Ex. APS-29 at 26).)

4. Calpine/Direct

Calpine/Direct are GSPs under APS's AG-X program, and they support and urge expansion of

[344] This does not seem to be consistent with Mr. Higgins's testimony. (*See* Ex. AECC-2 at 38-39.)

[345] There are between 80 and 107 unique school district APS customers in APS's service area, with 1400 individually metered accounts. (*See* ASBA Br. at 2 (citing Ex. ASBA-1 at 4); Ex. ASBA-3 at 4.)

the AG-X program, with some modifications, and oppose adoption of the AG-Y program. Calpine/Direct urge the Commission to reject APS's AG-Y program for the following reasons:

- It does not comply with the AG-Y Policy and would not achieve the benefits intended by the Commission in adopting the AG-Y Policy because AG-Y does not allow for any buy-through of energy from an entity other than APS. (Calpine Br. at 6 (citing Ex. CSD-1 at 9; Tr. at 2304-2307, 2642; Ex. CS-3).)
- It would not allow AG-Y participants to control their energy costs through hedging products available to AG-X participants, leaving AG-Y customers subject to "extreme market price spikes." (Calpine Br. at 6-7 (citing Ex. CSD-1 at 10-11).)
- Because of a mismatch between the market index rates charged to AG-Y participants and the energy credit provided by APS to AG-Y participants, which would result in AG-Y not producing the class revenue target authorized for the class in this case, AG-Y would shift costs to other customers in the same manner that APS opposes elsewhere. (Calpine Br. at 7-8 (citing Ex. CSD-1 at 12-13; Tr. at 2288-2289, 2313-2318).)
- It would be illegal under *Phelps Dodge Corp. v. Ariz. Elec. Power Coop., Inc.,* 207 Ariz. 95, 107 (Ct. App. 2004) ("*Phelps Dodge*"), unlike AG-X, because AG-Y would result in the Commission not establishing any rates and instead allowing rates to be established solely based on the market index price, with no upper or lower bound, whereas AG-X establishes a range of rates.[346] (Calpine Br. at 9-10 (citing *Phelps Dodge* at 107-109; Decision No. 75975 at 121; Ex. CS-4 at 5; Tr. at 2309-2313; Ex. CSD-1 at 13; contra Decision No. 77856 at 160 (concluding that AG-X does not establish a range of rates)).)

Calpine/Direct urges the Commission to require adoption of an AG-Y program that expands upon AG-X, at a scale of up to 200 MW, with the current capacity reserve charge for AG-X, the same imbalance provisions with penalties, and the same requirements for delivery of power by GSPs, but with revisions to allow for intra-day scheduling as recommended by AECC/Freeport and to allow for participation by smaller customer sizes (down to 101 kW with aggregation to 1 MW). (Calpine Br. at

[346] Mr. Bass testified that APS ignored his criticism of AG-Y for not including a range of rates. (Ex. CSD-2 at 7.)

11, 23, att. No. 2[347]; Ex. CSD-1 at 16-18.) On brief, Calpine/Direct included an attachment that is a copy of the current AG-X tariff with Calpine/Direct's recommended modifications for AG-Y as to size, but not including language regarding the intra-day scheduling provision. (Calpine Br. at att. No. 2.) Mr. Bass testified that making AG-Y available only to E-32 M and E-32 L customers is too restrictive, because the AG-Y Policy intended for AG-X to be expanded to smaller customers (those with less than 10 MW demand). (Ex. CSD-1 at 12.) Mr. Bass noted that APS does not intend to allow customers with demand between 3,000 kW and 10 MW (there are 23) and customers with demand over 10 MW who did not make it onto AG-X (there are 13) to participate in AG-Y. (Ex. CSD-1 at 12, ex. GB-1.)

Calpine/Direct argue that the AG-Y program should be an expansion of the AG-X program rather than the APS-proposed AG-Y program for the following reasons:

- Making AG-Y a buy-through program that expands eligibility to smaller customer sizes would be consistent with the Commission's AG-Y Policy, which called for a buy-through option. (Calpine Br. at 11.)
- Customers prefer the AG-X format to the AG-Y format, as evidenced by both AG-1 and AG-X being fully subscribed from their initial lottery, and testimony from witnesses for Walmart, Kroger, and AECC/Freeport who all expressed a preference for AG-X for various reasons—because it allows for hedging to manage risks, because AG-Y would not be economic, and because AG-X allows for buy-through from a GSP. (Calpine Br. at 12-13 (citing Ex. CSD-1 at 7; Tr. at 2947-2949, 3029, 3045-3046, 3049, 4615, 4632).)
- APS's objections to expanding AG-X are "misplaced and unsupported." (Calpine Br. at 13.)

Responding to APS objections related to expansion of AG-X, Calpine/Direct assert that APS is wrong that cost shifts would occur because APS would incur additional resource adequacy costs that would not be recovered through the AG-X charges, arguing that AG-X participants pay "substantial charges" for the "limited generation services" provided by APS, in the form of the reserve capacity charge, the requirement for GSPs to supply "firm energy," the liquidated damages payments to APS if supply is curtailed, and the premium over the FERC-approved imbalance charges when there are

[347] Official notice is taken of Attachment No. 2 to Calpine's brief.

mismatches between schedule and load. (Calpine Br. at 13-14 (citing Ex. APS-30 at 12, 14; Ex. APS-9 at 12; Ex. CSD-1 at 17).) Calpine/Direct also emphasize that curtailments under the WSPP Schedule C contracts are very rare, pointing out that Calpine's supply had reliability in the range of 99.31% to 99.95% in each of the last four years, which Mr. Bass asserted means that the WSPP Schedule C contracts can be used as a resource adequacy resource. (Calpine Br. at 14 (citing Ex. CSD-2 at 11-12; Tr. at 2734-2735).) Calpine/Direct argue that "California [recognizes] imports of non-resource specific contracts with no economic curtailment, such as the WSPP Schedule C, as a resource adequacy contract." (Calpine Br. at 14-15 (citing a California PUC rulemaking order, Decision 20-06-028 (June 25, 2020) at 50-52[348]).) Calpine/Direct further argue that the AG-X liquidated damages provisions cover APS's costs in obtaining replacement power, as acknowledged by APS, and thus avoid a cost shift if curtailment occurs. (Calpine Br. at 15 (citing Ex. CSD-2 at 12; Tr. at 1222-1226, 2678, 2703-2704, 4714-4715; Ex. AECC-3 at 32).) Additionally, Calpine/Direct argue that APS has failed to quantify any costs incurred that exceed the revenues paid to APS under the AG-X program, dismissing Mr. Snook's assertions that the PSA mitigation of $15 million quantifies the cost shift because the PSA mitigation assigns 100% of APS's bundled capacity charges to the AG-X load, essentially assuming that GSPs provide no capacity value, a position that Calpine/Direct refute due to Calpine's reliability

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[348] The date of the order has been corrected. This order, which is available as 2020 WL 4002003 (Cal.P.U.C.), was not offered as an exhibit in this matter, and official notice is taken of it. The CPUC decision stated the following about non-specific resources:

> The **Commission adopts** the following requirements for non-resource-specific [Resource Adequacy ("RA")] imports. An import that does not qualify as a resource-specific import is a non-resource-specific import. A non-resource-specific import shall count towards RA requirements provided that:
> (1) The contract is an energy contract with no economic curtailment provisions.[132]
> (2) The energy must be self-scheduled (or in the alternative, bid in at levels between negative $150/MWh and $0/MWh) into the day-ahead and real-time CAISO markets at least during the Availability Assessment Hours throughout the RA compliance month, consistent with the [maximum cumulative capacity ("MCC")] buckets.
> (3) The energy must be delivered[133] to the [load-serving entity ("LSE")] in accordance with the governing contract, consistent with the MCC buckets.
>
> [132] As stated in D.04-10-035, an example of non-economic curtailment is "a provision in the contract that allows for interruption to serve the seller's native load, in the context of a force majeure situation..." D.04-10-035 at 54 (adopting Section 5 of the Workshop Report on Resource Adequacy Issues at 21, Footnote 13).
> [133] Deliver" is used in this decision to mean energy flows from the source Balancing Authority to the intertie location. Consistent with the CAISO Tariff, intertie location is defined as a "transmission corridor that interconnects the CAISO Balancing Authority Area with another Balancing Authority Area."

2020 WL 400203 at *28.

data. (Calpine Br. at 16 (citing Tr. at 2321-2324, 2525-2526, 2678-2681.) Calpine/Direct also cite Mr. Higgins's testimony to the effect that the $15 million cost shift addressed by the PSA mitigation "is a contrivance" and represents the difference between what is collected from AG-X customers through the reserve capacity charge and what would be collected if AG-X customers paid the full bundled capacity generation charges. (Calpine Br. at 16 (citing Tr. at 4614, 4672).) Calpine/Direct subscribe to Mr. Higgins's belief that AG-X customers are over-paying rather than under-paying and that expansion of the AG-X program as AG-Y would not result in a cost shift if the full reserve capacity charge were collected from AG-Y customers. (Calpine Br. at 17 (citing Tr. at 4672, 4674-4676, 4727-4728).) Calpine/Direct also cite Dr. Dismukes's testimony to the effect that the Commission in its AG-Y Policy would not have authorized APS to propose expansion of AG-X if AG-X resulted in an impermissible cost shift. (Calpine Br. at 17 (citing Tr. at 4906).)

Calpine/Direct assert that if the Commission is concerned about resource adequacy costs, the Commission should direct APS to work with parties to propose a solution that allows AG-X to expand, because Mr. Albert appeared to agree that resource adequacy issues could be resolved through program changes or adoption of more stringent resource adequacy requirements, such as unit-contingent contracts, and Mr. Snook acknowledged that APS has not evaluated such solutions. (Calpine Br. at 18 (citing Tr. at 1226-1228, 2324-2325).) In the alternative, Calpine/Direct asserted, the Commission could investigate developing a curtailment protocol as discussed at hearing, although Calpine/Direct assert that such a protocol should be narrowly tailored to its identified need and should limit curtailment of wholesale buy-through loads to circumstances when GSPs' deliveries are cut and there is no capacity available to APS to avoid curtailments within its balancing authority. (Calpine Br. at 18 (citing Tr. at 4676-4678, 4679-4680).) If the Commission were to adopt a curtailment protocol for AG-X or AG-Y loads, Calpine/Direct assert, the Commission would also need to consider whether capacity-related charges in AG-X and AG-Y should be reduced, including the reserve capacity charge and the requirement for firm energy contracts with liquidated damages penalty provisions. (Calpine Br. at 19 (citing Tr. at 3181-3182, 4678-4679).)

Additionally, Calpine/Direct assert, APS has not established that there is a transmission constraint at the Palo Verde hub or that there will be such a constraint. (Calpine Br. at 19.) Mr.

Goddard testified that APS's claims of transmission constraints originate from an alleged transmission study conducted 20 years ago by the Salt River Project that APS was unable to produce and that no current APS employee has reviewed. (Ex. CS-1 at 4, 7-8.) Calpine/Direct point to Mr. Goddard's testimony that APS has already reserved 3,200 to 4,000 MW of transmission capacity from Palo Verde to load that could be used to accept additional deliveries from GSPs for AG-Y without any additional reservation of transmission capacity and that there is at least 264 MW of incremental available transmission capacity for future transmission reservations from Palo Verde through 2025. (Calpine Br. at 19 (citing Ex. CS-2 at 4).) Calpine/Direct also point out that Mr. Albert agreed with Mr. Goddard that APS has reserved enough transmission capacity to allow for expansion of wholesale buy-through supply by 200 MW for delivery at Palo Verde (although Calpine/Direct acknowledge that Mr. Albert suggested there may be a transmission constraint in the future) and that Mr. Albert agreed that an additional charge could be developed for wholesale buy-through customers' preferential use of the Palo Verde hub if such a constraint were to develop.[349] (Calpine Br. at 19-20 (citing Tr. at 1057-1061, 1063).) According to Mr. Goddard, "Palo Verde is the only liquid delivery point to which GSPs could likely deliver power in a wholesale buy-through program." (Ex. CS-1 at 9.)

Calpine/Direct also refute APS's claim that it incurs unrecovered ramping and load-following costs for AG-X customers, pointing to Mr. Goddard's testimony that AG-X customers and GSPs already pay charges intended to recover ramping and load-following costs through the FERC-approved imbalance charges and the penalties for scheduling deviations. (Calpine Br. at 20 (citing Ex. CS-1 at 9-12; Tr. at 2675-2676).) Calpine/Direct further assert that AG-X customers pay for ramping and load-following through unbundled transmission costs and the capacity reserve charge. (Calpine Br. at 20-21 (citing Ex. CS-1 at 10-11).)

Calpine/Direct further assert that the recent decision in the TEP Rate Case (Decision No. 77856) should not influence the outcome of this case because the facts of this case are distinguishable, both because the TEP program allows for limited buy-through from GSPs (unlike AG-Y as proposed) and because the Commission's decision for TEP's program was based on concern that TEP lacked the

[349] Mr. Albert testified that giving preference to AG-X at the Palo Verde hub puts other customers at a cost disadvantage because they are then forced to use more expensive delivery points. (Tr. at 1058.)

experience to implement a program like AG-X (experience that APS does not lack). (Calpine Br. at 21-22 (citing Decision No. 77856 at 146, 151, 159; Tr. at 4630).)

Finally, Calpine/Direct urge the Commission to make the following modifications to the AG-X program, as proposed by AECC/Freeport:[350]

- Reduce the reserve capacity charge by 50% to $2.7699/kW/month;
- Allow AG-X load to grow by up to 10% at existing locations that are currently taking AG-X service for deliveries at Palo Verde and to grow with no limitations at existing locations that take AG-X service for deliveries at other delivery points;
- Allow GSPs to make intraday scheduling updates to their AG-X loads; and
- Eliminate use of the PSA mitigation mechanism for AG-X and instead design rates to recover the approved jurisdictional revenue requirement, so that the PSA mitigation mechanism can be used for the new AG-Y buy-through program.

5. FEA

FEA asserts that AG-Y as proposed disadvantages customers with peak demands higher than 3 MW and urges the Commission, if it authorizes the new AG-Y program, to remove the customer size limit so that customers who were unable to participate in AG-X due to the lottery are able to participate in AG-Y. (FEA Br. at 36; Ex. FEA-3 at 28.) According to Ms. Alderson, 27 customers attempted to participate in AG-1 and AG-X through the lottery process but were unsuccessful, and approximately half of them take service under E-34 or E-35, which would make them ineligible for AG-Y as proposed. (Ex. FEA-3 at 28.) Ms. Alderson testified that APS should not limit AG-Y to small commercial customers between 101 kW and 2,999 kW and, further, that APS should hold a lottery if the amount of interested load exceeds the proposed 200 MW program limit. (Ex. FEA-3 at 4, 28.) Ms. Alderson supported having the AG-Y approved and available to both medium and large business customers that were not able to participate in AG-X, although she agreed with other parties that AG-Y provides significantly diminished value in comparison to AG-X. (Ex. FEA-4 at 11-12.) FEA believes that expanding access to market-based price offerings for small and large customers would support the

[350] Calpine Br. at 23 (citing Ex. AECC-2 at 15-24; Ex. AECC-3 at 24-38).)

Chairwoman's objective of reducing costs to ratepayers through new and innovative rate options because various price offerings can create overall average rate decline. (FEA Br. at 36 (citing Ex. FEA-3 at 27-28; Ex. FEA-21 at 1-2; Ex. FEA-4 at 12; Ex. RUCO-17 at 2).)

6. Kroger

Kroger has 49 stores operating as Fry's in the APS service territory, and they consume more than 100 million kWh per year. (Ex. Kroger-1 at 5.) Kroger takes service under E-32 M, E-32 L, and AG-X and is a major participant for AG-X. (Ex. Kroger-1 at 6.) Kroger desires to continue participating in AG-X and was concerned that existing E-32M customers served under AG-X through load aggregation might not be able to continue as AG-X customers if AG-Y were approved. (Ex. Kroger-1 at 22; Kroger Br. at 5.) APS confirmed that such customers would be able to stay on AG-X, but Kroger requests that the Commission expressly require this in its decision. (Kroger Br. at 5 (citing Ex. Kroger-1 at ex. SJB-2); Ex. Kroger-1 at 8, 22.)

Kroger also was concerned that EE efforts at stores with loads aggregated for AG-X could drop to levels that would result in AG-X ineligibility and requested that APS allow such customers to add accounts to their aggregate group if usage changes at a specific location due to EE. (Kroger Br. at 6.) APS agreed on rebuttal that customers should be able to add accounts to meet the 10 MW threshold if their aggregate load falls below the 10 MW threshold due to participation in EE programs. (Kroger Br. at 6 (citing Ex. APS-29 at 25).) Kroger requests that the Commission expressly require this in its decision. (Kroger Br. at 6; Ex. Kroger-1 at 24.)

Mr. Baron testified that AG-Y would not be cost effective for a high load factor E-32 M or E-32 L customer like Kroger because the energy credit is insufficient to offset the hourly index charges. (Ex. Kroger-1 at 25.)

7. Walmart

Walmart urges the Commission to reject the AG-Y program as proposed and instead require APS to work with stakeholders on expanding AG-X in a way that serves the Commission's goals of expanding commercial customers' opportunities to manage energy costs while minimizing impacts on other customers. (Walmart Br. at 3 (citing Ex. Walmart-1 at 14).) Walmart argues that the proposed AG-Y program does not conform to the AG-Y Policy because it is not a competitive supply program

like AG-X and would not provide AG-Y customers access to flexible supply-side procurement tools used by GSPs to manage energy costs. (Walmart Br. at 2 (citing Ex. Walmart-1 at 11-12).) Rather, Walmart asserts, AG-Y customers would remain captive APS customers for generation services while moving to an energy cost that offers no supply-side risk management tools. (Walmart Br. at 2-3 (citing Ex. Walmart-1 at 12-13; Tr. at 3046-3050).) Mr. Chriss testified that the only way to manage costs on the AG-Y program is through load management, because it is not a competitive supply program like AG-X. (Ex. Walmart-1 at 12). Mr. Chriss also testified that AG-Y would not help Walmart reach its renewable energy and carbon emissions goals. (Ex. Walmart-1 at 13.)

8. Staff

Staff did not brief the AG-X/AG-Y issue, other than to say that Staff believes the proposed AG-Y program would not negatively impact non-participating ratepayers. (Staff Br. at 50.) At hearing, Dr. Dismukes indicated that he had not formed an opinion concerning whether AG-X's design negatively affects non-participating ratepayers. (Tr. at 4876.) Dr. Dismukes was under the impression that the Commission had already concluded in a decision that AG-X was consistent with the AG-Y Policy. (Tr. at 4872.)

Regarding the proposed AG-Y program, Dr. Dismukes did opine that the AG-Y program was consistent with the AG-Y Policy and that it did not impact other customers, although he had not been aware that APS was the generation source under AG-Y. (Tr. at 4868-4871, 4905-4906.) Dr. Dismukes conceded that AG-Y would not be a buy-through program if APS was the generation source, but stated that AG-Y could be considered alternative generation and consistent with the AG-Y policy because it would send market-oriented signals for customers to potentially save on energy costs. (Tr. at 4870.) Dr. Dismukes acknowledged that AG-Y would not result in exploration of other generation resources. (Tr. at 4872.) Dr. Dismukes also stated that whether a range of rates is necessary for a buy-through program "to pass legal muster" is a legal question that he could not answer. (Tr. at 4874.)

Staff accepted APS's adjustment related to the PSA mitigation mechanism, stating that APS retains $1.25 million from the margins on wholesale sales each month as a credit to the overall APS fuel costs in the PSA and that because APS retains these revenues through the PSA mechanism, the $15 million should not be included in the base rate revenue deficiency. (Ex. S-15 at 38-39.)

9. APS Response

APS's arguments against expanding AG-X focus largely on a lack of reliability and thus resource adequacy provided by GSPs. According to Mr. Snook, the biggest problem with the AG-X program is that GSPs do not provide all of the generation services their customers need because they do not serve their customers with firm power from reliable power plants that can ramp up and down to match the customers' loads and instead generally serve their customers through block energy purchases from wholesale brokers or suppliers like the CAISO, which can be interrupted during critical load hours, requiring APS to provide the capacity resources and reserves necessary to ensure their customers have reliable service. (Ex. APS-29 at 20.) Mr. Snook and Mr. Albert disputed Mr. Bass's claim that the WSPP Schedule C contracts provide firm power, with Mr. Snook asserting that Mr. Bass confuses capacity and energy, and that contrary to Mr. Bass's claims, the WSPP Schedule C contracts provide firm **energy** but not firm capacity and actually can have their energy cut during critical hours. (Ex. APS-29 at 21; Ex. APS-9 at 12.) Per Mr. Albert, the WSPP Schedule C purchases are firm financially for the buyer (due to the penalty provisions), but not firm regarding delivery, because the "firm service" may be curtailed through agreement, due to force majeure, or to meet public utility or legal obligations. (Ex. APS-8 at 28.) Mr. Albert testified that Mr. Bass's insistence that WSPP Schedule C contracts provide firm power "shows a fundamental difference between a marketer's perspective versus how a utility must reliably plan to serve customers," adding that "APS does not agree that a non-physically backed transaction is more reliable than a steel-in-the-ground resource, especially given the lack of liquidity in the market" and that an after-the-fact penalty payment does not "help serve customer load in real time." (Ex. APS-9 at 12.)

Mr. Albert testified that GSPs do not and are not required to provide resource adequacy or to participate in an integrated planning process to ensure they have the resources needed to serve load reliably. (Ex. APS-9 at 11.) Per Mr. Albert, the North American Reliability Corporation ("NERC") defines resource adequacy as the ability of supply-side resources and demand-side resources to meet aggregate electrical demand (including losses), and the anticipated reserve margin is used to evaluate resource adequacy by comparing expected resources' capability to serve forecasted peak demand. (Ex. APS-8 at 28.) Mr. Snook testified that the WSPP Schedule C contracts "do not provide any of the

power plant capacity attributes or resource adequacy requirements for ensuring a reliable supply of power to the customer." (Ex. APS-29 at 21.) Mr. Snook also disputed Mr. Bass's argument that the one-year notice provision to leave AG-X alleviates the capacity issue, pointing out that because APS cannot curtail customers if GSPs fail to provide generation during critical times, APS must still provide back-up service to the AG-X customers. (Ex. APS-29 at 22.)

During the summer heat storm on August 18, 2020, CAISO curtailed imports into the APS balancing area from AG-X GSPs and some irrigation district suppliers, with almost 60% of the AG-X scheduled energy curtailed from 5 p.m. to 6 p.m. (Ex. APS-8 at 29.) The imports curtailed were from short-term market purchases not backed by firm supplies from designated resources. (Ex. APS-8 at 29.) APS did not curtail the loads of its AG-X or irrigation district customers and made up for the generation with its own reserves. (Ex. APS-8 at 29.) APS was unable to curtail the AG-X customers' load when their power supplies were cut and, as the balancing authority, was obligated to serve their loads. (Ex. APS-29 at 21; Ex. APS-9 at 12.) During the same time on August 18, 2020, APS also had its own CAISO imports curtailed, but it was able to serve its retail load reliably because of its portfolio of firm resources (such as its generation assets and asset-backed purchases), its 15% reserve margin, and its day-ahead purchases made to prepare for contingency events that could occur on August 18. (Ex. APS-8 at 29-30.) Mr. Snook added that although the GSPs are required to pay liquidated damages after the fact when they cannot deliver their contracted power supplies, and the liquidated damages are set based on the cost of replacement energy for the deficient hours, APS passes the liquidated damages through to ratepayers using the PSA and cannot retain the liquidated damages to cover the costs of actual power plants or capacity contracts needed to provide resource adequacy to customers. (Ex. APS-29 at 22; Tr. at 2678, 2704.)

In response to criticism that APS itself uses WSPP Schedule C contracts to serve its customers, Mr. Albert stated that APS enters into such contracts to provide lower cost generation, although it has generation assets or asset-backed purchases as backup, and that APS does not rely on WSPP Schedule C purchases for reliability; does not include them in meeting its reserve margin obligations; and (aside from AG-X purchases) does not include them in its resource plans. (Ex. APS-8 at 29.) Mr. Snook also indicated that APS is revisiting how it addresses AG-X load in its IRPs because of the potential for

curtailments (and the actual August 2020 curtailments) as well as issues with ramping and other critical capacity-related requirements. (Ex. APS-8 at 30; Ex. CSD-1 at ex. GB-1 (response to Calpine 1.5).)

Mr. Snook asserted that AG-X customers, like all APS customers, receive a "regulation and frequency response" service, paid for through retail transmission charges, that provides a very small amount of generation that can instantly and automatically ramp up or down to match supply with load continuously, covering minor load deviations that were not anticipated or provided for in the scheduled power supply. (Ex. APS-29 at 22.) Mr. Snook asserted that if APS only provided blocks of power like the GSPs provide under AG-X, there might not be enough resources to provide the regulation and frequency response service, and the cost for the service would be much higher than what is currently being paid, which he stated indicates that GSPs are not paying fully for the type of generation needed to follow their loads constantly. (Ex. APS-29. at 23.) Mr. Snook also asserted that the reserve capacity charge and transmission ancillary charges paid by AG-X customers do not fully cover the costs for the capacity services provided by APS, and the remaining costs are mitigated through the retained PSA margins or shifted to other customers. (Ex. APS-29 at 23.)

Mr. Snook disagreed with AECC/Freeport's claims that the PSA mitigation is no longer needed for AG-X, asserting that without the PSA mitigation, AG-X would have a revenue shortfall that would need to be made up through higher rates to other customers. (Ex. APS-29 at 18.) Mr. Snook stated that the $1.25 million in retained margins from the PSA continues to be needed for the AG-X program and that Mr. Higgins's proposal to use the $15 million to expand the AG-X program through the AG-Y program "is an admission that expanding the AG-X program in its current form requires a cost shift to be recovered from other customers." (Ex. APS-30 at 13.) APS argues that Mr. Higgins's proposal would only work if the $15 million were embedded in rates, meaning that it would be paid for by non-AG-X/AG-Y participants, because if the $15 million PSA mitigation mechanism were used to support an expanded AG-X-like AG-Y program, APS's revenue requirement would need to be increased by $15 million. (Ex. APS-30 at 13; APS RBr. at 63.)

APS also disagrees with proposals for the AG-X program to be expanded, asserting that the AG-X program cannot be expanded without requiring additional PSA mitigation, increased AG-X/AG-Y charges, removal of the buy-through priority to deliver power at the Palo Verde hub, and resolution

of the resource adequacy deficiencies in the AG-X program, or the costs would be shifted significantly to non-AG-X customers. (Ex. APS-29 at 19, 24.)

APS also disagrees with proposals to cut the reserve capacity charge by 50%. Contrary to Mr. Bass's assertions, Mr. Snook stated, the reserve capacity charge does not pay for legacy power plants that are no longer needed to serve AG-X customers and is not paid down in any manner; rather, it only partially recovers the costs of APS power plants that are still needed to serve AG-X customers due to the infirmities of the GSPs' power supply. (Ex. APS-29 at 23; Ex. APS-30 at 15.) Although APS is not proposing to make the change to the AG-X program in this case, Mr. Snook testified that AG-X customers ideally should pay the full unbundled generation capacity charge from their retail rates, while avoiding paying the generation energy charge and PSA adjustor charge, which is what the AG-Y program would achieve, because the AG-X reserve capacity charge does not cover the entire unbundled generation capacity charge, and the uncovered costs are shifted to other customers. (Ex. APS-29 at 23-24; Ex. APS-30 at 14.) Mr. Snook opined that the reason parties oppose the AG-Y program proposal is because customers can save more money and GSPs can make more money under AG-X, due to the generation capacity services that APS provides essentially being paid for by the PSA mitigation or other customers, resulting in higher benefits for the AG-X participants. (Ex. APS-29 at 24.)

APS did not oppose allowing for reasonable load growth for AG-X customers, which Mr. Snook quantified as 10% of the original program allotment, but did oppose a mechanism that would allow for dramatic increases in load, such as doubling of permissible load, as maintaining the overall program size limitation is important. (Ex. APS-29 at 25.) APS also opposed having the 10% growth limit apply only to loads served through the Palo Verde hub, asserting that the restriction on growth is needed because AG-X "is not scalable in its current form," and having the additional load delivered through a point other than the Palo Verde hub would address only one small fairness issue with AG-X caused by AG-X load receiving priority delivery at the Palo Verde hub. (Ex. APS-30 at 13.)

Mr. Albert also testified that because APS plans for and maintains the transmission capacity needed to serve its customers reliably, there would be sufficient transmission to accommodate expanding the AG-X program, although if the Commission were to expand AG-X, APS urges the Commission to require that AG-X capacity be delivered through all APS major delivery points, based

on a pro rata share of the affected transmission line Total Transmission Capability ("TTC") ratings, not just the Palo Verde hub. (Ex. APS-9 at 12-13.) According to Mr. Albert, the Palo Verde hub is the least expensive and most liquid of APS's major delivery points, but giving preference to delivery of AG-X load there disadvantages other customers because their load must be delivered more expensively. (Ex. APS-9 at 13.)

During his testimony, Mr. Snook also conceded that there is a flaw in how the imbalance fees are calculated under the AG-X tariff because the imbalance currently is the difference between the schedule and the load, even if there is a curtailment and no power is delivered. (Tr. at 2660-2661.) As a result, for example, if the load is 25 MW, and the schedule is 20 MW, there is an imbalance of 5, even if no power whatsoever is delivered due to curtailment. (*Id.*) The origin of the imbalance provision in the AG-X tariff is FERC wholesale market imbalance language; APS had not considered that with AG-X there is a specific customer for the load who still needs to be served, because that is not the case with wholesale transactions. (*Id.*)

APS disagreed with criticisms that AG-Y is inconsistent with the AG-Y Policy, pointing out that the AG-Y Policy clearly requires that the program not shift costs to non-AG-Y customers. (Ex. APS-29 at 18.) Mr. Snook testified that neither AECC/Freeport nor Calpine/Direct addressed that the Commission required access to market pricing without shifting costs to non-participating customers, which is what the AG-Y program is designed to achieve. (Ex. APS-30 at 12.)

APS also opposed ASBA/AASBO's aggregation proposal for AG-Y, because schools are already eligible for AG-Y without aggregation, and opposed ASBA/AASBO's carve-out proposal for AG-Y, because AG-Y was designed for smaller customers like schools, and APS may lift the 200 MW cap on AG-Y to allow for additional participation after seeing how the AG-Y program functions. (Ex. APS-29 at 26; Ex. APS-30 at 15.) Mr. Snook agreed that because of schools' load characteristics, they could greatly benefit from the day-ahead pricing structure. (Ex. APS-29 at 26.)

In its briefs, APS did not address the argument that AG-Y is unlawful because it does not include a range of rates. However, Mr. Snook testified at hearing that APS believes it has specified all the charges from APS "and that the market index is a formula, so that would be the rate that's approved and there is no need for a range," and nothing further is necessary. (Tr. at 2643.) Mr. Snook also

offered, however, that APS would not oppose having a range included in the AG-Y program if the Commission were to determine that it was necessary. (*Id.*)

10. Resolution

In its AG-Y Policy, the Commission ordered: "Arizona Public Service Company shall either expand and modify its current AG-X to allow medium size commercial customers to participate or propose a new AG-Y alternative generation/buy-through program that would be for medium size commercial customers in its next rate case." (Ex. CS-3 at 4.) The Commission also directed APS, with its proposal, to address a number of factors, including, *inter alia*, the costs of the program, rate impacts on non-participating customers, and resource adequacy and planning issues. (*Id.* at 3.) Further, the Commission directed "that the proposed program shall not shift costs to non-participating customers" and "shall consider consumer protections for both participants and non-participants." (*Id.* at 3-4.)

The proposed AG-Y, as set forth in Exhibit A hereto, is not an alternative generation/buy-through program. Rather, it is a program that provides a market-based pricing option for a limited set of medium and large general service customers (up to 200 MW total load). APS asserts that AG-Y is structured in this manner to ensure that its costs are not shifted to non-AG-Y customers. That may be true, as APS has strongly and consistently asserted that AG-X does not cover its costs, but it does not change that AG-Y as proposed does not meet the requirement imposed by the AG-Y Policy Statement. AG-Y as proposed has no alternative generation options, as all power would be served by APS's existing generation resources, and provides no opportunity for buy-through of power from the market. Additionally, we note that AG-Y appears not to meet the directive for the new program to provide consumer protections for participants, as the AG-Y POA does not provide any restrictions to protect AG-Y participants from skyrocketing day-ahead wholesale market prices and would, as the intervenors assert, leave them completely subject to such market price spikes. Finally, and crucially, we do not believe that AG-Y as proposed is lawful, because it does not include any type of constraints on the day-ahead wholesale market prices that could be charged to AG-Y participants, meaning that the Commission would not be establishing even a range of just and reasonable rates to satisfy its constitutional obligation under Article 15, § 3 and would instead be "improperly delegating to the competitive marketplace the Commission's duty to set just and reasonable rates." (*Phelps Dodge*, 207

Ariz. at 108.) Thus we cannot approve AG-Y as proposed.

We also cannot approve expansion of AG-X as proposed by various intervenors, however, because of the issues with the current AG-X that need to be addressed and resolved in order for the Commission to determine that it is just and reasonable to expand it. For example, resource adequacy is a major issue that must be addressed, because as Mr. Albert testified, "there's only a very few critical hours, critical peak hours, where resource adequacy matters, but it matters greatly in those hours." (Tr. at 1227.) The Commission cannot in good conscience expand a program that could result in APS's customers losing their air conditioning during a heat storm because of curtailment, and APS's obligation to serve AG-X customers' loads. Liquidated damages may cover the costs of any replacement power that can be provided or obtained, but they do not keep the lights or air conditioning on during critical periods.

Thus, we will require APS to engage in a collaborative process with AG-X stakeholders (including at least GSPs, AG-X customers, prospective AG-X customers, RUCO, and Staff) to analyze and identify solutions to at least[351] the following issues that have been identified as to AG-X:

- Whether AG-X's current rates and charges adequately cover the costs to APS of serving AG-X customers or instead result in a cost shift to non-AG-X customers;
- If AG-X's current rates and charges do not adequately cover the costs to APS of serving AG-X customers, whether there are solutions that can be put in place to ensure that costs are not shifted to non-AG-X customers;
- Whether AG-X contracts provide resource adequacy and, if so, to what extent;
- If AG-X contracts do not provide resource adequacy on a MW-for-MW basis, whether there are solutions that can be put in place to ensure that they do provide resource adequacy on a one-to-one basis or, in the alternative, to allow for curtailment of AG-X load when GSPs' deliveries are cut and there is no capacity available to APS to avoid curtailments within its balancing authority;
- Whether and in what manner to fix the "flaw" in AG-X's current tariff that requires

[351] This list is not and is not intended to be exhaustive. To make the collaborative process as valuable as possible, the participants, including APS, should consider in good faith every issue relating to improvement and expansion of AG-X that arises during their discussions. This is intended to be a problem-solving project.

imbalance payments to be made based on variances from scheduled rather than delivered load;

- Whether there is now or will in 2025 and thereafter be a transmission capacity resource constraint at the Palo Verde hub and, if so, what transmission capacity will be available for APS to use for expansion of AG-X or another buy-through program without adversely impacting APS's ability to deliver power from Palo Verde to APS's non-AG-X/buy-through customers;
- If there is or will in 2025 be a transmission capacity resource constraint at the Palo Verde hub, whether and to what extent it is possible and feasible for the load for an expanded AG-X or another buy-through program to be delivered at other transmission points of delivery without adversely impacting APS's ability to deliver power from those other points of delivery to APS's non-AG-X/buy-through customers;
- Whether and to what extent AG-X or another buy-through program should allow for participation by customer sizes smaller and larger than those served by E-32 M, E-32 M TOU, E-32 L, E-32 L TOU, and E-32 L;
- Whether it is reasonable and lawful to provide a carve-out in AG-X or another buy-through program for the schools class or any other specific customer class and why or why not; and
- How to ensure prospective customers have equitable opportunities for participation in AG-X or another buy-through program if/when the demand for the program exceeds the MW cap.

To provide an opportunity for the modifications to AG-X and/or the expansion of AG-X or adoption of another buy-through program to be considered in light of the record in this case, the record in this docket will remain open for 12 months to allow APS to submit such a proposal, with supporting documentation as well as an indication of whether the parties believe an additional evidentiary hearing should be held and a proposed form of notice to be provided to APS's customers. To ensure that the collaborative process described above progresses at a reasonable pace, we will require APS to file monthly updates, beginning on the first day of the month following the effective date of this Decision, providing information on the meetings and other communications that have occurred, the stakeholders

involved in those meetings and other communications, and the progress in terms of the issues that have been resolved and that remain unresolved. For each resolved issue, APS shall also include a full description of the resolution.

Because the parties are in agreement that the following modifications to AG-X should be made at this time, and we conclude that they are in the public interest, we will require APS to make the following modifications to its AG-X tariff:

- AG-X shall allow customers that aggregate accounts to meet AG-X's 10 MW minimum load-size eligibility requirement to add accounts if their aggregate load falls below the 10 MW threshold because of participation in EE programs.
- AG-X shall allow AG-X load to grow by up to 10% at existing locations that are currently taking AG-X service for deliveries at Palo Verde.[352]
- AG-X shall allow for intra-day scheduling changes by GSPs. This provision shall be developed by APS with the assistance of GSPs, AG-X customers, and Staff.[353]

Additionally, because it is likely that the AG-X program is not covering its costs, and the 10% growth provision will only exacerbate any lack of cost recovery, the $15 million PSA mitigation shall be increased proportionately to any increases in AG-X beyond its 200 MW cap.

R. Adjustor Mechanisms and the AEM

1. APS Position

As described above, APS currently has seven active adjustor mechanisms, and those adjustor mechanisms, according to the effective dates in their respective POAs, could result in rate changes on the first of each month for the first six months of each year: REAC in January, PSA in February, DSMAC and TEAM in March, EIS in April, LFCR in May, and TCA in June. (See Ex. APS-53.) According to APS, from January 2018 to July 2019, the adjustor mechanisms have saved the average APS residential customer 6.5% or approximately $10 per month on their bills, adjustors promote rate gradualism and guard against rate shock, and adjustors are critical to balancing the goals of less frequent rate cases and rate gradualism. (Ex. APS-1 at 22-23; Ex. APS-28 at 20-21.) In its application, although

[352] This is not intended to and shall not be interpreted to change any of the requirements of AG-X related to imbalances.
[353] RUCO may also participate if it desires to do so consistent with its statutory authority.

APS proposed to retain its current adjustors, APS in the alternative proposed a formula rate plan, such as the one used by FERC for transmission rate cases, to serve as an alternative to some of its adjustors and to promote gradualism through incremental annual rate adjustments with additional annual regulatory oversight. (Ex. APS-1 at 23-24.) The formula rate plan annual proceeding would have allowed for scrutiny of APS's annual earnings. (Ex. APS-28 at 22.) Due to a lack of support from other parties, APS dropped its alternate formula rate proposal on rebuttal. (Ex. APS-29 at 14-15.) APS's position is that each of its current adjustors allows for timely recovery of costs/pass-through of cost savings, has a fairly specific scope, serves its purpose well, and has a manageable annual process. (Tr. at 2533.)

On rebuttal, APS proposed for the first time the AEM, including a proposed term sheet and addressing the AEM in testimony. The POA for the AEM, which is attached hereto and incorporated herein as Exhibit B, was provided on rejoinder and reflects changes made by APS in response to other parties' positions, including dropping a proposal for the AEM to recover EE expenses, lost fixed costs associated with EE and DG requirements, and renewable energy investments (i.e., to replace the DSMAC, LFCR, and REAC). (Tr. at 2501-2502; Ex. APS-2 at 7-8; Ex. APS-29 at 15.) APS is not proposing the AEM because of any problems with its existing adjustors but because of a desire to streamline. (Tr. at 2596; Ex. S-52.)

APS anticipates that a substantial portion of its new generation investments will be made for clean energy assets. (Tr. at 2502.) The AEM is proposed to recover the capital carrying costs for approved clean energy plan investments, which includes any APS-owned,[354] newly constructed or acquired plants,[355] as well as APS's proposed annual CCT costs that would be covered by ratepayers ($13 million). (Tr. at 2501-2502; Ex. APS-29 at 12.) The capital carrying costs would include (1) the return on net plant based on APS's WACC approved in its most recent rate case plus any authorized return on the FVI,[356] (2) depreciation expense, (3) income taxes, (4) property taxes, and (5) associated

[354] The AEM is not proposed to recover for non-APS-owned expenses such as from third-party PPAs, which would instead flow through the PSA and, if renewables also the REAC, as they do currently. (Tr. at 2535, 2595.)

[355] APS has excluded nuclear energy investments from recovery through the AEM due to stakeholder concerns because while nuclear energy is carbon-free, it is unlikely that APS would develop a large base load nuclear power plant in the future, and stakeholders prefer that APS use renewables and storage. (Tr. at 2588.)

[356] Per Mr. Snook, if the AEM is working timely, there would be no fair value increment for new plant because the OCRB and RCND would be the same. (Tr. at 2601.)

O&M expenses. (Ex. APS-29 at att. LRS-02RB; Tr. at 2502.) Per Mr. Guldner, because APS anticipates needing to make significant investments in clean energy to meet its Clean Energy Commitment, APS either needs to have an adjustor such as the AEM or to have very frequent rate cases to recover those investments. (Ex. APS-5 at 7.) Mr. Snook echoed this sentiment, asserting that without the AEM, APS could use "perpetual continual rate cases" to recover these costs.[357] (Tr. at 2503.) Mr. Snook testified that the AEM would provide timely cost recovery of the capital carrying cost and expense of APS's approved and prudent clean energy plan investments, including APS-owned newly constructed or acquired plants not already recovered in base rates or through another Commission-approved adjustor (such as the PSA, which covers purchased power costs and third-party storage costs). (Ex. APS-29 at 16.) APS proposes for the AEM to have a year-over-year cap set at $0.005/kWh ("5 mill"),[358] a balancing account, and an earnings test.[359] (Tr. at 2285; Ex. APS-29 at att. LRS-02RB.) The AEM would also directly reflect and credit to customers the O&M savings from coal plant closures occurring between rate cases, although this provision was not included in the proposed AEM POA and was proposed in response to the Sierra Club. (Tr. at 2290-2291.) Further, APS proposes to have the AEM reset in each rate case and the APS-owned resource investments moved into base rates. (Ex. APS-29 at att. LRS-02RB.) According to Mr. Snook, the clean energy plan investments would be authorized by the Commission through its approval of APS's IRP Action Plan or Clean Energy Implementation Plan and would be subject to a robust RFP process and significant stakeholder involvement. (Ex. APS-29 at 16; Tr. at 2285.) APS views the AEM as an instrument to facilitate achievement of the Clean Energy Commitment to be 100% carbon free by 2050 and proposes to have the AEM apply to all customers, including AG-X customers. (Tr. at 2504, 2510-2511.) APS estimated that it would not reach the cap. (Tr. at 2695.)

The proposed AEM process would involve APS reviewing its IRP action plan and holding stakeholder meetings from January to May each year to discuss the AEM budget and projects proposed

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[357] There was a period, from 1977 through 1991, during which APS had 13 rate increases, with multiple rate case decisions in some years, due to development of Cholla and the Palo Verde nuclear plant. (*See* Ex. S-61; Tr. at 2589-2590.) Mr. Snook indicated that the AEM could avoid this type of rate case activity. (Tr. at 2589-2591.)

[358] Based on adjusted TY kWh sales, the annual cap would be approximately $138 million. (Tr. at 2597; Ex. S-53.)

[359] APS proposes for the earnings test to take into consideration weather normalization and potentially also PTYP. (Tr. at 2600.)

for inclusion in the AEM, with APS ultimately deciding the projects to be included and filing its application with the Commission by June 1; the proposed AEM costs would be projected for the year following the filing based on estimated in-service dates for the new assets, in the same manner as AZ Sun assets have been recovered through the REAC; parties would have an opportunity to intervene in the AEM proceeding, discovery would be available, and Staff would review the application and prepare a Staff Report and Proposed Order for consideration by the Commission at an Open Meeting; and the AEM proceeding process would be completed by the end of December so that the AEM rate could become effective in January. (Tr. at 2505-2508.) APS believes that the annual AEM process would result in fewer rate cases and save resources and time and energy for participants and be more efficient, in comparison to a general rate case, similar to how the individual adjustor proceedings that APS currently has each year are efficient and "easy to get your head around." (Tr. at 2509-2510, 2531-2532, 2536.) APS also believes that the AEM would be beneficial because it would smooth the way for achieving the clean energy goals, providing APS recovery in a timely fashion and providing customers rate gradualism. (Tr. at 2532.)

If the AEM were not approved, Mr. Snook stated, APS could use the REAC, DSMAC, and LFCR for clean energy plan cost recovery, and the CCT funding could be added to base rates. (Ex. APS-29 at 16.) Per Mr. Snook, the costs for the clean energy plan investments would still be incurred, so APS would still need to request recovery, but would do so through its other adjustors or rate cases instead of through the AEM. (Tr. at 2598.) Mr. Snook noted, however, that battery storage systems are not currently listed as a technology in the Commission's REST rules, although he suggested that perhaps they could be viewed as a companion asset to renewables to make them eligible under the REAC. (Tr. at 2596-2597.) Mr. Snook also noted that in addition to seeing rate increases through the AEM, customers would also see O&M savings from coal plant closures in the AEM and a reduction in fuel costs flowing through the PSA with APS's transition to clean energy. (Tr. at 2598-99.) Mr. Guldner opined that APS's credit rating could be negatively impacted if the AEM were not approved. (Ex. APS-5 at 7.)

2. AARP

AARP urges the Commission to reject the AEM, characterizing it as "yet another way to collect

funds quicker from consumers to recover certain expensive clean energy costs (outside of the thorough review of a general rate case)." (AARP RBr. at 4.) AARP asserts that the AEM is unnecessary because APS can use its existing adjustors (DSMAC, REAC, and LFCR) to recover these costs and, further, that "[n]o utility in the country has nearly as many surcharges and other adjustor mechanisms as APS." (AARP RBr. at 4 (citing Tr. at 2530.[360]) AARP laments that adjustors "have begun to erode the underlying function of cost-of-service regulation" by avoiding thorough examination through a rate case and opines that "rate regulation would be improved with fewer way[s] to raise consumer rates outside of a rate case." (AARP RBr. at 4.)

3. AECC/Freeport

AECC/Freeport also urges the Commission to reject the AEM and the $13 million rate increase associated with it, arguing that the CCT issues should instead be addressed in the Generic Transition Docket and that it is premature to resolve them in this case. (AECC Br. at 6, 43-44.) AECC/Freeport argues that because a substantial portion of APS's new generation investment will be for clean energy technologies, the AEM would allow APS continual rate increases outside of a general rate case, which AECC/Freeport argues would amount to single-issue ratemaking. (AECC Br. at 41.) AECC/Freeport further adds that because automatic adjustor mechanisms like the AEM are an exception to the constitutional requirement for the Commission to find fair value when setting rates, they should be used sparingly and only for costs that are volatile or outside of the utility's control. (AECC Br. at 41-42.)

AECC/Freeport further argues that the AEM, due to its proposed process, would not be a more efficient and effective way for APS to obtain cost recovery than rate cases would, because there would be stakeholder meetings from January-May, APS would file its application by June 1, Staff would review the application and file a Staff Report and recommendation, other parties could intervene and conduct discovery, and the whole process would take approximately 180 days, from June 1 to the end of the year. (AECC Br. at 42-43.) Because the AEM would result in a year-round annual process, AECC/Freeport argues, it would not save APS, the Commission, or interested stakeholders time or

[360] Neither the cited portion of the transcript nor the rest of the record herein establishes that APS has more surcharges and adjustor mechanisms than any other utility in the U.S.

resources as opposed to frequent general rate cases. (AECC Br. at 43.)

Additionally, AECC/Freeport asserts, AG-X customers should not be subject to the AEM because they do not take generation service from APS. (AECC Br. at 43.)

AECC/Freeport argues that the Commission should reject the AEM because the public interest will be served by traditional ratemaking through general rate cases that provide for greater transparency as to all of the factors that go into setting rates. (AECC RBr. at 12.)

4. Citizen Groups

The Citizen Groups did not expressly brief the issue of the AEM, instead focusing on CCT approval. Ms. Horseherder and Mr. Eisenfeld both testified, however, that the Citizen Groups support the AEM as the mechanism to fund the ratepayer portion of the CCT costs, although Ms. Horseherder also asserted that APS must strive to minimize the financial impact to its customers. (Ex. CG-2 at 16, 18; Ex. CG-4 at 3-6.)

5. FEA

FEA recommends that the Commission reject the AEM in this case, arguing that while APS has identified potential benefits to itself from the AEM (fewer rate cases needed to recover and more timely recovery of clean energy investments, resulting in a favorable view from credit rating agencies), APS has not established that it needs the AEM because its existing means of recovery are insufficient. (FEA Br. at 35 (citing Ex. APS-5 at 7; Ex. FEA-5 at 13-14; Tr. at 2874.) In his testimony, Mr. Gorman emphasized that in a rate case, not only the clean energy expenditures would be reviewed, but also the reductions in cost of service potentially resulting from the use of newer technology and even refinancing of old debt, whereas with an adjustor that allows for recovery of significant capital investments but leaves base rates static, customers may be paying excessive charges as compared to what would have resulted in a rate case. (Tr. at 2876-2877.) Mr. Gorman also opined that having an adjustor such as the AEM could remove APS's incentive to keep costs down because the costs would be flowed through to customers without adequate scrutiny from the Commission. (Tr. at 2877-2878; Ex. FEA-5 at 14; FEA Br. at 35.) Mr. Gorman asserted that it would be more appropriate to consider the recovery mechanism for APS's clean energy investments after more details of an approved Commission clean energy environment have been identified. (FEA Br. at 35 (citing Ex. FEA-5 at 14.)

FEA asserts that "APS's proposal to bypass customer protections and streamline rate increase proposals for capital investments would tilt the regulatory balance significantly in favor of investors and APS while eroding customer protections in the rate-setting process." (FEA RBr. at 14 (citing Tr. at 2877-2878).)

6. Mr. Gayer

Mr. Gayer argues that the AEM "is a potential runaway addition to bills that should not be approved in this case" and urges the Commission to reject it. (Gayer Br. at 5, 7.) Mr. Gayer expressed concern that if APS were to reach the cap for the AEM four years in a row, the adjustor rate would be $0.02/kWh, because Mr. Gayer has found that typical individual adjustor amounts have been slightly over $0.01/kWh and collectively the adjustors have totaled less than $0.03/kWh. (Gayer Br. at 6 (citing Tr. at 2695; Gayer Ex. 9; Gayer Ex. 10).) Additionally, Mr. Gayer expressed concern about the potential expansion of the AEM to include the DSMAC, the REAC, and the LFCR, although he acknowledged that Mr. Snook testified that would not occur in this case. (Gayer Br. at 6 (citing Tr. at 2428-2429).) Mr. Gayer also noted that Mr. Snook had stated if APS were to accrue a large sum in the balancing account for the AEM, APS would file for a rate case, and APS could also request interim rates. (Gayer Br. at 6 (citing Tr. at 2693-2694, 2697-2698).) According to Mr. Gayer, the AEM would impose excessive risk on APS's customers, "which must be balanced against APS's imaginary risk of losing revenue." (Gayer Br. at 7.)

7. The Nation

The Nation urges the Commission to approve the AEM to fund the CCT, but also acknowledged that the Commission may consider securitization to be a better financing method to save customers money. (Nation Br. at 19-20.)

8. Sierra Club

Sierra Club urges the Commission in this case to approve either the AEM or another adjustor to recover CCT costs. (SC Br. at 36.) In case the Commission chooses to approve the AEM, the Sierra Club made the following recommendations for the AEM POA, to provide protections for ratepayers:[361]

[361] SC Br. at 36-39.

- The Commission should adopt the AEM recommendations made by WRA/SWEEP's witness Mr. Baatz, which included requiring APS to come in for a rate case every three years and imposition of an earnings test for the AEM;
- The Commission should retain authority to hold a full hearing as part of an AEM proceeding, during which parties would be permitted to contest the prudency of specific investments;
- The Commission should make the AEM a two-way mechanism that captures savings resulting from the closure of fossil plants and allows for return of savings to customers, something that APS supported at hearing (citing Tr. at 2685-2686);
- The Commission should include a clear definition of "clean plan investments" eligible for recovery through the AEM to exclude from clean plan investments the burning of biomass or fossil fuels in any way, such as through a fossil fuel plant equipped with carbon sequestration technology or hydrogen energy technologies that rely on fossil fuels for hydrogen production; and
- The Commission should consider reducing APS's authorized rate of return for investments approved through the AEM, because the AEM would reduce APS's regulatory risks.

Sierra Club took issue with APS's proposal to bifurcate prudence for purposes of the AEM into "planning prudence," determined through an Integrated Resource Action Plan or Clean Energy Implementation Plan, and "execution prudence," determined through the AEM proceeding, arguing that the Commission does not make prudence determinations for specific investments during the IRP process and, further, that APS's bifurcated prudence would not take into account "adequate resource-specific prudence." (SC Br. at 37.) According to Sierra Club, APS is wrong to assert that once IRP planning prudence is determined, it must never be reviewed again, because a utility has an obligation to evaluate whether changed circumstances require alteration of the utility's selected course of action. (SC Br. at 37-38.) Sierra Club argues that the Commission should reject APS's prudence standard and should retain the full right to review prudence for contested AEM expenditures. (SC Br. at 38.)

9. SEIA/AriSEIA

Although SEIA/AriSEIA did not brief the issue, Mr. Lucas testified on surrebuttal that the AEM

is a reasonable approach that would help APS make its transition to clean energy. (Ex. SEIA-2 at 3.)

10. Vote Solar

Although Vote Solar did not brief the issue, Mr. Sandoval testified on surrebuttal that he supports the AEM because APS should be able to receive timely cost recovery for investments that result from a "robust planning and acquisition process" and that have been approved by the Commission, to ensure that APS can meet its clean energy commitments. (Ex. VS-2 at 4.)

11. WRA/SWEEP

WRA/SWEEP urge the Commission to approve the AEM with the following modifications that would, in WRA/SWEEP's view, result in an AEM that protects ratepayers and is in the public interest:[362]

- APS should be required to come back in for a rate case every three years so that costs collected in the AEM can be put into base rates at a regular frequency and revenue requirements are reevaluated regularly.
- The AEM should be subject to an earnings test, which APS has proposed but with no detail, and recovery of new plant additions through the AEM should be contingent on APS showing that recovery is justified given other pro forma adjustments, including plant retirements and depreciation expense from existing plant balances.
- The Commission's process for consideration of the AEM each year should allow for parties to object to and litigate the prudency of the expenditures for which recovery through the AEM is sought, providing for additional processing time and for a full evidentiary hearing as needed.

12. RUCO

RUCO argues that the Commission should reject the AEM, pointing out that APS already has seven adjustor mechanisms and that "adjustment mechanisms are the exception to fair value in Arizona" under *Scates* and asserting that the "Commission has approved adjusters more as the rule than the exceptions that they truly are supposed to be." (RUCO Br. at 23.) RUCO asserts that adjustor

[362] WRA Br. at 25-26.

mechanisms: are permissible under *Scates* when they allow rates to adjust for variations in specific, narrowly defined operating expenses; result in single-issue ratemaking; and "should only be used in extenuating circumstances" such as with volatile costs or costs that are not within the utility's control when the costs might cause significant financial harm to the utility if not for an adjustor mechanism. (RUCO Br. at 23 (citing *Scates*, 118 Ariz. at 535; Ex. AECC-1 at 26; Tr. at 4684).) RUCO added that adjustor mechanisms remove a utility's incentive to keep its expenses down, because expenses are not scrutinized like they are in a rate case, and result in higher revenues because they cost ratepayers more than recovery through traditional ratemaking. (RUCO Br. at 23 (citing Tr. at 4687).) RUCO also criticized adjustors as "piecemeal" ratemaking that is "fraught with potential abuse." (RUCO Br. at 24.)

RUCO concluded that the AEM should be rejected for numerous reasons, perhaps chief among them that APS can recover the costs through traditional ratemaking and has no need for extraordinary ratemaking at this time. (RUCO Br. at 24.) RUCO also criticized APS for proposing the AEM with the CCT late in the case, which RUCO asserted did not provide intervenors the ability to investigate or analyze the appropriateness of either thoroughly. (RUCO Br. at 24.) RUCO characterized APS's request for the AEM to support the Clean Energy Commitment as APS seeking "a blank check to do whatever programs and investments it undertakes, under the banner of clean energy[,] and have ratepayers pay for it without any meaningful determinations regarding prudency, efficiency, cost-effectiveness, and the achievement of quantifiable goals." (RUCO Br. at 24 (citing Ex. RUCO-3 at 7).)

13. Staff

Staff opposes approval of the AEM in this case as premature based on the record in this matter. (Staff Br. at 53.) Staff argues that because the AEM was proposed at a late stage of this case, it could not be thoroughly vetted by the parties. (Staff Br. at 53.) Staff also expressed concern that the AEM could collect large amounts that would produce significant annual rate increases, potentially as high as $138 million per year. (Staff Br. at 53 (citing Ex. S-53).) Additionally, Staff argues, the existence of the AEM would not provide any assurance that APS would not continue to file rate cases on a regular basis. (Staff Br. at 53.) Staff argues that a rate case "stay out" typically accompanies "prophylactic

measures" like the AEM and notes that the AEM does not include such a provision and APS has not made such a commitment. (Staff RBr. at 8.) Staff also reiterated RUCO's arguments against the AEM and Sierra Club's and WRA/SWEEP's support for the AEM that is conditioned upon various modifications to the AEM POA. (Staff RBr. at 9.) Finally, Staff notes that both Mr. Snook and Mr. Guldner acknowledged that APS could use the DSMAC, REAC, and LFCR for recovery of eligible costs associated with its clean energy plan, meaning that the AEM is not needed at this time. (Staff RBr. at 9.)

14. APS Response

APS argues that the AEM is "essential to facilitating a cost-effective and efficient transition of APS's portfolio of generation resources toward reliance upon carbon-free resources by 2050" and that the objections of those parties who oppose the AEM "represent outlier perspectives and have no grounding within the record for this proceeding or state utility law." (APS RBr. at 87.) Further, APS argues, "[w]hether the AEM is, strictly speaking, necessary . . . misses the point" because it is "a far superior way to implement cost recovery for the exigent and unique high-capital investments" needed for APS to transition to clean energy and is better for APS and its customers. (APS RBr. at 87.) According to APS, the AEM is a more appropriate method to recover the significant clean energy investment costs APS will incur because its earnings test provides "guardrails" against excess earnings, it has a balancing account and cost cap, it has a thorough stakeholder vetting process, the Commission's review and approval process will ensure that the clean energy projects are prudent before recovery of investments, the AEM promotes rate gradualism, and Commission resources will be saved because frequent rate cases will be avoided. (APS RBr. at 87-89.) APS also notes that in the long-term, customers will benefit from the transition to carbon-free generation, which will substantially reduce O&M costs and fuel expenses. (APS RBr. at 88.)

APS refutes claims that parties have not had a sufficient opportunity to analyze the AEM, asserting that APS provided both a term sheet and POA and that the parties in question made little or no effort to secure additional information or identify missing details. (APS RBr. at 89.) APS asserts that it responded to numerous data requests from both Staff and Sierra Club and points out that APS's witnesses sponsored evidence about the AEM and were subject to cross-examination during the

hearing. (APS RBr. at 89.) Thus, APS argues, there is an extensive record justifying Commission approval of the AEM. (APS RBr. at 90.)

APS criticizes FEA and RUCO for arguing that the AEM lacks sufficient controls but not identifying any specific deficiencies or flaws in the AEM procedures that should be corrected, emphasizing that the proposed process would include a "[f]irst-layer project prudency review" completed with APS's IRP Action Plan and then a "final review" during a rate case "to confirm that a given project was constructed cost effectively." (APS RBr. at 90.) APS also criticizes AECC for suggesting that the AEM process's protections go too far and will result in no savings of Commission resources. (APS RBr. at 91.) APS asserts that this is incorrect because the AEM is "laser focused" on carbon-free generation and associated energy storage investments, unlike general rate cases that evaluate "every angle of APS's business," and the AEM would allow APS to avoid having rate cases annually or every other year. (APS RBr. at 91 (citing AEM POA; Tr. at 285-286, 443, 735-736).) APS acknowledges that Staff would be required to perform an annual review for the AEM, but asserts that it "would be focused . . . on only a limited number of high-capital cost projects proposed for recovery . . . [and that] subsequent rate case review would be limited to only whether such projects were implemented and constructed prudently," which "should produce substantial efficiencies." (APS RBr. at 91-92 (citing Tr. at 2531-2535).)

APS also refutes assertions by FEA, Mr. Gayer, AECC, RUCO, and Staff that the AEM would result in excessive customer costs, arguing that it would only affect the manner and timing of cost recovery, not the quantity of the costs that will need to be recovered. (APS RBr. at 92 (citing Tr. at 2503).) Further, APS denies that the AEM would eliminate APS's incentives to control costs or would lead to maximum customer cost increases up to the cap each year, asserting that the AEM would have no effect on APS's cost-control incentives,[363] that the quantity of investments allowed under the AEM would be limited to generation acquisitions APS needs to serve customer demand and meet its Clean Energy Commitment, and that APS does not expect its clean energy investments over the next five

[363] Mr. Snook refuted RUCO's suggestion that adjustors remove APS's incentive to keep costs down and do not provide savings benefits to customers, asserting that APS always has the incentive to keep costs down and rates as affordable as possible, that the AEM is proposed to have the O&M savings from coal plant closures flow through it, and that the PSA rate goes down when fuel costs go down and has gone up and down over its existence. (Tr. at 2537-2538.)

years to reach the cap. (APS RBr. at 92-93 (citing Ex. S-53[364]; Tr. at 2538, 2597-2598).) APS adds that the "duel-layer of prudency review" for each project qualified for the AEM would provide sufficient cost-control incentives. (APS RBr. at 93 (citing A.A.C. R14-2-103(A)(3(l)).) Additionally, APS also notes Mr. Guldner's testimony about APS's culture of reinforcing customer affordability. (APS RBr. at 93 (citing Tr. at 737-739).)

The AEM would not result in greater costs to customers than would occur through traditional rate cases, APS asserts, because under the AEM APS would directly pass through to customers O&M expense savings realized through closure or reduced operation of APS coal-fired power plants (more quickly than with a rate case); credit rating agencies would view the AEM favorably as a risk-reducer, helping to ensure that APS maintains a lower cost of capital; and the AEM would enable APS to maintain an accelerated pace of resource acquisition that will reduce reliance on carbon-emitting fossil-fueled generation and thus result in fuel-cost savings. (APS RBr. at 93-94 (citing Tr. at 916-917, 2290-2291, 2598-2599; Ex. APS-5 at 7; Ex. APS-18 at 27[365]).)

Further, APS argues, the AEM is a legally permissible mechanism to recover incremental capital cost increases from clean energy investments and would not constitute single-issue ratemaking, contrary to the assertions of RUCO and AECC. (APS RBr. at 94.) APS argues that the carbon-free investments that would be eligible for recovery through the AEM are "the exact sort of exceptional conditions for cost recovery that permissible, non-rate case utility rate mechanisms are intended to capture." (APS RBr. at 94-95.) Additionally, APS argues, the AEM is "entirely consistent with recent Arizona Supreme Court precedent concerning concurrent cost-recovery mechanisms for periodic utility capital investments," citing *Residential Util. Consumer Office v. Ariz. Corp. Comm'n*, 240 Ariz. 108 (2016) ("*RUCO v. ACC*"), which upheld the Commission's approval of the system improvement benefit charge ("SIB mechanism") for Arizona Water Company ("AWC"). (APS RBr. at 95 (citing *RUCO v. ACC*, 240 Ariz. at 112-113).) APS notes that the Arizona Supreme Court determined that the SIB process built on the fair value determination made in a previous rate case by adding the value of the infrastructure improvements once made and required AWC to submit updated financial statements

[364] In Exhibit S-53, APS states that the cap would not likely be reached in 2021-2025. (Ex. S-53.)

[365] Mr. Shipman testified that "Arizona has a relatively low standing with S&P and in the investment community with regard to regulatory risk." (Ex. APS-18 at 26.)

with each SIB surcharge application. (*Id.*) According to APS, the earnings test for the AEM is analogous to the SIB process because APS would be required to compare its adjusted earnings (resulting from cost recovery through the AEM) against the earnings authorized in its most recent rate case, and this would enable the Commission to supplement and update the fair value determination from APS's previous rate case. (*Id.*)

Finally, APS asserts, if the AEM is not approved, APS plans to request recovery for its clean-energy-investment capital carrying costs and expenses through its existing adjustors, such as the REAC. (APS RBr. at 96.) APS argues that there is precedent for APS to secure recovery for the capital carrying costs and other expenses associated with clean-energy investments because the Commission authorized APS to use the REAC for such recovery related to the AZ Sun program that developed utility-scale solar-powered generation facilities. (APS RBr. at 96 (citing Tr. at 568, 727-728, 2409-2410, 2613-2614).) APS notes that Staff supports the use of APS's existing adjustor mechanisms (REAC, DSMAC, and LFCR) to obtain concurrent investment recovery for the clean generation and storage costs incurred to transition to clean energy. (APS RBr. at 96 (citing Tr. at 5029-5030, 5166; Ex. S-15 at 48; Staff Br. at 53).) At hearing, Mr. Snook also conceded that the CCT costs could be collected through a specific surcharge or a different adjustor mechanism rather than through the AEM, and that it would have a negligible or no impact on the frequency of APS's rate cases. (Tr. at 2592.)

15. Resolution

In *Scates*, the Arizona Court of Appeals stated the following about adjustors:

> The automatic adjustment clause is a device to permit rates to adjust automatically, either up or down, in relation to fluctuations in certain, narrowly defined, operating expenses. Such clauses usually embody a formula established during a rate hearing to permit adjustment of rates in the future to reflect changes in specific operating costs, such as the wholesale cost of gas or electricity.
>
> "(T)he impact of certain increased or decreased costs are passed on to the consumer so that the utility neither benefits from a decreased cost nor suffers a diminished return as a result of an increase in a cost covered by the adjustment clause."
>
> Thus, although a utility may receive increased gross revenues when utility rates increase under automatic adjustment clauses, a utility's net income should not be increased, because operating costs also will have risen to offset the increased revenue.

> When courts have upheld such automatic adjustment provisions, they have generally done so because the clauses are initially adopted as part of the utility's rate structure in accordance with all statutory and constitutional requirements and, further, because they are designed to insure that, through the adoption of a set formula geared to a specific readily identifiable cost, the utility's profit or rate of return does not change. . . .[366]

In *RUCO v. ACC*, the Arizona Supreme Court upheld the constitutionality of the SIB mechanism approved for AWC, finding that the SIB process involved the Commission updating AWC's FVRB and thus satisfied the constitutional requirement for the Commission to "ascertain the fair value" of AWC's property "to aid it in the proper discharge of its duties." (*RUCO v. ACC*, 240 Ariz. at 109, 113 (quoting Ariz. Const. Art. 15, § 14).) Although the Court vacated the appellate court's opinion, it also agreed with the appellate court's determination that the SIB was neither an interim rate nor an adjustor mechanism.[367] (*Id.* at 113.)

Interestingly, in this case, APS has characterized the AEM both as an adjustor and as a SIB-like mechanism. Additionally, APS has claimed that the AEM is essential, that those asking if it is necessary (i.e., essential) are missing the point, and that APS would be able to (and plans to) use an existing adjustor or adjustors to obtain recovery of the costs that it seeks to recover through the AEM if the AEM is not approved. To a large extent, APS's arguments in favor of the AEM come with what amounts to a subtle underlying threat—if the Commission does not approve the AEM, APS will be filing annual or nearly annual rate cases to obtain recovery of the costs that it desires to obtain through the AEM. APS argues that this would result in a far greater use of Commission and other resources than would the AEM process. If this case is any indication, APS is correct about that. But not every APS rate case is fully litigated, as history has shown.

We will refrain from making a determination whether the AEM is appropriately characterized as an adjustor mechanism or a SIB-like mechanism, or neither, because we are not persuaded that the AEM would serve the public interest or that APS or any other party will somehow be disadvantaged if the AEM is not approved. APS has already acknowledged that it has other adjustors that it can use to

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[366] *Scates*, 118 Ariz. at 535 (citations omitted)(quoting Ariz. Op. Atty. Gen. No. 71-15 (1971)).

[367] The Court also found that Scates was inapposite to its consideration of the SIB because *Scates* involved the Commission imposing a rate increase without considering any measure of fair value. (RUCO v. ACC, 240 Ariz. at 113 (citing Scates, 118 Ariz. at 534-537).)

request recovery of these costs.

On the subject of APS's other adjustors, we note, again, that APS currently could theoretically have a rate increase authorized on the first of each month from January through June. The Commission must acknowledge its culpability in allowing this to happen, and now concludes that this may not be just and reasonable and in the public interest. We are not determining at this time that one or more of APS's adjustor mechanisms needs to be eliminated, but we are determining that the issue of whether all of the adjustor mechanisms continue to be necessary, as individual adjustor mechanisms, needs to be examined thoroughly, as does the issue of whether any of the individual adjustor mechanisms would more appropriately be combined into a single adjustor mechanism or a few adjustor mechanisms to ensure that APS's customers are not continually surprised by the rate changes that may occur during the first six months of the year. To that end, we will direct APS, Staff, RUCO, and any other parties that desire to participate, within the next 12 months, to meet in good faith and create, and to file with the Commission, a joint proposal (our preference) or multiple proposals for modification and/or elimination and/or consolidation of APS's current seven adjustor mechanisms. The proposal or proposals filed must include clear and detailed schedules setting forth all of the adjustments that would need to be made to implement the proposal or proposals, with any supporting documents necessary to understand the schedules. Additionally, electronic versions of the schedules, with all formulas and links intact and all linked documents provided, must be submitted to the Commission's Hearing Division. With the proposal/s filing/s, each proponent party or group shall include a proposed form of notice to be provided to APS's customers explaining what its/their proposal would do and how it would impact APS's customers. Additionally, each proponent party or group shall indicate the process through which the proposal should be considered by the Commission, including whether another evidentiary hearing should be held specifically concerning the proposal/s.

Because the Commission has determined that approval of the AEM is not in the public interest at this time, to the extent the Commission approves the collection of CCT costs from ratepayers herein, we direct APS to include such CCT costs in its next REAC application. APS shall not request recovery of any carrying costs associated with the CCT costs.

. . .

S. Rate Base Determinations

The parties who presented evidence on APS's rate base proposed the following final positions ($ amounts are in thousands):

	APS Final[368]	AECC/Freeport[369]	FEA[370]	RUCO[371]	Staff[372]
OCRB	$8,896,268	$8,537,831	$8,332,253	$8,370,104	$8,899,442
RCND[373]	$15,734,140	$15,390,176	$15,159,384	$15,136,256	$15,737,669
FVRB	$12,315,204	$11,964,004	$11,745,818	$11,753,180	$12,318,556
FVI	$3,418,936	$3,426,173	$3,413,565	$3,383,076	$3,419,114

As a result of the determinations that have been made herein, we find that APS has the following OCRB, RCND, FVRB, and FVI ($ amounts are in thousands):

OCRB	$8,325,497
RCND	$15,163,369
FVRB	$11,744,433
FVI	$3,418,936

VI. Cost of Capital

A. Capital Structure

The parties presenting cost of capital ("COC") evidence agreed on APS's proposed TY capital structure of 54.67% common equity and 45.33% long-term debt, based on its adjusted TY capital structure, which excludes short-term debt.[374] (See Ex. APS-12 at 13; Ex. APS-39 at sched. D-1; Ex.

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[368] LFE APS-87 at sched. A-1.
[369] AECC-Final Sched. at ex. KCH-1-S at 1.
[370] FEA-Final Sched. at sched. A-1.
[371] RUCO-Final Sched. at sched. A.
[372] Staff-Final Sched. (from Staff's Reply Brief) (hereinafter "Staff-Final Sched.") at sched. A, sched. B.
[373] A.A.C. R14-2-103(A)(3)(n) defines RCND as "[a]n amount consisting of the depreciated reconstruction cost new of the property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used and useful, plus a proper allowance for working capital and including all applicable pro forma adjustments." It further provides that contributions in aid of construction ("CIAC") and advances in aid of construction ("AIAC") must be increased to a reconstruction cost new basis. A.A.C. R14-2-103(B)(1) requires all classes to file RCND information with their applications and provides that if RCND information is not filed, use of RCND is deemed waived.
For its RCND, APS performed a Reconstructed Cost New ("RCN") study using Handy-Whitman indices and, for transportation equipment and general plant not covered by Handy-Whitman, Consumer Product Index ("CPI") indices. (Ex. APS-12 at 8.) APS asserted that these indices have long been used by all major Arizona utilities and accepted by the Commission and the utility industry for determining RCN amounts. (*Id.*) Each plant account is assigned a RCN amount, which is then multiplied by a percentage representing its condition (determined by dividing the net book value for the account by the original cost) to determine the RCND for the account. (*Id.* at 8-9; *see* Ex. APS-39 at sched. B-4.)
The RCND figure was then determined by making the same types of deductions and additions to the net PIS amount as are made to determine OCRB, with the additions identical to those made for OCRB, but the deductions for deferred income taxes and regulatory liabilities significantly higher than those amounts for OCRB. (*See* LFE APS-87 at sched. B-1.)
[374] APS's actual TY capital structure was 43.86% long-term debt, 52.65% common equity, and 3.50% short-term debt. (Ex. APS-39 at sched. D-1.) APS excluded short-term debt from its capital structure in accordance with Federal Energy

S-1 at 2-3, 22; Ex. FEA-2 at 21, att. CCW-1DR; Ex. RUCO-4 at 1, 35-36.) Nonetheless, FEA witness Christopher Walters asserted that because APS's common equity ratio is high relative to the recently authorized common equity ratios for other electric utilities in the U.S., it might be appropriate to recommend a ROE from the lower end of his range of COE results, a position with which Ms. Bulkley disagreed. (Ex. FEA-2 at 6, 21; Ex. APS-21 at 119-120.)

B. Cost of Debt

The parties also agreed on APS's proposed TY cost of debt, 4.10%, which represents APS's actual TY cost of debt of 4.19%, adjusted to reflect a reduction that occurred directly after the TY. (See Ex. APS-12 at 13; Ex. APS-39 at sched. D-1; Ex. S-1 at 2-3, 22; Ex. FEA-2 at CCW-1DR; Ex. RUCO-4 at 1, 35-36.)

C. Cost of Equity

Cost of Equity ("COE") represents the expected return that investors require from their capital investment in a utility, to be obtained through dividends and stock price appreciation. (See Ex. APS-20 at 33; Ex. FEA-2 at 17.) The seminal U.S. Supreme Court cases of *Bluefield Water Works & Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*"), and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"), have established that the authorized return on equity ("ROE") for a public utility must be sufficient to maintain the utility's financial integrity, enable the utility to attract capital under reasonable terms, and be commensurate with returns that investors could earn by investing in other enterprises of comparable risk. (*See, e.g.,* Ex. APS-20 at 9-10; Ex. FEA-2 at 17; Ex. S-1 at 5-7.)

Although APS's only shareholder, PNW, is publicly traded, the parties to this matter agreed that it is appropriate to estimate APS's COE using a proxy group. APS, FEA, RUCO, and Staff presented competing COE analyses, each using a proxy group and multiple COE models to determine its recommended COE. AECC/Freeport used a 9.75% ROE as a placeholder in its analyses, but expressly deferred to the recommendations of Staff and RUCO on the appropriate ROE for APS. (Ex. AECC-3 at 3.)

Regulatory Commission ("FERC") regulations. (*See id.*) APS also adjusted its capital structure to remove impacts to equity of non-cash accounting adjustments for pension and derivatives, because no equity or debt issuance was used for the balance. (*See id.*; Ex. APS-12 at 13.)

Based on their COE analyses, discussed below, APS, FEA, RUCO, and Staff recommend the following ROEs:

APS	FEA	RUCO	Staff
10.0%	9.3%	8.7%	9.40%

1. APS

To perform her COE analyses, Ms. Bulkley used a proxy group of publicly traded utilities that she determined to possess operating and risk characteristics substantially comparable to APS.[375] (Ex. APS-20 at 30.) On direct, the proxy group included the following 14 utilities: ALLETE, Inc.; Ameren Corporation; American Electric Power Company, Inc.; DTE Energy Company; Duke Energy Corporation; Exelon Corporation; FirstEnergy Corporation ("FirstEnergy"); Evergy, Inc.; OGE Energy Corporation; Otter Tail Corporation; PNM Resources, Inc.; PPL Corporation ("PPL"); Southern Company; and Xcel Energy Inc. (Ex. APS-20 at 32.) On rebuttal, Ms. Bulkley excluded FirstEnergy, PPL, DTE Energy Company, and Southern Company because they no longer met her screening criteria. (Ex. APS-21 at 19 n.20.) Ms. Bulkley did not modify her recommendations on rejoinder. (See Ex. APS-22.)

To formulate her COE recommendation, Ms. Bulkley used a historical Constant Growth Discounted Cash Flow ("DCF") model,[376] a projected DCF model, the Capital Asset Pricing Model ("CAPM"),[377] a Bond Yield Plus Risk Premium approach,[378] and an Expected Earnings analysis.[379]

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[375] The proxy group included U.S. companies classified as electric utilities by Value Line, screened to exclude those that do not consistently pay quarterly cash dividends, do not have positive long-term earnings growth forecasts from at least two equity analysts, do not have investment grade long-term issuer ratings from Standard & Poor's ("S&P") and Moody's, derive less than 70% of their total operating income from regulated operations, derive less than 80% of their total regulated operating income from regulated electric operations, do not own regulated generation assets that are included in rate base, do not have at least 35% of owned regulated generation capacity from regulated coal-fired or nuclear power plants, or were party to a merger or other transformative transaction during the analytical period used. (Ex. APS-20 at 31-32.)

[376] The DCF is based on the theory that a stock's current price represents the present value of all expected future cash flows. (Ex. APS-20 at 39.) The Constant Growth DCF model assumes a constant growth rate for earnings and dividends, a stable dividend payout ratio, a constant price-to-earnings ratio, and a discount rate greater than the expected growth rate. (Ex. APS-20 at 40.)

[377] The CAPM is a risk premium approach that estimates COE for a security as a function of a risk-free return plus a risk premium, to compensate investors for the non-diversifiable or systemic risk of the security. (Ex. APS-20 at 43.) The risk premium is the product of the market risk premium and the Beta coefficient, which represents the relative riskiness of the individual security. (Ex. APS-20 at 43-44.)

[378] The Bond Yield Plus Risk Premium approach is based on the principle that equity investors bear the residual risk from equity ownership and thus require a premium over the return they would have earned as bondholders and calculated using the sum of the equity risk premium and the yield on a particular class of bonds. (Ex. APS-20 at 49.)

[379] Ms. Bulkley described her Expected Earnings method as a comparable earnings analysis that calculates the earnings an investor expects to receive on the book value of a stock. (Ex. APS-20 at 52-53.)

(Ex. APS-20 at 2-3, 5; Ex. APS-21 at 19, att. AEB-2RB.) Ms. Bulkley excluded results lower than 7.00%, stating that they do not provide a sufficient risk premium above long-term debt costs. (Ex. APS-20 at 42; Ex. APS-21 at 19.)

The adjusted results of Ms. Bulkley's analyses on direct and rebuttal are shown below:

Constant Growth DCF[380]			
Historical	**Mean Low**	**Mean**	**Mean High**
30-Day Average Price	Dir: 8.09% Reb: 8.52%	Dir: 9.07% Reb: 9.20%	Dir: 10.21% Reb: 10.05%
90-Day Average Price	Dir: 8.17% Reb: 8.41%	Dir: 9.14% Reb: 9.08%	Dir: 10.28% Reb: 9.94%
180-Day Average Price	Dir: 8.17% Reb: 8.23%	Dir: 9.26% Reb: 8.91%	Dir: 10.40% Reb: 9.76%
Projected DCF	Dir: 8.51% Reb: 7.55%	Dir: 9.66% Reb: 8.44%	Dir: 10.75% Reb: 9.29%

CAPM[381]				
Direct Testimony				
	Current Risk-Free Rate (2.57%)	**Projected Risk-Free Rate 2019-2020 (2.66%)**	**Projected Risk-Free Rate 2021-2025 (3.60%)**	**Mean Result**
Bloomberg Beta	10.07%	10.11%	10.42%	10.20%
Value Line Beta	9.54%	9.58%	9.94%	9.69%
Rebuttal Testimony[382]				
	Current Risk-Free Rate (1.42%)	**Projected Risk-Free Rate 2020-2021 (1.64%)**	**Projected Risk-Free Rate 2022-2026 (3.00%)**	**Mean Result**
Market Return sourced from Bloomberg				
Bloomberg Beta	11.23%	11.27%	11.52%	11.34%
Value Line Beta	11.93%	11.96%	12.13%	12.01%
Market Return sourced from S&P Earnings and Estimates Report				
Bloomberg Beta	11.74%	11.78%	12.03%	11.85%
Value Line Beta	12.47%	12.50%	12.67%	12.55%

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[380] Ex. APS-20 at 5, 42-43, 62, att. AEB-2DR; Ex. APS-21 at 19, att. AEB-1RB, att. AEB-2RB, att. AEB-5RB, att. AEB-6RB, att. AEB-7RB.

[381] Ex. APS-20 at 5, 48, 62; Ex. APS-21 at 19, att. AEB-5RB, att. AEB-5.5RB.

[382] On rebuttal, Ms. Bulkley modified her CAPM analyses in response to criticism from Staff Witness David Parcell. (Ex. APS-21 at 48, att. AEB-5RB, att. AEB-5.5RB.)

Bond Yield Plus Risk Premium[383]				
Direct Testimony				
	Current Risk-Free Rate (2.57%)	**2019-2020 Projected Risk-Free Rate (2.66%)**	**2021-2025 Projected Risk-Free Rate (3.60%)**	**Mean Result**
Bond Yield Plus Risk Premium	9.75%	9.79%	10.20%	9.91%
Rebuttal Testimony				
	Current Risk-Free Rate (1.42%)	**2020-2021 Projected Risk-Free Rate (1.64%)**	**2022-2026 Projected Risk-Free Rate (3.00%)**	**Mean Result**
Bond Yield Plus Risk Premium	9.29%	9.38%	9.96%	9.54%

Expected Earnings Analysis[384]		
Direct Testimony		
	Mean	**Median**
Value Line 2022-2024	11.15%	10.81%
Rebuttal Testimony		
	Mean	**Median**
Value Line 2023-2025	10.05%	10.17%

Ms. Bulkley emphasized the impact of "anomalous" market conditions on the COE estimation models, specifically market uncertainty and lower government bond yields that had caused utility stocks to be overvalued and dividend yields to be depressed. (Ex. APS-20 at 6, 11-15.) On direct, Ms. Bulkley attributed the lowered federal funds rate and lower government bond yields to federal intervention in capital markets after the Great Recession as well as strained U.S.-China trade relations. (Ex. APS-20 at 12-14, 18-22.) Ms. Bulkley asserted that the overvalued utility stocks would decline, that the yield on long-term government bonds would not endure, and that it was thus appropriate to select a return toward the upper end of the range of ROE estimates obtained through the DCF. (Ex. APS-20 at 15-17, 22-24, 43.) Ms. Bulkley also stated that her CAPM results were impacted by low interest rates, which resulted in a lower risk-free rate and a higher market risk premium. (Ex. APS-20 at 34.) Ms. Bulkley also asserted that the impacts of the Tax Cuts and Jobs Act ("TCJA") passed in December 2017 needed to be considered in determining COE because the TCJA was expected to reduce

[383] Ex. APS-20 at 5, 52; Ex. APS-21 at 19, ex. Att. AEB-6RB at 3.
[384] Ex. APS-20 at 5, 54, 62, att. AEB-8DR; Ex. APS-21 at 19; *see* Ex. APS-21 at att. AEB-7RB.

utility revenues, leading to weaker credit metrics and negative ratings actions for some utilities. (Ex. APS-20 at 24-26, 29.) Ms. Bulkley noted that S&P had changed its rating outlook on APS and PNW from "Positive" to "Stable" in May 2018 because of slightly weaker forward-looking financial metrics related to the TCJA, capital spending, and increased distributed generation; that Moody's had stated in June 2019 that APS's financial metrics would deteriorate in 2019 due to the continuing impacts of the TCJA; and that FitchRatings had downgraded APS's outlook to "Negative" in June 2019 due to the delay in approving recovery of the 4CPP SCR costs as well as the Commission's reexamination of retail rates and review of potential overearnings at APS. (Ex. APS-20 at 27-28, 56.) As of October 31, 2019, APS had an investment grade long-term rating of A2 from Moody's and A-1 (Outlook: Stable) from S&P. (Ex. APS-20 at 30-31.)

On direct, Ms. Bulkley stated that her ROE recommendation was based on the results of the DCF and CAPM analyses and that she had used the Bond Yield Plus Risk Premium analysis and Expected Earnings analysis only to corroborate the range for her recommended ROE. (Ex. APS-20 at 6-7, 50.) Ms. Bulkley concluded that APS's COE fell within a range from 10.0% to 10.5% and that APS's requested 10.15% ROE was just and reasonable, would balance the interests of APS's shareholders and ratepayers, and might be a conservative estimate of the COE. (Ex. APS-20 at 3, 7, 61.) Ms. Bulkley opined that her ROE recommendation would enable APS to maintain its financial integrity and ability to attract capital at reasonable rates under a variety of economic and financial market conditions, while continuing to provide safe, reliable, and affordable electric utility service to its customers in Arizona. (Ex. APS-20 at 61.)

On rebuttal, Ms. Bulkley acknowledged that the results of certain models had declined and that interest rates on government and utility bonds had decreased since her direct testimony, but attributed the interest rate conditions to "short-term events including the COVID-19 pandemic" and the actions taken in response by the Federal Reserve and U.S. Congress to stabilize financial markets. (Ex. APS-21 at 15, 20-21.) Ms. Bulkley also acknowledged that utility stock prices had seen substantial market correction and that the yield on long-term government bonds had been increasing since her direct testimony and was expected to increase markedly in the coming years. (Ex. APS-21 at 75, 77-78.) Nonetheless, Ms. Bulkley asserted that investors continue to expect higher interest rates on government

and corporate bonds over the long term, that equity markets have become uncertain and volatile, and that the COE had increased since her direct testimony. (Ex. APS-21 at 15, 21-29.) Ms. Bulkley somewhat downplayed the importance of the COE estimation models, which she described as a "starting point in establishing a just and reasonable ROE," asserting that the results of each model must be considered, but emphasizing consideration of company-specific risks, capital market conditions, and the capital attraction and comparable return standards from the *Hope* and *Bluefield* cases. (Ex. APS-21 at 15, 32-33.) Ms. Bulkley asserted that DCF results in particular are understating forward-looking COE because they have been "distorted" by utilities' high valuation and low dividend yields, while her forward-looking CAPM provides a better reflection of analyst and investor expectations. (Ex. APS-21 at 29-33.) Ms. Bulkley presented her updated range of results as 9.75% to 10.25%[385] and recommended a revised APS-requested ROE of 10.0%, which she characterized as conservative. (Ex. APS-21 at 15.) Ms. Bulkley asserted that an authorized ROE significantly below the authorized ROEs in other jurisdictions could hinder APS's ability to attract capital on reasonable terms and that the ROEs recommended by RUCO, FEA, and Staff were well below the vast majority of authorized ROEs for vertically integrated electric utilities since January 2018. (Ex. APS-21 at 16.) Ms. Bulkley noted that Charles Schwab had rated the Utilities sector as "Underperform" in October 2020. (Ex. APS-21 at 30-33.) She also stated that in January 2020, Moody's had revised its outlook for APS from "Stable" to "Negative" based on the potential for increased leverage or reduced cash flow and a deterioration of credit metrics from heightened capital investments, while suggesting that the rating could be further decreased by evidence of a less supportive regulatory environment. (Ex. APS-21 at 74.)

Throughout her testimony, Ms. Bulkley emphasized the need to use forward-looking inputs and assumptions to determine ROE and to take the impact of currently high utility stock values into consideration. (Ex. APS-20 at 7; Ex. APS-21 at 29-30.) Ms. Bulkley also asserted that she had considered the following "risk factors" affecting APS's required ROE, although she had not made any adjustments for them: (1) APS's capital expenditure requirements relative to the proxy group; (2) APS's regulatory risk relative to the proxy group, including its current and proposed adjustor

[385] In light of the much larger span of results from Ms. Bulkley's analyses on rebuttal, it is not entirely clear how Ms. Bulkley selected this range of results. *See*, *e.g.*, Ex. APS-21 at 19.

mechanisms; and (3) APS's dependence on nuclear generation. (Ex. APS-20 at 3, 54; Ex. APS-21 at 17.) Ms. Bulkley opined that APS's negative free cash flow would grow, and its credit ratings would be negatively impacted, if the Commission did not provide APS timely cost recovery for its estimated $4 billion in capital investments in 2019 through 2021, and that this warrants an ROE toward the upper end of her results. (Ex. APS-20 at 57-59.) Ms. Bulkley further opined that because APS faces greater regulatory risk than the proxy group, and has greater dependence on nuclear generation than the proxy group, APS's ROE should be set toward the upper end of her results. (Ex. APS-20 at 57, 59-60.)

On rebuttal, Ms. Bulkley roundly criticized the COE analyses and recommendations of Staff witness David Parcell and RUCO witness John Cassidy, finding, *inter alia*, that their analyses were not sufficiently forward-looking and did not respond appropriately to current economic conditions, that they did not adequately consider APS's relatively higher risk associated with its generation portfolio or APS's relatively higher regulatory risk in Arizona, and that their recommended ROEs were too low. (Ex. APS-21 at 34-50, 52-69.) Ms. Bulkley also called out what she viewed as inconsistencies in certain aspects of Mr. Parcell's and Mr. Cassidy's testimonies. (*See, e.g.,* Ex. APS-21 at 50, 66-67.) Additionally, Ms. Bulkley criticized the weights Mr. Cassidy gave to the results of his analyses, for which she stated he had provided no rationale or support, and asserted that RUCO's ROE recommendation would not meet the comparable return standard and likely would not meet the financial integrity or capital attraction standard of *Hope* and *Bluefield*. (Ex. APS-21 at 52-53.) Ms. Bulkley also criticized the COE analyses and recommendations of FEA witness Christopher Walters, finding, *inter alia*, that he had mischaracterized the impacts of current economic conditions on APS's ROE, that he was incorrect in disputing that there is an inverse relationship between interest rates and equity risk premia, that he does not accurately assess or adjust for APS's relative riskiness for investors, that his assertion that investors should only be compensated for market risk because they can diversify away company-specific risks is outdated, that some of his criticisms of her analyses were inconsistent with his own analyses, and that his so-called corrections/adjustments/improvements to her analyses resulted in unreasonably low ROE estimates. (Ex. APS-21 at 69-120.)

On rejoinder, Ms. Bulkley criticized the updated ROE analyses of Mr. Parcell and Mr. Cassidy for being "well below" the vast majority of authorized ROEs for vertically integrated electric utilities

since January 2018 and not in compliance with the requirements for a just and reasonable return for APS as outlined in *Hope* and *Bluefield* and specifically criticized Mr. Parcell for not adjusting Staff's ROE recommendation to account for company-specific risk. (Ex. APS-22 at 3-4, 13-14.) Ms. Bulkley cautioned that a significant reduction in APS's ROE would be viewed unfavorably by credit rating agencies and suggested that it could result in a downgrade and, to the extent it was materially lower than other jurisdictions' ROE decisions under similar capital market conditions, would also violate *Hope* and *Bluefield*. (Ex. APS-22 at 5-6.) Ms. Bulkley also emphasized that the COVID-19 pandemic has significantly impacted the economy and that markets have not yet recovered because volatility and long-term interest rates have increased. (Ex. APS-22 at 6-7.) Ms. Bulkley opined that the continued uncertainty in the market means that there is greater risk and that investors are requiring higher returns. (Ex. APS-22 at 9-11.) She further opined that because the utility sector has historically underperformed in comparison to the broad market when interest rates increase and the economy recovers, it is important to give more value to the CAPM because it is more forward-looking and better able to reflect investor expectations. (Ex. APS-22 at 11-12.)

2. AECC/Freeport

AECC/Freeport used a "placeholder" COE of 9.75% based on a national median of ROEs granted to vertically integrated electric utilities in the U.S. between July 1, 2019, and June 30, 2020. (Ex. AECC-1 at 32, ex. KCH-12; Ex. AECC-3 at 2.)

2. FEA

FEA witness Christopher Walters presented data to show that the authorized ROEs for both electric and gas utilities have declined over the past 10 years, have been relatively stable and well below 10.0% for approximately the past six years, and have mostly been below 9.7% since 2016. (Ex. FEA-2 at 4-5.) Mr. Walters also presented data to show that the authorized common equity ratios for the electric industry since 2016 on average have hovered around 50.5%, significantly lower than APS's common equity ratio. (Ex. FEA-2 at 6.) Mr. Walters further presented data to show that credit ratings for the electric utility industry have markedly improved since 2009, with more than 80% of electric utility companies having S&P bond ratings of BBB+ to A or higher since 2016 (86% in 2019 and 2020). (Ex. FEA-2 at 7.) Mr. Walters characterized APS's A- S&P bond rating as among the strongest

in the industry. (Ex. FEA-2 at 7.) Mr. Walters further observed that capital expenditures for electric and natural gas utilities had increased considerably since 2009 and were forecasted to remain elevated and opined that the capital investments are enhancing shareholder value and that electric utilities have access to both equity and debt capital under reasonable terms. (Ex. FEA-2 at 8-10.) Mr. Walters described credit analysts' observations related to the impacts of the TCJA (negative in the short-term but modestly positive in the long-term) and the COVID-19 pandemic (challenging for the U.S. economy as a whole), but opined that "utilities are expected to weather the economic downturn caused by the pandemic" and to be financially strong as the economy recovers. (Ex. FEA-2 at 10-13.) Mr. Walters also asserted that independent economists had come to a consensus that the Federal Reserve's monetary policy actions will keep the federal funds rate at decreased levels near term and that long-term interest rates (30-year U.S. Treasury bonds) will remain flat or slightly decline through Q4 2021. (Ex. FEA-2 at 13-16.) Mr. Walters further opined that economists' projections for interest rates and capital market conditions reflect Federal Reserve actions and all other relevant factors. (Ex. FEA-2 at 16-17.)

To determine his ROE recommendation, Mr. Walters used a proxy group of publicly traded utilities that he determined to have investment risk similar to APS and performed a constant growth DCF using the consensus of analysts' growth rate projections, a constant growth DCF using sustainable growth rate estimates, a multi-stage DCF, a Bond Yield Plus Risk Premium model, and a CAPM. (Ex. FEA-2 at 18.) Mr. Walters determined the market's assessment of APS's investment risk based on APS's current S&P (A-) and Moody's (A2) ratings; S&P's "Stable" outlook, "Excellent" business risk, and "Significant" financial risk for APS; and Moody's "Negative" outlook for APS (as of January 22, 2020), although Mr. Walters asserted that Moody's rationale largely concerned potential decline in the relationship between APS and the Commission, based on actions taken by APS and PNW, and that customers should be held harmless if additional negative actions by APS or PNW result in further downgrading by Moody's. (Ex. FEA-2 at 18-20.) Mr. Walters's used the same proxy group as Ms. Bulkley had used on direct, which had an average S&P corporate credit rating of BBB+ and an average Moody's corporate credit rating of Baa2, both of which are below APS's credit ratings, leading Mr. Walters to conclude that APS is less risky than the proxy group. (Ex. FEA-2 at 22.) Mr. Walters also

concluded that the proxy group's lower average and median common equity ratios (excluding short-term debt) meant that an ROE for APS in the lower half of his range of results could be warranted. (Ex. FEA-2 at 22.)

Mr. Walters's COE analyses yielded the following results:

Constant Growth DCF Using Analysts' Growth Rate Projections[386]		
	Mean	Median
13-Week Analysis	9.50%	9.35%
26-Week Analysis	9.47%	9.31%
Constant Growth DCF Using Sustainable Growth Rate Estimates[387]		
	Mean	Median
13-Week Analysis	9.18%	8.82%
26-Week Analysis	9.17%	8.74%
Multi-Stage DCF[388]		
	Mean	Median
13-Week Analysis	8.67%	8.78%
26-Week Analysis	8.64%	8.77%
Selected DCF:	**9.1%**	

Bond Yield Plus Risk Premium[389]		
Projected Treasury Yield	8.8%	
	A-Rated Utility Bond	Baa-Rated Utility Bond
13-Week Average Yield	8.5%	8.9%
26-Week Average Yield	8.7%	9.2%
Selected Risk Premium:	**9.0%**	

CAPM[390]			
	Risk Premium MRP	FERC 2-Step DCF MRP	DCF MRP
Current Value Line Beta	10.19%	10.82%	12.16%
Historical Value Line Beta	8.53%	9.03%	10.11%
Current S&P Global Market Intelligence Beta	8.31%	8.79%	9.83%
Selected CAPM:	**9.6%**		

Based on the results of his analyses, Mr. Walters estimated that APS's COE fell within the range of 9.0% to 9.6% and recommended use of the midpoint estimate of 9.3%. (Ex. FEA-2 at 52.)

[386] Ex. FEA-2 at 25, 35, 52, att. CCW-5DR.
[387] Ex. FEA-2 at 28, 35, 52, att. CCW-7DR.
[388] Ex. FEA-2 at 35, 52, att. CCW-10DR.
[389] Ex. FEA-2 at 41, 52, att. CCW-12DR, att. CCW-13DR, att. CCW-14DR, att. CCW-15DR.
[390] Ex. FEA-2 at 50-52, att. CCW-17DR.

Mr. Walters expressed confidence that his recommended ROE would support an investment grade bond rating for APS. (Ex. FEA-2 at 52-56.)

Mr. Walters asserted that Ms. Bulkley's estimated ROE is overstated for a number of reasons and should be rejected and, further, that with corrections and improvements, Ms. Bulkley's ROE estimates support an ROE no higher than 9.30%. (Ex. FEA-2 at 56-74.) Mr. Walters also opined that Ms. Bulkley's "additional risks" for APS would all have been considered by credit agencies when making their ratings and, additionally, pointed out that financial theory dictates investors should only be compensated for market risk, not specific business risk, because specific business risk can be eliminated with diversification. (Ex. FEA-2 at 74-75.)

Mr. Walters did not update his COE analyses on surrebuttal. However, he responded to criticisms of his COE analyses made by Ms. Bulkley that he considered to be without merit. (Ex. FEA-6 at 2-6, 10-28.) Mr. Walters also questioned Ms. Bulkley's exclusion of a 8.20% ROE awarded in August 2020 from her data presented on authorized ROEs of vertically integrated electric utilities since 2018, pointing out both the omission and that she had actually included ROEs for both vertically integrated and distribution utilities; observed that there had been a significant decline in expected volatility since Ms. Bulkley's rebuttal testimony; and presented data to dispute Ms. Bulkley's assertion that there is an inverse relationship between interest rates and equity risk premiums (Ex. FEA-6 at 2-7, 10-13.) Further, Mr. Walters asserted that even if lower interest rates were to cause equity risk premiums to increase, this would not result in an increased COE but instead a reduced COE because the increase in the risk premium would not be of the same magnitude as the decrease in interest rates. (Ex. FEA-6 at 13-14.) Mr. Walters also disagreed with Ms. Bulkley's use of long-term projected interest rates, which he stated are consistently overestimated over an intermediate time period of 18 months and likely to be completely unreliable for longer term projections such as that used by Ms. Bulkley. (Ex. FEA-6 at 14-15.) Mr. Walters added that current interest rate policy is expected to be in place through at least 2023. (Ex. FEA-6 at 16.)

3. RUCO

RUCO witness John Cassidy presented extensive multi-year data concerning economic indicators that he stated influence cost of capital, including real gross domestic product ("GDP")

growth, industrial production growth, unemployment rate, consumer price index ("CPI"), producer price index, interest rates, and stock price indicators. (Ex. RUCO-4 at 9, sched. JAC-6.) Mr. Cassidy described the economic impacts of the COVID-19 pandemic and the actions taken by the Federal Reserve to improve economic conditions; he also observed that the U.S. economy is in recession, that the current economic crisis may be more severe than the Great Recession, and that rapid economic recovery is unlikely. (Ex. RUCO-4 at 10-23.) Mr. Cassidy asserted that because the Federal Reserve has stated that short-term interest rates will remain near zero through at least 2023, there is no reason to believe interest rates will rise anytime soon. (Ex. RUCO-4 at 22.) Mr. Cassidy also opined that APS and PNW must anticipate interest rates remaining low, as the Value Line quarterly update for PNW dated October 23, 2020, projected its long-term debt ratio to rise from 47.1% (December 31, 2019) to 55.0% by December 31, 2024. (Ex. RUCO-5 at 12.) Mr. Cassidy stated that because inflation remains low, and is expected to decrease further through 2029, capital costs are low. (Ex. RUCO-4 at 24-26.) Mr. Cassidy noted that the yield on 10-year U.S. Treasury bonds hit a new all-time low of 1.31% in February 2020 and fell further to levels below 1.00% for March-August 2020. (Ex. RUCO-4 at 28.) Likewise, Mr. Cassidy noted, the yield on 30-year Treasury bonds fell to an all-time low below 2.0% in 2019 and stayed below 2.0% for February-August 2020. (Ex. RUCO-4 at 28-29.) Based on the conclusions of a 2016 report from the McKinsey Global Institute, Mr. Cassidy asserted that it is reasonable to assume that expected equity investment returns for public utilities may decline going forward. (Ex. RUCO-4 at 29-35.)

To calculate his COE estimates, Mr. Cassidy used a proxy group of 12 publicly traded electric utility companies that included the utilities in Ms. Bulkley's proxy group on direct other than FirstEnergy and PPL, which Mr. Cassidy concluded were not representative of companies within the domestic electric utility industry due to their specific circumstances. (Ex. RUCO-4 at 36-42, ex. JAC-C.) Mr. Cassidy calculated his COE estimates using Constant Growth DCF, CAPM, and Comparable Earnings methods and reported the following results on direct and surrebuttal:[391]

[391] Ex. RUCO-4 at 1, 46, 52-53, 54, sched. JAC-3, sched. JAC-4, sched. JAC-5; Ex. RUCO-5 at 2, surr. sched. JAC-3, surr. sched. JAC-4, sched. JAC-5.

Constant Growth DCF			
Mean Low	Mean High	Median Low	Median High
Dir: 6.98% Sur: 6.96%	Dir: 9.33% Sur: 8.88%	Dir: 7.06% Sur: 7.10%	Dir: 9.58% Sur: 9.26%
Selected Range		**Selected DCF (Midpoint)**	
Dir: 8.00% - 9.50% Sur: 8.00% - 9.26%		**Dir: 8.75%%** **Sur: 8.63%**	
CAPM			
Low	High	Mean	Median
Dir: 6.71% Sur: 6.78%	Dir: 8.93% Sur: 8.99%	Dir: 7.73% Sur: 7.80%	Dir: 7.64% Sur: 7.70%
Selected Range		**Selected CAPM (Midpoint)**	
Dir: 7.64% - 7.73% Sur: 7.70% - 7.80%		**Dir: 7.68%** **Sur: 7.75%**	

Comparable Earnings ("CE")		
	Mean	Median
Value Line 2010-2019	Dir & Sur: 9.4%	Dir & Sur: 9.7%
Value Line 2015-2019	Dir & Sur: 9.3%	Dir & Sur: 9.8%
Projected 2020-2024	Dir: 9.7% Sur: 9.8%	Dir & Sur: 10.0%
Selected Range	**Selected CE (Midpoint)**	
Dir & Sur: 9.50% - 10.0%	**Dir & Sur: 9.75%**	

Based on his results, Mr. Cassidy calculated a COE of 8.94% on direct and a revised COE of 8.90% on surrebuttal. (Ex. RUCO-4 at 6; Ex. RUCO-5 at 2.) Mr. Cassidy explained that RUCO's COE was derived by assigning a 40% weight to the DCF result and the CE result and a 20% weight to the CAPM result. (Ex. RUCO-4 at 6; Ex. RUCO-5 at 2-3.) RUCO's recommended ROE, however, was 8.74% on direct and 8.70% on surrebuttal, determined by making a 20-basis point downward adjustment from RUCO's calculated COE. (Ex. RUCO-4 at 6-7; Ex. RUCO-5 at 2, 13.) Mr. Cassidy noted that RUCO Director Jordy Fuentes recommended the 20-basis-point downward adjustment based on poor customer service. (Ex. RUCO-4 at 1,6.) Mr. Cassidy asserted that the resulting recommended COE was supported by his COE analyses, which resulted in an unweighted average COE of 8.73% on direct and of 8.71% on surrebuttal. (Ex. RUCO-4 at 6-7; Ex. RUCO-5 at 2.)

Mr. Fuentes recommended that the Commission adopt a 20-basis-point reduction to APS's ROE to "send a strong message to [APS] and to all other utilities that good customer service is the minimum standard necessary to provide service and maintain a CC&N." (Ex. RUCO-6 at 11.) Mr. Fuentes opined that a rate case is the best forum for addressing customer service issues because the Commission

can make prudency determinations not only related to capital expenses but also for operating expenses to place the risk of utility mismanagement on utility owners. (Ex. RUCO-6 at 8-9.) Mr. Fuentes stated that the 20-basis-point reduction to APS's ROE would result in a $12.1 million annual reduction to APS's revenue requirement and was "estimated . . . to be commensurate to the annual harm ratepayers have received." (Ex. RUCO-6 at 11, 18.) Mr. Fuentes stated that his testimony was based on his review of reports undertaken by the Commission in various dockets, reports by private consultants prepared for the Commission and APS,[392] Commission orders and findings,[393] his own participation in Open Meetings, a review of other state's methods and practices, his interactions with other stakeholders and APS, independent reports relating to customer service failures by APS,[394] and consumer comments filed in Commission dockets and expressed in media sources. (Ex. RUCO-6 at 3.) Based on APS's elimination of J.D. Power and Associates ("J.D. Power") customer satisfaction ratings as one of the metrics for its executive compensation in 2018, after APS's ranking dropped to second-to-last among large electric utilities in the west in 2017, and APS's tie for last place among 13 large utilities in the west in 2019, Mr. Fuentes concluded that APS had chosen to avoid the negative effects that a poor quality ranking would have rather than focusing on improving customer satisfaction. (Ex. RUCO-6 at 6-8.) Mr. Fuentes suggested that the Commission could consider performance-based rates for APS, although RUCO did not request that the Commission adopt such rates in this rate case. (Ex. RUCO-6 at 12-17.) RUCO also opposed APS's formula rate concept alternative and did not recommend the adoption of any Performance Incentive Mechanism ("PIM") in this case. (Ex. RUCO-6 at 14.)

Mr. Cassidy asserted that Ms. Bulkley's COE recommendations significantly overstated APS's actual COE. (Ex. RUCO-4 at 1-2; Ex. RUCO-5 at 2.) According to Mr. Cassidy, Ms. Bulkley improperly used yields on 30-year U.S. Treasury bonds rather than Moody's Baa-rated corporate utility bonds in her Bond Yield Plus Risk Premium analysis, resulting in an overstated equity risk premium component; employed an Expected Earnings analysis although FERC has determined that rates

[392] Mr. Cassidy cited the Alexander Report and the Overland Report.
[393] Mr. Fuentes extensively quoted Decision No. 77270.
[394] Mr. Fuentes cited and described APS-related information in Energy Policy Institute, *Pollution Pay Day: Analysis of Executive Compensation and Incentives of the Largest U.S. Investor-Owned Utilities* (September 23, 2020). (Ex. RUCO-6 at 5-6.)

established based on estimates from the Expected Earnings model are unjust and unreasonable;[395] used the highest mean estimate rather than the lower median estimate from her Expected Earnings analysis; exclusively used analyst forecasts of EPS growth to estimate the dividend growth rate for her Constant Growth DCF analysis; and used inflated estimates of the risk-free rate based on Blue Chip forecasts of 30-year Treasury yields in her CAPM analyses.[396] (Ex. RUCO-4 at 1-2, 55-71; Ex. RUCO-5 at 2-13.)

4. Other Intervenors

AARP supports RUCO's position on COE, states that APS's current 10% COE is much too high and out of line with other recent regulatory decisions in the country and southwest, and states that Staff's COE is within the upper limits of a zone of reasonableness. (AARP RBr. at 3.)

The IBEW Locals support APS's requested 10.0% COE, which the IBEW Locals state is in keeping with legal standards of fairness and reasonableness, current and prospective market conditions, ROE models, investor return requirements, and APS's risks (regulatory, business, and financial). (IBEW RBr. at 1-2.) The IBEW Locals criticize RUCO's COE, specifically its 20-basis-point deduction, as "unsupported by any testimony or relevant factors." (*Id.* at 2.) The IBEW Locals argue that this is not the forum to penalize APS for any alleged customer service deficiencies. (*Id.* at 2.) The IBEW Locals also assert that the Commission should consider APS's reliable performance during the heat storm in August 2020, which should be considered when evaluating RUCO's assertions about inadequate and unacceptable customer service. (*Id.* at 2-3.)

5. Staff

Staff witness David Parcell examined economic statistics from 1975 to 2020, encompassing four distinct business cycles identified by The National Bureau of Economic Research (1975-1982, 1982-1991, 1991-2001, and 2001-2009), each of which included a complete period of expansion and contraction. (Ex. S-1 at 9.) Mr. Parcell asserted that the U.S. economy has entered a new and possibly significant recession, largely due to the COVID-19 pandemic, and observed the actions taken by the federal government through the CARES Act stimulus program and the Federal Reserve's actions taken

[395] FERC Opinion No. 569-A (May 21, 2020) was admitted herein as Exhibit RUCO-21. Mr. Cassidy quoted FERC Opinion No. 569-A, which found that "the flaws of the Expected Earnings model are significant enough to render the model inappropriate for ROE calculations." (*See* Ex. RUCO-4 at 71 (quoting Ex. RUCO-21 at 26).)

[396] Mr. Cassidy presented a figure showing that the median forecasts of 50 private-sector forecasters consistently overestimated 10-year U.S. Treasury rates between 2000 and 2015. (Ex. RUCO-4 at ex. JAC-B.)

to help maintain the U.S. financial system. (Ex. S-1 at 9-10, 12-15.) Mr. Parcell stated that both the Great Recession and the current COVID-19-related recession have reduced actual and expected investment returns and thus capital costs, as evidenced by lower short-term and long-term interest rates and COE model results. (Ex. S-1 at 10-11.) Mr. Parcell also observed that the inflation rate has generally declined over the past few business cycles and is at its lowest level for the past 35 years, also reflecting lower capital costs. (Ex. S-1 at 11-12.) According to Mr. Parcell, the average and median electric utility ROEs authorized by state regulatory agencies were 10.32% and 10.23%, respectively, in 2007 and had declined to 9.53% and 9.54%, respectively, in 2020. (Ex. S-1 at 15-16.)

Mr. Parcell noted that as of October 2, 2020, APS's Senior Unsecured and Issuer bond ratings from Moody's were A2 and A2, from S&P were A- and A-, and from Fitch were A and A- and that APS's ratings have remained in the single-A category since 2015. (Ex. S-1 at 17.) Mr. Parcell also noted that of the 37 electric utilities covered by Value Line (Standard Edition), APS's ratings are above the most common rating categories, indicating a lower financial risk for APS. (Ex. S-1 at 17-18.) Based on APS's relatively higher Moody's rating and S&P rating, as well as APS's relatively higher common equity ratio, as compared to all or most of the proxy group companies, Mr. Parcell concluded that APS has a lower financial risk than do the proxy companies. (Ex. S-1 at 17-18, 20-21.)

On direct, Mr. Parcell conducted most of his COE analyses using two proxy groups: a group of electric utilities that he selected based on specified criteria[397] ("Parcell proxy group") and the proxy group selected by Ms. Bulkley ("Bulkley proxy group"). (Ex. S-1 at 23.) Mr. Parcell opined that based on the superior credit ratings and Value Line Safety and Financial Strength ratings of APS and PNW, as compared to the Parcell proxy group and the Bulkley proxy group, APS and PNW are low-risk utilities. (Ex. S-1 at 23.) On surrebuttal, Mr. Parcell used a modified Parcell proxy group that eliminated one company no longer satisfying his criteria and used the modified Bulkley proxy group used by Ms. Bulkley on rebuttal. (Ex. S-3 at 13.)

Mr. Parcell calculated his COE estimates using Constant Growth DCF, CAPM, Comparable

[397] Each company had to have a market "cap" of $1 to $20 billion, a common equity ratio of 40 to 60%, a Value Line Safety and Financial Strength rating of 1 or 2, and Moody's and S&P bond ratings of A or BBB; had to be currently paying dividends; and could not have reduced dividends in the past five years. (Ex. S-1 at 23.) The Parcell proxy group included Alliant Energy Corp, Ameren Corp, Avista, Black Hills Corp, Evergy, Inc., Hawaiian Electric Industries, IDACORP, Northwestern Corp, OGE Energy Corp., Otter Tail Corp, PNW, and Portland General Electric. (Ex. S-2 at sched. 6.)

Earnings, and Risk Premium methods. With his Comparable Earnings analyses, Mr. Parcell considered Market-to-Book Ratios ("M/Bs") to assess the degree to which a given level of return equates to the COC, based on the principle that for utilities, an M/B greater than 100% reflects a situation where a company is able to attract new equity capital without dilution (above book value). (Ex. S-1 at 36-37.) Mr. Parcell reported the following results on direct and surrebuttal:[398]

Constant Growth DCF			
Parcell proxy group			
Mean Low	Mean High	Median Low	Median High
Dir: 6.6% Sur: 6.9%	Dir: 8.7% Sur: 8.9%	Dir: 6.7% Sur: 7.2%	Dir: 9.0% Sur: 9.2%
Bulkley proxy group			
Mean Low	Mean High	Median Low	Median High
Dir: 7.4% Sur: 6.9%	Dir: 9.2% Sur: 8.9%	Dir: 7.5% Sur: 7.3%	Dir: 9.3% Sur: 9.4%
Selected DCF Range:		Dir: 8.7% - 9.3%	
Selected DCF (Midpoint):		**Dir & Sur: 9.0%**	
CAPM			
Parcell proxy group			
Low	High	Mean	Median
Dir: 6.0% Sur: 6.1%	Dir: 7.6% Sur: 7.6%	Dir: 6.6% Sur: 6.6%	Dir: 6.4% Sur: 6.4%
Bulkley proxy group			
Low	High	Mean	Median
Dir: 5.7% Sur: 5.8%	Dir: 7.9% Sur: 7.6%	Dir: 6.6% Sur: 6.6%	Dir: 6.5% Sur: 6.4%
Selected CAPM Range:		Dir: 6.4 – 6.6%	
Selected CAPM (Midpoint):		**Dir & Sur: 6.5%**	

Comparable Earnings ("CE")		
Parcell proxy group		
	Mean	Median
Value Line 2002-2008	Dir: 9.2% M/B: 140% Sur: 9.2% M/B 141%	Dir: 9.2% M/B: 145% Sur: 9.2% M/B: 145%
Value Line 2009-2019	Dir: 9.3% M/B: 159% Sur: 9.4% M/B: 162%	Dir: 9.3% M/B: 154% Sur. 9.5% M/B: 157%
Projected 2020	Dir: 8.8% Sur: 8.9%	Dir: 8.8% Sur: 9.0%
Projected 2021	Dir: 9.0% Sur: 9.3%	Dir: 8.8% Sur: 9.0%
Projected 2023-2025	Dir: 9.5% Sur: 9.7%	Dir: 9.3% Sur: 9.5%

[398] Ex.S-1 at 24-28, 31-35, 36-39; Ex. S-2 at sched. 7 at 5, sched. 9, sched. 10; Ex. S-4 at sched. 7, sched. 9, sched. 10.

Bulkley proxy group		
	Mean	Median
Value Line 2002-2008	Dir: 12.1% M/B: 183% Sur: 11.4% M/B: 174%	Dir: 11.6% M/B: 164% Sur: 10.8% M/B: 160%
Value Line 2009-2019	Dir: 10.0% M/B: 165% Sur: 9.3% M/B: 157%[399]	Dir: 9.7% M/B: 161% Sur: 9.2% M/B: 154%
Projected 2020	Dir: 9.9% Sur: 9.0%	Dir: 10.0% Sur: 9.0%
Projected 2021	Dir: 10.5% Sur: 9.5%	Dir: 10.3% Sur: 9.8%
Projected 2023-2025	Dir: 10.6% Sur: 9.8%	Dir: 10.5% Sur: 10.0%
Selected Range:	Dir & Sur: 9.0% to 10%	
Selected CE (Midpoint):	**Dir & Sur: 9.5%**	
Risk Premium[400]		
Direct		
	A-Rated Utility Bond	
November 2019-January 2020	8.77% - 9.07%	
June-August 2020	8.25% - 8.55%	
Selected Range:	8.3% - 9.1%	
Selected Risk Premium (Midpoint):	**8.7%**	
Surrebuttal		
	A-Rated Utility Bond	
Calendar Year 2019 (Midpoint)	9.1%	
Q1 through Q3 2020 (Midpoint)	8.6%	

In addition to the above analyses, Mr. Parcell considered the earned ROEs and M/Bs for the S&P 500 from 2002 through 2019 (as representative of the competitive market), determining that the average ROEs ranged from 12.4% to 13.8%, with average M/Bs ranging from 256% to 275%. (Ex. S-1 at 38-39.) Mr. Parcell then compared several risk indicators for the proxy groups and the S&P 500 group, determining that the S&P 500 group is riskier than the utility proxy groups. (Ex. S-1 at 39.)

On direct, Mr. Parcell recommended a ROE range of 9.3% to 9.5% and, specifically, a ROE of 9.4% (the midpoint). (Ex. S-1 at 44.) Mr. Parcell stated that this range included the upper end of his DCF results and the midpoint of his Comparable Earnings results and was supported by his Risk Premium results. (Ex. S-1 at 44.) Mr. Parcell acknowledged that his CAPM results were lower than the results of his other analyses, due to the lower risk premia and lower interest rates on Treasury bonds

[399] This figure was calculated from the figures on Mr. Parcell's surrebuttal schedule 10, from which it was omitted. (*See* Ex. S-4 at sched. 10.)
[400] Ex. S-1 at 41-44; Ex. S-2 at sched. 2, sched. 13; Ex. S-4 at sched. 2, sched. 13, sched. 14.

(the risk-free rate) that he said have become the "new norm," and that he had not given the CAPM results weight in developing his recommended ROE range, but also stated that CAPM results should be considered in determining where within the range APS's ROE should fall. (Ex. S-1 at 45.)

On surrebuttal, Mr. Parcell updated his COE analyses using information as of the end of October 2020 and maintained his ROE recommendation of 9.40%. (Ex. S-3 at exec. summ.)

Mr. Parcell criticized Ms. Bulkley's DCF analysis, stating that for her "High DCF ROE," she "cherry pick[ed]" by only considering the highest of three growth rates for each individual company, and she improperly relied only on analysts' EPS forecasts for growth rates. (Ex. S-1 at 28-30.) Mr. Parcell cited a 2010 McKinsey & Company study[401] that concluded analysts' earnings forecasts are excessively optimistic as well as a 2010 U.S. Securities and Exchange Commission ("SEC") report that prompted investors not to rely solely on analysts' recommendations. (Ex. S-1 at 30-31.) Mr. Parcell criticized Ms. Bulkley's use of projected interest rates for the risk-free rate in her CAPM analysis, stating that the appropriate measure is current yield, which is known and measurable and reflects investors' current collective assessment of all market conditions. (Ex. S-1 at 35.) Mr. Parcell also criticized Ms. Bulkley's CAPM for using a constant growth DCF for the S&P 500 and the current yields on 30-year U.S. Treasury securities to calculate her market risk premium, because her DCF overstates the COE, and the effects of Federal Reserve actions on U.S. Treasury yields make their use as the baseline improper. (Ex. S-1 at 35-36.) Mr. Parcell criticized Ms. Bulkley's Expected Earnings analysis because she used Value Line projected ROEs for her proxy group for 2022 through 2024, although the current estimated ROEs for her proxy group are much lower, and the projected ROEs for 2020 and 2021 are lower still, and because she failed to consider M/Bs, which are higher than 200%. (Ex. S-1 at 40.) Mr. Parcell stated that Ms. Bulkley's Bond Yield Plus Risk Premium analysis suffered from the same deficiencies as her market risk premium and CAPM analyses, as evidenced by none of the quarterly average electric decisions since 2012 that she used having a ROE as high as her recommended 10.15%. (Ex. S-1 at 41.)

Further, Mr. Parcell asserted that none of the additional "risk factors" identified by Ms. Bulkley

[401] McKinsey & Company, McKinsey on Finance, *Equity Analysts: Still Too Bullish*, No. 35 (Spring 2010).

warrant a higher ROE for APS, because each is considered by the rating agencies when they make their credit ratings (they are "already 'baked into the cake'"), APS has higher Moody's and S&P credit ratings than the proxy group companies (indicating lower risk), and PNW has superior Value Line Safety and Financial Strength ratings compared to the proxy group companies (also indicating lower risk). (Ex. S-1 at 46.)

Mr. Parcell did not find merit in any of Ms. Bulkley's criticisms of his COE-related testimony. (See Ex. S-3 at 2-11.)

6. Resolution

After considering all of the COE analyses provided by the parties, as well as their fervent criticisms of each other's analyses, we conclude that APS's COE should be established at 9.16%[402] and, further, that it is not appropriate to make a 20-basis point reduction to APS's ROE as recommended by RUCO. Rather, the question of how best to address APS's customer service performance is discussed further below in Section (IX)(B).

The COE established herein will allow for an authorized ROE that is sufficient to maintain APS's financial integrity, that will enable APS to attract capital under reasonable terms, and that is commensurate with returns that investors could earn by investing in other enterprises of comparable risk. The Commission does not believe that it is necessary or appropriate to increase APS's COE for what Ms. Bulkley has characterized as its additional risks, because the record does not support the claim that APS has relatively higher risk than the proxy group companies.

D. Return on Fair Value Increment

1. APS

On direct, Ms. Bulkley stated that the rate of return on the FVI should be set between the risk-free rate and the COE established by the proxy group analyses because equity holders require a return greater than the risk-free rate. (Ex. APS-20 at 69.) Ms. Bulkley disagreed with the Commission's past practice of setting the rate of return on the FVI at half the risk-free interest rate, stating that it has "no basis whatsoever"; that it is "inconceivable" that an investor would accept a rate of return less than the

[402] This does not reflect our decision related to the return on FVI, made in the next section.

cost of debt for an equity position in any investment; and that the market would expect a rate of return that at least exceeds the risk-free rate. (Ex. APS-20 at 69-70.) Ms. Bulkley estimated the real risk-free rate using three different scenarios (yielding results of 1.41%, 2.72%, and 2.52%) and decided to use 2.52% as the real risk free rate. (Ex. APS-20 at 70-72.) Although Ms. Bulkley believes that the appropriate return on the FVI would fall between the risk-free rate and the recommended ROE in this matter, Ms. Bulkley recommended a 1.00% rate of return on the FVI on direct at APS's request. (Ex. APS-20 at 73.)

On rebuttal, Ms. Bulkley's calculations of the risk-free rate yielded results of 1.09%, 1.83%, and 0.93%, and she determined the real risk-free rate to be 1.28%. (Ex. APS-21 at 69, 119.) However, at APS's request, Ms. Bulkley recommended a 0.80% rate of return on the FVI on rebuttal and rejoinder. (Ex. APS-21 at 122; Ex. APS-22 at 17.)

Ms. Bulkley disagreed with Mr. Walter's calculation of the real risk-free rate, which he determined to be 1.30%, and with his recommended 0.65% return on the FVI. (Ex. APS-21 at 118.) Ms. Bulkley also disagreed with Mr. Walters's statement suggesting that the FVI reduces a company's overall risk profile. (Ex. APS-22 at 16.)

Ms. Bulkley disagreed with Mr. Cassidy's calculation of the real risk-free rate, which he found to be 0.28%, stating that if Mr. Cassidy's calculation had instead used long-term projected yield on U.S. Treasury bonds, or Duff & Phelps's normalized risk free rate, his real risk-free rate would have been 1.70% or 2.20%. (Ex. APS-21 at 68-69.) Ms. Bulkley further disagreed with Mr. Cassidy's recommendation for the Commission to authorize a 0.0% return on the FVI, pointing out that the Commission had not adopted Mr. Cassidy's 0.0% return on the FVI for TEP in the TEP Rate Case and further stating that allowing no return on the FVI would "negate the intent of the Arizona statute, which is to allow the utility to earn a return on the FVI of rate base."[403] (Ex. APS-21 at 68.)

Ms. Bulkley also disagreed with Mr. Parcell's calculation of the real risk-free rate, which he found to be 0.6%, stating that if Mr. Parcell's calculation had used the 30-year Treasury bond, his real risk-free rate would have been 1.83%. (Ex. APS-21 at 52.)

[403] This is understood to be a reference to Article 15, §14 of the Arizona Constitution.

Additionally, Ms. Bulkley asserted that it is important not to conflate changes in the ROE with changes in the return on the FVI because a change in the ROE results in a larger change to the FVROR than does a change in the return on the FVI, and reducing the ROE by the amount of the return on the FVI effectively results in a negative return on the FVI. (Ex. APS-22 at 16.)

2. FEA

Mr. Walters criticized Ms. Bulkley's scenario 2 and 3 methods for determining the risk-free rate, asserting that rather than calculating the risk-free rate, Ms. Bulkley used a measure of the real risk-free rate (the 180-day average yield on 30-year U.S. Treasury Inflation Protected Securities ("TIPS") of 0.98%), called it inflation, and deducted it from her starting points of a projected 30-year Treasury yield and a Duff & Phelps normalized nominal risk-free rate, with the results actually being breakeven inflation rates. (Ex. FEA-2 at 79-81.) Mr. Walters concluded that if Ms. Bulkley's scenario 2 and 3 calculations were corrected, the result would be real risk-free rates of 1.82% and 1.62%, which combined with her scenario 1 result would produce an average real risk-free rate of 1.62%. (Ex. FEA-2 at 83.)

Mr. Walters indicated that although he does not agree with Arizona's FVI methodology,[404] he understood that it has been used for some time and (per Ms. Bulkley's testimony) that the Arizona Constitution entitles a utility to a fair return on the fair value of its property devoted to public use. (Ex. FEA-2 at 83.) Thus, Mr. Walters calculated estimates of the real risk-free rate to calculate an appropriate return on the FVI. (Ex. FEA-2 at 83-84.) Mr. Walters used the same three scenarios as Ms. Bulkley, with the corrections he identified and more recent data, and produced real risk-free rates of 1.09%, 1.85%, and 0.95%, which he averaged to produce his recommended real-risk free rate of 1.30% and his recommended return rate on the FVI of 0.65%. (Ex. FEA-2 at 84-85.)

In his surrebuttal testimony, Mr. Walters noted that Ms. Bulkley's rebuttal testimony had corrected the mathematical errors he had identified in her direct testimony but criticized Ms. Bulkley's recommended FVI cost rate of 1.28% because, had she maintained the method of using half of the calculated risk-free rate, it would have been 0.64% and thus lower than APS's requested 0.80%. (Ex.

[404] FEA acknowledged that the Commission has a practice of authorizing a return on the FVI, based on Arizona law, and offered its recommendation in conformance with the Commission's recent practice. (FEA Br. at 23-24.)

FEA-6 at 28-29.)

3. RUCO

On direct, Mr. Cassidy computed a FVI cost rate for APS by subtracting a forecasted Q4 2021 CPI inflation component of 1.30% from the forecasted Q2 2021 nominal risk-free rate of 1.58% for 30-year Treasury yield to obtain a real risk-free rate of 0.28%. (Ex. RUCO-4 at 72.) However, because financial theory dictates that a utility is entitled to a return on investment, and the FVI represents inflation and not an investment, RUCO recommended a FVI cost rate of 0.0%. (Ex. RUCO-4 at 72-73.) Mr. Cassidy asserted that allowing a return on the FVI would be "patently unfair to ratepayers." (Ex. RUCO-4 at 73.) On surrebuttal, Mr. Cassidy maintained RUCO's recommendation for a 0.0% return on the FVI. (Ex. RUCO-5 at 13.)

4. Staff

Mr. Parcell indicated that he does not agree that APS's COC must be applied to its FVRB. (Ex. S-1 at 47.) Mr. Parcell indicated that his "non-legal understanding" is that the Commission has discretion to determine the rate of return to be applied to the FVRB. (Ex. S-1 at 48.) According to Mr. Parcell, the concept of COC is designed to apply to OCRB, because COC is derived from the equity side of a utility's balance sheet, and rate base is derived from the asset side of the balance sheet, and applying the COC to OCRB represents a "matching of rate base and capitalization." (Ex. S-1 at 48.) Mr. Parcell stated that because the FVI is not financed by investors or at all, it is inconsistent with financial theory to provide an opportunity to earn a return on the FVI and logical and appropriate to assume that the FVI has no financing cost. (Ex. S-1 at 49.) Mr. Parcell suggested that the COC, through the capital structure, could be modified to account for a level of cost-free capital in a dollar amount equal to the FVI increment, which would still provide for a return on all investor-supplied funds, consistent with financial standards. (Ex. S-1 at 49.) Mr. Parcell's primary recommendation was for a 0.00% return on the FVI. (Ex. S-1 at 50.) According to Mr. Parcell, "an above-zero cost rate for the FVI represents a bonus to the Company that would have to find its justification in policy considerations instead of in pure economic or financial principles." (Ex. S-1 at 53.)

In recognition of Arizona's "fair value standard," however, Mr. Parcell recommended in the alternative that a return of 0.30% be authorized on the FVI. (Ex. S-1 at 50, 52-53.) Mr. Parcell

calculated the 0.30% return on FVI by deducting a 2.0% inflation rate (derived from the forecasted CPI for 2021) from a 2.6% nominal risk-free rate (derived from 2019 yields on long-term U.S. Treasury securities) to obtain a real risk-free rate of 0.6%, which he stated is the highest return that could be used for the FVI. (Ex. S-1 at 52-53.) Mr. Parcell stated that the real risk-free rate, rather than the nominal risk-free rate, should be used as to determine the appropriate return on the FVI because the FVI itself represents inflation, and using the nominal risk-free rate (from which inflation has not been deducted) would double count the inflation. (Ex. S-1 at 53.) Mr. Parcell stated that any value between 0.0% and 0.6% could be used as the cost rate on the FVI, as any "above-zero cost rate . . . represents a bonus to the Company . . . that would have to find its justification in policy considerations instead of in pure economic or financial principles." (Ex. S-1 at 53.) Mr. Parcell recommended that if the Commission desires to provide a positive return on the FVI, the Commission allow a return on FVI of 0.3%.[405] (Ex. S-1 at 52-53.) On surrebuttal, Mr. Parcell noted that current U.S. Treasury bond yields at that time were 1.5%. (Ex. S-3 at 12.)

5. Resolution

As the non-APS parties explained, it is inconsistent with financial theory to grant a ROR on the FVI, as the FVI does not represent investment of capital. Rather, as the difference between the OCRB and the FVRB, the FVI represents the inflation recognized in the RCND. The Commission has not consistently authorized a positive return on the FVI and has indicated that it is not legally required to do so. (*See, e.g.,* Ex. Navajo-9 at 69-70 (indicating that no positive return on the FVI was required but authorizing such a return as appropriate for TEP in that case); Decision No. 77850 (December 17, 2020) at 74 (indicating that no positive return on the FVI was required but authorizing such a return as appropriate for Southwest Gas in that case); Decision No. 77380 (August 19, 2019) at 55 (denying a return on the FVI).)

Nonetheless, APS asserts that under *Chaparral City Water Co. v. Arizona Corp. Comm'n*, 2007 WL 971085 (Ariz. Ct. App. 2007), the Commission is required to use FVRB to set rates, and this means that the Commission must also allow a positive return on the FVI. (APS Br. at 34-35.) According to

[405] Staff's revenue requirement on direct was calculated using the 0.3% return on FVI. (Ex. S-1 at 54.)

APS, the Commission's recent deduction from TEP's ROE of the same percentage as the ROE allowed on the FVI, resulting in a revenue requirement lower than that calculated using OCRB and WACC, was unconstitutional and represented reversible error. (APS Br. at 35-36.) Additionally, Staff implies in its opening brief that a positive return on the FVI is necessary, stating that "the parties agree that the Commission has consistently used the risk-free rate of return as the basis for calculating the return on FVI to properly satisfy AZ law." (Staff Br. at 39 (emphasis added).)

As RUCO points out, the *Chaparral* case cited by APS is a Memorandum Decision that does not create legal precedent and generally cannot be cited as precedent under Arizona Supreme Court Rule 111(c).[406] (RUCO Br. at 9.) RUCO argues that the more recent Arizona Supreme Court decision in *RUCO v. Arizona Corp. Comm'n*, 240 Ariz. 108, 112 (2016) ("SC SIB Decision"), established that the Commission is not required to award a positive return on the FVI because the court stated that "the 'fair value' requirement applies only to the 'rate base' element of the traditional ratemaking equation" and not to rate of return. (RUCO Br. at 9-10; 240 Ariz. at 112.) Although RUCO is correct that the SC SIB Decision makes this statement, it was made in dicta and thus may not prove to be reliable authority should the return on FVI issue be put before the court in future.

Arizona's requirement for rates to be determined using FVRB rather than OCRB does not increase the risk for investors in Arizona's utilities and thus does not logically necessitate an additional return in excess of what would be necessary if Arizona were not a FVRB jurisdiction. Indeed, if a positive return on FVI is awarded, the risk for investors in an Arizona utility is decreased. While it is crucial that the interests of ratepayers and shareholders be balanced in any rate case, it is especially important in this rate case that ratepayers' interests are thoroughly considered, as the impacts of the 2016 Rate Case and the various adjustor mechanism increases since have been truly financially challenging for many ratepayers, and this is a particularly challenging time. From a ratepayer perspective, there is no justification for authorizing a positive return on the FVI. Additionally, APS's legal mandate argument is overstated and under-supported by the cited caselaw. However, it is unlikely

[406] In pertinent part, Rule 111(c) provides that a Memorandum decision of an Arizona state court is not precedential and may be cited only "to establish claim preclusion, issue preclusion, or law of the case" or "for persuasive value, but only if it was issued on or after January 1, 2015; no opinion adequately addresses he issue before the court; and the citation is not to a depublished opinion or a depublished portion of an opinion." (Arizona Supreme Court Rule 111(c)(1)(A), (C).)

that APS ratepayers or the public interest would be served by a lawsuit predicated on the Commission's denying APS a return on the FVI. In light of the discussion and information above, and in recognition that the return on the FVI decreases shareholder risk, we conclude that it is reasonable and appropriate to grant APS a return on FVI of 0.15% (half the amount recommended by Staff in the alternative) and to make a corresponding reduction to APS's COE of 0.10%.

E. Fair Value Rate of Return

APS's agreed upon adjusted capital structure and capitalization, along with the decision made on APS's COE and COD, are reflected below ($ amounts are in thousands):

Capitalization	$ Amount	% Amount	Cost Rate	Composite Cost
Common Equity	$5,700,968	54.67%	9.16%	5.01%
Long-Term Debt	$4,726,125	45.33%	4.10%	1.86%
			WACC:	**6.87%**

If Arizona were not a FVRB jurisdiction, or if APS had chosen to use its OCRB as its FVRB (thereby saving the time and other resources necessitated for a RCND study), the WACC would be applied to APS's OCRB to obtain APS's revenue requirement.

However, because Arizona is a FVRB jurisdiction, and APS has chosen not to use its OCRB as its FVRB, the following additional calculations, using APS's FVRB and FVI (as well as the related downward adjustment to the COE), are necessary to establish the FVROR to be applied to APS's FVRB ($ amounts are in thousands):

	$ Amount	% Amount	Cost Rate	Composite Cost
Common Equity	4,850,860	39.41%	9.06%	3.57%
Long-Term Debt	4,022,124	32.67%	4.10%	1.34%
FVI	3,437,279	27.92%	0.15%	0.04%
			FVROR:	**4.95%**

We conclude that the FVROR to be applied to APS's FVRB is 4.95% and that this FVROR will result in a revenue requirement that meets the *Hope* and *Bluefield* standards described above.

VII. Revenue Requirement

In light of the other determinations made herein, we conclude that APS has a base rate revenue requirement of $3,326.009 million, which represents a decrease of $111.431 million from APS's adjusted TY operating revenues of $3,437.440 million and results in operating income of $581.349 million. The following compares APS's amended application with our determinations herein:

	APS Amended Application	Commission
OCRB	$8,896,268	$8,325,497
RCND	$15,734,140	$15,163,369
FVRB	$12,315,204	$11,744,433
FVI	$3,418,936	$3,418,936
Operating Revenues	$3,437,440	$3,437,440
Operating Income	$648,909	$664,843
Current Rate of Return on OCRB	7.29%	7.99%
Required Operating Income on OCRB	$652,096	$571,962
Required Rate of Return on OCRB	7.33%	6.87%
Operating Income Deficiency on OCRB	$3,187	($92,881)
Gross Revenue Conversion Factor	1.3346	1.3346
Increase in Base Revenue Requirement Based on OCRB	$22,948	($123,959)
Required Rate of Return with FVI	5.51%	4.95%
FVI Revenue	$35,973[407]	$12,528[408]
Requested/Required Increase in Base Revenue Requirement	$40,226	($111,431)
Required Base Rate Revenue Based on FVRB	$3,477,666	$3,326,009

VIII. Rate Design & Specific Tariff Issues

A. Residential Rate Design – Non-Solar & Non-Limited-Income Issues

1. APS Position

APS proposes the following changes to its residential rate design:

- Freezing residential demand rate R-2 so that it is unavailable for new customers and APS will offer only one residential demand rate, R-3, although existing R-2 customers will be allowed to continue on R-2;[409]
- Adding a winter super off-peak period of 10 a.m. to 3 p.m. to residential demand rate R-

[407] APS's FVI revenue was described by APS as "After Tax Return on Fair Value Increment," although APS's requested revenue increase of $40.226 million is comprised of $4.253 million based on OCRB plus $35.973 of FVI revenue, which must be comprised of operating income and income taxes, for which our estimated calculation is $27.351 million in operating income and $8.622 million in income taxes. (*See* LFE APS-87 at sched. A-1.)

[408] The FVI revenue is comprised of $9.387 million in operating income and $3.141 million in income taxes. Original cost operating income of $571.962 million + FVI operating income of $9.387 million = total operating income of $581.349 million.

[409] Ex. APS-26 at 2, 8.

3;[410]

- Eliminating the following customer charges in Service Schedule 1 and recovering them through base rates instead: service establishment charges (also non-residential), after-hours charges (standard meter and non-standard meter), same-day connect charge, field call charge, and termination process charge;[411]
- Un-freezing R-Basic L and combining R-XS, R-Basic, and R Basic L into one tariff, although the eligibility requirements and rate design as to each tariff will remain unchanged;[412]
- Offering a one-time waiver of a Basic customer's reassignment to a higher tier based on annual kWh usage, provided that the customer calls the APS Customer Care Center;[413]
- Eliminating the current mandatory 90-day TOU trial period for new residential customers (required before they could switch to a Basic rate) and eliminating the reassignment of larger usage customers from the Basic rate to a TOU rate when their usage exceeds the current R-Basic eligibility requirements;[414]
- Waiving the following customer charges in Service Schedule 1 once per year per customer: dishonored payment fee, meter test charges (shop and field), and trip charges (non-residential also) due to lack of access to point of delivery;[415] and
- Modifying Service Schedule 1 to increase the amount of time customers have to remit payment after a bill is issued from 14 to 21 days.[416]

APS's summer rate period is May through October, and APS does not propose to change it. (Ex. APS-26 at 16.) APS's on-peak period for residential rates is 3 p.m. to 8 p.m., although TOU E also has a winter super-off-peak period from 10 a.m. to 3 p.m., and APS does not propose to change either of these periods. (Ex. APS-25 at 5; Ex. APS-26 at 12.)

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[410] Ex. APS-25 at 3-5; Ex. APS-26 at 32.
[411] Ex. APS-25 at 15, att. JEH-19DR.
[412] Ex. APS-26 at 1-2.
[413] Ex. APS-26 at 10.
[414] Ex. APS-26 at 2.
[415] Ex. APS-25 at att. JEH-19DR.
[416] Ex. APS-26 at 46.

2. AARP

AARP's rate design expert testified that in his almost 40 years of experience, he had never before seen a residential rate structure as "complicated and confusing" as that of APS. (Tr. at 4458.) AARP argues that APS's complicated residential rate design is costing APS's ratepayers (300,000 of the 750,000 sample analyzed) approximately $65 million per year more than they should be paying. (AARP Br. at 4.) On brief, AARP expressed support for the residential rate design changes APS agreed to make during this matter and urged the Commission to make the following additional changes to APS's residential rate design:[417]

- The eligibility for the middle tier of the new combined flat rate tariff should be expanded to include customers who use 7,201 to 18,000 kWh in a calendar year; and
- The one-year grace period for a customer being moved to a higher-cost Basic rate tier based on usage should be made available to all similarly situated customers, not just those who contact APS's customer care center.

AARP argues that the middle tier of the Basic rate tariff needs to be expanded because Mr. Rubin found that virtually no customers who use more than 12,000 kWh per year would pay lower bills on the highest tier of the Basic rate tariff (as compared to TOU E or a demand rate) and many customers who use between 12,000 and 18,000 kWh would pay lower bills on the middle tier (as compared to TOU E or a demand rate). (AARP Br. at 6-7 (citing Ex. AARP-2 at 4-5).)

AARP also argues that the one-year grace period to stay on a Basic rate tier although the prior year's usage exceeded the tier threshold must be made available to all similarly situated customers because offering the grace period only to customers who contact the customer care center "would be unduly discriminatory and grossly unfair to customers who are not lucky (or knowledgeable) enough to contact the call center." (AARP Br. at 7.) AARP reasons that such benefits "should not be just for those who figure out the right way to complain." (*Id.*)

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[417] AARP Br. at 6-7. AARP reiterated Mr. Rubin's original recommendations, but then indicated that AARP appreciated APS's decisions to offer only one optional demand rate for residential customers, to eliminate automatic assignment of new customers to TOU E, and to improve customers' ability to understand rates. (AARP Br. at 6.) We understand this to mean that AARP is no longer proposing Mr. Rubin's originally provided recommendations, except as set forth in the subsequent sections of its brief.

3. SEIA/AriSEIA

According to SEIA/AriSEIA, the evidence establishes that the summer period should be limited to four months: June through September. (SEIA Br. at 7, 9.) Mr. Lucas testified that because none of APS's 500 peak system hours occur outside of the period from June through September and 81% of the 500 peak system hours occur in July and August, the months of May and October should be eliminated from the summer peak season. (SEIA Br. at 9 (citing Ex. SEIA-1 at 59).) In his direct testimony, Mr. Lucas provided graphs showing both the top 500 system load hours from 2016 through 2019 and the top 500 residential load hours from 2016 through 2019, both of which showed that the top 500 hours occurred exclusively in the June through September period. (See Ex. SEIA-1 at 60-61.) Mr. Lucas also found that May and October's average system loads are approximately 2,000 MW lower than the core summer peak. (Ex. SEIA-2 at 10.)

Although SEIA/AriSEIA did not brief the issue, Mr. Lucas also recommended that the Commission require APS to change its on-peak period for R-2, R-3, and TOU-E to 2-7 p.m. only in June through September, as these would better reflect the cost drivers on APS's system and would target both system load and residential load. (Ex. SEIA-1 at 64-65.) Mr. Lucas found that the hour between 2 p.m. and 3 p.m. contained more of the top 100 residential peak hours than the hour between 7 p.m. and 8 p.m., but that the 3-8 p.m. peak hours were better aligned with the residential class distribution peak than with the system peak. (*Id.*) Mr. Lucas also found that neither system load nor residential load was trending toward later peaks, as system peak hours occurred between 4:36 p.m. and 4:42 p.m. in 2016-2018 and at 3:54 p.m. in 2019, while residential peak hours occurred between 5:04 p.m. and 5:19 p.m. in 2016-2018. (*Id.* at 63-65.)

Additionally, SEIA/AriSEIA argue that the current R-Tech tariff is a poorly designed " failure" and should be redesigned to be more attractive to customers by making the changes described below:[418]

	R-Tech (APS Proposed)	SEIA/AriSEIA R-Tech
Summer Months	May-October	June-September
Peak Hours	3-8 p.m. weekdays	2-7 p.m. weekdays
Super Off-Peak Hours	N/A	10 a.m-2 p.m. weekdays
BSC ($/day)	$0.505	$0.437

[418] *See* SEIA Br. at 14; Ex. APS-53. Oddly, in its brief, SEIA/AriSEIA compared its alternative R-Tech proposal to TOU-E rather than to R-Tech.

On-Peak Demand – Summer ($/kW)	$20.653	N/A
On-Peak Demand – Non-Summer ($/kW)	$14.540	N/A
Off-Peak Demand ($/kW after 5 kW)	$6.642	N/A
Summer Energy ($/kWh)		
Peak	$0.05888	$0.28550
Off-Peak	$0.04869	$0.11420
Super Off-Peak	N/A	$0.04941
Non-Summer Energy ($/kWh)		
Peak	$0.04869	$0.22840
Off-Peak	$0.04869	$0.11420
Super Off-Peak	N/A	$0.03294[419]
Grid Access Charge	N/A	N/A

SEIA/AriSEIA assert that although APS has 694 DG customers with battery storage and there are more than 16,500 electric vehicles in APS service territory, only 14 solar customers were on the R-Tech tariff at the end of the TY, and the average number of customers on R-Tech fluctuated between 18 in the summer and 21 in the winter during the TY. (SEIA Br. at 13 (citing Ex. SEIA-1 at 66; Ex. APS-39 at sched. H-5 at 16).) Mr. Lucas opined that R-Tech is poorly designed because it has an off-peak demand charge that applies during NCP and does not send meaningful signals to customers or encourage them to shift usage to times such as overnight hours because they will still incur sizable demand charges at those times. (Ex. SEIA-1 at 69.) Mr. Lucas also stated: "The rate should be changed to target energy and demand reductions during months and hours when they are most useful to all customers and do so through a mechanism that is easier for customers to understand and respond to." (Ex. SEIA-1 at 71.) SEIA asserts that its redesigned R-Tech is reasonable and in the public interest and urges the Commission to adopt it. (SEIA Br. at 15.)

5. WRA/SWEEP

WRA/SWEEP recommend that the Commission freeze both R-2 and R-3 to new residential customers and phase out existing customers over time, asserting that APS has not properly educated its customers about demand rates (and should not be permitted to try again using ratepayer money), customers do not understand the demand rates, and customers did not respond to the demand rates in a meaningful way. (WRA Br. at 7-8 (citing Ex. WRA-2 at 8).) Mr. Baatz testified that demand charges send a poor price signal to residential customers concerning when and how to use electricity in a manner

[419] This number has been corrected from SEIA/AriSEIA's brief to be consistent with the correction in Exhibit SEIA-4.

to benefit the system and are inferior to other time-based rate options, including TOU rates, which are better understood, get a more significant price response, and are familiar to APS customers. (Ex. WRA-1 at 14.) WRA/SWEEP also assert that demand rates cause customer confusion and require costly education efforts. (WRA RBr. at 6.) According to WRA/SWEEP, APS should promote its TOU rate for its residential customers, because TOU rates are understood and provide greater peak demand reductions, and APS should also offer a flat rate option. (WRA Br. at 8.) WRA/SWEEP add that if the Commission decides to retain a residential demand rate, the super off-peak period of 10 a.m. to 3 p.m. weekdays during winter months should be added to whichever demand rate remains. (WRA RBr. at 5.)

WRA/SWEEP urge the Commission to approve a BSC of $8.03 for all residential customers, rather than allowing APS to increase the BSCs for its residential rates, because none of the costs cited by APS as the impetus for the rate increase (the OMP, the SCRs, depreciation rate changes, low-income bill assistance, and other expenses) are customer-related costs. (WRA Br. at 9 (citing Ex. APS-41 at 2; Ex. WRA-1 at 28-29).) Mr. Baatz testified that a BSC should collect only customer-related costs, which he defined as the operating and capital costs that vary with the number of customers regardless (or nearly regardless) of consumption and criticized APS for including other costs such as distribution infrastructure costs in its BSC, which he stated causes some customers to pay more than the costs they cause while others pay less. (Ex. WRA-1 at 29-31.) Mr. Baatz determined that based on inclusion of only the costs he identified as customer-related, the BSC should be $8.03 for APS's residential rates. (Ex. WRA-1 at 29-31.) Mr. Baatz criticized APS's use of higher BSCs, asserting that they reduce customers' incentive to engage in EE and to conserve, they harm low-income customers because they make it difficult to control bills, and they result in a lower volumetric rate that discourages investment in EE or DG by increasing the time it takes customers to recoup their investments in those technologies and sends a price signal to increase consumption (thereby driving higher peak demand and system costs). (Ex. WRA-1 at 24-25, 31-32.) WRA/SWEEP dispute APS's assertion that APS's proposed BSCs are already below cost of service for most of its residential rates and that the WRA/SWEEP-proposed BSC would result in recovery of less than half of the costs the BSC is intended to recover, maintaining that APS is including costs other than customer-related costs in its BSC. (WRA RBr. at

7.)

WRA/SWEEP also urge the Commission to shorten APS's residential on-peak period from 3-8 p.m. to 4-7 p.m., arguing that the three-hour on-peak period would capture most of the top usage hours on APS's system, thereby reducing peaks and future costs, and would focus on the hours when load shifting is most necessary and critical while also providing customers greater flexibility to shift usage and pre-cool in the summer months. (WRA Br. at 14 (citing Ex. WRA-2 at 14-15; Tr. at 2120).) WRA/SWEEP observe Mr. Albert's projection that in July 2021 the hours with the highest net load would be between 4 p.m. and 7 p.m. and, further, that 63% of the top 90 hours in 2021 would occur during those hours (while all 90 hours fall between 1 p.m. and 9 p.m. and 84% of the top 90 hours fall within the current 3-8 p.m. on-peak window). (WRA Br. at 11-13 (citing Ex. APS-8 at 23-24).) WRA/SWEEP argue that if customers cannot respond to the price signals from TOU rates because the on-peak period is too long, the TOU rates will not produce the desired shifts in usage from high load hours to lower load hours; that APS has acknowledged that its customers have complained about the 8 p.m. end of the on-peak period as too late; and that shortening the on-peak period to 4-7 p.m. would balance the needs of the system and the needs of customers. (WRA Br. at 13-14 (citing Ex. WRA-1 at 14; WRA-2 at 14-15; Tr. at 2120, 2183).) Further, WRA/SWEEP assert that APS's argument that removing the 7-8 p.m. hour from on-peak would be misaligned with wholesale market prices is a "red herring," because APS has also stated that it does not rely on the wholesale market for power during on-peak hours because there is no market capacity. (WRA RBr. at 3 (citing Tr. at 1199-1200).) WRA/SWEEP also refute APS's argument that APS's system will be shifting to a later peak, like California, with the addition of more renewables, asserting that APS's current system peak load occurs between 5:30 and 6:00 p.m. and, further, arguing that APS's on-peak hours should be based on its current peak rather than speculation about the future. (WRA RBr. at 3-4 (citing Tr. at 585, 1190, 1200-1201).) WRA/SWEEP also note that Staff's recommendation for on-peak hours is consistent with their own. (WRA RBr. at 4.)

In response to APS's argument that the lack of a bill impact analysis for the residential rate designs proposed by Staff and WRA/SWEEP should disqualify their recommendations, WRA/SWEEP argue that the Commission should first decide APS's revenue requirement and class revenue allocation

and then, before approving any changes to rate design and implementing new rates, require APS to provide a bill impact analysis and proof of revenue for the residential rate designs recommended by Staff, WRA/SWEEP, and other parties or Commissioners. (WRA RBr. at 4.) WRA/SWEEP note that APS provided a bill impact analysis for an on-peak period of 4-7 p.m. during the hearing, but assert that the analysis was problematic because APS used its current rates and increased the off-peak rate to recover the deficiency, rather than increasing the on-peak rate, which would have been more consistent with creating appropriate TOU price signals. (WRA RBr. at 4 (citing Tr. at 2252; Ex. APS-55; Ex. APS-8 at 21; Ex. WRA-1 at 19).) WRA/SWEEP further assert that contrary to APS and RUCO's contentions that raising the on-peak rate to recover the deficiency would result in large bill impacts, a shorter window would allow customers greater opportunities to shift consumption to lower cost off-peak hours, such as by pre-cooling their homes, which is challenging with a five-hour on-peak period. (WRA RBr. at 5 (citing Ex.WRA-1 at 19).) Additionally, WRA/SWEEP assert that because APS's proposed on-peak rate is approximately 123% higher than its proposed off-peak rate, which is similar to the ratio for its current rates, and APS's customers respond to it, raising the off-peak rate to make up a revenue deficiency from changing the on-peak period "does not make sense" and "would ruin the conservation signals." (WRA RBr. at 5 (citing Tr. at 793-794, 2232; Ex. APS-26 at 14-17).)

WRA/SWEEP also argue that the Commission should require APS to place all new residential customers on TOU-E as a default, because APS currently does not have a default rate and instead has a Customer Advisor work with each new customer to find the "best" rate option, while TEP and UNSE both have a TOU rate as the default rate for new residential customers. (WRA Br. at 15 (citing Ex. WRA-1 at 15).) According to WRA/SWEEP, TOU-E should be APS's default residential rate because TOU rates provide significant benefits, APS does not have a good history of selecting the best rate plans for its customers, APS has a significant number of customers on TOU rates, and APS's customers understand and respond well to TOU rates. (WRA Br. at 15 (citing Tr. at 793-794).) WRA/SWEEP further assert that customers assigned to the default TOU rate should have the option to move to a flat rate at any time if they so desire. (WRA Br. at 15 (citing Tr. at 3741).)

Further, WRA/SWEEP urge the Commission to require APS to restructure residential electric vehicle ("EV") rates by adding a year-round, night-time super off-peak period of 11 p.m. to 5 a.m. with

a lower energy rate to encourage charging when system utilization is lowest, which would increase the efficiency of the grid and help spread around fixed costs, to the benefit of all customers. (WRA Br. at 15-16 (citing Tr. at 584-585; Ex. WRA-1 at 23); WRA RBr. at 6.) WRA/SWEEP point to Mr. Guldner's testimony concerning the danger of having a lot of EVs plugged in when people get home at 6 p.m., although APS typically has a peak around 6 p.m. in the summer months, because this could "add a thousand megawatts of peak that requires [APS] to go out and build a thousand megawatts of combustion turbines to serve." (WRA Br. at 16 (quoting Tr. at 585).) WRA/SWEEP criticize APS's use of equivalent gasoline price per gallon to oppose WRA/SWEEP's proposal, opining that if equivalent gasoline price is the measure, R-3 customers would have an incentive not just to charge off-peak, which APS said "translates to less than $0.50 per gallon of gas," but also to charge on-peak, which Mr. Baatz determined would translate to less than $1.00 per gallon of gas. (WRA Br. at 16-17 (quoting Ex. APS-26 at 39); Ex. WRA-2 at 15-16.) Mr. Baatz asserted that instead of focusing on gasoline cost equivalency, APS's approach to EV charging should be focused on getting customers to charge during the hours of lowest system usage. (Ex. WRA-2 at 15-16.) WRA/SWEEP urge the Commission to approve the EV super-off-peak period now because EV adoption will only increase, and the costs for educating and marketing the new rates to customers will only be higher later when substantially more customers are involved. (WRA Br. at 17 (citing Ex. CP-3[420]; Ex. WRA-1 at 23).)

Finally, WRA/SWEEP urge the Commission to approve a revenue requirement and class revenue allocation and then require APS to provide bill impact analyses and proof of revenue for a variety of residential rate designs, including those proposed by WRA/SWEEP and Staff, before approving any changes to rate design and implementing any new rates. (WRA RBr. at 8.) WRA/SWEEP remind the Commission: "The effect of the rate upon persons to whom services are rendered is as deep a concern in the fixing thereof as is the effect upon the stockholders or bondholders. A reasonable rate is one which is as fair as possible to all whose interests are involved." (WRA RBr. at 7-8 (quoting *Arizona Cmty. Action Ass'n v. Arizona Corp. Comm'n*, 123 Ariz. 228, 231 (1979)).)

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[420] Exhibit CP-3 is Decision No. 77289 (July 19, 2019), the Commission's Electric Vehicle Policy Implementation Plan.

6. RUCO

RUCO recommends adding a second TOU rate class, freezing R-2 to new customers, and modifying the annual reassignment of rate classes. (RUCO Br. at 38.) RUCO also advocates for minimal changes within each rate class to avoid confusion, as follows: (1) retain existing BSCs, (2) retain the super off-peak energy charge for TOU E, and (3) allocate the rate change to demand and energy rates equally. (RUCO Br. at 41-42.)

RUCO recommends the addition of a second TOU rate to provide customers additional options to manage electric bills. (RUCO Br. at 39.) RUCO's proposed TOU rate would have the following:[421]

BSC	$0.50/day
Off-peak energy rate	$0.07/kWh
On-peak energy rate	$0.25/kWh

According to RUCO, the off-peak rate is set 33-45% lower than for other non-demand residential rates and the on-peak rate is set 8% higher than TOU E and 125% higher than APS's Basic rates, to encourage customers to shift load to off-peak hours. (RUCO Br. at 39 (citing Ex. RUCO-2 at 14-15.) RUCO asserts that with 20% on-peak usage and 80% off-peak usage, the average energy rate would be $0.113/kWh, a 4% discount from the lowest residential rate, and that the discount would be lost if on-peak usage increased to 22%. (RUCO Br. at 39 (citing Ex. RUCO-2 at 14-15).) RUCO believes that this "carrot and stick" approach would attract customers who are truly committed to shifting load to off-peak periods. (RUCO Br. at 39.)

RUCO asserts that because R-2 has not resulted in a meaningful shift of load by customers and has had "no discernible positive results," it should be frozen, and APS should deemphasize its demand rates. (RUCO Br. at 39.)

RUCO agrees with the Alexander Report's conclusion that mandatory migration from one rate plan to another should not be completed without customer education. (RUCO Br. at 20 (citing Ex. RUCO-2 at 17; Ex. RUCO-15).)

Although RUCO did not brief the issue, Mr. Radigan testified that APS's current summer period should be retained because shortening the summer period would result in higher bills, as non-summer

[421] RUCO Br. at 39.

rates would need to be increased to produce the same revenue. (Ex. RUCO-3 at 22-23.) Mr. Radigan pointed out that APS collects between 62% and 65% of its total annual revenues during the summer period and that no witness proposing to change the summer period has provided a bill analysis to show the impact. (See Ex. RUCO-3 at 22-23.)

7. Staff

Staff recommends that APS be required to make the following changes to APS's residential rate design that APS has not already adopted through its own proposals:[422]

- Discontinue all seasonally differentiated demand charges and all time-differentiated energy rates on APS's demand rates, to assist in simplifying APS's rate structure and reduce customer confusion.[423]
- Adopt new demand rates for R-2 and R-3 based on 50% and 100% of full demand-related cost of service.[424]
- Reject the proposed super off-peak winter energy rate for R-3 and discontinue the super off-peak energy rate within TOU-E, to simplify APS's rates.[425]
- Shorten the on-peak period to 4-7 p.m., because APS's system historically peaks between 6 and 7 p.m.; residential customer demand peaks between 5 and 7 p.m. during the summer months; and shortening on-peak hours would send customers a clearer price signal and make it easier for them to alter their energy usage.[426]
- Establish a uniform BSC across all standard residential rates—R-Basic, TOU-E, R-2, and R-3.[427]
- Reject APS's proposed residential BSC increases because they would negatively impact the public policy goal of increasing EE and would burden low-use customers.[428]

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[422] Staff's proposals that were adopted by APS are not included here.
[423] Staff Br. at 49 (citing Ex. S-5 at 38-39; Tr. at 4840-4842).
[424] Staff Br. at 49 (citing Ex. S-5 at 45-46). Dr. Dismukes calculated that total demand-related costs for residential customers are $13.22/kW. (Ex. S-5 at 45.) He recommended that the demand charge for R-3 be set at $13.22 and that the demand charge for R-2 be set at half of that, or $6.61/kW. (Ex. S-5 at 45-46.)
[425] Staff Br. at 49 (citing Ex. S-5 at 46).
[426] Staff Br. at 50 (citing Ex. S-5 at 48-49; Tr. at 2233-2234, 4842, 4853).
[427] Staff Br. at 50 (citing Ex. S-5 at 49).
[428] Staff Br. at 50 (citing Ex. S-5 at 56-57).

8. APS Response

APS opposes AARP's proposal to default customers who use 7,200 kWh or less per year to R-XS and to make TOU-E and demand rates unavailable to such customers.[429] (APS Br. at 65.) APS argues that such a restrictive approach should not be used and that each customer should have the choice of a Basic, TOU, or demand rate, noting that APS has offered demand rates for 40 years and that the number of customers voluntarily migrating to demand rates over that period has increased dramatically. (APS Br. at 66 (citing Ex. APS-26 at 28-29).)

APS also opposes AARP's recommendation for the R-Basic-to-R-Basic L threshold to be raised to 18,000 kWh/year to make the less expensive middle tier (R-Basic) rates available to customers who would otherwise be required to pay the highest tier rates (R-Basic L), asserting that AARP's proposal would require an adjustment of all of the Basic tiered rates to recover the same amount of authorized revenue from the Basic customer class by increasing the lower tier and middle tier rates, which would benefit approximately 7,000 high-energy-use customers to the detriment of current lower tier and middle tier customers. (APS Br. at 66 (citing Ex. APS-27 at 5; Tr. at 4461, 4470-4472).) APS further added that AARP's recommendation would discourage energy conservation by making higher energy usage cheaper and punishing current moderate and frugal energy customers with increased rates to benefit higher energy users. (APS Br. at 67.)

APS also opposes AARP's position that the one-time waiver of rate reassignment from one tier to a higher tier on Basic rates, based on annual kWh exceeding the assigned tier, should be offered to all customers rather than just those who contact APS. (APS Br. at 64.) APS argues that "AARP's claim of unfairness falls flat" because APS makes the one-time waiver available to all customers, once they contact APS directly to obtain the waiver. (APS Br. at 64 (citing Ex. APS-26 at 10).) APS argues that there is value in providing the one-time courtesy waiver because some customers will not be aware why they have been reassigned to a higher tier rate and will call APS to ask, providing APS Customer Advisors the opportunity to "provide helpful tools to assist customers in monitoring the amount of energy consumed monthly such as usage notifications or information available on the bill and aps.com

[429] We believe that AARP is no longer proposing this.

so they are prepared for future reassignments." (APS Br. at 65 (citing Ex. APS-26 at 10).) APS asserts that if it is approved by the Commission, APS intends to include the one-time courtesy waiver in Service Schedule 1, making it available to all "flat rate" customers. (APS Br. at 65 (citing Ex. APS-26 at 10).)

APS disagrees with Mr. Lucas that the summer season should be shortened to four months, asserting that it would be inappropriate because the daily load shape patterns for the shoulder months (May and October) more closely resemble the daily load shape patterns for the four core summer months than those of the non-summer months due to the high heat and because, although the weather in the shoulder months may vary, the shoulder months typically require significant use of air conditioning. (Ex. APS-26 at 16; APS Br. at 55-56[430].) APS also notes that RUCO supports retaining the current summer months and that neither SEIA/AriSEIA nor any other party has provided a bill impact analysis for a shortened summer season. (APS Br. at 56.)

APS also opposes SEIA/AriSEIA's proposed revisions to R-Tech. (APS Br. at 70.) Ms. Hobbick testified that as of November 2020, R-Tech had 55 enrolled customers and essentially conceded that it has not performed as expected. (See Ex. APS-26 at 35.) According to Ms. Hobbick, the off-peak excess demand charge was included in R-Tech to protect against creation of a new peak during the evening hours, because the first 5 kW of off-peak demand incurs no demand charge, and the off-peak demand above 5 kW incurs a demand charge much smaller than the on-peak demand charge. (Ex. APS-26 at 35.) Ms. Hobbick characterized SEIA/AriSEIA's proposal as a technology TOU rate, asserted that customers who invest in multiple energy management technologies can save more on demand rates than on TOU rates because demand rates typically have lower energy charges, and opined that SEIA/AriSEIA's proposed technology TOU rate "is simply not a rate designed with proper price signals for technology." (Ex. APS-26 at 36.) Ms. Hobbick added that APS believes the recently approved Residential Energy Storage Pilot, which provides incentives, may result in added participation in R-Tech and allow for its performance to be evaluated further. (Ex. APS-26 at 36.) APS desires to continue monitoring R-Tech to see if its desired objectives will be achieved due to the

[430] In its brief, APS also includes April in the shoulder months. (*See* APS Br. at 55.)

storage pilot. (*Id.*; APS Br. at 71)

APS opposes WRA/SWEEP's proposals to freeze demand rates and lower the BSC, arguing that APS has a long history of offering voluntary demand and TOU rates to its residential customers, that WRA/SWEEP did not perform a bill impact analysis, and that Mr. Baatz acknowledged that a Colorado study he relied on in his testimony does not "directly transfer" to APS and Arizona. (APS Br. at 69-70 (citing Ex. APS-27 at 7; Tr. at 3726).) APS argues that its customers should continue to have the choice to enroll in demand rates. (APS Br. at 70.)

Additionally, APS disagrees with WRA/SWEEP's recommended BSC of $8.03 for all residential rate classes, arguing that APS's proposed BSCs are already below cost of service for all but one of APS's residential rates (R-Basic L) and that adoption of the $8.03 BSC would reduce the recovery through each BSC to less than 50% of the costs the BSC is intended to recover, making it necessary to increase energy rates to recover the revenue deficiency. (APS Br. at 70 (citing Ex. APS-26 at 23-24).) APS argues that this would move recovery of more fixed costs into variable rate components, which is inappropriate because fixed costs do not decline when consumption declines. (APS Br. at 70.)

APS also disagrees with other parties' recommendations that its residential on-peak period of 3-8 p.m. weekdays should be changed. (APS Br. at 56.) According to APS, its current on-peak period appropriately balances customer convenience, hourly system load, and market prices. (APS Br. at 57.) APS notes that on July 5, 2018, APS's system load decreased by 40 MW at 3 p.m. and increased by 60 MW at 8 p.m., which APS asserts shows that the on-peak period is having a positive impact on customers' usage. (APS Br. at 57 (citing Ex. APS-26 at 14).) According to APS, the on-peak period pricing signals were even effective in getting customers to shift usage on the day APS reached its record peak system load (July 30, 2020), when it was 118 degrees out and many customers were working from home due to the pandemic, because system load decreased by 100 MW at 3 p.m. and then increased by 75 MW at 8 p.m. (APS Br. at 57-58 (citing Ex. APS-26 at 12, 15-16).) According to APS, additional reasons to retain the current on-peak period is that it will provide stability to customers, will avoid having a broad range of bill impacts, and will avoid difficulties that occur when trying to use historical data to inform customers' rate selection. (APS Br. at 58 (citing Ex. APS-26 at 12.) APS notes that its

system's and customers' reliability needs are driven by the 90 highest net load hours in the year and that 84% of APS's top 90 hours fall between 3 p.m. and 8 p.m. (APS Br. at 58-59 (citing Ex. APS-8 at 22-23).) Further, APS argues that because wholesale market prices are highest from 6-7 p.m., and second highest from 7-8 p.m., retaining the 7-8 p.m. hour in the on-peak period provides customers immediate benefits by reducing on-peak purchased power costs and long-term benefits by reducing the need for additional infrastructure.[431] (APS Br. at 59 (citing Ex. APS-8 at 22).)

APS argues that SEIA/AriSEIA's proposal to revise APS's on-peak hours to 2-7 p.m. only in June-September should be rejected because it does not align with APS's peak loads and "is designed for the sole purpose of increasing the value of distributed solar systems for [SEIA/AriSEIA's] member agencies that sell solar or solar with storage systems." (APS Br. at 59 (citing Ex. SEIA-1 at 64-65).) APS also criticizes the 4-7 p.m. on-peak period proposed by WRA/SWEEP and Staff for not aligning adequately with APS's load, which APS states is high from 3-4 p.m. and also from 7-8 p.m. (APS Br. at 59 (citing Ex. WRA-1 at 17-19; Ex. S-5 at 47-49).) Regarding Staff's proposal, APS further alleges several shortcomings: erroneous use of annual average load shape (as opposed to summer period load shape), analysis using only a subset of customers (by not including solar residential customers), and reliance on only customer load and not system load (thereby omitting renewable generation). (APS Br. at 60-61 (citing Ex. APS-8 at 26-27).) Mr. Albert testified that non-summer load has little impact on APS's system reliability and future resource additions and that the TOU pricing is meant to reduce future investment in new infrastructure, which is driven by summer system net loads including solar customers. (Ex. APS-8 at 26.) Additionally, APS asserts, because its system has significant renewables now, and the amount is expected to grow, it is important to consider that renewables' generation drops off in late afternoon. (APS Br. at 61.) Mr. Albert asserted that with additional solar added to the system, ramping periods are becoming steeper, and APS's annual peak is shifting later in the day, as seen by APS's instantaneous net peak load in 2020 that occurred at 6:24 p.m., 45 minutes later than the system peak load. (Ex. APS-8 at 25, 27.) Further, Mr. Albert stated, the annual peak load in three of the last five years occurred at 6 p.m. (Ex. APS-8 at 25.) Mr. Albert testified that when the sun starts

[431] Mr. Albert showed that projected July 2021 wholesale market prices are highest from 6-7 p.m., and second highest from 7-8 p.m., meaning that keeping those hours in the on-peak period and thereby reducing the need to purchase power during those hours helps save customers money. (Ex. APS-8 at 22, 25.)

to go down, solar production (from DG and grid-scale facilities) ramps down to zero, while customer loads remain high, requiring APS to serve the load with thermal and storage technologies. (Ex. APS-9 at 4.) Mr. Albert opined that with enough solar generation on APS's system, net peak load could shift to 8 p.m. (Ex. APS-9 at 4.)

APS also criticizes the various parties for not providing a bill impact analysis for their on-peak-period proposals, which APS argues is "reason alone to deny their proposed changes." (APS Br. at 59-60 (citing Ex. RUCO-3 at 23).) APS cites with approval RUCO's observation that shortening the on-peak hours would require either a substantial increase to the on-peak rate or an increase to the off-peak rate to cover the ensuing revenue shortfall and adds that changing the on-peak period would also result in bill impacts more disparate than proposed by APS. (APS Br. at 60 (citing Ex. RUCO-3 at 22-23).) Additionally, APS asserts that its own analysis showed that reducing APS's current on-peak period would result in a revenue deficiency of $65 million.[432] (APS Br. at 60 (citing Ex. APS-55).) In its analysis, APS also noted that APS's rate comparison tool and pro forma billing feature would need to be taken offline for at least three months to allow actual customer usage to accumulate and preferably for 12 months and that there would need to be a three-to-four month transition period to reprogram meters for the new on-peak hours. (Ex. APS-55 at 2.)

APS opposes RUCO's proposal for a second TOU rate, asserting that it would add complication to APS's rates and that the proposed rate is not designed to be cost neutral with TOU-E and would potentially result in a substantial change in customer impacts. (APS Br. at 62.) APS asserts that if the rate was not redesigned to be revenue neutral, it would create a large cost shift to residential customers on other rates, because it would result in a revenue deficiency of approximately $150 million each year. (APS Br. at 62 (citing Ex. APS-26 at 17, 20-21).) Thus, either the rate would need to be significantly redesigned or the deficiency would need to be spread across other rates to achieve the revenue requirement. (APS Br. at 62 (citing Ex. APS-26 at 20-21).) APS adds that RUCO's new TOU rate would also result in a broad range of bill impacts across customer and rate classes and seemingly also criticizes RUCO for proposing it because RUCO agreed to the current rate design in the 2016 Rate

[432] Like WRA/SWEEP, we find APS's method of estimating the impact of a 4-7 p.m. on-peak period, by increasing off-peak pricing, counterintuitive.

Case settlement. (APS Br. at 63 (citing Ex. ApS-26 at 18, 21).)

APS also urges the Commission to reject Staff's recommendations to discontinue the existing super off-peak period in TOU-E and to disallow addition of a super off-peak winter period in R-2 and R-3. (APS Br. at 60 (citing Ex. S-5 at 38-39).) APS asserts that the winter super-off-peak period would offer substantial potential bill savings to customers and pointed out that its TOU-E customers increased consumption during the super off-peak period by 52,163 MW after it was introduced. (Ex. APS-26 at 32.) Further, APS argues that Staff opposes inclusion of the super off-peak period and energy rates solely based on its desire to simplify APS's rates, without regard to the benefits of the super off-peak period, and points out that Staff did not provide a bill impact analysis for this proposal. (APS Br. at 61.)

APS also objects to Dr. Dismukes's proposal to replace APS's method of measuring residential customer peak demand over a one-hour period during on-peak hours with a customer's highest "anytime instantaneous demand,"[433] which would require residential customers to manage their demand at all times—at all hours and on every day of the week. (APS Br. at 68 (citing Tr. at 4860-4861).) APS asserts that by effectively eliminating on-peak price signals, anytime instantaneous demand can undermine conservation when it is most needed and, further, that it is "punitive and not customer friendly." (APS Br. at 68 (citing Ex. APS-26 at 31-32; Ex. SEIA-2 at 5).) APS also points out that Dr. Dismukes did not perform a customer bill impact analysis for this proposal. (APS Br. at 68 (citing Tr. at 4861).)

Further, APS opposes Dr. Dismukes's proposals to retain two residential demand rates and to eliminate seasonal variations in rates, asserting that Dr. Dismukes has offered no bill impact analysis and that these proposals are not supported by other parties. (APS Br. at 69 (citing Ex. S-8 at 2; Tr. at 3780, 4194-4195, 4863-4864).) Additionally, APS notes, Ms. Hobbick estimated that if all of Dr. Dismukes's proposals were adopted, they would create a broad range of impacts, with some customers experiencing increases greater than 25%.[434] (APS Br. at 69 (citing Ex. APS-26 at 33; Ex. APS-27 at

[433] Staff did not include this proposal in its brief.

[434] Ms. Hobbick's analysis showed that 23% of residential customers would experience no impact or a decrease, 31% would experience an increase of up to 2.50%, 16% would experience an increase between 2.51% and 5%, 13% would experience an increase between 5.01% and 7.5%, 13% would experience an increase between 7.51% and 15%, and the remaining 3% would experience an increase between 15.01% and 50%. (Ex. APS-26 at 33.)

7).)

In its briefs, APS did not respond to WRA/SWEEP's proposals for TOU-E to be a default rate for residential customers, for the addition of a super off-peak EV rate, or for the Commission to hold off on establishing rate design until after APS is required to provide bill impact analyses and proof of revenue for a variety of residential rate designs. However, Ms. Hobbick testified that APS opposes having a default rate because APS supports allowing customers to choose the rate they prefer and does not agree that customers who do not select their MEPs misunderstand the available rates. (Ex. APS-26 at 11.) Ms. Hobbick also testified that APS has not proposed an EV rate or a super off-peak EV charging period because APS believes the R-3 rate accommodates EV charging well by offering low-cost energy during off-peak periods, at rates lower than SRP's EV price plan. (Ex. APS-26 at 39.) Ms. Hobbick also indicated that APS intends to increase marketing of R-3 specifically for EV charging so that customers who are looking to acquire or have acquired EVs are aware of the value. (Ex. APS-26 at 39.)

9. Resolution

We agree with APS's proposal to freeze R-2 to additional customers. R-2 is not optimally designed to send appropriate price signals, as it does not increase its demand rates in summer.

We also agree with APS's proposal to add a winter super off-peak period of 10 a.m. to 3 p.m. to R-3. This is designed to encourage more efficient use of APS's system and may result in a greater shift of usage from higher demand to lower demand hours. While we are not adopting WRA/SWEEP's recommendation to freeze R-3, it has been established that many APS customers do not understand demand rates, and we are concerned that it can be difficult for a customer to save money on R-3, so we will require APS to allow a residential customer to transfer to R-3 only after completing an educational program that describes what R-3's rates are, how R-3 works, how best to save money on R-3, and how much demand is associated with typical home appliances (using information such as that included in Exhibit APS-45). The educational program can be an online click-through presentation, a similar presentation through APS's app, or written materials followed by a requirement for an attestation of having reviewed the written materials. Finally, concerning R-3, because we do not want residential customers to lose their incentive to conserve based on a high-demand incident early in the month, we

will require APS to calculate demand based not on the highest on-peak average hour but based on an average of the two highest on-peak average hours in the month.

We agree with APS's proposals related to Service Schedule 1—to eliminate the specified customer charges, to provide once per year waivers of the other specified customer charges, and to allow an additional 7 days to remit payment after a bill is issued. These are customer-friendly changes and, especially with the dishonored payment fee, can make a difference to customers who are suffering economic difficulties.

We also agree that it is more customer-friendly to have all of APS's Basic tariff rates included within one tariff, and for the Basic L tier to be unfrozen for inclusion in that tariff, because it will be easier for APS customers to find the rates if they are consolidated. However, we find it problematic that the Basic rate plans are apparently not well designed to recover their costs (in comparison to the other residential rate plans) and that the Basic rates do not even send a seasonal price signal. In recognition of APS's summer-peaking status, this is a situation that needs to be remedied; all APS customers should be receiving a price signal to conserve (or pay up) during the summer months. To that end, we will require APS to design, before its next rate case and for inclusion in its next rate case application, two sets of Basic rates that include higher energy rates for the summer months than for the winter months—one that is designed to be revenue neutral with APS's existing Basic rates and one that is designed to recover a greater proportion of the cost of service for APS's Basic rate class (as combined in the single tariff).

We will not adopt the suggestion to shift Basic customers to TOU-E when they exceed middle tier eligibility, as doing so is inconsistent with unfreezing Basic-L and combining the Basic tariffs into one tariff. Likewise, we will not adopt AARP's proposal to expand the Basic middle tier pricing to customers who use between 12,001 and 17,999 kWh in a calendar year. The results of such a change would be regressive.

Regarding the one-time waiver of Basic rate tier reassignment based on annual usage, we agree with AARP that restricting the waiver to those who know to call APS Customer Advisors on the telephone is inappropriate, as it would disadvantage similarly situated customers who are less inquisitive or less knowledgeable about how to interact with APS. This would not be unlawfully

discriminatory, as the waiver would literally be available to all APS customers and included in APS's Service Schedule 1, but it would be unfair. However, we believe that including on each Basic customer's bill a notice providing both the availability of the one-time waiver and the contact information to obtain the waiver would level the playing field and mitigate our concerns. Thus, we will require APS to provide such notice (in English and Spanish) and, additionally, to provide each Basic customer whose average monthly usage during the year is approaching the next tier level at least two warnings about the consequences of exceeding the maximum threshold for their current tier. Further, we will require APS to allow a Basic customer to request the one-time waiver of reassignment by writing to APS (at a specified address), by calling a Customer Advisor by phone, by emailing a Customer Advisor, or by online chatting with a Customer Advisor (to the extent that functionality exists). We expect APS to be able to share the educational materials about other rate plans and conservation tools that it desires to provide to these Basic customers through all of these means of communication. There is value in having customers contact APS, particularly when their electric usage has increased, because it provides an opportunity for the customers to learn methods for efficient usage.

Contrary to APS's proposal, we do not agree that APS should eliminate the 90-day TOU-E trial period required before a new residential customer is able to transfer to a Basic rate. TOU-E is superior to the Basic plans in that it clearly comes closer to recovering cost of service while also shaving peak through appropriate price signals. Thus, we conclude that TOU-E should be the default rate for the first 90 days of a new residential customer's service. We recognize that TOU-E is not an option for new residential customers in mobile home or long-term recreational vehicle parks who are not separately metered by APS, as is discussed further in Section (VIII)(E)(2).

We will retain APS's May-October summer period, as the evidence herein establishes that the load curve in May and October is more similar to the load curves for the core summer months than for the load curves for the non-summer months, and we are cognizant that although weather varies, there is still a great need for air conditioning during May and October in much of APS's service territory.

Reasonable minds can and do differ concerning the appropriateness of APS's on-peak period. At five hours long, it is significantly longer than TEP's 4 p.m. to 7 p.m. on-peak period. It is also less convenient for many of APS's customers with young families and more traditional work schedules. It

is also working, however, as there is a notable drop in demand at 3 p.m. and a notable increase in demand at 8 p.m., even on APS's highest demand days. Because APS can only reasonably expect to have more solar installed on its system in the coming years, the addition of solar (at least without storage) can be expected to result in APS's net peak load shifting later in the day rather than earlier, and it would be disadvantageous (to everyone) for APS to have to build peaking plant or to purchase market power in those high-cost later evening hours, it is appropriate and in the public interest to maintain APS's 3 p.m. to 8 p.m. on-peak period. This has the added advantages of not necessitating a reworking of the TOU-E tariff to make up for the lost revenue that would otherwise result from the shorter on-peak period, not causing unforeseeable bill impacts, and not making historic usage data obsolete for use in comparing rates.

We will not adopt WRA/SWEEP's $8.03 BSC, as we are concerned that it would not collect APS's customer costs, which we consider to be broader than do WRA/SWEEP, as discussed under cost of service.

WRA/SWEEP's summer super off-peak period of 11 p.m. to 5 a.m. for TOU-E, intended to encourage overnight EV charging, is an intriguing idea but would require shifting of revenue recovery to other time periods and would have an unknown impact on TOU-E customer bills. We believe that it currently makes more sense to add this feature to R-Tech, which we believe should be revised somewhat in this rate case, although not as drastically as proposed by SEIA/AriSEIA. R-Tech currently has only 55 customers because it is unappealing. One of the things that makes R-Tech unappealing is likely its relatively high BSC, which we believe should be the same as the BSC for TOU-E and R-3. One of the other things that makes R-Tech unappealing is its off-peak demand charges. We understand that APS created the off-peak demand charges to avoid a second peak late in the evening. But the off-peak demand charges mean that a one-EV home could incur excess demand charges during off-peak hours by using a level 2 EV charger alone, by using an electric dryer, or by using a level 1 EV charger plus an air conditioner.[435] A customer should not incur excess demand charges when using high-demand appliances during times of very low system demand, such as during the period from 11 p.m.

[435] Exhibit APS-45 shows that a level 2 EV charger uses 6.6 kW, a level 1 EV charger uses 2.3 kW, an electric dryer uses 5.6 kW, and an air condition/heat pump uses 3.4 kW (per unit).

to 5 a.m. on weekdays. Thus, we will require APS to revise R-Tech by: (1) setting its BSC at the same rate as for TOU-E and R-3; (2) adding a super off-peak energy charge to apply from 11 p.m. to 5 a.m. every day all year, set at the same level as the R-3 super off-peak energy charge; (3) eliminating excess off-peak demand charges during the super off-peak period of 11 p.m. to 5 a.m.; and (4) raising the threshold for assessing excess off-peak demand charges to 10 kW.

We will not adopt RUCO's proposed second TOU rate because APS's analysis indicates that it would result in a substantial cost shift and because having another TOU rate option would work against APS's attempts to simplify customer choices to increase understandability and the ability to make informed choices.

Finally, we cannot agree with Staff's rate design recommendations, except for two pertaining to residential BSCs. We agree that residential BSCs should not be increased. We agree with Staff's position on not increasing BSCs because increasing BSCs has a regressive effect, as they reduce frugal customers' abilities to control their bills through their behavior. We also agree with Staff's recommendation to adopt the same BSC for R-Basic S and L, TOU-E, and R-3. With the exception of the BSC for R-XS, which is set lower at $0.329/day (approximately $9.87/month) for public policy reasons, it is unclear why the BSCs for the residential rate classes vary as much as they do. Currently, these residential rates have the following BSCs:

	R-Basic	**R-Basic L**	**TOU-E**	**R-3**
Daily BSC	$0.493	$0.658	$0.427	$0.427
Approximate Monthly Rate	$14.79	$19.74	$12.81	$12.81

As Mr. Baatz explained, high BSCs reduce customers' incentives to engage in EE and to conserve because doing so has less impact on their monthly bills, harm low-income customers because it is harder to control monthly bills through behavior, and result in lower volumetric rates that discourage investment in EE and DG because it takes more time to recoup such investments and send a price signal to increase consumption (driving higher peak demand and system costs). Thus, we will require APS to adopt the same $0.400 BSC for the middle and high R-Basic tiers (aka R-Basic and R-Basic L), TOU-E, and R-3, and we will require that the revenue differences be made up through on-peak energy and demand charges.

We cannot adopt Staff's other recommendations because discontinuance of time-differentiated energy rates and seasonally differentiated demand rates would be counterproductive. The intent of the demand rates is to encourage a shift in consumption to lower demand and lower cost hours. Eliminating the price signals that encourage that behavior is inconsistent with efficient pricing and energy use objectives. Also, Staff's proposed revision to R-2 (which is being frozen) and R-3 based on percentages of demand-related cost of service would create unknown impacts and could result in over-recovery, particularly because we have not been able to determine accurately what APS's cost of service is for any customer class.

B. Residential Rate Design – Solar Issues

1. APS Position

APS has not proposed changes to its residential rate design specific to solar customers.

2. SEIA/AriSEIA

SEIA/AriSEIA argue that the Grid Access Charge ("GAC") must be eliminated because the rate design changes that have occurred since it was adopted have resulted in DG solar customers paying the GAC covering a higher percentage of their cost of service than nearly 500,000 non-solar APS customers, making the GAC unfair, discriminatory, and illegal. (SEIA Br. at 2.) SEIA/AriSEIA assert that the GAC has never before been fully litigated because it was adopted in Decision No. 74202 without a hearing, based on an alleged cost shift from DG solar customers to non-solar customers, and was increased in the 2016 Rate Case settlement. (SEIA Br. at 2.) According to SEIA/AriSEIA, the GAC now costs the average solar customer approximately $9.00 per month, and APS has not justified its continuation. (SEIA Br. at 2 (citing Tr. at 2168).) SEIA/AriSEIA argue that due to the rate design changes in the 2016 Rate Case, new solar customers now provide greater cost recovery than do R-Basic customers, with Solar R-TOU customers covering 82.1% of their costs of service without the GAC, while R-Basic customers cover only 78.2% (and all three tiers of flat rate customers combined covering only 81.9% of their costs). (SEIA Br. at 3-4 (citing Tr. at 2174-2178; Ex. APS-27 at 11).) SEIA/AriSEIA argue that the GAC represents discriminatory ratemaking, which is prohibited under Article 15, § 12 of the Arizona Constitution as well as A.R.S. § 40-334 because APS is charging a different rate "for rendering a like and contemporaneous service" and has an "unreasonable difference

as to rates . . . between classes of service" and is subjecting solar customers to a "prejudice or disadvantage." (See SEIA Br. at 5 (quoting Ariz. Const. Art. 15, § 12; A.R.S. § 40-334).) SEIA/AriSEIA state that the Arizona Supreme Court has instructed that to avoid being discriminatory, a public service corporation must charge all customers the same price "for the same or substantially the same or similar service." (SEIA Br. at 5 (quoting *Town of Wickenburg v. Sabin*, 68 Ariz. 75, 77 (1948)).)

SEIA/AriSEIA also argue that APS should be required to offer the demand limiter to solar customers on demand rates in the same way that it does for non-solar customers on demand rates. (SEIA Br. at 6.) The demand limiter caps billed demand for non-solar residential demand customers at the level that would occur if the customer had a 15% load factor for the month, and there is no limit on the number of times the demand limiter can be applied for a customer. (SEIA Br. at 6 (citing Ex. SEIA-1 at 90).) Mr. Lucas testified that the demand limiter was triggered on approximately 5.7% of non-solar R-2 customers' monthly bills and on approximately 2.3% of non-solar R-3 customers' monthly bills and for solar customers on R-2 and R-3 would have been triggered approximately on 15.3% and 9.6% of monthly bills, respectively. (Ex. SEIA-1 at 94.) Mr. Lucas found that more than 1,700 non-solar demand customers triggered the demand limiter in six or more months during the year. (Ex. SEIA-1 at 94.) According to Mr. Lucas, the average non-solar customer saved $23.46 per year from the demand limiter, although some of those customers saved more than $1,000 from it and the cumulative savings for the non-solar demand class was $1.06 million. (Ex. SEIA-1 at 94.) In comparison, Mr. Lucas found, the average DG solar customer could have saved $25.07 per year from the demand limiter, for a cumulative savings to the DG solar demand class of $44,423. (Ex. SEIA-1 at 94.) SEIA/AriSEIA argue that it is unreasonable to continue denying DG demand customers the same protection from unusually high demand events that non-solar demand customers receive. (SEIA Br. at 7.) Further, SEIA/AriSEIA suggest that if there is concern that the demand limiter will be triggered too frequently, the Commission could consider installing a cap on the number of times the demand limiter can continue to be used in a year. (SEIA Br. at 7.)

SEIA/AriSEIA also argue that the RCP tariff rate should be locked in for 18 years rather than 10 years so that residential solar customers have the same level of certainty as do utility scale solar

projects. (SEIA Br. at 9.) SEIA/AriSEIA argue that when utilities make investments in assets that will last for several decades, they are permitted to recover their costs over a similar period, which provides long-term certainty and enables the utilities to make significant investments. (SEIA Br. at 9 (citing Ex. SEIA-1 at 81).) Additionally, SEIA/AriSEIA point out, Public Utility Regulatory Policies Act ("PURPA") qualifying facility developers receive 18 years of certainty as to the rates to be paid for the energy they produce and deliver to Arizona utilities. (SEIA Br. at 9-10 (citing Decision No. 77512 (December 17, 2019)[436]).) Yet the RCP provides residential DG solar customers only 10 years of certainty as to their RCP export rate, SEIA/AriSEIA assert, which makes it impossible for them to know what they will be paid for exported energy in year 11 and thereafter, although their solar systems will last as long as utility scale solar facilities. (SEIA Br. at 9 (citing Ex. SEIA-1 at 81).) SEIA/AriSEIA argue that there is "no rational reason" to force residential solar customers "to absorb significantly greater uncertainty than the utility and large power producers" and urge the Commission to "eliminate this inherent unfairness." (SEIA Br. at 10.)

3. Vote Solar

Vote Solar also urges the Commission to eliminate the GAC, which it asserts has no evidentiary basis and is unfair and unlawful. (VS Br. at 1.) According to Vote Solar, the GAC recovers shared costs caused by all residential customers, not just solar-specific costs, but is only imposed on solar TOU customers, making it unlawfully discriminatory under both Arizona and federal law. (VS Br. at 4-5 (citing Ariz. Const. Art. 15, § 12; A.R.S. § 40-334; *Gen. Cable Corp. v. Citizens Utils. Co.*, 27 Ariz. App. 381 (1976); 16 U.S. § 824a-3; 18 C.F.R. §§ 292.203, 292.303, 292.305;).) Vote Solar argues that APS is required to charge solar customers the same rates that it would charge non-solar customers with similar load or other cost-related characteristics, except to the extent any difference is based on accurate data and consistent systemwide costing principles. (*Id.*) Vote Solar notes that TOU-E, the only rate that requires solar customers to pay the GAC, is the rate applicable to most solar customers who have connected within the past four years because solar customers must select either TOU-E or one of the demand rates. (VS Br. at 2.) According to Vote Solar, because the GAC is

[436] Official notice is taken of this decision that concerned APS's request for approval of a revised APS partial requirements rate schedule EPR-2 and in which it was determined that APS's tariffs needed to provide qualifying facilities with nameplate capacity over 100 kW with a contract term of at least 18 years. (Decision No. 77512 at 31.)

applied per kW per month, based on a residential solar system's capacity rather than its actual generation and regardless of a site's usage of APS-delivered electricity or amount of exported electricity, and is applied in addition to usage-based rates, solar TOU-E customers will always pay more for their APS-provided energy than do non-solar customers with the same usage. (VS Br. at 2-3.)

Vote Solar also argues that because the GAC produces higher revenue recovery from solar customers (at 87.6%) than most non-solar customers provide, the record does not support the need for the GAC to make up for any subsidy, and the GAC discriminates against solar customers and is not just, reasonable, and equitable. (VS Br. at 2, 6-8 (citing Ex. APS-27 at 10-11; Ex. VS-1 at 14; Ex. SEIA-2 at 15-16; Ex. SEIA-1 at 21; Tr. at 2168-2178).) When the GAC is not included, Vote Solar asserts, solar customers provide revenues as a percentage of cost of service within the range of other residential subclasses, for example, providing 82.1% coverage as compared to R-Basic customers that cover approximately 78.2%. (VS Br. at 9-10 (citing Ex. APS-27 at 10-11; Tr. at 2170, 2175, 2178).) Additionally, Vote Solar argues, these numbers are based on APS's COSS, which overstates the cost to serve solar customers, and would be even higher for solar customer cost-coverage if the COSS errors were corrected. (VS Br. at 10-11).)

Vote Solar further argues that even if the record were to establish that solar customer revenues cover a lower percentage of their costs compared to the residential class average, there still is no evidence that solar customers cover a lower percentage of their costs than non-solar customers with similar usage, because reduced revenue from volumetric rates and low-usage customers is not unique to solar customers. (VS Br. at 7 (citing Ex. VS-1 at 14; Ex. SEIA-2 at 27; Ex. SEIA-1 at 20, 24).)

Vote Solar further asserts that solar and non-solar customers impose similar costs on the grid, arguing that there is no evidence demonstrating that APS incurs additional costs from serving solar customers as compared to non-solar customers and that APS has not identified or quantified any such costs. (VS Br. at 7-8 (citing Ex. SEIA-2 at 16; Ex. SEIA-1 at 86; Ex. VS-1 at 14).) Vote Solar further asserts that because Ms. Hobbick testified that the GAC was the result of settlement and set to provide

a level of expected bill savings per kWh to solar customers,[437] APS may not now claim that it was established to recover solar-specific costs. (VS Br. at 8 (citing Ex. SEIA-2 at 16-17).)

Vote Solar also argues that the GAC "seeks to partially claw back and undermine the value of export credits as determined by the Commission" when it approved the RCP because solar customers are charged more for the inflow electricity they receive than are non-solar customers with similar usage, effectively reducing the value of credits for exported electricity and undermining the balance struck in the Commission's Value of Solar Docket. (VS Br. at 8-9 (citing Decision No. 75859 at 133, 148-149).) Vote Solar argues that eliminating the GAC would help encourage solar growth in Arizona and that APS is one of the only U.S. utilities to charge solar customers a GAC and the only U.S. utility to charge a GAC "for the same common system costs that non-solar customers pay for only through usage-based rates." (VS Br. at 1-2.)

Vote Solar further argues that the Commission should require APS to allow solar customers to take service under any available residential rate. (VS Br. at 3.)

In its responsive brief, Vote Solar criticizes APS for treating SEIA/AriSEIA's rate design proposals dismissively (and for not addressing Vote Solar's advocacy) and expresses support for SEIA/AriSEIA's proposals as to the GAC and the demand limiter. (VS RBr.)

4. IBEW Locals

The IBEW Locals oppose SEIA/AriSEIA's and Vote Solar's arguments for elimination of the GAC assessed on solar customers. (IBEW RBr. at 7.) The IBEW Locals assert that while the GAC should be higher to reflect fully solar customers' use and reliance on the grid and ensure that solar customers contribute to the cost of grid maintenance (including the wages paid to employees to build and maintain the grid), the current GAC does partially recover the expenses APS incurs to provide solar customers access to an expensive and reliable grid and should be retained. (IBEW RBr. at 7-8 (citing Ex. IBEW-1 at 9).)

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[437] Vote Solar provided the following quotation from Mr. Lucas's testimony that is attributed to an APS data response: "The present [GAC] was developed and approved by the [Commission] as part of a settlement in the [2016 Rate Case]. The approved amount was the result of negotiations and therefore not derived from any specific cost basis. The charge was instead set to provide a certain level of expected bill savings per kWh to solar customers." (Ex. SEIA-2 at 16.) Mr. Lucas further asserted that APS had stated that the revenues and costs from the GAC were not included in the proof-of-revenue in this case and that the associated costs were removed from the COSS. (Ex. SEIA-2 at 16.)

5. APS Response

APS opposes elimination of the GAC and extension of the demand limiter to residential solar customers. (APS Br. at 70.) APS states that the original purpose of the demand limiter was to avoid penalizing residential customers on demand rates for occasional spikes in demand. (APS Br. at 70-71.) According to APS, residential solar customers would trigger the demand limiter four times as often as non-solar customers, and the demand limiter was "not intended for solar customers who typically purchase a low level of energy from APS but continue to draw a high level of demand and, therefore, would likely have their billed demand limited on a routine basis." (APS Br. at 71 (citing Ex. APS-27 at 9-10).) Although it did not truly brief the GAC issue,[438] at the hearing, Ms. Hobbick testified:

> [T]he reason behind the [GAC] was based on testimony in the last rate case proceeding that highlighted the difference in the contribution to cost of service that residential solar customers contribute on energy rates versus demand rates. And so the intent of that [GAC] was intended to help recover some of the shifted costs that were supported in that testimony at roughly $865 per customer.[439]

Ms. Hobbick pointed out that even though solar TOU-E customers cover 87.6% of their costs of service when the GAC is included, that is still well below the 97% coverage provided by the non-solar TOU-E customers. (Tr. at 2175.)

6. Resolution

In our resolution concerning the COSS and DG solar customers, we require APS, for its next rate case, to identify and quantify the extra costs APS incurs to serve DG solar customers and to make changes to its COSS so that the COSS more accurately reflects the cost to serve DG solar customers. At this time, we do not know the true extra cost to serve DG solar customers, as compared to non-solar customers, although the evidence establishes that there is an extra cost. What is more easily observable is that DG solar customers on TOU-E, even with the GAC, apparently are not covering their costs of service to the same extent that non-solar TOU-E customers are or to the same extent that DG solar demand customers are. Acknowledged problems with the APS COSS aside, this indicates that without the GAC, DG solar TOU-E customers would be covering an even lower portion of their costs.

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[438] We agree with Vote Solar's opinion that APS was dismissive concerning the solar advocates' arguments.
[439] Tr. at 2168.

SEIA/AriSEIA's and Vote Solar's common argument for why DG solar TOU-E customers should be relieved from paying the GAC is essentially that the R-Basic rates do a bad job of recovering cost of service, so DG solar TOU-E customers should not be required to do a better job of recovering cost of service. To the extent that shortcomings may exist in one tariff, such as R-Basic, it does not provide justification for creating similar weaknesses in others.

Furthermore, DG solar customers are not similarly situated to non-solar customers. DG solar customers rely on APS for only a portion of their electricity, and they have the ability to export energy and sell it to APS; they are partial requirements customers and generators. In contrast, almost all non-solar customers rely on APS for all of their electricity, have no ability to generate or export energy, and are not partial requirements customers. It is not discriminatory or unlawful to require DG solar customers to pay a charge that is not imposed on non-solar customers who are on the same rate plan. The GAC helps to minimize the extent to which non-solar customers on TOU-E subsidize the DG solar customers on TOU-E, and it will be retained.

We also are not persuaded that it is appropriate to apply the demand limiter to DG solar customers, again because they are different than non-solar customers on demand rates. The demand limiter is intended to be used only sparingly, and for most R-2 and R-3 customers it is used only sparingly. It would be used much more regularly by DG solar customers on demand rates, and such frequent use would defeat the purpose of the limiter, which is essentially to help customers who have occasional slipups, not those with regular instances of high demand. However, it is apparent that some R-2 and R-3 customers have been abusing the demand limiter by having it applied six or more times per year. Thus, we will require APS to restrict demand limiter use to three times per year, which may include only one occurrence in the summer months, and to highlight this restriction in its materials concerning R-3.

Additionally, we are not persuaded that residential solar customers who benefit from the RCP export rates should have their tranche's rate locked in for 18 years rather than the 10 years authorized by Decision No. 75859 issued in the Value of Solar Docket. The above-market prices that could result from such an extension would be paid during all of those extended years by other APS customers who do not benefit from receiving the RCP export rates. This likely additional subsidization would not be

in the public interest.

C. Residential Rate Design – Low-Income Programs

1. APS Position

In this case, APS proposes to increase the amount of funding for Crisis Bill Assistance from $1.25 million to $2.5 million, to be funded by ratepayers; to revise its low-income program tariffs (E-3 and E-4) to credit back to customers the transaction fees assessed when they pay their bills with a credit card; and to be authorized an accounting order allowing it to defer, for future recovery in a rate case, the costs of APS's low-income programs to the extent that they exceed TY costs. (APS Br. at 93, 95, 96 (citing Ex. APS-23 at 11; Ex. APS-25 at 12, 14; Ex. APS-26 at 40-41; Ex. Wildfire-1 at 3, 9, 11; Tr. at 2108, 3886, 3901).) The E-3 and E-4 discount programs, respectively, currently provide a 25% and a 35% discount from eligible customers' electric bills, regardless of household size or income level (provided that income is at or below 200% of the FPL). (Ex. APS-53.)

APS has already implemented the following improvements related to its low-income programs since the 2016 Rate Case (some during the pendency of this rate case and in response to the COVID-19 pandemic):[440]

- Automatic enrollment in E-3 and E-4 is available for residential customers who are already qualified for certain government assistance programs, such as subsidized housing, Crisis Bill Assistance, and the Low-Income Home Energy Assistance Program ("LIHEAP").[441]
- Online recertification for E-3 and E-4 is available.[442]
- Recertification is now a two-year process rather than an annual process.[443]
- The customer consent process has been revised to allow for telephonic and online consent rather than only in-person verification.[444]
- APS's website has been updated to make assistance programs easier to find.[445]
- APS has provided outreach and information about its assistance programs through both

[440] This list does not include program improvements that were required by the Commission, such as changing the eligibility for its low-income programs from 150% of the FPL to 200% of the FPL.
[441] APS Br. at 94 (citing Ex. APS-23 at 10; Tr. at 3879).
[442] APS Br. at 94 (citing Ex. APS-23 at 11; Tr. at 3880).
[443] APS Br. at 94 (citing Ex. APS-23 at 11; Tr. at 3880).
[444] *Id.*
[445] APS Br. at 94 (citing Ex. APS-23 at 11; Tr. at 3881).

targeted and mass communications, including 13 different communications channels.[446]

According to APS, its efforts have resulted in 25% increased enrollment in its low-income programs from the end of the TY through September 2020, and growth in the programs continues. (APS Br. at 95 (citing Ex. APS-23 at 12; Tr. at 3881-3882).) APS reported that more than 72,000 limited-income customers received bill discounts under E-3 and E-4 in 2020, at a cost of approximately $27-$28 million. (APS Br. at 95-96 (citing Tr. at 1934, 2086, 3881-3882, 3886; Ex. APS-23 at 12).)

Additionally, directly in response to the COVID-19 pandemic, APS created a Customer Support Fund comprised of "voluntary commitments of funds," approximately $8.8 million of which are not recoverable through rates, which were used to provide credits to residential and small business customers who contacted APS's Customer Service Center for assistance. (APS Br. at 96 (citing Tr. at 1935, 3887).)

2. Wildfire[447]

Wildfire expressed appreciation for APS's recent efforts to improve its low-income programs, which included making online enrollment available, increasing the length of time between recertification of eligibility (from one to two years), increasing advertising regarding the availability of low-income programs, and distributing millions of dollars in shareholder funds during 2020 to help pay customer bills and mitigate the impact of the pandemic. (Wildfire Br. at 2-3.) Wildfire noted that the oral and written public comments in this case were overwhelming and made it clear that there could not be a worse time for a rate increase. (Wildfire Br. at 4.) If the Commission nonetheless approves a rate increase for APS in this case, Wildfire requests that low-income customers be held harmless. (*Id.*; Wildfire RBr. at 2.)

Wildfire supports APS's request to increase ratepayer-funded Crisis Bill Assistance from $1.25 million to $2.5 million and asserted that because Wildfire has been administering these funds from the inception of the program (in the early 1990s),[448] Wildfire sees the positive impact the funds have on the families assisted. (Wildfire Br. at 4.) Wildfire notes that the grants can be used to pay current and

[446] APS Br. at 94 (citing Ex. APS-23 at 13; Tr. at 3881).

[447] Wildfire is a non-profit advocacy organization focused on assisting low-income communities and working to end poverty. (Wildfire Br. at 1.)

[448] Wildfire contracts with 10 of the 11 Community Action Agencies in Arizona as well as nine community partners representing nonprofits and faith-based organizations to distribute the funds to eligible APS customers. (Wildfire Br. at 4.)

past due charges (including reconnection fees) and cannot be used to place a credit on an account or to cover a deposit. (Ex. Wildfire-1 at 9-10.) To be eligible for Crisis Bill Assistance, household income must be at or below 200% of the FPL,[449] the application must assert a crisis, and the agency/community partner must retain documents used to verify the crisis. (*Id.*) Wildfire opined that the documentation requirement is superfluous because the income level alone for anyone living at or below 200% of the FPL should suffice to establish need, but did not expressly request that the requirement be eliminated. (Wildfire Br. at 5 (citing Ex. Wildfire-1 at 10).)

Wildfire supports APS's proposal to provide bill credits to E-3 and E-4 customers who pay by credit card, asserting that it will facilitate bill payment by low-income customers. (Wildfire Br. at 5.)

Wildfire urges the Commission to replace the flat percentage discounts offered by the E-3 and E-4 discount programs with a Wildfire-proposed tiered rate structure that provides greater discounts to customers with higher energy burden levels, with a goal of achieving a 5.0% energy burden level. (Wildfire Br. at 6-9.) Energy burden is the percentage of household income needed to pay the household's energy bill, and Wildfire asserts that APS's low-income customers have very large energy burdens that require "terrible choices" such as whether to forgo food, medicine, or clothing or to maintain an unhealthy indoor temperature so that the utility bill can be paid. (Wildfire Br. at 6-7.) Ms. Zwick testified that in 2019 for households with incomes below 50% of the FPL, the average home energy burden was 24% (meaning that 24% of household income went to pay the energy bill), whereas for households with incomes between 185% and 200% of the FPL, the energy burden was approximately 5%. (Ex. Wildfire-1 at 8.)

Wildfire proposes four discount tiers based on household income as a percentage of the FPL, and to have the discount calculated by taking 5% of the income at the tier midpoint and subtracting that from the average annual electricity expenditure for residential customers, to get an annual dollar discount that can be shown as a percentage discount, as follows:[450]

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[449] The Commission recently increased the threshold for E-3 and E-4 eligibility from 150% to 200% of the FPL in Decision No. 77849 (December 17, 2020), which was admitted herein as Exhibit APS-78 and was issued in Docket No. E-00000A-19-0128, In the Matter of Investigation and Comprehensive Review of the Commission's Disconnection Rules and the Disconnection Policies of Public Service Corporations.

[450] Wildfire Br. at 8-9 (citing Ex. Wildfire-1 at 16).

Household Income as % of FPL	Example Discount Provided
0-75%	79.4%
76-125%	44.8%
126-150%	24.2%
151-200%	25.0%

Wildfire asserts that APS understands the intent of the tiered discount proposal, agrees with the principle that assistance should be targeted to those who need it most, and believes that the proposal deserves further consideration, although APS asserted that it is too complex and too costly as proposed and needs additional development. (Wildfire Br. at 9 (citing Tr. at 1942-1945); Wildfire R Br. at 3 (citing Ex. APS-23 at 15).) Wildfire argues that the tiered discount proposal is "not complex" but instead "quite simple" and that APS would need to obtain only household income and family size information to calculate the discount, information that is readily available from the community agencies that already provide program certification information to APS. (Wildfire Br. at 9.) According to Wildfire, Mr. Howat estimated the annual cost of the tiered discount program to be approximately $59 million, while APS asserted that the cost could approach $100 million. (Wildfire Br. at 10 (citing Tr. at 1940).) Wildfire notes that the cost of the tiered program could be reduced by increasing the target energy burden above 5%, which APS acknowledged. (Wildfire Br. at 10 (citing Tr. at 2104).)

Wildfire's proposal also would eliminate over a period of 12 months customer arrearages for low-income customers, which Wildfire asserts is important for customers because arrearages can lead to service loss, collection activities, and credit score damage and for APS because elevated levels of bad debt can potentially risk utility financial stability, challenge customer service structures and personnel, and spread added cost to all customers. (Wildfire Br. at 7 (citing Ex. Wildfire-3 at 6-9).) To address arrearages and promote regular and timely payments, Wildfire proposes that under the tiered low-income program, 1/12 of a customer's arrearage amount would be forgiven (written down) each month for a 12-month period provided that the customer pays the current bill amount. (Wildfire Br. at 8.) Wildfire asserts that customer arrearages have increased substantially since the beginning of the COVID-19 pandemic and pointed out that Ms. Whiting testified customers were $70 million in arrears as of January 4, 2021. (Wildfire Br. at 7 (citing Ex. Wildfire-3 at 6-8); Wildfire RBr. at 3 (citing Tr. at 2036).)

Wildfire urges the Commission to approve the tiered discount program, which it describes as "a more rational assistance program that targets greater assistance to customers who need it most." (Wildfire Br. at 10.) Wildfire also requests that the Commission direct APS to work with Wildfire and other stakeholders to develop a low-income assistance program focused on customers' energy burdens and file a proposal for the Commission's consideration within six months after the decision in this case. (Wildfire RBr. at 4.)

In the alternative, Wildfire urges the Commission to increase the discount for the E-3 and E-4 programs from 25% to 30%. (Wildfire Br. at 6; Wildfire RBr. at 2.) Wildfire asserts that the 5% increase would increase APS's costs only modestly, by nearly $1 million, but would provide low-income customers additional help "at a time of their greatest financial stress." (Wildfire RBr. at 2.) Wildfire notes that the cost of the E-3 and E-4 programs was $19 million for the TY, although APS expected the program cost to be $28 million in 2021 and indicated that the cost would be $40 million if all eligible customers were to participate. (Wildfire Br. at 10 (citing Tr. at 1940).)

Further, because Wildfire considers the E-3 and E-4 programs to be of vital important to APS's low-income customers, Wildfire urges the Commission to approve the requested accounting order that would allow APS to recover the full cost of the E-3 and E-4 discount programs by deferring costs that exceed the TY expense for recovery in a future rate case. (Wildfire Br. at 10.)

3. APS Response

APS does not agree with Wildfire's proposal to hold low-income customers harmless from any rate increase approved in this case, pointing out that this would result in a revenue deficiency that would need to be collected from other customers and that other customers' interests must also be considered. (APS Br. at 97 (citing Ex. APS-26 at 42; Tr. at 3889).) Further, APS asserts, low-income customers already will experience a smaller bill impact than other residential customers because of the 25% or 35% discounts applied to their bills. (APS Br. at 97-98 (citing Ex. APS-26 at 42; Ex. APS-23 at 14-16).)

APS also opposes Wildfire's proposed tiered bill discount for low-income customers, which would be coupled with an arrearage write-off program. (APS Br. at 98.) APS asserts that Wildfire's proposal would result in additional complexity and costs and, further, that Mr. Howat significantly

underestimated the participation and resulting cost impact by using a participant number lower than APS's E-3 enrollment at the end of 2020 and that did not take into account the recent increase in income eligibility to 200% of the FPL (from 150%).[451] (APS Br. at 98-99 (citing Ex. APS-23 at 14-15; Ex. APS-24 at 4-5; Ex. APS-26 at 40-43; Ex. Wildfire-1 at 12; Tr. at 1934, 2101-2103).) APS estimates that rather than costing the approximately $59.2 million per year estimated by Mr. Howat, the tiered discount and arrearage program would cost APS more than $100 million per year. (APS Br. at 99 (citing Ex. APS-26 at 40-42; Tr. at 2100-2102).) APS points out that Mr. Howat acknowledged his proposal would result in a bill impact to other customers, which he estimated at $2.07 per customer, based on his estimated cost. (APS Br. at 99 (citing Tr. at 3923).) APS also points out that Wildfire's proposal would result in a smaller discount amount for customers with lower income levels, which is "counterintuitive," and that Mr. Howat himself referred to the proposal as "a discussion starting point" rather than "a final program design." (APS RBr. at 73 (citing Tr. at 3927-3928).) According to APS, because its 25% discount is already higher than comparable discounts provided by other Arizona utilities, and it is simple for customers to understand and for APS to administer, APS's discount should be retained. (APS Br. at 99-100.)

APS further disagrees with Wildfire's proposal to increase the E-3 discount from 25% to 30%, asserting that it would impose an additional burden on other customers, that APS's discounts are already higher than others in the industry, and that the increase would not strike the appropriate balance between APS's customers. (APS RBr. at 70-71.) APS adds that the Commission has already approved an additional benefit for low-income customers by making the low-income discount a percentage of the customer's entire bill. (APS RBr. at 71.) APS also points out that the average monthly discount for APS's E-3 customers ranged from just over $22 in April 2020 to over $58 in August 2020, showing that the percentage discount method provides customers greater relief during higher usage months. (APS RBr. at 71 (citing Ex. APS-23 at 15).) Further, APS states, TEP, UNSE, and SRP offer flat monthly discounts of $18, $16, and $23 per month to their low-income customers, and SRP's low-income program is only available to those with household income at or below 150%. (APS RBr. at 71

[451] Mr. Howat used a figure of 64,000 customers, although APS was already serving a higher number of low-income customers through its discount programs as of the hearing. (APS RBr. at 72 (citing Tr. at 3919-3921).) As of the end of Q1 2021, APS was serving more than 77,700 low-income customers through its discount programs. (APS RBr. at 73.)

(citing Ex. APS-23 at 15).)

4. Resolution

While Wildfire's proposal is well intended, it would be neither simple to administer (as Wildfire asserts) nor fair to non-participating customers. As proposed, it would also provide a slightly greater discount to low-income customers with higher income, which is insupportable. Further, we note that the proposed program's own creator and proponent referred to the proposal as only a starting point and not a final program, indicating that it is not ready to be adopted.

APS's current discount programs (E-3 and E-4) provide flat percentage discounts each month for eligible customers who are enrolled. During low consumption months, the discounts are in keeping with those of other electric utilities in Arizona, and during high consumption months, the discounts significantly exceed the other electric utilities' discounts. The costs of APS's discount programs are funded by APS's non-participating customers, at an estimated cost of $27-$28 million per year, which is expected to increase with the already expanded and still expanding participation numbers. It would be neither just nor reasonable to shoulder those non-participating customers with a discount and arrearage program with an unknown cost that could be $100 million per year or more. Additionally, based on the record in this matter, we do not find at this time that it is necessary to increase the E-3 discount from 25% to 30%. The impact of such an increase is unknown, other than that it would cause an increase for APS's non-participating customers.

Finally, because APS's E-3 and E-4 programs are of vital importance to its low-income customers, as Wildfire said, and the participation level has increased and is expected to continue increasing, we will authorize APS to defer the costs of the E-3 and E-4 discounts, beyond those incurred in the TY, with no carrying costs, and to request recovery of those costs in its next rate case.

D. General Service Rate Design

1. APS Position

Aside from AG-X/AG-Y, which has been addressed above, APS proposes the following changes to its General Service Rate Design:[452]

[452] Ex. APS-41 at 9.

- Revising streetlight rates to simplify and conform them to current conditions by freezing the current E-47 and E-58 street lighting rate schedules, which contain rates for each specific type and style of light fixture and each component of street lighting equipment, making them unwieldy and cumbersome to keep current due to the evolution of technology (such as development of LED light fixtures), and establishing a new E-45 and a new E-68 that will calculate the rate for new types of equipment based on the installation cost of the fixture and will include the formula to calculate the energy portion of the rate;[453]
- Revising E-221 to better align the rates with cost of service by keeping E-221 for non-agricultural water pumping customers and establishing a new E-221 AG and a new E-221 AG TOU (within a winter super-off-peak period) for agricultural irrigation customers, because the attributes of agricultural customers are distinguishable from non-agricultural water pumping customers, such as municipalities, due to the seasonality of their business and the infrastructure in place to serve them;[454] and
- Canceling the E-36 M rate rider for power station use for small power producers with a power supply capacity of less than 3 MW, due to low enrollment, as there are only five customers served by E-36 M, and all would save money by eliminating the rate rider.[455]

APS also proposes to make the following changes to Service Schedule 9, which establishes the terms and conditions under which APS may offer financial incentives to potential new (or existing) commercial or industrial customers who are adding significant new load: changing the eligibility criteria for new customers by reducing the minimum customer load requirement in rural municipalities from 2 MW to 1 MW to provide additional opportunities and benefits for rural businesses; and revising the conflict-of-interest provisions (applicable to the affidavit APS is required to submit to Staff regarding each prospective Schedule 9 customer) to clarify that disclosure is required for only substantial and material interests, to narrow the applicable timeframes for circumstances that result in a conflict, and to address circumstances when an affidavit disclosing a conflict cannot be obtained. (Ex. APS-25 at 16-17, att. JEH-21DR.)

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[453] Ex. APS-25 at 8-9.
[454] Ex. APS-25 at 9-10.
[455] Ex. APS-25 at 8, 11.

APS and Staff have reached agreement on the conflict-of-interest language for Service Schedule 9 included in Mr. Metzger's Direct Testimony, which replaced APS's proposed language for § 2.1 with the following:

> 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, to the Company's knowledge, has or had any material interest, direct or indirect, in any substantial services, including real estate broker services, provided to the Customer in connection with the New or Expansion Project; and
>
> (B) A statement that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries or affiliates has, or within the prior 12 months had, any direct or indirect material interest in any real property owned in whole or in part by the Customer in connection with the New or Expansion Project.[456]

2. ASBA/AASBO

ASBA/AASBO assert that for the 1400 individually metered school customer accounts in APS's service territory, 787 have average demand less than 100 kW, and the remaining 613 have average demand greater than 100 kW. (ASBA Br. at 2.) Metered accounts with average demand greater than 100 kW may receive service under E-32 M or L, E-32 TOU M or L, or GS-Schools M or L, depending on their demand. (ASBA Br. at 2; *see* Ex. APS-53.) Currently, 339 metered accounts (55%) are on E-32 M or L, 2 metered accounts (0.1%) are on E-32 TOU M or L, and 272 metered accounts (45%) are on GS-Schools M or L. (ASBA Br. at 2.)

ASBA/AASBO criticize the GS-Schools M and L ("GS-Schools") rates because unlike other TOU rates, the GS-Schools rates have three time periods—on-peak, off-peak, and shoulder[457]—as well as three seasons—summer peak (June-August), summer (May, September-October), and winter (November-April). (ASBA Br. at 3.) According to ASBA/AASBO, the shoulder rate is generally double the off-peak rate, and the on-peak rate is approximately triple the off-peak rate, and these

[456] Ex. S-11 at 5-6.

[457] In summer and summer-shoulder months, on-peak hours are 3 p.m. to 8 p.m. weekdays, shoulder-peak hours are 11 a.m. to 3 p.m. weekdays, and all remaining hours are off-peak hours. (Ex. APS-53.) In winter months, on-peak hours are 5 a.m. to 11 a.m. weekdays, shoulder-peak hours are 3 p.m. to 8 p.m. weekdays, and all remaining hours are off-peak hours. (Ex. APS-53.)

"drastic increases" between off-peak and on-peak rates do not exist in the other general service rate plans. (ASBA Br. at 3.) For example, ASBA/AASBO assert, the E-32 TOU M and L ("E-32 TOU") plans increase only 25% from off-peak to on-peak, and the E-32 M and E-32 L ("E-32") plans have the same kWh charge all day. (ASBA Br. at 3.) ASBA/AASBO report that APS stated the GS-Schools shoulder rates reflected the cost of service in 2010, when they were created, rather than current cost of service. (ASBA Br. at 3.) ASBA/AASBO also note that the on-peak period for the E-32 rates was shortened in the 2016 Rate Case, but that the GS-Schools periods were not altered in any way. (ASBA Br. at 3 (citing Ex. ASBA-1 at 8).)

ASBA/AASBO argue that the GS-Schools rates need to be revised by eliminating the shoulder periods and applying off-peak pricing to the former shoulder period hours. (ASBA Br. at 4 (citing Ex. ASBA-1 at 15).) Additionally, contrary to APS's assertion that the shoulder period could be removed if the off-peak pricing were increased to maintain revenue neutrality, ASBA/AASBO argue that the revisions need to be made without increasing the off-peak pricing, so that no schools will receive higher bills as a result of the revision. (ASBA Br. at 4 (citing Ex. APS-29 at 55-56).) ASBA/AASBO argue that it is inappropriate to require any increase in the GS-Schools pricing because APS's COSS already over-allocates costs to the schools, as described above. (See ASBA Br. at 4-8.) ASBA/AASBO argue that eliminating the shoulder period and applying the off-peak energy charge to the shoulder period hours would reduce APS's revenue by $1.4 million, which should be spread over and would have a negligible impact on the other general service customer classes. (ASBA Br. at 8.) ASBA/AASBO further argue that the GS-Schools rates should be redesigned to have the same seasons and on-peak period as APS's other TOU rates. (ASBA Br. at 8.) ASBA/AASBO also state that if APS can deviate from its COSS by spreading its requested revenue increase proportionately among rate classes, "it can certainly do so for what is the very small School TOU rate class." (ASBA RBr. at 4.)

Additionally, ASBA/AASBO argue, the Commission should require APS to work collaboratively with schools to modify Service Schedule 4,[458] which allows for aggregation of meters at a single address but includes requirements that exclude most schools from participating. (ASBA Br.

[458] Service Schedule 4 is for "Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service." (Ex. APS-53.)

at 10.) According to Mr. Sarver, the two requirements are (1) § 4.2, which requires each service entrance section ("SES") to have a National Electric Code ("NEC") section size of 3,000 amps (three phase) or greater; and (2) § 4.3, which requires the totalized load to have a minimum demand of 2,000 kVa or 1,500 kW for three-phase power. (Ex. ASBA-3 at 13; *see* Ex. APS-53.) Mr. Sarver testified that because school campuses commonly have multiple meters that vary widely in size (XS to L), §§ 4.2 and 4.3 prohibit almost all schools from aggregating. (Ex. ASBA-3 at 13.) In response to Mr. Sarver's testimony, APS agreed that §§ 4.2 and 4.3 of Service Schedule 4 are worth evaluating for school customers and indicated that it is willing to work collaboratively with schools to create a proposed modification to Service Schedule 4 that would be filed with the Commission within six months after the Decision in this case. (ASBA Br. at 10 (citing Ex. APS-30 at 11).) APS also indicated that it would not object to having such a requirement included in the Commission's decision. (ASBA Br. at 10 (citing Tr. at 2379).)

3. Kroger

Kroger argues that APS should not be permitted to increase the unbundled kWh delivery charge for E-32 M because 100% of distribution plant and O&M expenses are either demand-related or customer-related in the COSS, and no distribution costs are energy-related. (Kroger Br. at 3 (citing Ex. Kroger-1 at 21).) Kroger argues that although the unbundled delivery charge is not cost-based, APS proposed to increase it by 13%, which is more than six times as much as the overall proposed increase to E-32 M. (Kroger Br. at 3 (citing Ex. Kroger-1 at 19-20).) Kroger argues that this proposal is unfair to AG-X customers on E-32 M because they are not required to pay unbundled generation energy charges but are required to pay unbundled energy delivery charges as well as the unbundled SBC, which APS is proposing to increase by 19%. (Kroger Br. at 4.) Kroger asserts that these large increases are obscured by the generation energy charges that make up most of the E-32 M bundled energy charges (and which AG-X customers do not pay). (Kroger Br. at 4 (citing Ex. Kroger-1 at 20-21).) Kroger opines that the unbundled energy delivery charge should be eliminated for E-32 M, as it has been for E-32 L, but to mitigate intra-class bill impacts instead recommends that the unbundled energy delivery charge not be increased in this case. (Kroger Br. at 4.) Kroger asserts that because this would also mean that the bundled E-32 M summer and winter energy charges would be reduced,

the revenues that would otherwise have been collected should be shifted to demand charges to be consistent with cost of service. (Kroger Br. at 5.) According to Kroger, this would improve the misalignment between the E-32 M energy charges and the cost of service. (Kroger Br. at 5.)

4. SEIA/AriSEIA

SEIA/AriSEIA assert that the E-32 L demand ratchet[459] should be reduced or eliminated and that the commercial battery storage pilot rate, E-32 L SP, has not been used and should be revised. (SEIA Br. at 15.) According to SEIA/AriSEIA, the E-32 L's 80% demand ratchet, which creates "a floor on the demand billed to customers," is poorly designed and a "built-in disincentive for demand reduction." (SEIA Br. at 15 (citing Ex. SEIA-1 at 112).) Because an E-32 L customer is charged for demand based on 80% of the highest kW measured during the summer months, and the highest kW is measured based on a single 15-minute period at any time during a month, the ratchet ensures that a customer pays a certain level of demand charge even if demand is lower in all other months of the year. (*Id.*) Mr. Lucas testified that in the 12 months of data reviewed, every customer on E-32 L had to pay ratcheted demand (rather than actual demand) in at least one month, and many had to pay ratcheted demand in 6 to 8 months. (Ex. SEIA-1 at 114.) According to Mr. Lucas, the demand ratchet applies to all demand-based billing components, including generation and transmission elements, which is problematic both because generation and transmission infrastructure benefits from load diversity and because the demand ratchet is based on a customer's NCP that may occur outside of system peak hours, when the customer's demand level does not impact the need for generation and transmission. (Ex. SEIA-1 at 113.) SEIA/AriSEIA argue that it is inappropriate for the demand ratchet to collect for non-distribution related billing components. (SEIA Br. at 16.) Additionally, Mr. Lucas testified, the demand ratchet can disincentivize demand reduction completely because if a customer sets a demand charge based on an unusually high 15-minute period in the summer, the customer is stuck with 80% of that demand level for the next year, regardless of any demand-reduction efforts made during that year, which could cost the customer tens of thousands of dollars. (Ex. SEIA-1 at 114.) SEIA/AriSEIA also

[459] According to Mr. Lucas, the theory behind demand ratchets is that large non-residential customers are served by distribution infrastructure with less load diversity and that is sized closer to the sum of the NCPs of the customers served by the infrastructure, meaning that if a customer has an unusually high peak demand in a single month but low demand in other months, the customer will under-contribute to revenue recovery for the infrastructure serving it unless there is a demand ratchet. (Ex. SEIA-1 at 112-113.)

argue that the demand ratchet makes battery storage installation "overly risky" because a "single slip during any 15-minute period over the entire summer can effectively lock out savings the remainder of the year," meaning that no savings will be achieved from installed storage for the next year. (SEIA Br. at 17 (citing Ex. SEIA-1 at 114-115).) Thus, SEIA/AriSEIA argue, the demand ratchet is inconsistent with the Commission's goal of sending consistent demand reduction price signals and should be either eliminated or reduced by 50% to reduce the risk to customers and maintain the monthly price signal to reduce demand. (SEIA Br. at 16-17.)

In addition, SEIA/AriSEIA argue that E-32 L SP, the large non-residential battery storage pilot rate authorized in the 2016 Rate Case, has failed to attract any customers or to achieve its purpose and must be revised to support battery storage adoption by large customers. (SEIA Br. at 117.) Mr. Lucas testified that E-32 L SP has significant flaws, as evidenced by the fact that a customer with no solar or storage who switches to E-32 L SP would have a higher bill than the customer would have on a different rate (E-32 L or E-32 TOU L), meaning that a customer's "energy storage system doesn't just have to save money, it has to overcome the higher costs embedded in the E-32 L SP tariff." (Ex. SEIA-1 at 127-128.) Further, Mr. Lucas identified the following problems with the E-32 L SP tariff, at least when solar is used for charging:[460]

- Requiring 20% demand reduction for eligibility is too restrictive;
- The six-hour on-peak period[461] is too long because most behind-the-meter storage has a capacity of four hours, meaning that the tariff would require additional costs to be incurred for the storage system;
- There is no difference in the demand charges for the on-peak and remaining-hour TOU period, which means that if a customer reduces demand on peak by shifting usage to a remaining hour, the customer will still be charged the same amount as if the reduction had not occurred;
- Requiring customers to actively manage demand for 12 hours a day (on-peak and remaining

[460] SEIA Br. at 18-19 (citing Ex. SEIA-1 at 128-130).)

[461] E-32 L SP has a summer on-peak period of 2 p.m. to 8 p.m. and a non-summer on-peak period of 4 p.m. to 10 p.m. (Ex. APS-53.) It also has the following "remaining hours," which incur the same demand charge as on-peak hours: summer—11 a.m. to 2 p.m. and 8 p.m. to 11 p.m.; and non-summer—6 a.m. to 10 a.m., 3 p.m. to 4 p.m., and 10 p.m. to 11 p.m. (*Id.*) It also has a different summer period: June through September. (*Id.*)

hours) rather than just during on-peak hours requires conservative management during peak hours, which reduces the incentive for storage systems to reduce demand during system peak hours; and

- The tariff may not give storage systems time to charge fully before the 11 a.m. onset of remaining hours in the summer.

SEIA/AriSEIA urge the Commission to require APS to redesign E-32 L SP by eliminating the 20% peak demand reduction requirement, reducing on-peak hours to four hours, creating a reasonable differential between on-peak and remaining-hour demand rates, increasing the differential in the energy rates, and allowing sufficient time for storage systems to charge fully before the peak period. (SEIA Br. at 19.)

5. APS Response

APS recommends that ASBA/AASBO's request to modify the GS-Schools rates be rejected, characterizing it as ASBA/AASBO seeking a $1.4 million rate cut at the expense of other customers and asserting that the requested modification is neither warranted nor supported by cost-of-service data. (APS RBr. at 65.) APS argues that schools on the GS-Schools tariffs pay 100.4% of their costs of service, which is "almost precisely at equilibrium" and significantly less than the E-32 S and E-32 M classes pay. (APS RBr. at 66.) APS argues that ASBA/AASBO do not really have a problem with cost of service for the GS-Schools rates, although they do with the E-32 rates, but are still asking that APS be required to cut the GS-Schools rates. (APS RBr. at 66.) APS suggests that a more appropriate remedy would be for schools to select the GS-Schools rates, which were specifically designed for schools. (APS RBr. at 66.)

APS is willing to modify the GS-Schools rates as long as the changes are revenue neutral, so that the costs will not be shifted from schools to other APS customers. (APS RBr. at 66-67.) APS asserts that removing the shoulder-peak period and using the off-peak price for those hours in the GS-Schools rates as urged by ASBA/AASBO would not be revenue neutral unless the off-peak price was adjusted to prevent a cost shift. (APS Br. at 92-93.) APS also asserts that the modification to the GS-Schools rates would need to be more extensive than suggested by ASBA/AASBO and would bring the GS-Schools rates more in line with APS's other general service and irrigation rates, such as by changing

the on-peak period to 3 p.m. to 8 p.m. weekdays. (APS Br. at 93 (citing Ex. APS-29 at 55; Ex. APS-30 at 9).) APS notes, however, that making such changes to the GS-Schools rates would result in disparate impacts for individual schools, which could experience increases or decreases beyond the general revenue change APS proposed in this case. (APS Br. at 93 (citing Ex. APS-29 at 55-56).)

APS agrees to work collaboratively with ASBA/AASBO to address the totalization/aggregation of meters within a contiguous property and asserts that it will file a proposed modification to Service Schedule 4 within six months after the decision in this matter. (APS RBr. at 67 (citing Ex. APS-30 at 11).)

APS did not brief the unbundled delivery charge rate increase issue raised by Kroger.

APS asserts that SEIA/AriSEIA's proposals would favor customers who adopt SEIA/AriSEIA's favored technology while shifting costs to and increasing the bills of other customers. (APS Br. at 92 (citing Ex. APS-29 at 54); APS RBr. at 69 (citing Ex. APS-29 at 53).) Mr. Snook testified that the demand ratchet is designed "to fairly recover a customer's demand costs through monthly demand charges, even though the costs are primarily driven by the customer's demand in the core summer months," although some demand-related costs are driven by customer demand in all months of the year. (Ex. APS-29 at 52.) Mr. Snook stated that the demand charges could alternatively be applied only to summer bills, but that this would result in very high summer bills and very uneven monthly bills. (Ex. APS-29 at 52.) Mr. Snook also testified that demand ratchets are a common feature in electric rates for large and extra-large commercial and industrial customers. (Ex. APS-29 at 53.) According to APS, the demand ratchet is used to match the demand component of a customer's bill with the customer's actual cost of service and, if some customers' demand revenues were reduced, other customers in the same class would pay the shifted costs through higher demand rates. (APS Br. at 91 (citing Ex. APS-29 at 52).) APS notes that SEIA/AriSEIA did not provide any bill analysis for this change, argues that they also failed to provide any compelling reason for the change, and notes that no other intervenors support the change. (APS RBr. at 69-70 (citing Ex. APS-29 at 54).)

APS also opposes SEIA/AriSEIA's proposed modifications to E-32 L SP, arguing that the minimum storage requirement is needed to prevent customers from "gaming" the rate schedule by installing de minimis storage technology and that the 2 p.m. to 6 p.m. on-peak period proposed does

not reflect the critical hours on APS's system and would only promote DG solar. (APS Br. at 91-92 (citing Ex. APS-29 at 54-55).) Mr. Snook testified that E-32 L SP was not designed by APS but actually proposed by solar parties in the 2016 Rate Case and based on another utility's storage rate. (Ex. APS-29 at 54.) Mr. Snook surmised that SEIA/AriSEIA now seek to change the rate design because it was "ineffective at driving the adoption of storage technology." (Ex. APS-29 at 54.) Further, APS asserts: "Rates should be technology agnostic and the bill savings from adopting a certain technology should be commensurate with the cost savings provided back to the grid." (APS Br. at 92.) APS notes that no other party supported SEIA/AriSEIA's proposals. (APS Br. at 92.)

6. Resolution

We agree with and approve APS's proposed changes to streetlight rates (freezing E-47 and E-58 and adopting a new E-45 and a new E-68), as this more modern approach should be significantly easier for customers to understand and for APS to implement, due to constantly changing technologies and products. We also agree with and approve APS's proposed changes to its water pumping rates (transitioning E-221 to non-agricultural customers only and adding a new E-221 AG and a new E-221 AG TOU for agricultural customers), as it is logical and consistent with cost considerations to treat these very different operational models differently. Additionally, we agree with and approve APS's cancellation of the E-36 M rate rider due to low enrollment and the apparent problems with its rate design.

Because Staff and APS have worked out clearer language for the conflict-of-interest provision in Service Schedule 9, we also agree with and approve APS's changes to Service Schedule 9, which are expected to provide economic benefits in rural municipalities.

From the COSS data provided by APS and Staff, it appears that the GS-Schools rates are likely well-designed to recover cost of service and not to over-recover cost of service to the extent that the extra small, small, and medium general service TOU rates do. That gives us pause, as ASBA/AASBO desire to use the same TOU periods and seasonal periods as APS's other TOU rates. It is understandable that ASBA/AASBO desire to have a more simplified rate design. It is less understandable that ASBA/AASBO believe the cost of that simplified rate design, estimated at $1.4 million, should be spread to the other general service rate classes, particularly to the other general

service rate classes that appear to be recovering a significantly greater portion of their costs of service. Because we are approving a revenue decrease in this matter, the GS-Schools rates will be reduced. To mitigate the disagreements ASBA/AASBO have with the GS-Schools rates, the rate reduction for the GS-Schools rates will be made through reductions to the summer-shoulder and winter periods' shoulder-peak and off-peak energy charges and not the other components of the rate design.

We will adopt the requirement, supported by ASBA/AASBO and APS, to require APS to work collaboratively with ASBA/AASBO and any other interested school stakeholders over the next six months to create a proposed modification to Service Schedule 4 that will allow for aggregation of multiple meters located on a school's contiguous campus and to have the proposed modification to Service Schedule 4 filed in this docket within six months after the date of this Decision.

Because we are concerned that AG-X customers may not be covering their costs of service, Kroger's proposal, apparently intended primarily to provide economic benefits to AG-X customers on E-32 M, causes us some concern. We note, however, that Kroger's request is simply not to have the unbundled energy delivery charge in E-32 M increased in this case. Because we are approving a revenue decrease rather than a revenue increase in this case, Kroger's request will be satisfied, although we will not know the truth about AG-X's coverage of its costs of service until the AG-X filing/s required by Section (V)(Q) is/are made.

We do not agree with and will not adopt SEIA/AriSEIA's proposal to remove (or reduce significantly) the demand ratchet that exists in E-32 L. The demand ratchet in E-32 L is designed to ensure that large commercial customers, who can have a large impact on system load due to their size, are billed for demand based on the demand they represent at the most critical period of the year, when demand and reliability really matter. This sends an appropriate price signal to presumably sophisticated customers. We also are not persuaded that the demand ratchet would discourage the installation of battery storage, as it makes sense that installing storage to use during the peak hours in the summer months would be the natural approach to take. Finally, we note that based on the COSS data provided by APS and Staff, the E-32 L class is recovering relatively less of its costs of service than most of the other general service classes. Removing or significantly reducing the demand ratchet would only

exacerbate any existing deficiency in recovering cost of service, absent an offsetting increase in rates, and would have an unknown impact on revenues.

We find SEIA/AriSEIA's arguments regarding the revamping of E-32 L SP to be somewhat disingenuous, as SEIA/AriSEIA's briefs would create the impression that APS designed E-32 L SP independently and inappropriately. In fact, it appears that E-32 L SP was adopted by the Commission in the 2016 Rate Case in response to a proposal by EFCA, represented by the attorney who represents SEIA/AriSEIA in this matter.[462] (See Ex. APS-70 at 2, 63-80.) The Commission approved what became E-32 L SP as a new, optional, storage-friendly rate without a demand ratchet, off-peak demand charge, and declining block demand charge, although the Commission did allow for an off-peak excess demand charge for off-peak demand exceeding 150% of on-peak billing demand. (Ex. APS-70 at 78, 80.) The Commission directed APS to include an on-peak period comprising "the 6 greatest average system demand hours during the previous three years by season" and an off-peak period comprising "the 12 lowest average system demand hours during the previous three years by season" and designated all other hours as remaining hours.[463] (Ex. APS-70 at 79.)

Comparing E-32 L SP to E-32 L, the most striking difference initially is that the BSCs for E-32 L SP are significantly higher (ranging from almost twice as high to almost nine times as high). It is unclear why the unbundled customer accounts charge for E-32 L SP would be more than $26 per day when it is less than $2.50 per day for E-32 L. And this is not even an issue that SEIA/AriSEIA mentioned in its briefs. Because there has been no participation to date in E-32 L SP, it is appropriate to require in this case that it be redesigned so that it can be used and evaluated as a means of encouraging the shifting of significant load from high demand and high cost periods. Thus, we will require APS to engage in a collaborative process with SEIA/AriSEIA and other interested stakeholders (including Staff) to analyze and identify solutions to at least the following potential issues that have been identified as to E-32 L SP:

- Whether there is justification for the BSC to be as high as it is and, if not, what would be an appropriate cost-based BSC;

[462] SEIA had different representation in the 2016 Rate Case.
[463] We are interested to know what more recent years would produce.

- Whether requiring 20% demand reduction for eligibility is too restrictive and, if so, what would be an appropriate threshold for eligibility;
- Whether the six-hour on-peak period is too long because most behind-the-meter storage has a shorter capacity;
- Whether there is justification for demand charges to be the same on-peak and during remaining hours and, if not, what different cost-based demand charges would be appropriate for the different periods;
- Whether there is justification for requiring customers to manage demand actively for 12 hours per day (on-peak and remaining hours) rather than just on-peak;
- Whether the current on-peak period comprises "the 6 greatest average system demand hours during the previous three years by season" and the current off-peak period comprises "the 12 lowest average system demand hours during the previous three years by season" and, if not, what on-peak period and off-peak period would; and
- Whether the tariff allows sufficient time for storage systems to charge before the onset of remaining hours in the summer months.

To provide an opportunity for the modifications to E-32 L SP to be considered in light of the record in this case, the record in this docket will remain open for 12 months to allow APS to submit such a proposal, with supporting documentation as well as an indication of whether the parties believe an additional evidentiary hearing should be held and a proposed form of notice to be provided to APS's customers. To ensure that the collaborative process described above progresses at a reasonable pace, we will require APS to file monthly updates, beginning on the first day of the month following the effective date of this Decision, providing information on the meetings and other communications that have occurred, the stakeholders involved in those meetings and other communications, and the progress in terms of the issues that have been resolved and that remain unresolved. For each resolved issue, APS shall also include a full description of the resolution.

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E. Other Tariff Issues

1. DC Fast Charger Rate Rider

a. APS Position

APS requests authority to implement its proposed "Rate Rider DCFC, General Service Direct Current Fast Charging Pilot" ("DCFC Rider"), the POA for which is attached hereto and incorporated herein as Exhibit C.[464] The DCFC Rider would be available to standard offer retail customers served under E-32 S TOU, E-32 M TOU, and E-32 L TOU, at locations where electricity usage is limited to public, fast-charge EV charging stations (discharge capacity of 50 kW or greater) that are separately metered.[465] (Ex. APS-77.) The DCFC Rider would be limited to 500 customers accounts and would expire after the July 2031 billing period. (*Id.*) The purpose of the DCFC Rider is to facilitate deployment of public DCFC[466] EV charging stations, and it would accomplish this by imposing a demand limiter on bills based on load factor, with a 25% load factor limit from July 1, 2021, through June 30, 2025; a 20% load factor limit from July 1, 2025, through June 30, 2028; and a 15% load factor limit from July 1, 2028, through June 30, 2031. (*Id.*) APS asserts that DCFC facilities served on a TOU rate are beneficial because EV charging at off-peak times results in more efficient grid use, whereas on-peak EV charging adds incremental load that could necessitate investments in additional infrastructure and generation resources. (APS Br. at 89 (citing Tr. at 4527).) APS also asserts that increased electricity sales for off-peak EV charging drive down rates for all customers because the fixed cost of the grid is spread across a larger volume of sales. (APS Br. at 89 (citing Tr. at 4527-4528).) According to APS the DCFC Rider is consistent with Decision No. 77289 (July 19, 2019), the Commission's Electric Vehicle Policy Implementation Plan ("EV Plan"),[467] which encouraged electric utilities to propose rate designs and load management strategies to incentivize off-peak EV charging to take advantage of low- or negative-priced periods and times when excess renewable generation is available. (APS Br. at 90 (citing EV Plan at 5).) APS asserts that because EVgo supports the DCFC Rider, it has dropped its initial request for a commercial rate and that ChargePoint is also generally

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[464] The DCFC Rider was admitted herein as Exhibit APS-77.
[465] Incidental usage is also permitted. (Ex. APS-77.)
[466] DCFC chargers are commonly known as Level 3 EV chargers. (Tr. at 4450.)
[467] The EV Plan was admitted herein as Exhibit CP-3 and Exhibit EVgo-5.

supportive of the DCFC Rider although it offered certain modifications to it. (APS Br. at 90 (citing Tr. at 4435-4436, 4528).)

b. ChargePoint

ChargePoint did not brief this issue. During the hearing, however, Mr. Wilson stated that ChargePoint was generally supportive of the DCFC Rider but thought it would make sense to revise it by (1) allowing the DCFC Rider to apply at locations where multiple level 2 chargers are installed that combined would have a load greater than 50 kW, and (2) allowing the DCFC Rider to apply also to non-public charging locations such as for fleets of delivery vehicles. (Tr. at 4435-4436, 4449-4450.) Mr. Wilson also stated that ChargePoint would support the DCFC Rider even if ChargePoint's two proposed changes were not made. (Tr. at 4450-4451.)

c. EVgo

EVgo is the owner/operator of the largest public network of DCFC stations in the U.S. and plans to triple its DCFC network across 40 metropolitan areas in the coming years by building more than 2,700 additional fast chargers. (Ex. EVgo-1 at 2-3.) EVgo urges the Commission to approve the DCFC Rider because it will provide a solution to issues that have challenged DCFC station operators desiring to invest in DCFC stations in Arizona and provide the rate relief and certainty needed to encourage third-party investment in EV charging infrastructure. (EVgo Br. at 9-10 (citing Tr. at 4415.) The DCFC Rider does this by providing a demand limiter that corresponds with the customers' kWh usage and days in the billing cycle and that gradually decreases until 2031, during which time EV adoption is expected to increase. (EVgo Br. at 9 (citing Ex. APS-77).) EVgo points out that because the DCFC Rider will apply only to commercial TOU rates, it maintains the TOU price signals to encourage off-peak charging and maintains cost causation principles inherent in the underlying rate design. (EVgo Br. at 7-8 (citing Ex. EVgo-3 at 4).) EVgo compared the load profile of EVgo's existing Arizona DCFC stations to production from solar generation and solar generation plus storage and found that DCFC station usage was clearly aligned with standalone solar generation and solar generation plus storage, peaking at approximately 2 p.m. when solar generation is high and again at approximately 5

p.m. to 6 p.m. when solar plus storage is high.[468] (EVgo Br. at 3-4 (citing Ex. EVgo-3 at 12; Tr. at 4523-4524).) EVgo highlighted both APS and WRA/SWEEP witness testimony explaining that increased use of EVs place downward pressure on rates for all customers as EV load increases by spreading the costs of grid infrastructure to customers over more generation and sales. (EVgo Br. at 4-5 (citing Ex. APS-10 at 5; Ex. WRA-1 at 25).) EVgo further points out that a 2018 study commissioned by WRA/SWEEP estimated that off-peak EV charging and widespread EV adoption could save the average Arizona household approximately $176 in annual bill savings in 2050. (EVgo Br. at 5 (citing Ex. WRA-1 at 26).) Additionally, EVgo asserts, the DCFC Rider is consistent with the Commission's EV Plan because it would "alleviate, or address demand charges and other issues faced when deploying [DCFC] stations." (EVgo Br. at 9 (citing EV Plan).)

d. IBEW Locals

The IBEW Locals urge the Commission to approve the DCFC Rider, agreeing with the benefits cited by EVgo and Tesla, which include encouragement of private sector investment in public EV charging solutions as well as improved grid utilization and lower costs for all customers. (IBEW RBr. at 10.)

e. Tesla

Tesla urges the Commission to approve the DCFC Rider, as the solution to the issues caused by traditional commercial rate design that are obstacles to development of DCFC stations in Arizona because of high demand charges and low usage, at least in the early years. (Tesla Br. at 3-5 (citing Tr. at 4412, 4519.) Tesla agrees that the DCFC Rider would result in benefits to the grid and savings for all APS customers. (Tesla Br. at 1-2, 5 (citing Ex. WRA-1 at 25-26; Ex. APS-10 at 5).) Additionally, Tesla agrees that the DCFC Rider is consistent with the Commission's EV Plan. (Tesla Br. at 4 (citing EV Plan).)

f. APS Response

APS asserts that the DCC Rider should be approved because it is consistent with the Commission's EV Plan; EVgo and Tesla support it; ChargePoint generally supports it; no parties have

[468] DCFCs are usually sited at places where EVs will be parked for less than an hour during daytime hours, such as grocery stores, parks, or shopping malls. (EVgo Br. at 3 (citing Tr. at 4421-4423; Ex. EVgo-3 at 12).)

opposed it; and Electrify America, a member of the industry, also expressed support for it in a letter to the docket.[469] (APS Br. at 68.)

g. Resolution

We agree with APS and the other parties that the DCFC Rider should be approved, as a means of encouraging development of the public EV DCFC infrastructure that would support greater adoption of EVs in Arizona. The demand limiter is reasonable under the circumstances, as it will limit demand charges during the early years of DCFC station development, will gradually decrease, and will ultimately expire in approximately 10 years. The evidence establishes that the DCFC stations' demand will be well aligned with solar generation and solar generation plus storage, meaning that the DCFCs will increase grid efficiency and ultimately lower costs for all APS customers.

We will adopt the DCFC Rider included as Exhibit C herein, without adopting the revisions proposed by ChargePoint because we are concerned about how the longer charging times for Level 2 chargers would align with renewables generation and storage and, additionally, agree that private companies with vehicles fleets should be able to control their charging activities in a manner that obviates the need for a demand limiter.

2. Designated Rate for Mobile Home & Long-Term RV Parks

a. MHCA Proposal

MHCA intervened in this case for one reason: mobile home park landlords and long-term recreational vehicle ("RV") park landlords who desire to bill their tenants separately for utilities are required to install submeters for each tenant and to charge their tenants no more than the "prevailing basic service single family residential rate charged by the serving utility or provider," and APS does not have a designated "basic service single family residential rate" ("designated rate"). (MHCA Br. at 3 (quoting A.R.S. §§ 33-1413.01, 33-2107).) MHCA asserts that APS had a basic service single family residential rate at one time, but now has numerous rates from which single-family residence customers can choose. (MHCA BR. at 3-4.) As a result, MHCA asserts, mobile home and long-term RV park landlords who are APS customers do not know which rate they may charge their tenants to comply

[469] The cited letter is not part of the evidentiary record in this matter.

with A.R.S. §§ 33-1413.01 and 33-2107. (MHCA Br. at 4 (citing Ex. MHCA-5 at 10-11).) MHCA proposes for the R-Basic rate (601-999 kWh) to be the designated rate and asserted that APS has agreed to this. (MHCA Br. at 5 (citing Ex. APS-27 at 15); Tr. at 2962.)

Mr. Haney testified that most mobile home parks are master-metered communities, meaning that the utility has not run lines to individual spaces, only to a single delivery point and meter. (Tr. at 2969-2970.) By law, if mobile home and long-term RV park operators desire to bill tenants separately for utilities, they are required to install their own meters at each home site. (Tr. at 2969-2970, 2979, 2983-2984.) According to Mr. Haney, mobile home park and RV park operators "would love to be out of the business of providing . . . utilities," but the utilities are not willing to take over the systems because the systems were not installed by the utilities and often old, and the only way for tenants to be individually metered by the utility would be for the utility to install new lines to each separate home, which only started to occur in the early 1980s. (Tr. at 2969-2970.) Additionally, MHCA asserts, most mobile home and RV part operators do not have smart meters and lack the ability to track time of use or peak demand and to duplicate the suite of APS residential rates available to single-family residences. (Tr. at 2958-2962.)

Mr. Haney testified that most tenants use between 750 and 850 kWh per month, and he did not anticipate a problem from tenants using more than 1,000 kWh or less than 600 kWh on average per month, because the tenants' main concern seems to be that they just want to know what rate they will be charged. (Tr. at 2971.) Mr. Haney also indicated that if a park operator could confirm after 12 months that a tenant's average annual usage was lower than 600 kWh per month, the operator could charge the lower tier rate instead, although the operator could not charge a rate higher than the designated rate upon determining a tenant's higher average annual usage per month. (See Tr. at 2972-2975.) Additionally, Mr. Haney clarified that the operator of a master-metered park pays the utility a commercial rate for electricity that generally is more than the operator is able to bill all of the tenants combined. (Tr. at 2980.)

b. APS Response

APS states that if the Commission adopts a designated rate for purposes of A.R.S. §§ 33-1413.01 and 33-2107, that designated rate should be R-Basic. (APS Br. at 90.) APS does not express

a view on whether the Commission should adopt a designated rate and disagreed with MHCA's characterization that APS has consented to MHCA's proposal. (APS RBr. at 68.)

c. Resolution

MHCA's request is reasonable and will be approved. A.R.S. §§ 33-1413.01(B) and 33-2107(B)(3) both require a landlord "not [to] charge more than the prevailing basic service single family residential rate charged by the serving utility or provider." (Ex. MHCA-1; Ex. MHCA-2.) The R-Basic rates are the most appropriate rates for this use, as APS's other residential rates would require smart meters, which the park operators do not have. We will require APS to include the following language in its new combined R-Basic tariff:

> For purposes of A.R.S. §§ 33-1413.01(B) and 33-2107(B)(3), the prevailing basic service single family residential rate charged by APS as the serving utility or provider is the middle tier of this tariff (601-999 kWh).

3. Rooftop Solar Sizing Requirements

a. SEIA/AriSEIA Proposal

SEIA/AriSEIA assert that APS's rooftop solar system sizing requirements, in Rate Riders EPR-6 and RCP, conflict with the Commission's Interconnection of Distributed Generation Facilities ("Interconnection") Rules and the Commission's Net Metering Rules and that the Commission should require APS to update the system size limits for residential customers in EPR-6 and RCP to conform with the rules and specifically should require APS to adopt TEPs sizing methodology for non-residential customers. (SEIA Br. at 10-12.) SEIA/AriSEIA argue that as a result of APS's sizing requirements, "residential and commercial customers are being forced to install DG Systems that are smaller than they should be, thereby depriving these customers of the opportunity for savings and decreasing the amount of clean energy installed in the state. (SEIA Br. at 10.)

SEIA/AriSEIA urge the Commission to require APS to adopt the following system size limits in EPR-6 and RCP for residential customers:

Service	200 amps	400 amps	600 amps	800 amps
DG System Size Limit	15 kW-ac	30 kW-ac	45 kW-ac	60 kW-ac

For non-residential customers, SEIA/AriSEIA urge the Commission to require APS to adopt the

following system size limit language, which Mr. Lucas attributes to TEP's net metering documentation: "No system may exceed 125% of connected load for that meter, where connected load is defined as the maximum demand divided by 0.6." (SEIA Br. at 12 (citing Ex. SEIA-1 at 102).)

Specifically, SEIA/AriSEIA assert that the following language in Rate Rider RCP conflicts with the Interconnection Rules and the Net Metering Rules:

> 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 8 kW-ac, the maximum system size that could be installed would be 12 kW-dc).[470]

According to SEIA/AriSEIA, because the Net Metering Rules allow sizing up to 125% of "total connected load," but APS uses a standard involving 150% of "maximum one-hour peak demand," APS's language does not conform to the Net Metering Rules. (SEIA Br. at 11 (citing Ex. SEIA-1 at 96 (citing A.A.C. R14-2-2301, definition of "Net Metering Facility").) In his testimony, Mr. Lucas conceded that "total connected load" is not defined in the Net Metering Rules or anywhere else in A.A.C. Title 14. (Ex. SEIA-1 at 96.) Mr. Lucas pointed to two instances when APS indicated that it is aware maximum connected load will exceed maximum one-hour demand: (1) in a chart included in the Direct Testimony of Charles A. Miessner in the 2016 Rate Case, illustrating the difference between instantaneous versus one-hour demands and showing the one-hour demand as a straight horizontal line while the instantaneous load was a widely spiking line ranging from 0 kW to twice the one-hour load level; and (2) in a data response to SEIA 16.1 discussing the maximum amount of load that can be served through a customer's service drop and calculating that a customer with a 200-amp service can theoretically support 38.4 kW-ac, although a more typical residential installation would be 12.2 kW-ac. (Ex. SEIA-1 at 96-97 (citing the reproduced chart and Ex. SEIA-1 at att. KL-43).)

SEIA asserts that APS's sizing requirement using kW-dc is also impermissible because the Interconnection Rules clearly refer to "nameplate AC capacity." (SEIA Br. at 11 (referencing A.A.C. R14-2-2601(32), definition of "Maximum Capacity").) Mr. Lucas testified that a solar system's generating capacity should be measured based on its inverter's kW-ac because the inverter is the

[470] Ex. SEIA-1 at 95 (quoting RCP Rider at 2).

component that takes DC power from the PV panels and transforms it to AC power for use in a house or on the grid. (Ex. SEIA-1 at 98.) According to Mr. Lucas, the nameplate kW-dc rating does not determine the power that a solar system can export to the grid. (*Id.*)

c. APS Response

APS did not brief the issue. In its data response cited by Mr. Lucas, which concerned questions specific to EPR-6, APS stated that distribution equipment is not sized to serve a customer's maximum potential draw based on their service amperage and also not sized to accommodate solar generators that could export 150% of the customer's maximum load to the grid. (Ex. SEIA-1 at att. KL-43.) APS also stated that the settlement in the 2016 Rate Case, approved by the Commission, provided that the provisions in EPR-6 were a reasonable way to implement the size requirements under the Net Metering Rules. (*Id.*) Further, APS stated that Arizona utilities are subject to the peak-load-based size limitation required by the Net Metering Rules (as opposed to annual energy) and that APS would not support any changes to EPR-6 because it is closed to new residential customers and existing grandfathered solar customers are restricted to a 10% or 1 kW increase in the size of their systems. (*Id.*)

d. Resolution

In the Net Metering Rules, "Net Metering Facility" is defined, in pertinent part, to include "a facility for the production of electricity that . . . [h]as a generating capacity less than or equal to 125% of the Net Metering Customer's total connected load, or in the absence of customer load data, capacity less than or equal to the Customer's electric service drop capacity." (A.A.C. R14-2-2301(13).) Neither "total connected load" nor "capacity" is defined. (See A.A.C. R14-2-2301.) In the Interconnection Rules, "Maximum Capacity" is defined to mean either "[t]he nameplate AC capacity of a Generating Facility" or [i]f the Operating Characteristics of the Generating Facility limit the power transferred across the Point of Interconnection to the Distribution System, only the power transferred across the Point of Interconnection to the Distribution System, not including Inadvertent Export." (A.A.C. R14-2-2601(32).) The Interconnection Rules became effective on February 25, 2020,[471] after the application was filed in this matter.

[471] Official notice is taken of this fact, memorialized in the Legal Division's filing to Docket No. RE-0000-0A-07-0609 on February 26, 2020, which included a copy of the Attorney General's approval of the rules and the Secretary of State's dated receipt of the Notice of Final Rulemaking package for filing.

In the RCP, APS includes the following restrictions on the size of DG solar PV:

> 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 8 kW-ac, the maximum system size that could be installed would be 12 kW-dc).[472]

While "total connected load," as included in the Net Metering Rules, is sufficiently vague that it can reasonably be interpreted to mean "150% of the Customer's maximum one-hour peak demand measured in AC over the prior twelve (12) months," as APS has included in the RCP, the same cannot be said for the definition of "Maximum Capacity" in the Interconnection Rules, which is at least the "nameplate AC capacity of a Generating Facility." A.A.C. R14-2-2605(G) prohibits a utility from disapproving interconnection of a generating facility that satisfies the requirements of the Interconnection Rules and the utility's Interconnection Manual. Thus, it would be a violation of the Interconnection Rules for APS to disapprove interconnection of a generating facility based on its RCP sizing restrictions as opposed to the sizing restriction in the Interconnection Rules, provided that the interconnection met all of the safety-related requirements in the Interconnection Rules, such as those set forth in A.A.C. R14-2-2615.

We will require APS to update its RCP POA to include the "Maximum Capacity" restriction from the Interconnection Rules rather than its current size restrictions. As EPR-6 is a legacy rider and unavailable to new interconnections, however, we will not require APS to change the language of EPR-6. Because SEIA/AriSEIA did not identify where they believe the TEP language for non-residential DG sizing should be included, and we are not inclined to guess, we will not require APS to adopt the TEP language quoted by SEIA/AriSEIA.

. . .

. . .

[472] Ex. APS-53.

4. DG Export Rate

a. APS Position

As required by Decision No. 75859, issued in the Value of Solar Docket, APS submitted with its application an avoided cost methodology and estimate of the avoided costs for rooftop solar. (Ex. APS-7 at 2.) Mr. Albert testified that APS did not propose to use the avoided cost methodology in this docket, for equitable reasons, but that APS believes it is important to stay on the path toward compensating rooftop solar exports at avoided cost. (*Id.*) Using its avoided cost methodology, APS calculated an avoided cost rate of $0.02254/kWh. (Ex. APS-7 at 18.) Although APS initially proposed to have the Commission approve APS's avoided cost methodology in this case, for use in future rate cases, APS subsequently agreed with Staff that it was unnecessary in this case. (Ex. APS-8 at 2, 30-31.)

APS now asserts that the Commission should set the formula for a new avoided cost methodology to set the DG export rate in the open Value of Solar Docket and should authorize the continued use of the Commission-approved RCP methodology in this case. (APS Br. at 82.) APS has been and is currently paying its customers for solar exports using the RCP methodology and believes that it would not be appropriate to use an avoided cost methodology in this rate case, on an ad hoc basis, rather than waiting for the Commission to finalize an avoided cost methodology in the Value of Solar Docket. (*Id.*)

b. Vote Solar

Due to the complexity of the avoided cost issues, Vote Solar urges the Commission to adopt the RCP method to value DG exports in this matter and to address avoided cost methodology issues in a separate docket. (VS Br. at 1-2, 23-24.)

e. Staff

Although Staff did not brief the issue, Mr. Metzger testified that Staff recommends not addressing the avoided cost methodology as part of this case because it has far-reaching impacts for ratepayers across Arizona and would be best addressed in a separate docket, such as the open Value of Solar Docket, that allows for input from a broad range of stakeholders. (Ex. S-11 at 7-8.)

. . .

f. Resolution

We agree with the parties that it is more appropriate to address the avoided cost methodology in the Value of Solar Docket, to ensure that the same methodology will be applied for all Arizona rooftop solar customers served by regulated electric utilities. We also note that in Decision No. 77997 (May 5, 2021), we relieved Staff of the obligation to develop an avoided cost methodology with five-year forecasting.[473]

We approve APS's continued use of the RCP.

IX. Customer-Related Issues

A. Residential Rate Names

a. APS Position

APS proposes to adopt the following changes to its residential rate plan names, which are based on a "multi-faceted, data-driven process that relied on extensive industry research and collaboration with and feedback from a number of important parties" conducted through a partnership with APS-hired consultant IBM:[474]

Current Tariff & Rate Name	APS-Proposed Name
R-XS – "Lite Choice"	As combined into one tariff: "Fixed Rate Plan"
R-Basic – "Premier Choice"	
R-Basic L – "Premier Choice Large"	
TOU-E – "Saver Choice"	"Time-of-Use 3pm-8pm Weekdays"
R-2 – "Saver Choice Plus"	No recommendation made
R-3 – "Saver Choice Max"	"Time-of-Use 3pm-8pm Weekdays with Demand"
R-Tech – "Saver Choice Tech"	No recommendation made

Specifically, the process involved the APS Customer Advisory Board ("CAB"), comprised of a statistically representative sample of APS customers; the APS Consumer Work Group, comprised of customer advocates and representatives of consumer advocacy groups (such as Wildfire, PIRG, RUCO, and AARP); and APS Customer Advisors. (LFE APS-86 at Cover Letter at 1.) APS's proposed names were recommended by IBM following industry research, behavioral economics research, qualitative research (interviews with customers, the CAB, Customer Advisors, and stakeholder groups), and two

[473] Official notice is taken of Decision No. 77997.
[474] LFE APS-86 at Cover Letter at 1.

rounds of quantitative customer research (web surveys). (See LFE APS-86 at Report at 2, 8.)

IBM identified the following "best practices for rate naming":

- Stating the plan in the rate plan name
- Using "customer-friendly" language in the rate description, focusing on behavior and lifestyle
- Establishing a rate name portfolio where the residential rates are easily compared across the portfolio based on the names alone[475]

Additionally, IBM identified the following "naming practices to avoid":

- Using abbreviations or acronyms in the rate name (e.g., TOU-DR1)
- Using tariff references (e.g., Rate Schedule GS-3)
- Using electrical engineering language in the rate name and description
- Having a rate portfolio where the rate names cannot be compared without reviewing the detailed rate descriptions, yet also stand on their own[476]

Based on its behavioral research, IBM further recommended that APS avoid using "Basic" in the flat rate name, because "this name was most used by utilities who did not have residential rate choice, [and IBM] felt that this might be perceived by customers as the 'default' rate" and disincentivize customers from choosing a rate that would be more economical for them or would fit their lifestyles better. (LFE APS-86 at Report at 6.)

b. RUCO

RUCO recommends that the Commission approve new explanatory names for APS's residential rate classes in this case. (RUCO Br. at 38.) RUCO believes that APS's current "formal class names" are biased toward having customers choose demand rates to maximize savings, although customers with low load factors do not save money on demand rates, and likely contributed to the number of complaints received when "unattractive financial consequences" occurred for these customers. (RUCO Br. at 41.) RUCO characterizes the current names as "meaningless at best and dangerous at worst" because of their implications for cost savings. (RUCO Br. at 41.) RUCO recommends that APS be required to change the current names as follows:[477]

. . .

[475] LFE APS-86 at Report at 6.
[476] LFE APS-86 at Report at 6.
[477] RUCO Br. at 41 (citing Ex. RUCO-2 at 20).

Current Tariff & Rate Name	RUCO-Proposed Name
R-XS – "Lite Choice"	"Small Flat Rate"
R-Basic – "Premier Choice"	"Medium Flat Rate"
R-Basic L – "Premier Choice Large"	"Large Flat Rate"
TOU-E – "Saver Choice"	"TOU"
N/A	"TOU – Off Peak"
R-2 – "Saver Choice Plus"	"Demand Rate"
R-3 – "Saver Choice Max"	"Large Demand"
R-Tech – "Saver Choice Tech"	"Large Demand w-TECH"

RUCO does not object to APS's proposed names, as they are similar to RUCO's. (RUCO Br. at 41 (citing LFE APS-86 at 2).)

c. Staff

Staff urges the Commission to require APS to adopt rate plan names that identify the purpose of the rates so that they are easier for customers to understand. (Staff Br. at 50 (citing Ex. S-5 at 46-47).) While Staff acknowledges that APS filed its proposed rate names on March 12, 2021, Staff asserted on brief that it has not finished its review of the rate name filing and will submit recommendations in the docket concerning APS's proposed rate names. (Staff RBr. at 16.) To date, no such filing appears to have been made.

c. APS Response

APS opposes RUCO's proposed names because APS's recommended names are based on a "data driven, utility best practices, and customer-focused approach." (APS Br. at 83.)

d. Resolution

Although we are surprised that APS felt it necessary to hire a consultant to create the names that it now proposes, we find that the proposed names are a significant improvement over the presumably marketing-inspired names that APS unilaterally selected[478] after the 2016 Rate Case. Nonetheless, we have some misgivings about calling the Basic rates a "Flat Rate," because that could be misinterpreted to mean that the bill will be the same each month regardless of usage, which obviously is not the case. Additionally, we note that IBM did not make a recommendation concerning the R-Tech tariff, which we believe could also use a more informative name. Thus, in keeping with IBM's caution not to use the term "Basic," we will require APS to adopt the following rate names:

[478] Ex. S-9 at 4.

Current Tariff & Rate Name	APS-Proposed Name
R-XS – "Lite Choice"	As combined into one tariff: "Fixed-Energy-Charge Plan"
R-Basic – "Premier Choice"	
R-Basic L – "Premier Choice Large"	
TOU-E – "Saver Choice"	"Time-of-Use 3pm-8pm Weekdays"
R-3 – "Saver Choice Max"	"Time-of-Use 3pm-8pm Weekdays with Demand"
R-Tech – "Saver Choice Tech"	"Technology Time-of-Use with Demand"

B. CEOP & Bill Simplification

Section (III)(E) above describes in some detail the analyses that occurred as a result of concerns regarding the effectiveness of the CEOP APS was required to implement after the 2016 Rate Case, which resulted in Decision No. 77270 and four separate consultants' reports—the Overland Report, the Alexander Report, the EnergyTools Report, and the Guidehouse Report. Decision No. 77270 imposed on APS a number of requirements for APS to implement, as described in Section (III)(E), among them that APS fund and implement a CEOP to educate its customers on all aspects of APS's rate plans and fund and organize a stakeholder group to collaborate and suggest better ways to communicate with residential customers concerning rate plans, the impact of changes and adjustor mechanisms, and ways to reduce energy usage. Although Decision No. 77270 had required Staff to develop (with a consultant) and administer the CEOP, the consultant, Ms. Alexander, recommended that APS be required to create and propose a CEOP consistent with the Alexander Report. APS obtained the Guidehouse Report as an independent analysis of the 2016 Rate Case CEOP and the Alexander Report. (Guidehouse Report at 3.)

1. APS Position

APS maintains that the CEOP implemented following the 2016 Rate Case was not a failure, as asserted by some parties, and that although it was not perfect, it complied with the 2016 Rate Case decision and followed or exceeded industry standards. (APS Br. at 71 (citing Ex. ApS-23 at 2, 16-19, att. MW-03RB; RUCO-13 at 5).) Additionally, APS argues that this rate case and any requirements concerning a new CEOP should be prospective in nature. (APS Br. at 72.) APS further states that it has carefully considered Staff's recommendations concerning the new CEOP and believes that it is

appropriate to adopt some of those recommendations, although not all of the recommendations in the Alexander Report, which APS describes as "incorrect and unreliable." (APS Br. at 72.) APS asserts that it is applying what it learned from the 2016 Rate Case CEOP to develop and implement a new CEOP that aligns with industry best practices, behavioral science, customer research, and performance measurements. (APS Br. at 72 (citing Ex. APS-23 at 2-3, 20-30; Ex. APS-24 at 6-7).) APS further asserts that the new CEOP includes direct and frequent communications with customers on topics such as rate plan options, customer assistance, billing and payment programs, and EE. (APS Br. at 72 (citing Ex. APS-23 at 2-3, 20-30; Ex. APS-24 at 6-7).)

In defense of its 2016 Rate Case CEOP (and perhaps the aftermath of the 2016 Rate Case generally), APS notes that in the 2016 Rate Case it had proposed to transition residential customers to what would be their lowest cost plans based on prior usage rather than their "most-like" plans, but that this was not what the settlement adopted based on Staff's and other parties' objections. (APS Br. at 72 (citing the 2016 Rate Case application and direct testimonies from the 2016 Rate Case of witnesses for Staff, the Arizona Utility Ratepayer Alliance, EFCA, SWEEP, and Vote Solar).) APS asserts that the CEOP was filed with the Commission and approved by Staff. (APS Br. at 73.) APS further asserts that neither the CEOP nor the rate design from the 2016 Rate Case assumed that customers would select their MEPs more than they had in the past and that APS's proof of revenue assumed an MEP adoption rate of approximately 53%. (APS Br. at 73 (citing Decision No. 77292 at 75; EnergyTools Report at 55; Guidehouse Report at 55.) According to APS, as of February 28, 2021, 52.5% of customers were on their MEPs. (APS Br. at 73 (citing Ex. APS-84).)

APS disagrees with Staff's recommendation for APS to adopt and implement the recommendations of the Alexander Report, the analysis and conclusions of which APS challenges through the Guidehouse Report; the Overland Report; and the testimony of Ms. Lockwood, Ms. Whiting, and Mr. Snook. (APS Br. at 74 (citing Ex. APS-2 at 9-11; Ex. APS-23 at 16-19; Ex. APS-29 at 7-8).) APS also argues that Ms. Alexander lauded APS's CEOP before the California PUC in 2018 and in its brief provides quoted language purported to be from Ms. Alexander's testimony, although

that testimony is not a part of the evidentiary record in this matter and will be disregarded.[479] (APS Br. at 74-75.) APS emphasizes that the Overland Report found APS's CEOP to be reasonable and understandable and that the Guidehouse Report identified "inappropriate comparisons and omissions of crucial facts" and found that APS's CEOP was at or above industry standards. (APS Br. at 74 (citing Overland Report at 5; Guidehouse Report).) APS asserts that the Guidehouse Report identified "two errors and six necessary clarifications to key points in the Alexander Report."[480] (APS Br. at 75-76.) APS asserts that the recommendations in the Alexander Report should not be adopted or implemented and that the Guidehouse Report, Overland Report, and testimony herein should instead be given greater weight. (APS Br. at 77.)

Additionally, APS asserts that it has implemented or is in the process of implementing a number of recommendations from the various consultants' reports, including some from the Alexander Report, as APS strives "to deliver year-over-year improvement in overall customer satisfaction by advancing an industry-leading customer experience for APS customers." (APS Br. at 77.) According to APS, its approach is also informed by utility education and outreach best practices; customer research from J.D. Power, IBM, and Guidehouse; and customer behavioral science. (APS Br. at 77-78.)

APS provided the following specific responses to recommendations identified as being made in the Alexander Report:[481]

Recommendation	APS Position
APS should notify customers before they are moved to a different rate.	If the Commission approves APS's proposals, APS will not be moving customers between rates.
APS's future CEOP should be developed with frequent and substantive interaction with stakeholders.	APS holds regular CAB and stakeholder meetings covering topics such as the disconnection moratorium, rate design, and customer education, and throughout the new CEOP development process will seek customer and stakeholder feedback through a structured process. APS is adding new graphic and visual functions to its website that will be tested with the CAB, Stakeholder Working Group, and customers before implementation. APS is using a data-driven approach with stakeholder input for

[479] This testimony before the California PUC was not offered as an exhibit in this matter and was not made available by APS before, during, or after the hearing.
[480] The issues with the Alexander Report identified in the Guidehouse Report are described in Section (III)(E).
[481] APS Br. at 78-81 (citing Ex. S-11 at 10-11; Ex. APS-23 at 3, 4-9, 20-24; Ex. APS-24 at 2-3; Ex. APS-26 at 1-2; Tr. at 3891-3892, 4754-4759; Decision No. 77270 at 9; Decision No. 77849 at 9).

	its new rate names and simplified bill. APS will establish a formal customer experience strategy, with annual customer improvement work plans, and will focus on communicating customer assistance programs and customer care, including for customers' phone and digital experiences.
APS should greatly expand its reporting to the Commission, with eight types of recurring reports related to the new CEOP.	APS already provides many of the reports to comply with Commission decisions, such as Decision No. 77270's requirement for APS to report quarterly on the status of its CEOP, including stakeholder engagement efforts, customer plan selection, and changes in usage patterns since implementation of the new rate plans and Decision No. 77849's requirement for APS to report quarterly its numbers for disconnections, customers with arrearages, accounts in payment arrangements, and customers in compliance with payment arrangements. APS believes that the additional reporting recommended in the Alexander Report is unnecessarily detailed, unduly burdensome, and overly specific to very narrow issues and asserts that Staff was unable to identify a purpose for the data that would be provided and acknowledged that the recommended reporting did not have an expiration date. APS also asserts that reporting requirements should provide meaningful insight into customer service or meaningfully help track the customer experience over time, which the additional reports would not do.
APS should integrate its CEOP with its limited income programs, DSM programs, and consumer protections.	APS asserts that it has done this and has either developed or is in the process of developing customer education and outreach to help customers better understand rate plans and manage their usage. For example, since March 2020, APS has been providing on monthly bills a rate plan analysis showing the customer's MEP, monthly savings from the MEP, and cumulative annual savings from the MEP.

2. RUCO

On brief, RUCO criticizes APS for having "a corporate culture that is clearly out of tune with regard to what constitutes good customer service" and for "spend[ing] its time, money and efforts commissioning reports and other means to support its misguided perception of superior customer service" rather than "embrac[ing] the obvious"—which RUCO states is that APS's customer service has been "wholly inadequate for a long time." (RUCO Br. at 12.) RUCO states that it identified the

following as inadequate and unacceptable APS customer service:[482]

- APS failed to establish adequate measures to determine if its CEOP was effective in educating customers about their best rate plans.
- APS had inadequate and confusing customer contacts.
- RC Tool 1 was defective.
- APS "summarily rejected customer advocates' proposals and suggestions."
- The rate plan names were confusing.
- Customer bills were difficult to understand.

RUCO adds that customer complaints are legion and notes that APS tied for last place among 13 West Region utilities in J.D. Power's 2019 ranking. (RUCO Br. at 13 (citing Decision No. 77270 at 7).) According to RUCO, APS changed its incentive compensation metric from J.D. Power to Customer Contact Tracker because of the low ranking, although APS denies that. (RUCO Br. at 13 (citing Ex. APS-23 at 25-26).) RUCO calls the change "a major miscue [that] has only worsened the situation." (RUCO Br. at 14.)

RUCO further characterizes APS's response to the Alexander Report as a "miscue," noting that APS responded to the recommendations in the Alexander Report by commissioning the Guidehouse Report that determined that APS was in a far more favorable position than determined in the Alexander Report. (RUCO Br. at 14 (citing Alexander Report; Ex. APS-23 at 19).) RUCO asserts that the "harsh rhetoric" of the Alexander Report is supported by the Consent Agreement[483] APS recently entered into with the Arizona Attorney General, under which APS will spend $25 million to settle 2016 Rate Case CEOP issues. (RUCO Br. at 14-15 (citing Ex. APS-23 at 19).)

In his testimony, Mr. Fuentes asserted that the Commission should order APS to adopt many of the recommendations of the Alexander Report, including the requirement for a comprehensive CEOP, to be developed with frequent and substantive stakeholder involvement and subject to a formal Commission review process; that integrates rate design education with limited income programs, DSM programs, and consumer protection rights and remedies; and that also includes performance standards

[482] RUCO Br. at 12-13 (citing the Overland Report at 5-7).
[483] The Consent Agreement is Exhibit APS-83.

that are measured and on which APS must report on a quarterly basis. (Ex. RUCO-6 at 9-10, 19.) Mr. Fuentes also recommended that the Commission require APS to pay for the new CEOP without recovery from ratepayers, as ratepayers paid $5 million for the 2016 Rate Case CEOP. (Ex. RUCO-6 at 10, 19.)

Additionally, Mr. Fuentes recommended that APS be required to make quarterly filings regarding its ranking in the J.D. Power Residential Customer Satisfaction Index and specifically within the West Region: Large Segment and, further, that APS be required to file its call center metrics related to call answer times and abandonment rates. (Ex. RUCO-6 at 18.) Mr. Fuentes noted that the industry standard for utility call centers, per the Alexander Report, is for 80% of phone calls to be answered within 30 seconds or less and an abandonment rate of less than 5%. (Ex. RUCO-6 at 18-19.)

RUCO recommends that the Commission approve a simplified customer bill format. (RUCO Br. at 38.) RUCO asserts that the bill format is hard to understand, poorly arranged, and too detailed, with so much information that "it takes on the appearance of white noise" and loses its value. (RUCO Br. at 40 (citing Ex. RUCO-2 at 18-19).) RUCO recommends moving "non-essential parts" of the bill to a new page or to the website where interested customers can go for more information and to enlarge and expand the information about energy usage and comparisons of this year's usage to last year's usage. (RUCO Br. at 40 (citing Ex. RUCO-2 at 19).) According to RUCO, another option would be to allow customers to select whether to receive a simplified or detailed bill. (RUCO Br. at 40 (citing Ex. RUCO-2 at 19).) Mr. Fuentes recommended that APS be required to solicit customer input on the bill redesign from both Spanish- and English-speaking customers. (Ex. RUCO-6 at 10-11.)

3. Sierra Club

Although APS has dropped its request for a waiver to allow for a simplified bill in this case, Sierra Club argues that the Commission should reject APS's bill simplification proposal and instead direct APS (1) to provide customers greater access to energy data and (2) to track specific metrics to measure customers' success in accessing that data. (SC Br. at 45.) Specifically, Ms. Roberto recommended that APS adopt and implement the North American Energy Standards Board's *Energy Service Provider (ESPI) Retail Energy Quadrant Book 21* standards ("Green Button standards"). (SC Br. at 46.) Sierra Club reports that APS has indicated that it intends to implement Green Button

standards by the end of 2021. (SC Br. at 46.) Sierra Club asserts that in addition to implementing the Green Button standards, APS needs to ensure that customers understand the functionality and are able to use it, noting that APS's current online portal is underutilized, with only 5% of APS's customers accessing their energy data monthly and no tracking of what percentage of those customers are able to share their energy data with a third party. (SC Br. at 46 (citing Ex. SC-2 at 25).) Sierra Club recommends that APS begin tracking the metrics recommended in the Alexander Report as well as the following:

- Customer usage of the energy portal (one-time and regularly);
- Number and percentage of customers opting out of or taking a price offering;
- Number of third parties successfully accessing customer data, including:
  - Percentage of customers who are able to authorize third-party requests on the first attempt (goal of 95%), and
  - Percentage of time third-party service providers receive access when authorized (goal of 95%).[484]

Sierra Club further recommends that APS be required to comply with the U.S. Department of Energy's *Data Privacy and the Smart Grid: A Voluntary Code of Conduct* ("*Voluntary Code of Conduct*"), which Sierra Club states complements the Green Button standards and establishes principles for data privacy, including for customer notice and awareness, customer choice and consent, customer data access, data integrity and security, and self-enforcement redress. (SC Br. at 47 (citing Ex. SC-2 at 18).)

Additionally, Sierra Club recommends that the Commission direct APS to investigate and report on whether the investment necessary to provide customers granular energy data from AMI meters (one-, five-, and 15-minute interval data) would be cost-effective, noting that most of APS's AMI meters are only able to record 60-minute intervals. (SC Br. at 47 (citing Ex. SC-2 at 22).)

Finally, Sierra Club asserts that because not all customers have Internet access, and energy data and other important bill information need to be available to all customers, the simplified bill concept

[484] SC Br. at 46-47 (citing Ex. SC-2 at 28-29).)

should be rejected unless it is assured that customers will have access to the necessary information in another format. (SC Br. at 47-48.)

4. Staff

Staff recommends that APS be required to adopt and implement Ms. Alexander's recommendations found at page 36 of the Alexander Report. (Staff Br. at 58.) These recommendations are as follows:[485]

- The Commission should order APS to create and propose a CEOP concerning rate design options, limited income programs, DSM programs, and consumer protection rights and remedies to ensure retention of service.
  - The CEOP should address all of the deficiencies identified in the Alexander Report for the 2016 Rate Case CEOP, particularly the need for ongoing customer research and feedback mechanisms.
  - The CEOP should be required to include performance standards and reporting mechanisms that will allow a meaningful and regular review of APS' progress in implementing the CEOP and achieving its goals and objectives, including at least measuring and quarterly reporting on:
    - Customer-initiated changes to customers' rate plans;
    - APS-initiated changes to customers' rate plans;
    - Number of customers not on their MEPs, by rate class;
    - Frequency and type of complaints;
    - Call center performance;
    - Results of customer research on messaging and bill presentment;
    - Enrollment for limited income programs;
    - Achievement of participation objectives for DSM programs;
    - Analysis of the impact of rate design on system benefits, such as peak load reduction and lower generation supply costs; and

[485] Alexander Report at 36-37.

- Key indicia of credit and collection activities, such as disconnection notices, disconnections, and payment arrangements.
  - The CEOP should be developed with frequent and substantive interaction with customer stakeholders and reflect an obligation for ongoing customer research and feedback mechanisms that will encourage an organic and updated plan and should be subjected to a more formal review process with opportunity for hearings if substantive disagreements cannot be resolved in a collaborative manner.
- The Commission should perhaps regularly consider whether the number and complexity of the current residential rate plans, particularly those with demand charges, should be simplified based on customer feedback and measurements of customer understanding and satisfaction as well as the actual impact of the current plans on reducing peak usage or contributing to lower generation supply costs and whether the move to time-based and demand charge rates for the vast majority of customers is achieving its intended purposes.

Staff also made the following recommendation, which it attributed to the Alexander Report: "In the event a customer is no longer qualified for their current rate plan, APS should notify the customer multiple times prior to the rate change and barring any action by the customer to change to another rate plan, [should provide[486]] a notification that the customer will be moved without explicit authorization to a specific plan on a determined date." (Staff Br. at 58; Ex. S-11 at 10.) The location of this within the Alexander Report is unclear.

Although Staff did not list them in its brief or elsewhere, the Alexander Report primarily identified the following deficiencies, which Staff apparently desires the Commission to direct APS to remedy in its new CEOP:[487]

- APS failed to identify the risks and barriers to achieving the CEOP's intended goals and objective, which included, *inter alia*, that there was only a short time period allowed for education and no significant change in bill presentation, even for demand charges.

[486] We believe that the bracketed words, which were not included, are what Staff intended to convey.
[487] Alexander Report at 3-7.

- APS did not include performance metrics for its CEOP to allow objective determination of its efficacy.
- Because it failed to include the following essential components, the CEOP did not conform to best practices:
  - Performance metrics or other measures of success regarding attainment of the stated goals of the CEOP;
  - Identification of the volume or type of customer inquiries or complaints to include for purposes of validating "touchpoints" as a useful measure of plan success;
  - Tracking of CEOP success by relying on call center call completion, abandonment rate, or other indicia of customer experience despite persistent below average call center performance;
  - Measurement of numbers of customers who signed up for text messages, enrolled in the web portal to view account usage details, or enrolled in budget billing;
  - Establishment of objectives or goals to measure customer behavior resulting from APS communications, including customer switch rates or whether customers were actually put on their MEPs as a result of educational efforts;
  - Research to determine customer comprehension or understanding of APS's communications about new rate plans, plan names, or plan details;
  - Consideration of the demographic characteristics of its customers (housing patterns, family size, educational achievement, literacy, income, and employment situations) in developing its education strategy and communications; and
  - Identification of the special needs of low income customers or special communications channels to reach these customers, coordination with community organizations to educate special needs or vulnerable customers about the rate changes, and funding to community organizations for targeted education and counseling.
- APS relied on its experience rolling out demand rates and demand rate plans; used the same "shift, stagger, and save" messaging that had been in use since 2016; did not include educational content to explain the demand rate plans or how the rate specific criteria to move customers

onto these plans would be explained, and did not discuss in the CEOP the change in peak usage hours from prior TOU and demand rate plans.

- APS did not evaluate the accuracy of its rate plan education for new and moving customers; relied on generic "lifestyle" questions about the square footage of the home, whether appliances are gas or electric, and whether there is a pool or spa; and did not research whether the plan recommendations to new or moving customers were their MEPs.
- The CEOP did not address annual involuntary plan migration due to no longer qualifying for current rate plans, and the level of such plan migration suggests that APS's CEOP is not effective.
- The CEOP did not include a formal plan for ongoing customer education from 2020 and beyond.

Staff also recommends that APS be required to implement the recommendations of the EnergyTools Report,[488] which were summarized as follows in Mr. Connolly's testimony:

> 1. Consider the implementation of an application or graphic showing ratepayers their levels of usage and peak usage ([kWh, kW]), along with specific recommendations on how to manage levels of both types of usage in order to maintain a reasonable demand charge for all the rate plans.
> 2. Consider a high usage alert, compared to peers in the same rate class.
> 3. Consider providing information on the typical consumption of common appliances with an explanation of how to estimate peak demand to determine which time-of-use plan the ratepayer might be more comfortable committing to.
> 4. Consider graphic/visual for ratepayer peak usage estimation.
> 5. Consider providing information on how future deviations in time-of-use could affect a ratepayer's choice of rate plan. Due to the increase in teleworking, customers who anticipate increased time spent at home should consider this apart from the [RC] Tool's recommendations.
> 6. Consider the implementation of an infographic/graph for recommended plans by most common time-of-use for any customer, given an average electric demand. Include similar visual for all plans.
>
> In the area of disclaimers, [EnergyTools] recommends the following:
> 1. Ratepayer forecasts are established based on average usage; therefore, consumers should be informed that any considerable changes in their actual usage cannot possibly be accounted for by the new rate

[488] Staff Br. at 59.

comparison web tool.

2. For customers switching to a demand-based rate plan, any significant peak charges as a result of extraneous circumstances (weather anomaly, or usage anomaly such as throwing a party) cannot possibly be accurately predicted by the [RC] Tool.
3. Rate tool recommendations are based on normal weather patterns and, as a result, any statistically uncommon weather patterns cannot be forecasted and considered when determining a most economical rate plan.
4. The rate tool is driven by prior customer usage and cannot forecast any accumulating charges due to alterations to a ratepayer's residence and/or the addition of electricity consuming appliances such as [Electric Vehicles] EVs.
5. Any significant changes in ratepayer time-of-use due to outside circumstances such as with the increase in teleworking due to the current state of emergency cannot be factored into the web tool's estimates.

In the areas of visual aid recommendations, EnergyTools] recommends a variety of suggestions designed to enhance customer understanding and awareness of such concepts as demand charges, usage[,] and energy costs or saving[s]. Given the format of the examples and source material presented in the [EnergyTools] Report, specific examples are not included here but can be referenced in [the EnergyTools Report]. See pages 45-52.[489]

Subsequently, Mr. Connolly presented the following modification of the first disclaimer, upon which Staff and APS have agreed:

1. The rate comparison tool is based on actual historical usage, therefore, consumers should be informed that any considerable changes in the future cannot possibly be accounted for by the rate comparison web tool.[490]

Additionally, Staff and APS have reached agreement on the following disclaimer language as a replacement for the third disclaimer recommendation:[491]

The tool looks back at up to 12 months of your energy use. It uses this information to estimate what you might have paid over that same period on different service plans and tells you which plan could have saved you the most money. The tool's calculations and estimated savings do not account for things such as bill adjustments, mid-cycle updates, or one-time charges/credits and, therefore, may not match your historic bills. The tool cannot guarantee future savings because it does not account for adjustments to rates/taxes, changes in weather, or changes you make to how you use energy. In fact, since your energy use changes over time, the plan that is estimated to save you the most money can change from month to month.

[489] Ex. S-9 at 3-4 (footnotes omitted). Citation in original.
[490] Ex. Staff-10 at 2; APS Br. at 59; Tr. at 4585-4586.
[491] Staff Br. at 59-60; Tr. at 4590.

> We encourage you to compare plans to ensure you are on the plan that is right for you.[492]

Staff further asserts that "APS agrees with Staff's recommendations that APS adopt graphics and ways to present customer information" and that APS has implemented some of the recommendations already and has indicated that it is in the process of implementing the rest. (Staff Br. at 60 (citing Ex. APS-23 at 5-7).) In its responsive brief, Staff asserts that APS has apparently accepted the EnergyTools Report's recommendations and reiterates Staff's recommendation for the Commission to order APS to comply with the EnergyTools Report's recommendations. (Staff RBr. at 15.)

Finally, Staff asserts that "APS appears to be dedicated to making customer service a priority," quoting the following testimony from Mr. Guldner:

> I think we're taking the right steps internally on being customer focused. It's really reflected in the mission vision values, which we overhauled in 2020, went through a process of adopting what we call the APS promise, and it is focused on being customer-centric and being stewards for our customers in our communities and the state of Arizona. And, so a lot of it is this culture, and I think you're seeing some of the progress that is driving.[493]

Staff asserts that its recommendations for the CEOP and improvements to the RC Tool 2 should be adopted because they are reasonable and necessary and will improve APS's customer service. (Staff Br. at 61.)

In response to APS's criticism of the Alexander Report and its recommendations, and APS's position that the Commission should disregard the Alexander Report and instead rely on the Guidehouse Report and Overland Report, Staff asserts that the Overland Report contained a much less detailed overview of the CEOP than the Alexander Report and that because the Guidehouse Report concluded that APS performed at industry norm or best practice on all five topic areas, "the findings of the Alexander Report [actually] raise significant questions about the Guidehouse Report commissioned by APS." (Staff RBr. at 14.) Staff further points out that although APS has suggested that problems with the 2016 Rate Case CEOP were due to the budget of $5 million, Ms. Whiting conceded that APS was not limited to spending the $5 million granted in the settlement agreement and could have spent additional money if it had believed it to be necessary. (Staff RBr. at 14 (citing Tr. at 2068-2069).)

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[492] Ex. APS-27 at 14.
[493] Tr. at 5273-5274.

Staff concludes that although APS apparently has implemented a more customer-centric philosophy, as well as numerous changes in response to deficiencies identified in Decision No. 77270, "there is more to be done and Staff stands by its recommendation that the Company implement the recommendations and correct the deficiencies contained in the Alexander Report issued in compliance with Decision No. 77270." (Staff RBr. at 14.)

6. APS Response

In its responsive brief, APS thanks Staff, AARP, and Wildfire for acknowledging APS's enhanced customer experience. (APS RBr. at 56 (citing Staff Br. at 60-61; AARP Br. at 3, 6; Wildfire Br. at 2-3).) APS asserts that it has already implemented or is in the process of implementing many of the recommendations from the EnergyTools Report, such as by proposing new rate plan names. (APS RBr. at 57.) APS asserts that because it has already worked extensively on the topics in the EnergyTools Report, no further action is needed on the EnergyTools Report recommendations, particularly because EnergyTools itself stated that "any recommendations that [APS] develops in conjunction with its customer working group and the efforts of that group are probably more useful for [APS] and its ratepayers than the [EnergyTools] recommendations." (APS RBr. at 57-58 (citing EnergyTools Report at 17, 43).) APS did not further address the Alexander Report.

Although APS originally proposed in this case to offer a simplified residential bill that would require waiver of the A.A.C. R14-2-210(B)(2) rule requirement to provide unbundled information, APS is still in the process of creating the simplified bill and no longer requests the waiver. (APS RBr. at 58; Ex. APS-23 at 10.) APS asserts that it is developing the simplified bill as part of its CEOP, with customer and stakeholder involvement, and again has partnered with IBM on the bill redesign, which is to include infographics and information about how to save money. (APS RBr. at 58 (citing Ex. APS-23 at 8; Tr. at 2023).) APS has been seeking customer and stakeholder input throughout the bill redesign process, it says, and IBM is "synthesizing these diverse perspectives" and coupling them with customer and industry research to develop an easy-to-understand and research-based proposed bill. (APS RBr. at 59 (citing Ex. APS-23 at 10).) APS anticipated completing the proposed bill redesign by

Q2 2021 and implementing it around the end of 2021.[494] (APS RBr. at 59 (citing Ex. APS-23 at 9).) Ms. Whiting testified that "APS will keep the Commission informed throughout the redesign and implementation process." (Ex. APS-23 at 9.)

7. Resolution

There are lessons to be learned from the 2016 Rate Case CEOP as well as the Overland Report, Decision No. 77270, the Alexander Report, the EnergyTools Report, and the Guidehouse Report. APS seems to be willing to accept the recommendations in the EnergyTools Report and the Overland Report, but is very much opposed to accepting the recommendations in the Alexander Report. Like APS's prior CEOP, the Alexander Report is not perfect. However, the Alexander Report includes insights into the shortcomings of the prior CEOP and recommendations that will benefit APS and its customers if they are implemented. Rather than requiring APS to adopt the Alexander Report recommendations wholesale, as Staff recommends, along with the EnergyTools Report recommendations, we will direct APS to work collaboratively with Staff, RUCO, and any additional parties who desire to participate on a CEOP for this rate case (and going forward) that addresses the recommendations made in the Overland Report, the Alexander Report, the EnergyTools Report, and the Guidehouse Report. This does not mean that each recommendation must be adopted verbatim, although each recommendation must be addressed. We will require APS to file a copy of the proposed new CEOP in this docket within 60 days after the date of this Decision. With that filing, we will also require APS to include a list of each recommendation/deficiency from each consultant's report (all four of them) along with the actions that APS has taken or intends to take (per the CEOP or otherwise) to address each recommendation/deficiency. After the proposed new CEOP is filed, Staff shall, within 60 days, issue a Staff Report and Proposed Order recommending whether the Commission should approve the proposed CEOP, with or without modifications that shall be fully explained, and, if the recommendation is that the proposed CEOP not be approved, Staff shall fully explain its reasoning.

We will adopt Sierra Club's recommendation to direct APS to investigate and report on whether the investment necessary to provide customers granular energy data from AMI meters (one-, five-, and

[494] This appears not to have happened.

15-minute interval data) would be cost-effective, as this level of granularity could be valuable to customers if it can be cost-effectively attained and made available through APS's website. We will require that investigation and reporting to be completed within 120 days after the effective date of this Decision.

We will not adopt Sierra Club's recommendations concerning Green Button standards, the additional metrics for APS to be required to collect, and adoption of the *Voluntary Code of Conduct*. APS has already indicated that it intends to implement the Green Button standards. The additional metrics will not be valuable to collect unless APS and/or the Commission puts them to some use, and that use has not yet been identified. We are not familiar with the *Voluntary Code of Conduct* and what it requires but will require APS to familiarize itself with the *Voluntary Code of Conduct* and make a filing in this docket thoroughly explaining to the Commission what it would require of APS and why APS should or should not commit to it. We will require this analysis and reporting to be completed within 120 days after the effective date of this Decision.

As stated earlier, we are encouraged by Mr. Guldner's stated commitment to a customer-centric philosophy and customer-centric operational decisions at APS. We expect this to result in APS's being more collaborative and problem-solving, and less defensive, in its approach to the requirements included herein regarding its CEOP and specific additional analyses and reporting. To be clear, we also expect APS to provide its redesigned bill to the Commission for its approval before it is implemented, so that the Commission can discern whether the redesigned bill complies with A.A.C. R14-2-210 and is sufficient and consistent with the convenience of its customers as contemplated by A.R.S. § 40-203 and Article 15, § 3 of the Arizona Constitution.

X. <u>Other Issues</u>

A. Securitization

A number of parties have discussed securitization as a potential means of reducing the costs to customers of APS's future stranded assets and its future clean energy investments. (*See, e.g.,* Ex. RUCO-3 at 12; RUCO Br. at 20-21; Nation Br. at 19; SC Br. at 40.) The cost savings would arise because APS would forgo an equity return on its initial investments and would fund the cost recovery for the assets through the issuance of low-cost asset-backed securities (bonds), secured by a present-

day property right in a defined pool of revenues paid by APS customers. (APS Br. at 111 (citing Ex. APS-2 at 15-16.) According to Sierra Club, "[s]ecuritization has three essential elements: (1) identification of large, well-defined, and non-recurring expenses authorized for recovery; (2) a finance order authorizing ratepayer-backed bonds to 'buy out' the utility's debt; and (3) the creation of a bankruptcy-remote entity responsible for paying the bondholders." (SC Br. at 40.) Sierra Club further asserts that the process for securitization would involve (1) the Commission approving costs as prudently incurred and eligible for recovery, generally through a regulatory asset to be recovered through securitization; (2) the Commission issuing a finance order authorizing the issuance of low-interest ratepayer-backed bonds to buy-out the utility's debt on the asset to be securitized, with the bond amount to become a surcharge on customers' monthly bills that may not be avoided or bypassed by customers; (3) establishment of a limited purpose bankruptcy-remote entity for the sole purpose of the transaction that is responsible for paying the bondholders and will receive as its property the ratepayer surcharge proceeds; and (4) APS taking the securitized asset off of its balance sheet and providing its shareholders full repayment of the invested capital, meaning that the capital would be available for other investments. (SC Br. at 40-42 (citing Ex. SC-2 at 50-52, 57).)

1. APS Position

APS argues that securitization is not currently an option because specific enabling legislation would be needed to protect the special property rights necessary for securitization to be an attractive financial investment for third-party lenders—namely to create intangible property rights for the collateral-securing issued bonds and to establish irrevocability from future impairment of revenues for the issued bonds. (APS Br. at 111 (citing Ex. APS-2 at 17).) APS requests for the Commission to express support for APS's "efforts to pursue the legal structures necessary for successfully implementing securitization for Arizona utility customers" and asserts that the Commission's support would "greatly aid the development of legal structures necessary for securitization to provide future benefits for Arizona electricity ratepayers." (APS Br. at 110, 111.)

Additionally, APS urges the Commission to explore securitization and to reject Sierra Club's position that enabling legislation is not required, arguing that Sierra Club has not made any effort to establish that Arizona law currently addresses the establishment of the intangible property rights and

pledging irrevocability necessary for securitization and pointing out that Ms. Roberto did not profess to have expertise or knowledge concerning how the Commission's constitutional ratemaking authority might relate to securitization and did not know whether securitization has ever been successfully implemented anywhere without enabling legislation. (APS RBr. at 97-98 (citing Tr. at 3120-3121).) APS argues that as a practical matter, "bond rating agencies and transaction underwriters demand assurances that all aspects of a securitization bond offering are supported by a robust legal foundation." (APS RBr. at 98 (citing Ex. APS-2 at 17).) APS argues that Arizona law currently provides no mechanism to establish the intangible property rights to the surcharge revenues that repay bondholders, which serve as collateral, or for the Commission to make a pledge of irrevocability (necessary to provide bondholders assurance that no action will be taken by the state, including the Commission, to impair, reduce, or otherwise adversely affect the bondholder investment). (APS RBr. at 98-99.) APS asserts that without legislation to provide these rights, securitization will not be successful in Arizona. (APS RBr. at 99.)

2. Nation

The Nation urges the Commission to remain open to the potential benefits of securitization for the SCRs and CCT and to adopt it if it can be used to promote the public interest. (Nation Br. at 19-20.)

3. RUCO

RUCO agrees with APS that "legislation is needed to make the securitized bonds marketable and to obtain the low interest rates needed to reduce costs to the utility's customers." (RUCO Br. at 20.)

4. Sierra Club

Sierra Club disagrees with APS and asserts that "[s]ecuritization squarely falls within the Commission's plenary ratemaking authority and thus, no additional authorization is required from the legislature" because securitization is a financing mechanism that dictates how debt is to be recovered. (SC Br. at 43-44.) Sierra Club further argues that even if securitization is not ratemaking, the Commission could institute securitization using its "permissive authority" because it would be "convenient" for APS's ratepayers to save hundreds of millions of dollars, it would be in the public

interest to free up funding for critical programs like CCT, and the legislature has not enacted any legislation on securitization. (SC Br. at 44 (citing Ex. SC-27 at 3).) Nonetheless, Sierra Club asserts, implementing securitization would require careful planning to ensure that it provides the benefits intended. (SC Br. at 44.) Sierra Club recommends that the Commission provide basic consumer protections when issuing any financing order authorizing securitization including by retaining bond counsel or an independent advisor to oversee the transaction, require documentation of consumer savings and rate impacts, and require that the bonds be competitively marketed rather than sold through private negotiations. (SC Br. at 44 (citing Ex. SC-2 at 61-62).) Sierra Club further recommends that the Commission retain an independent expert to evaluate the interest rates that ratepayer-backed bonds could attract in Arizona and which of APS's assets could cost-effectively be securitized. (SC Br. at 44 (citing Ex. SC-2 at 62).)

5. Staff

Staff does not take a position on whether enabling legislation is needed before the Commission may implement securitization. (Staff Br. at 43.) Staff states that the issue of securitization should be thoroughly examined by the Commission and urges the Commission to consider Sierra Club's recommendations concerning retaining consultants with expert legal and technical knowledge in the area to advise the Commission and assist it in navigating through the specialized issues associated with securitization. (Staff Br. at 43-44.) Staff suggests that the Commission could require "utilities" to pay for the expert consulting services, with the consultants' work to be directed and controlled by Staff and no other entity. (Staff Br. at 44.) Staff recommends that the Commission first order "the utilities" to submit securitization plans so that the Commission can review and understand the plans and more clearly determine what would be needed and the likely benefits and potential costs. (Staff Br. at 44.) Staff also recommends that the topic of securitization (as well as costs related to transitioning to clean energy) be addressed in a generic docket. (Staff Br. at 53 (citing Ex. S-15 at 51).)

In its responsive brief, Staff recommends that if APS presents a securitization plan in a future proceeding, the Commission require APS to pay up to $250,000 for Staff consultants with expert legal and technical knowledge in securitization to advise and assist the Commission in navigating the issues. (Staff RBr. at 10.) Staff believes that Sierra Club's suggested requirements for and elements of

securitization should be addressed in a future securitization plan and that the plan must also involve documentation of consumer savings and rate impacts and competitive marketing of the bonds. (Staff RBr. at 40.)

6. Resolution

It is unnecessary for us to engage in a legal analysis concerning the Commission's authority to require or authorize APS to use securitization for recovery of any of its assets because we agree with APS that on a practical level, to make the asset-backed bonds marketable, enabling legislation is needed. The Commission will publicly support APS efforts to obtain legislation that would establish (1) the intangible property rights to the surcharge revenues that repay bondholders and (2) the irrevocability necessary to provide bondholders assurance that no action will be taken by the state, including the Commission, to impair, reduce, or otherwise adversely affect the bondholder investment. This support is conditioned on any legislative bill on securitization not also including other provisions with which the Commission cannot agree, such as provisions that would limit the Commission's legal authority in other ways (aside from making the securitization surcharges inviolate) or in other areas. As securitization is not yet possible, we will not impose any requirements upon APS related to a securitization plan and its elements. We will, however, expect APS to communicate regularly and candidly with the Commission concerning its efforts to obtain legislation and any future securitization plans.

B. 4CPP Replacement; APS's Next IRP

In consideration of our determination on the SCRs, APS's Clean Energy Commitment, and the advocacy of the parties herein such as the Sierra Club and the Citizen Groups, we will require APS to complete, for inclusion in its next IRP, a comprehensive retirement assessment for the 4CPP, including evaluation of retirement of either or both units before 2031. In conducting its assessment, APS shall use realistic numbers for items such as carbon costs, avoidable O&M and capital expenditures, and capacity credits for storage, and APS shall include its justification for using the numbers selected when its IRP is filed.

C. Continuation and Expansion of Solar Communities

In its PTYP, APS included a $24.4 million Solar Communities program (formerly known as

AZ Sun II), which provides APS-owned rooftop solar panels to moderate- and limited-income customers, rural schools, and nonprofits, as authorized in the 2016 Rate Case. (Ex. APS-1 at 16; Ex. APS-39 at sched. B-2.) Under the Solar Communities project, APS takes care of the installation and maintenance of the solar panels, and the customer gets a bill credit for use of the roof space. (Ex. S-7 at 67.) No party advocated for disallowance of the Solar Communities PTYP or for discontinuation of the program.

ASDA requests that the Commission authorize continuation and expansion of the Solar Communities program, asserting that the program is beneficial to both APS and its customers, as it provides low- and moderate-income customers the opportunity to have solar and allows APS to study the impacts of advanced inverters on different modes of operation, ride-through capabilities, and other areas that will be impacted by higher levels of solar penetration on the system. (ASDA Br. at 1-2 (citing Tr. at 1405-1406).) ASDA notes that Mr. Tetlow testified APS would like to expand the program to include nonprofits or multifamily housing serving the same demographic. (ASDA Br. at 2 (citing Tr. at 1306).)

The Commission agrees that the Solar Communities program is beneficial both to APS and to the customers whose homes have solar installations provided and cared for by APS in return for financial consideration. The Commission will not take any action to hinder the Solar Communities program in this case and encourages APS to expand the program as it sees fit, while ensuring that its behavior is not unduly anticompetitive and that its plant investments and their costs are prudent.

D. EV Program & Investment Approval; Take Charge AZ

1. APS Position

In May 2019, APS implemented a pilot program known as Take Charge AZ, under which APS will provide approximately 100 Level 2 EV chargers, at its own cost, to businesses, government agencies, nonprofits, and multi-family communities over a period of five years. (Ex. S-7 at 68; Ex. APS-4 at 9.) Under the program, the participants are responsible for the costs of the energy used from the EV chargers, and customers are encouraged to use the EV chargers during the daytime when solar is plentiful and costs are lower. (Ex. APS-4 at 9.) APS owns and operates the chargers for five years and then gives the customer the option to keep and own the EV chargers or have them removed. (Ex.

S-7 at 68-69.) As of its application, APS had received 75 applications for the program and was starting to install. (Ex. APS-4 at 9.) APS included in PTYP the costs of the Take Charge AZ pilot infrastructure and chargers that were in service during the PTYP period. (Ex. APS-4 at 10; Ex. APS-39 at sched. B-2.)

As a second phase of Take Charge AZ, APS plans to install and own Level 3 (DCFC) EV chargers at five strategic locations outside of the Phoenix metro area along highway corridors,[495] to provide infrastructure support for long-distance EV driving. (Ex. APS-4 at 9; Ex. S-7 at 68-69.) Take Charge AZ DCFC is also to run for five years, and APS anticipated that the Level 3 EV chargers would be installed in the five underserved locations by the end of 2021. (Ex. APS-4 at 9; Ex. S-7 at 69.)

2. ChargePoint

ChargePoint does not oppose APS's requested cost recovery for Take Charge AZ. (CP Br. at 3.) However, ChargePoint[496] urges the Commission to "affirm that APS must seek and receive advance Commission approval for any EV pilot program or EV-related investment in order to receive cost recovery for the program or investment" and to "affirm that it will evaluate future EV-related pilot programs or investments for consistence with the Commission's [EV Plan]" (CP Br. at 2.) ChargePoint asserts that APS's position that it does not need to seek preapproval for future EV-related programs or investments and its seeking cost recovery for an unapproved program (Take Charge AZ) "turns the Commission's regulatory process on its head." (CP Br. at 2.) ChargePoint argues that the Commission must closely supervise APS in the "highly competitive EV charging market" so that APS "supports, and does not distort, this competitive market." (CP Br. at 3.) ChargePoint further asserts that if the Commission does not specifically order APS to obtain preapproval for its EV-related investments, it is reasonable to expect that APS will not seek such preapproval. (CP Br. at 10.)

ChargePoint acknowledges that APS designed Take Charge AZ and selected its DCFC vendor

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[495] The DCFC sites were identified by Navigant Consulting, which identified "10 near-term sites" that would "fill[] the immediate near-term need to complete the DCFC corridor charging network within APS territory, assuming a maximum distance of 115 miles between sites (excluding Tesla sites)" and prioritizing based on traffic demand. (Ex. EVgo-4.)

[496] ChargePoint is one of the world's largest EV charging networks, offering more than 115,000 charging locations, more than 1,100 of which are in Arizona. (Ex. CP-1 at 2.) ChargePoint's customers include workplaces, cities, retailers, apartments, hospitals, and fleets, and ChargePoint's business model is to sell "smart charging solutions" to businesses and organizations while also offering tools for site hosts and station owners to use, including network services and cloud capabilities. (Ex. CP-1 at 2-3.) ChargePoint participated in the development of the EV Plan. (Ex. CP-1 at 4.)

before the EV Plan was approved and asserts that APS thus should not be held to the EV Plan standards to obtain cost recovery in this case. (CP Br. at 3.) However, ChargePoint asserts, the EV Plan clearly demonstrates that the Commission expects utilities to seek preapproval of EV pilot programs before implementation, because the EV Plan encourages utilities "to propose EV pilot programs to the Commission for consideration and *approval* by no later than September 1, 2019," and states that "[c]ost recovery for *approved* EV pilot programs may be addressed in the [utility's] rate case." (CP Br. at 4 (quoting EV Plan).) ChargePoint points out three additional places in the EV Plan suggesting that preapproval of EV pilot programs is required: "[utilities should] develop and propose innovate rate designs . . . applicable to EV charging"; "[utilities should] propose rate design tariffs . . . "; and "[utilities] should develop education and outreach programs for Commission consideration and approval." (CP Br. at 5 (quoting EV Plan).) ChargePoint argues that if the Commission does not affirm that the EV Plan will govern any future EV-related programs, "it would mean that Decision No. 77289 [the EV Plan] is meaningless and that the Commission wasted countless hours of its own time and stakeholders' time developing a document with no legal effect." (CP Br. at 5.)

ChargePoint argues that APS has not supported its argument that preapproval of EV programs would be "an overly prescriptive process" that would "stifle investment and advancement of this technology" and, additionally, that this position is belied by many other states' requiring utilities to receive regulatory preapproval for EV charging-related programs, which ChargePoints asserts is the norm. (CP Br. at 6 (quoting Ex. APS-10 at 5; citing Tr. at 4439-4440).) Mr. Wilson testified that Commission preapproval would likely make APS and competitive EV charging providers willing to make larger EV infrastructure investments in Arizona because APS would know that the Commission found the investments to be reasonable, and the competitive providers would have a greater up-front understanding of the scope and design of APS's programs. (Ex. CP-2 at 5.) ChargePoint warns that "large and unsupervised investments in EV charging infrastructure by utilities have the potential to severely distort the competitive EV charging market and discourage market participation from private entities [that] do not have the luxury of recovering their costs from ratepayers like APS does. (CP Br. at 7 (citing Ex. CP-2 at 12-20).)

ChargePoint argues that APS's position that EV charging infrastructure is like distribution

infrastructure is "demonstrably false" because only APS can invest in and exercise control over its distribution infrastructure, while any APS customer can invest in EV charging equipment and facilitate market transactions with EV drivers. (CP Br. at 3.) Additionally, ChargePoint notes, if EV infrastructure were like distribution system investments, the EV Plan and the EV Policy Statement[497] that preceded it would not have been needed, and APS would not have needed to argue that Take Charge AZ was consistent with the EV Policy Statement, which had been adopted when Take Charge AZ was implemented. (CP Br. at 8.) Further, ChargePoint asserts, unlike distribution infrastructure, EV charging stations facilitate a market transaction for competitive EV charging services. (CP Br. at 8.) ChargePoint argues that the Commission recognized the distinction when it determined in the EV Plan that EV charging station owners and operators are not public service corporations subject to Commission regulation. (CP Br. at 9.) ChargePoint argues that Commission preapproval is not needed for distribution system investments because they do not impact a competitive market, and no competitors could be crowded out by such investments. (CP Br. at 9.)

3. EVgo

EVgo asserts that utility-owned DCFC stations should be focused on serving areas, such as rural areas, that are harder for competitive providers like EVgo to serve, which is consistent with the EV Plan. (EVgo Br. at 10 (citing Tr. at 4415).) EVgo originally proposed that the Commission not approve the Take Charge AZ DCFC pilot unless the APS-owned DCFC stations were to be located at least 31 miles away from any public third-party DCFC station, but now finds that the proposed five locations fill gaps without encroaching on competition. (EVgo Br. at 10 (citing Ex. EVgo-2 at 2).) EVgo encourages APS to work with competitive market participants to obtain experienced siting, installation, operations, and maintenance offerings for any APS-owned EV chargers and to continue exploring other program offerings such as "the make-ready model" or "joint investment model" included in the EV Plan. (EVgo Br. at 10.) Additionally, EVgo supports ChargePoint's position that APS should be required to obtain Commission preapproval of the sites for future APS-owned EV stations, before construction. (EVgo Br. at 10.)

[497] The EV Policy Statement is Decision No. 77044 (January 16, 2019). Official notice is taken of this decision.

4. IBEW Locals

The IBEW Locals expressed support for APS to receive cost recovery for the Take Charge AZ program because APS employs Arizona workers to install and maintain the EV chargers and infrastructure. (IBEW Br. at 8-9.) Additionally, the IBEW Locals oppose ChargePoint's argument that APS must be required to obtain preapproval of its EV-related investments. (IBEW RBr. at 8.) The IBEW Locals argue that the EV Plan does not mandate the electric utilities to proposed EV pilot programs but only encourages the utilities to do so because mandating such proposals "would run afoul of the management interference doctrine as it is not the purpose of regulatory bodies to manage the affairs of a corporation." (IBEW RBr. at 8 (citing *Southern Pac. Co. v. Ariz. Corp. Comm'n*, 98 Ariz. 339, 342-343 (1965); *State of Missouri ex rel. Southwestern Bell Tel. Co. v. Pub. Serv. Comm'n of Missouri*, 262 U.S. 276, 289 (1923); *Duquesne Light Co. v. Pennsylvania Pub. Util. Comm'n*, 63 A.2d 466 (Pa. 1949); *Miller v. Arizona Corp. Comm'n*, 227 Ariz. 21, 27 (Ct. App. 2011)).) The IBEW Locals argue that ChargePoint is requesting the Commission to engage in the undue interference of APS's managerial functions by supplanting APS's determinations of what costs to incur for EV-related programs or investments. (IBEW RBr. at 9.) The IBEW Locals assert that the Commission has the authority to review these determinations in a rate case to assess prudency, requiring preapproval would run afoul of the management interference doctrine. (IBEW RBr. at 9.)

5. APS Response

APS disagrees with ChargePoint and EVgo that APS should be required to obtain preapproval from the Commission before implementing future EV charging programs. (APS RBr. at 17.) APS argues that an "overly prescriptive process can stifle investment and advancement of EV technology" and that investment in EV infrastructure is similar to investment in distribution system infrastructure and should be treated in the same way—i.e., should not require preapproval. (APS RBr. at 17 (citing Ex. APS-10 at 4).) Further, APS asserts, Commission preapproval is not required by the EV Plan. (APS RBr. at 17 (citing Ex. APS-11 at 9-10).)

Additionally, APS opposes EVgo's proposal for APS to be required to ensure that there are at least 31 miles between APS-owned and other DCFCs, because the purpose of Take Charge AZ is to enable EV adoption by placing DCFCs in locations that do not have DCFCs, and placing a DCFC near

another DCFC is inconsistent with the program's goals and not planned by APS. (APS RBr. at 17-18 (citing Ex. APS-11 at 10).) APS urges the Commission to deny a mileage requirement because it could unnecessarily restrict APS's decision-making in a way that is not in its customers' best interests. (APS RBr. at 18.)

5. Resolution

Because the Take Charge AZ pilot program predated the EV Plan, there is no question that APS was not required to obtain prior approval of the pilot program from the Commission.

Reviewing the EV Plan, we conclude that the Commission has imposed several requirements (i.e., mandates), while also providing numerous discretionary "guidelines," as is the stated intent of the EV Plan. Those mandates are:

> [T]he prudency of incurred costs [for approved EV pilot programs] shall be evaluated [in a PSC's rate case].
>
> If PSCs provide turn-key EV charging station solutions for end users, it must be done in a manner that supports a competitive marketplace. Site hosts must have the option to choose from a qualified vendor and product list which chargers they want installed.
>
> . . .
>
> As part of the pilot program, a PSC shall allow vendors to submit proposals for EV infrastructure for each area that has been identified as having inadequate coverage. The PSC shall utilize a Request for Proposal process that includes an independent monitor in the review and selection process in consultation with Staff.
>
> . . .
>
> PSCs shall coordinate and jointly develop, with stakeholder input, a joint, long-term, comprehensive transportation electrification plan for Arizona, to be filed by December 31, 2019, for Commission review and approval. . . . The comprehensive plan shall incorporate goals and metrics for evaluating success, and the PSCs shall report publicly on a semi-annual and annual basis on their progress, achievements, budget, and expenditures.[498]

Although the EV Plan encouraged utilities to propose EV pilot programs for Commission consideration and approval, it did not require such submission or condition cost recovery in a utility's rate case on preapproval. Had the Commission chosen to impose such a restriction in the EV Plan, it would have done so clearly, as it did for the mandates quoted above. Thus, we will not require APS to submit its

[498] EV Plan at §§ (3)(a), (6)(c), (6)(f), (8).

EV-related pilot programs for Commission preapproval, although we encourage APS to do so to ensure that the Commission considers its pilot programs to conform to the mandates of the EV Plan, such as the mandate for turn-key EV charging station solutions to support a competitive marketplace. Because we do not need to reach the management interference doctrine argument to resolve this issue, we decline to analyze it.

E. Base Cost of Fuel & Production Related Chemicals

APS's actual average TY base cost of fuel and purchased power was 3.2112¢/kWh. (Ex. APS-28 at 18.) APS originally proposed to retain its current base fuel rate of 3.0168¢/kWh, which had been approved in the 2016 Rate Case, because it anticipated any changes to be very modest and within 0.05¢/kWh. (Ex. APS-28 at 18.) APS also proposed to retain its currently authorized rate of 0.0500¢/kWh for production-related chemicals recovered through the PSA, because its current expense was within 0.01¢/kWh of that rate. (Ex. APS-28 at 19.)

On rebuttal, APS adopted an updated base cost of fuel of $3.1451¢/kWh, which it had provided in a data response and Staff had adopted on direct. (Ex. APS-29 at 10; *see* Ex. S-12 at 59, att. RCS-2 at sched. C-11.) Staff states that the updated fuel cost was based on market pricing as of May 29, 2020. (Staff Br. at 20.)

No party other than Staff briefed the base cost of fuel, and it was not a disputed issue during the case.

We conclude that APS's base cost of fuel is $3.1451/kwh and that its base cost for production-related chemicals is 0.0500¢/kWh.

F. Distribution System Reliability & Reporting

1. Staff Proposal

Staff's engineer concluded that APS was properly operating and maintaining its electric system, was carrying out distribution system improvements appropriately, has system losses that are acceptable and within industry standards for electric utilities with comparable service areas, has reasonable and appropriate outage-reduction programs, and has reasonable and appropriate meter replacement practices and procedures. (Staff Br. at 54 (citing Ex. S-7 at exec. summ.); Ex. S-7 at 77.) Based on APS's outage data and Institute of Electrical and Electronics Engineers ("IEEE") benchmarking

studies, Staff concluded that APS's service reliability data is consistent with that of other utilities. (Ex. S-7 at 19.) Staff noted, however, that in the 2016 Rate Case, Staff recommended for APS to set its target for System Average Interruption Frequency Index ("SAIFI")[499] at 0.80 and its target for System Average Interruption Duration Index ("SAIDI")[500] at 75 minutes and that APS had not met those targets. (Ex. S-7 at 19.) Staff reported that excluding major event days, from 2013 through 2018, APS reported that its system on average had a SAIFI of 0.808 and a SAIDI of 80.8 minutes and from 2015 through 2019, APS reported that its system on average had a SAIFI of 0.77, a SAIDI of 76.8 minutes, and a Customer Average Interruption Duration Index ("CAIDI")[501] of 96.1 minutes. (Ex. S-7 at 19.) Mr. Belavadi testified that a SAIFI of one or less and a SAIDI of 90 minutes or less is generally considered to be a satisfactory level of reliability. (Ex. S-7 at 19.)

After reviewing APS's most recent IRP, Mr. Belavadi performed an analysis comparing APS's load forecasts to APS's actual customer and load growth for 2015 through 2019 and determined that while APS's customer counts had steadily increased at an annual average rate of 1.7%, APS's system peak demand had decreased at an annual average rate of 1% per year, and its energy delivered remained largely the same (decreasing at an annual average rate of 0.1%). (Ex. S-7 at 5-6.) Mr. Belavadi found that for 2020 through 2024, APS had projected system peak demand to grow by 625 MW (or 8.62%) and energy delivered to grow by 4,226,492 MWh (or 14.67%). (See Ex. S-7 at 7.) Through his comparison analysis, Mr. Belavadi determined that APS's forecasted demand was "aggressive and uncharacteristic of historical trends." (Ex. S-7 at 11.) Mr. Belavadi also found that the APS projections of peak demand and energy needs in its IRP were inconsistent with those projections in this case, with the projections in this case being higher. (Ex. S-7 at 11.) Mr. Belavadi opined that APS's forecasted load and demand growth are unlikely to occur and that APS's future projects were more "likely to be related to system reinforcement and grid modernization rather than . . . meeting peak demand and load growth." (Ex. S-7 at 11.) Mr. Belavadi opined that a revised load forecast was needed. (Ex. S-7 at 12.)

According to Mr. Belavadi, APS attributed recent trends in its Reliability Indices ("RI") (e.g.,

[499] SAIFI measures the number of times the average customer experiences a power interruption. (Ex. S-7 at 17.)
[500] SAIDI measures the total duration of an interruption to the average customer on an annual basis. (Ex. S-7 at 17.)
[501] CAIDI measures the average time to restore service. (Ex. S-7 at 17.)

SAIFI, SAIDI, CAIDI) to weather and storm-related events as well as a new fire risk mitigation program that leads to longer restoration times for feeders classified as "high fire risk" because of additional precautionary steps that must be taken. (Ex. S-7 at 20.) When APS disaggregated the fire risk mitigation program impacts, Mr. Belavadi stated, APS's 2019 SAIFI was 0.74 and its 2019 SAIDI was 78.8 minutes. (Ex. S-7 at 21.) Mr. Belavadi determined that APS tracks and maintains "robust data" on outage metrics, generally performs a root-cause analysis to understand trends and perform mitigation measures, and reported that it was actively trying to improve restoration times through data-driven practices and multiple programs. (Ex. S-7 at 21.) Staff determined that APS's leading cause of outages was underground ("UG") cable failure, which APS was addressing through Planned UG Cable Replacement and Unplanned UG Cable Replacement Programs. (Ex. S-7 at 23.) Staff also determined that wildlife-related outages were not uncommon. (Ex. S-7 at 23.) Staff concluded that APS's outage reduction programs are reasonable and appropriate, but expressed concern that excessive heat could impact some of the root causes of APS's outages and indicated that APS should prioritize exploring additional strategies and programs that target reducing the frequency and duration of outages during times of excessive heat. (Ex. S-7 at 29-30.) Further, Staff determined that APS's Metro, Southeast, and Southwest Divisions had the longest interruption durations and that APS's Metro, Southeast, and Southwest Divisions had the most frequent service disruptions. (Ex. S-7 at 39-41.) Staff also determined that in 2019, the Payson and Prescott areas (within the Northeast and Northwest Divisions, respectively) had more of APS's "worst performing feeders" than APS's other areas as well as a higher number of customers affected by those feeders. (Ex. S-7 at 42.) Staff expressed concern about APS's tracking of customer-level transformer failures, because APS was not tracking the age of the transformers at the tie of failure, and also observed a trend of higher transformer failures during summer months. (Ex. S-7 at 61.)

Staff recommends the following:

1. Staff recommends that APS sets its targets for SAIFI and SAIDI at 0.80 and 75 minutes, respectively.
2. Staff recommends that within one year of a Decision in this case, APS file, as a compliance item in this docket, a report that details its load forecasts and actual power delivered from 2010 to 2020, and describes the reasons forecasts were inaccurate and what actions are being taken

to improve its forecasts year-over-year.

3. Staff recommends that APS submit a report annually, beginning one year from the date of the Decision in this case, to Staff that includes: its system-wide RI; the RI disaggregated by division and district; actions taken to improve its RI; a summary of reliability programs that are in place to improve its RI; and a summary of projects and facilities, and their costs, placed into service that aim to improve reliability.
4. Staff recommends that within one year of a Decision in this case, APS develop and implement a program(s) that investigates the impact of excessive heat on the outage root causes listed in Table 10 [of Exhibit S-7], and specifically target reductions in frequency and duration of outages that occur in areas susceptible to excessive heat. Furthermore, Staff recommends that APS file a summary of the results of this program(s) annually, as a compliance item in this docket.
5. Staff recommends that APS be directed to meet with Staff annually to provide an overview of its strategies to reduce outages in its Metro, Northeast, and Northwest divisions.
6. Staff recommends that APS expand its 'Transformer Failure Tracking' program to track the service life of the transformers at the time of failure, investigate the higher transformer failure rate during the summer months and implement proactive measures to reduce the same.
7. Staff recommends that the case be left open for a period of 12 months, to address any unforeseen events. As stated, Staff was unable to perform an on-site inspection due to the Covid-19 pandemic. Although Staff performed a virtual inspection of the facilities, Staff may perform such inspection at a later date. This will enable Staff to make any appropriate recommendations, if necessary.[502]

In response to APS's objection to Staff's recommended SAIDI and SAIFI targets, Ms. Little pointed out that the targets are not mandates and, further, that APS's outage durations have not improved in a meaningful way in the past few years. (Staff Br. at 55 (citing Ex. S-8 at 5-7).) Staff argues that APS is responsible for providing safe and reliable service to its customers and has the management discretion to take actions to ensure the provision of such service. (Staff Br. at 55.) Staff further asserts that its SAIDI and SAIFI recommendations are reasonable, will help to ensure reliable service to APS customers, and should be approved. (Staff Br. at 55-56.)

In response to Mr. Tetlow's testimony that APS has not observed a strong correlation between asset age and failure, Staff argues that he did not say there was no correlation. (Staff Br. at 56.) Additionally, regarding excessive heat impacts, Staff notes that Summer 2020 was hotter than normal and that Staff believes excessive heat could impact root causes for and be a factor in an increase in

[502] Ex. S-7 at 77-78.

outages. (Staff Br. at 56.) Finally, in response to APS's opposition to Staff's additional recommended reporting requirements, Staff notes Ms. Little's testimony that because Staff is responsible for monitoring and reporting to the Commission on the condition and reliability of APS's system, Staff is in the best position to know what information it needs. (Staff Br. at 56 (citing Tr. at 4806-4807, 1353).) Staff also notes Mr. Tetlow's acknowledgment that adoption of the Staff reporting recommendations would not have a detrimental impact on APS or its customers. (Staff Br. at 56.) Staff urges the Commission to adopt all of its engineering recommendations, which Staff asserts will help ensure reliable service to APS's customers. (Staff Br. at 57; Staff RBr. at 13.)

2. APS Response

APS did not brief the issue. In his testimony, Mr. Tetlow stated that APS supports a number of Staff's recommendations, but believes that some would not bring value. (Tr. at 1401-1402.) Specifically, APS did not support the recommended SAIFI and SAIDI targets or the additional program/reporting regarding excessive heat impacts and transformer failure. (Ex. APS-10 at 9-10, 24-25.) Mr. Tetlow testified that APS was implementing an analysis tool to improve its ability to study transformer failures as needed to inform asset maintenance and replacement strategies and, further, that its maintenance decisions are guided by the goal of maintaining top quartile reliability performance. (Ex. APS-10 at 23.) Mr. Tetlow suggested an alternative format for data sharing that he believed would be less burdensome and possibly more useful. (Ex. APS-10 at 10.) Mr. Tetlow proposed that APS provide Staff an Annual Reliability Report including: (1) Overall system reliability performance, (2) Performance by geographic region, (3) System analysis and reliability impact by top outage cause code types, (4) Description of planned reliability maintenance programs, and (5) Fire mitigation seasonal impacts. (Ex. APS-10 at 25.) Additionally, APS did not support the idea of Division- or region-specific outage programs because it uses data to maintain awareness of the system's health holistically and asserted that the regional performance issues in Payson and Prescott in 2019 were directly related to APS's fire mitigation efforts. (Ex. APS-10 at 26.) Mr. Tetlow testified that Commission adoption of all of Staff's reporting recommendations would not have detrimental effects on APS or its customers but would cause unnecessary questions and extra paperwork. (Tr. at 1401-1402.)

. . .

3. Resolution

We view APS's lack of briefing on this issue as an indication that APS acquiesces in Commission adoption of Staff's seven enumerated engineering-related recommendations set forth above. Nonetheless, we conclude that recommendation #1 is unnecessary, as APS is already aware that the Commission expects it to provide reliable service and also of what the Commission considers to be reliable service. APS has every incentive to meet or exceed the SAIDI and SAIFI targets proposed by Staff, and the Commission does not believe it is necessary to impose these external targets.

Additionally, we conclude that recommendation #7 is unnecessary. This docket is already being held open for other purposes, as set forth above.

We will require APS to comply with Staff recommendations #2 through #6.

G. Performance-Based Ratemaking

No party recommends that the Commission adopt performance-based ratemaking ("PBR") in this case, and most parties (including, e.g., APS, RUCO, and Staff) did not brief PBR.

1. Sierra Club

In its brief, Sierra Club does not recommend that the Commission implement PBR in this case, but did recommend that the Commission consider PBR, which could incorporate two key tools: (1) multi-year rate plans, which Ms. Roberto testified would de-link APS's revenues from its actual costs and thus remove APS's incentive to increase rate base; and (2) performance-incentive mechanisms, which Ms. Roberto stated can be useful to promote desired outcomes like emissions reduction or grid modernization. (SC Br. at 48 (citing Ex. SC-2 at 42, 44).) Sierra Club notes that the Commission already has opened a new docket related to PBR, Docket No. E-00000A-20-0019 ("PBR Docket"), and recommends that the Commission direct APS, in this case, to begin tracking metrics that would assist the Commission in its investigation of PBR, including the metrics recommended in the Alexander Report, the metrics recommended by Ms. Roberto in reference to the CEOP and bill simplification, and the kWh of energy APS assists customers in saving relative to the kWh of energy APS sells. (SC Br. at 46-47, 49.) Sierra Club asserts that requiring APS to begin tracking these metrics now would provide APS adequate notice and establish the necessary baseline of performance from which APS can improve. (SC Br. at 49.)

2. WRA/SWEEP

WRA/SWEEP argue that Arizona's current utility business model that allows utilities to recover their cost of service plus a fair return is "outdated, overly focused on revenue recovery, and 'incentivizes utilities to promote sales growth and grow rate base through capital additions, while not focusing on the value of service to customers.'" (WRA Br. at 26 (quoting Ex. WRA-1 at 51).) WRA/SWEEP assert that PBR is an alternative approach to revenue recovery, which Mr. Baatz described as follows:

> PBR is generally made up of two parts, a formula rate or revenue recovery mechanism and a performance incentive mechanism. The formula rate allows a utility to recover prudently incurred costs in a timely manner. Customers are protected from overearning because revenues are reconciled with actual costs and sales, meaning customers are only charged for costs that are actually incurred. Formula rates, through well-defined protocols, also can reduce rate case expense and litigation that typically comes with traditional rate cases.[503]

WRA/SWEEP list Illinois, Massachusetts, Minnesota, and Hawaii and states in which PBR is being used or developed for use. (WRA Br. at 27-28.) WRA/SWEEP recommend that the Commission proceed with a generic investigation into PBR, in the PBR Docket, and urge the Commission to hold workshops in the docket to explore ways PBR could be used in Arizona to improve utility performance and customer service by tying utilities' earnings to performance measured using metrics such as emission reductions, customer satisfaction, reliability, and EE. (WRA Br. at 28.)

3. Resolution

We agree that PBR is an area that should be investigated further in the PBR Docket and will not take any action to implement PBR in this case. We will defer to the PBR Docket our consideration of additional reporting requirements to establish baseline performance for PBR.

H. Bring-Your-Own-Device Tariff

In its responsive brief, APS stated the following on this topic:

> In July 2020, Commissioner Márquez Peterson asked interested parties to address in this rate case Bring-Your-Own Device (BYOD) tariffs and incentives related to distributed energy resources including such programs as community solar and storage, demand-side load management,

[503] Ex. WRA-1 at 59.

> and energy trading and aggregation. As required by Decision Nos. 77855, 77762 and 77958, APS is working with stakeholders, including Staff and Lawrence Berkeley National Laboratory, to develop a distributed demand-side resource aggregation tariff (DDSR Aggregation Tariff). The DDSR Aggregation Tariff will provide customers with BYOD options to provide energy services to APS's grid with technologies such as connected smart thermostats, water heating controls, pool pump controls, managed EV charging, and battery energy storage. Each of these BYOD DDSR options are currently available or will be offered through APS's DSM programs. Staff recommends addressing these topics within the context of the Commission's already established Demand-Side Management or Renewable Energy Standard dockets. APS agrees with this approach.[504]

At a Staff Open Meeting on June 9, 2021, the Commission voted to have Staff prepare an amended order to extend APS's deadline to file its proposed DDSR Aggregation Tariff to May 1, 2022.[505] The Staff Memorandum and Order was scheduled to be considered by the Commission at its Open Meeting commencing on July 13, 2021.[506] The Commission considered and approved the Staff Order with verbal amendments at its Open Meeting on July 14, 2021, and Decision No. 78165 was issued on July 28, 2021, granting the extended deadline.[507]

We conclude that it is most appropriate for the Commission to consider the BYOD DDSR options in Docket No. E-01345A-19-0148.

I. Retail Electric Competition

In its responsive brief, APS stated the following on this topic:

> In September 2020, Commissioner Olson asked the parties in this case to address the topic of retail electric competition. This is currently an open docket regarding retail electric competition, Docket No. RE-00000A-18-0405, and the record in that docket shows that retail electric competition would have far-reaching impacts for ratepayers across Arizona that go beyond the scope of this rate case. For these reasons, APS agrees with Staff that retail competition is best addressed within that currently existing docket.[508]

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[504] APS RBr. at 99-100 (citing Ex. S-11 at 11, att. PWM-1, att. PWM-3; Decision No. 77762 (October 2, 2020); Decision No. 77855 (December 31, 2020); Decision No. 77958 (April 15, 2021); Ex. APS-26 at 39).) Official notice is taken of Decision No. 77855 and Decision No. 77958. Decision No. 77855 granted APS an extension of the deadline imposed by Decision No. 77762 for APS to file its DDSR aggregation tariff, from December 2, 2020, to April 1, 2021. Decision No. 77958 granted APS another extension of the filing deadline for its DDSR aggregation tariff, until May 1, 2021.

[505] Official notice is taken of Staff's Memorandum and Order filed in Docket No. E-01345A-19-0148 on June 29, 2021.

[506] Official notice is taken of the Revised Notice of the Open Meeting filed in Docket No. E-01345A-19-0148 on July 9, 2021.

[507] Official notice is taken of the Commission's actions, which may be viewed at the beginning of the archived video for July 14, 2021, available at azcc.gov/live. Official notice is taken of this decision.

[508] APS RBr. at 100 (citing Ex. S-11 at 12, att. PWM-3; Ex. APS-29 at 26).

As stated in the Procedural Order issued in this case on October 1, 2020, retail electric competition is a statewide issue appropriately resolved in a docket that applies to utilities other than APS and allows for stakeholder involvement broader than that available in a rate case. Thus, we will continue to consider retail electric competition in Docket No. RE-00000A-18-0405.

J. Undisputed Issues

Because of the sheer volume of contested issues in this matter, this Decision generally does not discuss undisputed issues. This should be understood as acceptance of the resolution of the issue that underlies the other determinations made herein. This should not be understood as any undiscussed undisputed issue's having been fully litigated and provided an express approval by the Commission.

J. APS's Next Rate Case

This rate case was unwieldy due to the number of parties, the number of disputed issues, and the volume of the exhibits involved. Several other circumstances also made this rate case more difficult than it needed to be, and we request that APS and future rate case participants remedy these before the next rate case:

- APS's total company schedules and jurisdictional schedules are presented together rather than segregated. This makes it more difficult to locate the correct information, as the Commission is primarily concerned with jurisdictional amounts rather than total company amounts. In its next rate case, APS should provide these schedules separately—such as by using one binder for total company schedules and a separate binder for jurisdictional schedules.
- APS and some other parties described some of their adjustments in testimony and related attachments using total company numbers. Some parties even did this in briefs. This makes it more difficult to discern the correct information and the party's position, as the Commission makes its adjustments based on jurisdictional amounts.
- APS did not consistently reveal in its schedules the allocation factor that it used to determine jurisdictional amounts, which is a problem because the allocation factors in different areas differ significantly.
- APS and other parties that provided electronic schedules to the Hearing Division did not

provide all of the workpapers linked in the schedules, did not consistently provide explanations for plugged in numbers without links, and did not provide adequate explanations of some numbers within their "supporting" workpapers. The electronic schedules and the workpapers linked therein are all supposed to be provided, and the workpapers are supposed to explain thoroughly (i.e., break out and support) the numbers to which they pertain.

FINDINGS OF FACT

1. The procedural history for this matter set forth in Section II of the Discussion portion of this Decision is accurate and we adopt it in its entirety as though set forth fully here.

2. The background information set forth in Section III of the Discussion portion of this Decision is accurate and we adopt it in its entirety as though set forth fully here.

3. The description of APS's amended application set forth in Section IV of the Discussion portion of this Decision is accurate and we adopt it in its entirety as though set forth fully here.

4. The background information, descriptions of parties' positions, and evidence described in Sections V, VI, VII, VIII, IX, and X of the Discussion portion of this Decision are accurate and we incorporate them as though set forth fully here.

5. The resolutions reached in the various subsections within Sections V, VI, VII, VIII, IX, and X of the Discussion portion of this Decision were reached after consideration of the evidence presented in this matter and the information officially noticed under A.A.C. R14-3-109(T), as well as existing laws (the Arizona Constitution, statutes, rules, and case law, as applicable), and are just and reasonable and in the public interest. We incorporate the resolutions as though set forth fully here.

6. The rates and charges and terms and conditions of service resulting from the resolutions described in Findings of Fact No. 5 are just and reasonable and in the public interest.

7. The rates, charges, and terms and conditions of service resulting from the Commission's resolution of the issued herein do not result in "discrimination in charges, service, or facilities . . between persons or places for rendering a like and contemporaneous service" under Article 15, § 12 of the Arizona Constitution.

8. The rates, charges, and terms and conditions of service resulting from the Commission's

resolution of the issues herein do not "make or grant any preference or advantage to any person or subject any person to any prejudice or disadvantage" and do not "establish or maintain any unreasonable difference as to rates, charges, service, facilities or in any other respect, either between localities or between classes of service" under A.R.S. § 40-334.

CONCLUSIONS OF LAW

1. APS is an Arizona public service corporation within the meaning of Article XV, § 2 of the Arizona Constitution.

2. The Commission has jurisdiction over APS, over the subject matter of its application as amended, and over the issues raised and resolved herein.

3. Notice of the application and hearing were provided as required by Arizona law.

4. Clear and convincing evidence has rebutted the presumption that the SCRs expenditures were prudently made.

5. APS's FVRB is $11,744,433,000.

6. A FVROR of 4.95% results in just and reasonable rates and a revenue requirement that meets the standards of the *Hope* and *Bluefield* cases described in Section (VI)(C) of the Discussion portion of this Decision.

7. The rates, charges, and terms and conditions of service resulting from the Commission's resolution of the issued herein do not result in "discrimination in charges, service, or facilities . . between persons or places for rendering a like and contemporaneous service" under Article 15, § 12 of the Arizona Constitution.

8. The rates, charges, and terms and conditions of service resulting from the Commission's resolution of the issues herein do not "make or grant any preference or advantage to any person or subject any person to any prejudice or disadvantage" and do not "establish or maintain any unreasonable difference as to rates, charges, service, facilities or in any other respect, either between localities or between classes of service" under A.R.S. § 40-334.

ORDER

IT IS THEREFORE ORDERED that APS is required to file with the Commission, on or before September 30, 2021, revised rate plan tariffs/plans of administration consistent with the resolutions

reached in this Decision.

IT IS FURTHER ORDERED that the rates and charges and terms and conditions of service approved herein shall become effective for all service rendered on and after October 1, 2021.

IT IS FURTHER ORDERED that APS shall notify its customers of the revised rates and charges by means of an insert in its next scheduled billing (sent by mail or electronically) and by posting a notice on its website, in a form acceptable to Staff.

IT IS FURTHER ORDERED that APS shall not recover its existing deferrals for the SCR costs, shall not recover the SCR deferred debt return, and shall not record future SCR costs as deferrals.

IT IS FURTHER ORDERED that APS shall recover its OMP deferred costs on a levelized basis over a 10-year period with a carrying charge set at APS's embedded cost of debt in this matter, which is 4.10%.

IT IS FURTHER ORDERED that APS is required to comply with the following related to CCT:

- APS shall, in equal payments over a period of 10 years, pay to the Nation a total of $50 million, which shall be recoverable from its retail customers through its REAC, without carrying charges.
- APS shall, through a single payment made within 60 days after the effective date of this decision, pay to the Tribe $1.675 million, which shall be recoverable from its retail customers through its REAC, without carrying charges.
- APS shall, in equal payments over a period of 5 years, pay to the Navajo County Communities, as identified by APS herein, a total of $5 million, which shall be recoverable from its retail customers through its REAC, without carrying charges.
- APS shall provide job redeployment offers, within the APS organizations, to all impacted APS employees at least six months before Cholla closes, at least six months before the 4CPP moves to seasonal operations, and at least six months before the 4CPP closes. Job redeployment offers may require employee relocation.
- APS shall modify the distribution line extension policy in its Service Schedule 3, as applicable only to residential and commercial buildings on the Nation and the Hopi reservation, so that distribution lines can be extended up to 2,000 feet at no cost to Navajo

and Hopi applicants.

- APS shall, within 12 months after the effective date of this decision, perform or pay for a census of unelectrified buildings in the Nation and may spend up to $1.25 million toward other home and business electrification projects within the Nation, which shall be recoverable from its retail customers through its REAC, without carrying charges.
- APS shall, within 12 months after the effective date of this decision, perform or pay for a census of unelectrified buildings in the Hopi reservation and may spend up to $1.25 million toward other home and business electrification projects within the Hopi reservation, which shall be recoverable from its retail customers through its REAC, without carrying charges.

IT IS FURTHER ORDERED that if the Generic Transition Docket identifies additional transition assistance that should be provided to the Nation or the Tribe, and APS desires authorization to recover from its customers the costs of this transition assistance, APS shall file an application, in this docket, requesting such recovery. The Commission shall hold open this docket for a period of 12 months after the effective date of the decision herein for APS to file such a request, and if no such request is filed within that time, APS may raise the issue in its next rate case.

IT IS FURTHER ORDERED that APS shall record 15% of the annual amortization for the NGS below the line as non-operating expenses.

IT IS FURTHER ORDERED that APS's proposed depreciation rates are approved, and APS shall use them on and after the effective date of this Decision.

IT IS FURTHER ORDERED the revenues currently collected in the LFCR shall not be swept into base rates in this case.

IT IS FURTHER ORDERED that APS shall revise its LFCR POA to include an earnings test that conforms with the following:

- The requested increase to the LFCR adjustor rate will be dependent on an earnings test, which will compare the previous year's rate of return, unadjusted, with a threshold rate of return.
- The threshold rate of return will be the ROE authorized in the most recent rate case with an updated capital structure and cost of debt, consistent with the actual numbers from the previous year.

- The earnings test will be based on APS's FERC Form 1, using the previous year's costs, revenues, and other financial information, with certain pro forma adjustments made as appropriate based on APS's most recent rate case—i.e, if a pro forma adjustment proposed by APS in its most recent rate case was not adopted by the Commission, the adjustment shall not be included in this calculation.
- If the previous year's rate of return is higher than the threshold rate of return, the LFCR rate for the coming year will be set at zero.

IT IS FURTHER ORDERED that APS shall file its proposed revised LFCR POA in this docket within 60 days after the effective date of this Decision, as a compliance item, for review and approval by Staff or, if Staff believes that it is appropriate, by the Commission after Staff files a Memorandum and Proposed Order with its recommendations.

IT IS FURTHER ORDERED that APS shall not continue to defer changes in its property tax expenses caused by changes in property tax rates for potential subsequent recovery.

IT IS FURTHER ORDERED that APS, for its next rate case, shall determine the extent to which production demand costs are embedded in its PPAs and reclassify that portion of the PPA cost as production demand-related rather than energy-related for purposes of its COSS.

IT IS FURTHER ORDERED that APS shall do the following related to the COSS for its next rate case:

- Complete an analysis to identify, quantify, and justify the additional costs ("extra costs") that APS incurs specifically to provide service to DG customers (beyond the costs of providing their delivered power and energy);
- Complete a COSS using delivered load for DG solar customers as well as a COSS using site load for DG solar customers, with the extra costs clearly included and identified within each;
- Complete a COSS including DG solar customers within the non-DG residential classes with which the DG solar customers' rates are most closely aligned (e.g., DG demand customers will be included with non-DG demand customers);
- Use in each COSS the actual costs for the bidirectional meters in use at the end of the TY

for the rate case;

- Omit from metering costs for DG customers in each COSS the production meters that APS is required to have for REST compliance and uses for LFCR computations;
- Align DG subclass/class NCPs with the combined total residential class peak in allocation of primary distribution costs in each COSS;
- Make available to the other parties in the case all of the schedules, formulas, and backup data necessary to create each COSS;
- File the analysis and each COSS required above with the Commission as part of its application.

IT IS FURTHER ORDERED that APS shall engage in a collaborative, problem-solving process with AG-X stakeholders (including at least GSPs, AG-X customers, prospective AG-X customers, RUCO, and Staff) to analyze and identify solutions to at least the following issues that have been identified as to AG-X:

- Whether AG-X's current rates and charges adequately cover the costs to APS of serving AG-X customers or instead result in a cost shift to non-AG-X customers;
- If AG-X's current rates and charges do not adequately cover the costs to APS of serving AG-X customers, whether there are solutions that can be put in place to ensure that costs are not shifted to non-AG-X customers;
- Whether AG-X contracts provide resource adequacy and, if so, to what extent;
- If AG-X contracts do not provide resource adequacy on a MW-for-MW basis, whether there are solutions that can be put in place to ensure that they do provide resource adequacy on a one-to-one basis or, in the alternative, to allow for curtailment of AG-X load when GSPs' deliveries are cut and there is no capacity available to APS to avoid curtailments within its balancing authority;
- Whether and in what manner to fix the "flaw" in AG-X's current tariff that requires imbalance payments to be made based on variances from scheduled rather than delivered load;
- Whether there is now or will in 2025 and thereafter be a transmission capacity resource

constraint at the Palo Verde hub and, if so, what transmission capacity will be available for APS to use for expansion of AG-X or another buy-through program without adversely impacting APS's ability to deliver power from Palo Verde to APS's non-AG-X/buy-through customers;

- If there is or will in 2025 be a transmission capacity resource constraint at the Palo Verde hub, whether and to what extent it is possible and feasible for the load for an expanded AG-X or another buy-through program to be delivered at other transmission points of delivery without adversely impacting APS's ability to deliver power from those other points of delivery to APS's non-AG-X/buy-through customers;
- Whether and to what extent AG-X or another buy-through program should allow for participation by customer sizes smaller and larger than those served by E-32 M, E-32 M TOU, E-32 L, E-32 L TOU, and E-32 L;
- Whether it is reasonable and lawful to provide a carve-out in AG-X or another buy-through program for the schools class or any other specific customer class and why or why not; and
- How to ensure prospective customers have equitable opportunities for participation in AG-X or another buy-through program if/when the demand for the program exceeds the MW cap.

IT IS FURTHER ORDERED that to provide an opportunity for the modifications to AG-X and/or the expansion of AG-X or adoption of another buy-through program to be considered in light of the record in this case, the record in this docket shall remain open for 12 months to allow APS to submit such a proposal, with supporting documentation, an indication whether the parties believe an additional evidentiary hearing should be held, and a proposed form of notice to be provided to APS's customers.

IT IS FURTHER ORDERED that to ensure that the collaborative, problem-solving process described above for AG-X progresses at a reasonable pace, APS shall file monthly updates, beginning on the first day of the month following the effective date of this Decision, as compliance items in this docket, providing information on the meetings and other communications that have occurred, the stakeholders involved in those meetings and other communications, the progress in terms of the issues that have been resolved and that remain unresolved, and a full description of the resolution for each

resolved issue.

IT IS FURTHER ORDERED that APS shall make the following modifications to its AG-X tariff/POA:

- AG-X shall allow customers that aggregate accounts to meet AG-X's 10 MW minimum load-size eligibility requirement to add accounts if their aggregate load falls below the 10 MW threshold because of participation in EE programs.
- AG-X shall allow AG-X load to grow by up to 10% at existing locations that are currently taking AG-X service for deliveries at Palo Verde.
- AG-X shall allow for intra-day scheduling changes by GSPs. This provision shall be developed by APS with the assistance of GSPs, AG-X customers, and Staff (and RUCO if RUCO desires to participate consistent with its statutory authority).

IT IS FURTHER ORDERED that APS shall file its proposed revised AG-X POA/tariff in this docket within 60 days after the effective date of this Decision, as a compliance item, for review and approval by Staff or, if Staff believes that it is appropriate, by the Commission after Staff files a Memorandum and Proposed Order with its recommendations.

IT IS FURTHER ORDERED that if the new 10% growth provision results in additional AG-X load, APS shall increase the $15 million PSA mitigation proportionately to any increases in AG-X beyond its current 200 MW cap.

IT IS FURTHER ORDERED that APS, Staff, RUCO, and any other parties that desire to participate shall, within the next 12 months, meet in good faith, create, and file with the Commission, as a compliance item in this docket, a joint proposal (our preference) or multiple proposals for modification and/or elimination and/or consolidation of APS's current seven adjustor mechanisms, in conformance with the following requirements:

- The proposal or proposals filed shall include clear and detailed schedules setting forth all of the adjustments that would need to be made to implement the proposal or proposals, with any supporting documents necessary to understand the schedules;
- Electronic versions of the schedules, with all formulas and links intact and all linked documents provided, shall be submitted to the Commission's Hearing Division on a USB

flash drive or in another format to which the Hearing Division agrees;

- With the proposal/s filing/s, each proponent party or group shall include a proposed form of notice to be provided to APS's customers explaining what its/their proposal would do and how it would impact APS's customers; and
- With the proposal/s filing/s, each proponent party or group shall indicate the process through which the proposal should be considered by the Commission, including whether another evidentiary hearing should be held specifically concerning the proposal/s.

IT IS FURTHER ORDERED that to the extent the Commission approves the collection of CCT costs from ratepayers herein, APS shall include such CCT costs in its next REAC application, with no request for carrying costs associated with the CCT costs.

IT IS FURTHER ORDERED that APS's R-2 rate shall be frozen to additional customers on and after the effective date of this Decision.

IT IS FURTHER ORDERED that APS shall add to its R-3 rate a winter super off-peak period of 10 a.m. to 3 p.m.

IT IS FURTHER ORDERED that on and after the effective date of this Decision, APS shall not allow a residential customer to transfer to R-3 until the customer has completed an educational program that:

- Describes what R-3's rates are, how R-3 works, how best to save money on R-3, and how much demand is associated with typical home appliances (using information such as that included in Exhibit APS-45); and
- Is an online click-through presentation, a similar presentation through APS's app, or written materials followed by a requirement for an attestation of having reviewed the written materials.

IT IS FURTHER ORDERED that for R-3, APS shall calculate demand based not on the highest on-peak average hour but based on an average of the two highest on-peak average hours in the month.

IT IS FURTHER ORDERED that consistent with APS's amended application and our Discussion of residential rates, APS is authorized to eliminate from Service Schedule 1 the specified customer charges identified, to provide once per year waivers of the other customer charges specified,

and to allow an additional 7 days to remit payment after a bill is issued.

IT IS FURTHER ORDERED that on and after the effective date in this case, APS's R-Basic L rate shall no longer be frozen to new residential customers.

IT IS FURTHER ORDERED that APS is authorized to combine its R-XS, R-Basic, and R-Basic L rates into a single POA/tariff.

IT IS FURTHER ORDERED that APS shall, before its next rate case and for inclusion in its next rate case application, design two sets of "Basic" (fixed energy charge, non-TOU, non-demand) rates that include higher energy rates for the summer months than for the winter months—one that is designed to be revenue neutral with APS's existing Basic rates and one that is designed to recover a greater proportion of the cost of service for APS's Basic rate class (as combined in the single tariff).

IT IS FURTHER ORDERED that, after implementing the requirements enumerated below, APS shall provide a residential customer served on one tier of its "Basic" rates a one-time waiver of annual reassignment from the customer's existing tier to the next higher tier based on the customer's usage:

- APS shall include on each Basic rate customer bill a notice (in English and Spanish) that the one-time waiver is available, along with the contact information to obtain the waiver;
- APS shall provide each Basic rate customer whose average monthly usage during the year is approaching the next higher tier level at least two warnings about the consequences of exceeding the maximum threshold for the customer's current tier;
- APS shall allow a Basic customer to request the one-time waiver of reassignment by writing to APS (at a specified mailing address), by calling a Customer Advisor by phone (at a specified number), by emailing a Customer Advisor (at a specified email address), or by online chatting with a Customer Advisor (to the extent that functionality exists); and
- APS shall be able to share educational materials about other rate plans and conservation tools that it desires to provide to these Basic customers through mail, by phone, by email, or through online chatting.

IT IS FURTHER ORDERED that APS shall require a new residential customer to take service under the TOU-E rate plan for the first 90 days of service, unless the new residential customer lives in

a mobile home or long-term recreational vehicle park that does not have separate APS-provided meters for each space.

IT IS FURTHER ORDERED that APS shall revise its R-Basic (combined), TOU-E, and R-3 POAs/tariffs by replacing the current BSC with a $0.400 BSC for the middle and high R-Basic tiers (aka R-Basic and R-Basic L), TOU-E, and R-3.

IT IS FURTHER ORDERED that in preparing its conforming rates and schedules, APS shall make up the revenue differences resulting from the changes to the BSCs for R-Basic, R-Basic L, TOU-E, and R-3 only through on-peak energy and demand charges.

IT IS FURTHER ORDERED that APS shall modify its R-3 POA/tariff by restricting use of the demand limiter to three times per year, with only one of the three occurrences allowed to occur in the summer months.

IT IS FURTHER ORDERED that APS shall highlight the new restriction on use of the R-3 demand limiter in its education materials (required to be developed in this Decision) concerning R-3.

IT IS FURTHER ORDERED that APS shall make the following modifications to its R-Tech tariff/POA:

- The BSC shall be set at the same rate as the BSC for TOU-E and R-3;
- A super off-peak energy charge shall be established for the period from 11 p.m. to 5 a.m. every day of the year, which shall be set at the same level as the R-3 super off-peak energy charge;
- Excess off-peak demand charges shall not apply during the super off-peak period; and
- The threshold for assessing excess off-peak demand charges shall be set at 10 kW.

IT IS FURTHER ORDERED that APS shall file its proposed revised R-Tech POA/tariff in this docket within 60 days after the effective date of this Decision, as a compliance item, for review and approval by Staff or, if Staff believes that it is appropriate, by the Commission after Staff files a Memorandum and Proposed Order with its recommendations.

IT IS FURTHER ORDERED that APS is authorized to defer the costs of the E-3 and E-4 discount programs, to the extent that those costs exceed the costs in the adjusted TY in this case, with no carrying costs, and to request recovery of those costs in its next rate case.

IT IS FURTHER ORDERED that APS is authorized to freeze E-47 and E-58 and to adopt its new proposed E-45 and a new E-68 for streetlight rates.

IT IS FURTHER ORDERED that APS is authorized to transition E-221 to non-agricultural customers only and to adopt its new proposed E-221 AG and E-221 AG TOU for agricultural customers.

IT IS FURTHER ORDERED that APS's E-36 M rate rider is cancelled as of the effective date of this Decision.

IT IS FURTHER ORDERED that APS is authorized to implement its proposed changes to Service Schedule 9, including the conflict-of-interest language agreed upon by APS and Staff.

IT IS FURTHER ORDERED that APS shall, in preparing its conforming rates and schedules, implement the revenue reduction for the GS-Schools rates solely by reducing the summer-shoulder and winter periods' shoulder-peak and off-peak energy charges.

IT IS FURTHER ORDERED that APS shall, within six months following the effective date of this Decision:

- Work collaboratively with ASBA/AASBO and any other interested school stakeholders to create a proposed modification to Service Schedule 4 that will allow for aggregation of multiple meters located on a school's contiguous campus; and
- File the proposed modification to Service Schedule 4, as a compliance item in this docket, within six months after the date of this Decision.

IT IS FURTHER ORDERED that APS shall engage in a collaborative, problem-solving process with SEIA/AriSEIA and other interested stakeholders (including Staff) to analyze and identify solutions to at least the following potential issues that have been identified as to E-32 L SP:

- Whether there is justification for the BSC to be as high as it is and, if not, what would be an appropriate cost-based BSC;
- Whether requiring 20% demand reduction for eligibility is too restrictive and, if so, what would be an appropriate threshold for eligibility;
- Whether the six-hour on-peak period is too long because most behind-the-meter storage has a shorter capacity;

- Whether there is justification for demand charges to be the same on-peak and during remaining hours and, if not, what different cost-based demand charges would be appropriate for the different periods;
- Whether there is justification for requiring customers to manage demand actively for 12 hours per day (on-peak and remaining hours) rather than just on-peak;
- Whether the current on-peak period comprises "the 6 greatest average system demand hours during the previous three years by season" and the current off-peak period comprises "the 12 lowest average system demand hours during the previous three years by season" and, if not, what on-peak period and off-peak period would; and
- Whether the tariff allows sufficient time for storage systems to charge before the onset of remaining hours in the summer months.

IT IS FURTHER ORDERED that to provide an opportunity for the modifications to E-32 L SP to be considered in light of the record in this case, the record in this docket shall remain open for 12 months to allow APS to submit such a proposal, with supporting documentation, an indication whether the parties believe an additional evidentiary hearing should be held, and a proposed form of notice to be provided to APS's customers.

IT IS FURTHER ORDERED that to ensure that the collaborative, problem-solving process described above for E-32 L SP progresses at a reasonable pace, APS shall file monthly updates, beginning on the first day of the month following the effective date of this Decision, as compliance items in this docket, providing information on the meetings and other communications that have occurred, the stakeholders involved in those meetings and other communications, the progress in terms of the issues that have been resolved and that remain unresolved, and a full description of the resolution for each resolved issue.

IT IS FURTHER ORDERED that APS is authorized to implement the proposed DCFC Rider included as Exhibit C hereto.

IT IS FURTHER ORDERED that APS shall include the following language in its new combined R-Basic tariff:

For purposes of A.R.S. §§ 33-1413.01(B) and 33-2107(B)(3), the prevailing basic

service single family residential rate charged by APS as the serving utility or provider is the middle tier of this tariff (601-999 kWh).

IT IS FURTHER ORDERED that APS shall update its RCP POA to include the "Maximum Capacity" restriction from the Interconnection Rules rather than its current size restrictions.

IT IS FURTHER ORDERED that APS shall continue to use its RCP POA for its DG export rate.

IT IS FURTHER ORDERED that APS shall adopt the following residential rate names:

Current Tariff & Rate Name	**APS-Proposed Name**
R-XS – "Lite Choice"	As combined into one tariff: "Fixed-Energy-Charge Plan"
R-Basic – "Premier Choice"	
R-Basic L – "Premier Choice Large"	
TOU-E – "Saver Choice"	"Time-of-Use 3pm-8pm Weekdays"
R-3 – "Saver Choice Max"	"Time-of-Use 3pm-8pm Weekdays with Demand"
R-Tech – "Saver Choice Tech"	"Technology Time-of-Use with Demand"

IT IS FURTHER ORDERED that APS shall, within 60 days after the effective date of this Decision:

- Work collaboratively with Staff, RUCO, and any additional parties who desire to participate on a CEOP for this rate case (and going forward) that addresses the recommendations made in the Overland Report, the Alexander Report, the EnergyTools Report, and the Guidehouse Report; and
- File, as a compliance item in this docket, the following:
  - A copy of the proposed new CEOP; and
  - A list of each recommendation/deficiency from each consultant's report (all four of them) along with the actions that APS has taken or intends to take (per the CEOP or otherwise) to address each recommendation/deficiency.

IT IS FURTHER ORDERED that Staff shall, within 60 days after the proposed new CEOP is filed, issue a Staff Report and Proposed Order recommending whether the Commission should approve the proposed CEOP, with or without modifications (which shall be fully explained), and, if the recommendation is that the proposed CEOP not be approved, Staff shall fully explain its reasoning.

IT IS FURTHER ORDERED that APS shall, within 120 days after the effective date of this Decision, investigate and report to the Commission (through a filing in this docket) whether the investment necessary to provide customers granular energy data from AMI meters (one-, five-, and 15-minute interval data) would be cost-effective.

IT IS FURTHER ORDERED that APS shall, within 120 days after the effective date of this Decision, familiarize itself with the *Voluntary Code of Conduct* and make a filing in this docket thoroughly explaining to the Commission what it would require of APS and why APS should or should not commit to it.

IT IS FURTHER ORDERED that before implementation of its redesigned bill, APS shall file its redesigned bill with the Commission for review and approval and a determination of whether the redesigned bill complies with A.A.C. R14-2-210 and is sufficient and consistent with the convenience of APS's customers as contemplated by A.R.S. § 40-203 and Article 15, § 3 of the Arizona Constitution.

IT IS FURTHER ORDERED that APS shall complete, and include in its next IRP, a comprehensive retirement assessment for the 4CPP, which shall include (1) evaluation of retirement of either or both units before 2031, prepared using realistic numbers for items such as carbon costs, avoidable O&M and capital expenditures, and capacity credits for storage, and (2) APS's justification for using the numbers selected.

IT IS FURTHER ORDERED that on and after the effective date of this Decision APS shall use a base cost of fuel of $3.1451/kWh and a base cost for production-related chemicals of 0.0500¢/kWh.

IT IS FURTHER ORDERED that APS shall comply with Staff recommendations #2 through #6 set forth in Section (X)(F) of the Discussion portion of this Decision.

IT IS FURTHER ORDERED that APS shall conform its regulatory accounting records to reflect the resolutions reached in the various subsections within Sections V, VI, VII, VIII, IX, and X of the Discussion portion of this Decision.

IT IS FURTHER ORDERED that any undisputed issue that is not discussed in this Decision should not be considered (or cited) as having been fully litigated and expressly approved by the Commission.

IT IS FURTHER ORDERED that APS and the parties to this case shall, in future rate cases, remedy the issues identified in Section (X)(J) of the Discussion portion of this Decision.

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

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRWOMAN MÁRQUEZ PETERSON COMMISSIONER KENNEDY

COMMISSIONER OLSON COMMISSIONER TOVAR COMMISSIONER O'CONNOR

IN WITNESS WHEREOF, I, MATTHEW J. NEUBERT, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this _____day of _____ 2021.

MATTHEW J. NEUBERT
EXECUTIVE DIRECTOR

DISSENT _____

DISSENT _____
SNH/(gb)

SERVICE LIST FOR: ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO.: E-01345A-19-0236

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EXPERIMENTAL RATE RIDER AG-Y
GENERAL SERVICE
HOURLY MARKET PRICE SERVICE

GENERAL DESCRIPTION

This schedule provides the customer an hourly market price signal for billing generation energy costs and credits the customer for the generation energy costs reflected on their retail rate schedule and the PSA fuel adjustor rate.

AVAILABILITY

This rate rider schedule is available in all territories served by APS ("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 are served under retail rate schedules E-32M, E-32MTOU, E-32L, E-32LTOU, or E32L Storage Pilot. Customers must have standard metering service with Advanced Metering Infrastructure equipment.

Total program participation will be limited to 200 MW of customer load, based on the summation of average monthly peak loads for each customer. APS may expand the program limit, at its discretion, upon notification to the Arizona Corporation Commission Staff.

This rate rider may not be used in conjunction with the following rates or programs: Schedules SGSP, EPR-6, E-56, SD-1 and the aggregation discount rate option in Schedule E32-L. Customer may have on-site generation billed under Schedule EPR-2 or E-56R.

CUSTOMER ENROLLMENT

Customers will be enrolled on a first come first served basis. However, if the participation exceeds 100 MW during an initial 3-month enrollment period, the Company will assess whether a lottery will be held for the remaining program MW or whether the program limit will be expanded. Customers must execute an Electric Supply Agreement with an addendum for the AG-Y program and complete any other program requirements prior to enrollment.

HOURLY PRICES

Hourly market prices for this schedule will be derived from relevant wholesale market prices and posted on a Company website on a day ahead basis.

aps

EXPERIMENTAL RATE RIDER AG-Y
GENERAL SERVICE
HOURLY MARKET PRICE SERVICE

RATES

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

- The unbundled generation energy costs in the retail rate will be credited on the monthly bill at the following credit rate:

  Monthly credit for generation energy costs $ 0.036 per kWh credit

- Adjustment Schedule PSA-1 charges will not apply;

Additional Schedule AG-Y charges include:

- The hourly prices applied to the customer's hourly metered kWh during the billing period

The rate credit specified above shall be revised in subsequent general rate case filings.

CONTRACT

The customer must execute an Electric Supply Agreement with an addendum for this rate rider.

Advanced Energy Mechanism Adjustment Charge
Plan of Administration

Table of Contents

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1 General Description

1.1 The Advanced Energy Mechanism (AEM) was authorized for Arizona Public Service Company (APS or the Company) by the Arizona Corporation Commission (Commission) in Decision No. XXX (XXX, 2021). The adjustor rates are approved by the Commission in the annual process described below, are effective beginning in billing cycle 1 of the January revenue month each year or the first bill cycle of the month following Commission approval and are not prorated.

1.2 The purpose of the AEM adjustment rate is to provide for timely cost recovery of the capital carrying costs and expenses of APS's clean plan investments and transition to a clean energy future, which are not already recovered in base rates or through another adjustor rate. Clean plan investments include all non-carbon emitting resources, including energy storage and excluding nuclear energy.

1.3 The clean plan investments are directed by the Integrated Resource Plan (IRP) Action Plan or any successor Commission-approved process (for example, the Clean Energy Implementation Plan contemplated by the Energy Rules recently approved by the Commission). Prudence of the investments will be determined by the Commission through the IRP process or other approved Commission process. As discussed below in Section 5, clean plan investments will be subject to a thorough stakeholder process, procured through competitive requests for proposal, and subject to a Commission approval process.

1.4 The AEM adjustor will be subject to an earnings test and a cap in year-over-year increases of $0.005 per kWh.

2 Allowable Costs

2.1 The capital carrying costs for clean plan investments include (1) the return on net plant, which is based on the weighted average cost of capital approved in APS's most recent rate case plus a return on the fair value increment (if any); (2) depreciation expense; (3) income taxes; (4) property taxes; and (5) associated operation and maintenance expenses (O&M).

2.2 If any of the qualified investments generate revenue, the revenue will be credited against the AEM revenue requirements.

2.3 Commission-approved Coal Community Transition costs (CCT) will be recovered in the AEM and will be detailed in the Attachments to the annual filing.

2.4 The allowable costs will be projected for the year following the annual filing. This projection will be based on the estimated in-service date for new assets.

2.5 The allowable costs will be detailed in the Attachments to the annual filing.

3 Balancing Account

3.1 The expected revenue and revenue requirements for the AEM adjustor rate, for the current year filing, will be projected for the following calendar year.

3.2 The actual revenue and revenue requirements will be recorded in a balancing account.

3.3 Variances in the balancing account may occur for such reasons as: differences in the actual versus projected in-service date and cost for a new asset; differences in the actual versus projected operating expenses for qualified assets; and differences in the actual versus projected revenue from the AEM adjustor rate.

3.4 Any balancing account balances, positive or negative, as of April 30 of the filing year will be included for recovery in the annual filing.

4 Adjustor Rate

4.1 The adjustor kWh charge will be derived by dividing the projected revenue requirements, including the balancing account amount, by the projected retail kWh, for the following year.

4.2 The kWh charge will be converted to a kW charge for every retail rate schedule that has a kW charge. The kW billing determinants will be the billed kW from the previous year

escalated by the projected kWh over the previous year kWh for the relevant customer class.

5 **Annual Process**

5.1 The Company will review the implementation of the IRP Action Plan, or any successor Commission process, including planned new investments and programs with Commission Staff and stakeholders each year. Stakeholder meetings will be held between January and May each year to discuss the AEM budget and projects to be included in the mechanism.

5.2 The Company will file an AEM Application with the Commission detailing the clean energy investments and revised charges for the AEM adjustor rate for the upcoming year by June 1 each year. The Application will include the information in the attached schedules as follows:

Attachment A - AEM Adjustor Calculation
Attachment B - Revenue Requirements
Attachment C - Qualified Investments and CCT Costs
Attachment D - Balancing Account
Attachment E - Earnings Test

5.3 Commission Staff will review the information along with input and comments from other parties. A Staff report and recommendation will be submitted to the Commission for approval.

5.4 If approved by the Commission, the revised AEM rates will be effective beginning in billing cycle 1 of the January revenue month or the first bill cycle month following Commission approval and will not be prorated.

6 **Earnings Test**

6.1 The requested increase to the AEM adjustor rate will be dependent on an earnings test, which will compare the previous year's rate of return, as adjusted, with a threshold level.

6.2 The threshold rate of return will be the return on equity authorized in the most recent rate case with an updated capital structure and cost of debt, consistent with the actual amounts from the prior year.

6.3 The earnings test will be based on the Company's Federal Energy Regulatory Commission (FERC) Form 1, using the previous year's costs, revenue, and other

financial information. This calculation will provide earnings information for the previous year, with certain pro forma adjustments as appropriate based upon the Company's most recent rate case.

6.4 If the adjusted earnings in the earnings test are higher than the threshold value, then the approved increase in the AEM revenue requirement through a reset of the AEM adjustor rate will be limited by the amount above the earnings threshold. The remaining amount, if any, will be transferred to the balancing account for recovery through the AEM in a future year.

7 Other Adjustor Rates

7.1 APS may seek Commission approval to transfer recovery of the revenue requirements, operating costs or program costs recovered through the Demand Side Management Adjustment Charge (DSMAC), Renewable Energy Adjustment Charge (REAC) or Lost Fixed Cost Recovery (LFCR) adjustor rates to the AEM adjustor rate, in whole or in part, in an annual AEM proceeding or future APS rate case.

7.2 If all or a portion of the revenue requirements, operating costs or program costs recovered through another adjustor rate are transferred to the AEM, this POA will be modified to incorporate the already authorized cost recovery in that adjustor rate.

EXHIBIT C

EXHIBIT APS-51

aps

RATE RIDER DCFC
GENERAL SERVICE
DIRECT CURRENT FAST CHARGING PILOT

DESCRIPTION

This pilot rate rider provides an upper limit to the monthly billed demand, relative to the customer's monthly kWh usage and billed days, to facilitate the initial deployment of public, direct current fast-charge, electric vehicle charging stations.

AVAILABILITY

This pilot rate rider is available to Standard Offer retail customer service accounts served under rates E-32 Small TOU, E-32 Medium TOU, and E-32 Large TOU, where electricity is consumed only by public, direct current fast-charge, electric vehicle charging stations that are separately metered from other facilities unless those facilities are incidental to the charging load.

This rider is limited to 500 customer service accounts on a first-come-first-served basis and will sunset after the July 2031 billing period.

Other buildings that are on the same site as the vehicle charging facilities will be separately metered and billed under a retail rate, without this rider.

LOAD FACTOR LIMITS

Monthly billing demands are limited to a kW no higher than that which would result in the applicable load factor limit, based on the customer's kWh usage, and billing days during the month. The monthly load factor limits are:

	Monthly Cycle Bills beginning with cycle 1 Between	Load Factor Limit
Period One	July 1, 2021 through June 30, 2026	20%
Period Two	July 1, 2026 through June 30, 2031	15%

The monthly billing demand shall be the lower of:

1. The Billing Demand metered and calculated according to the retail rate schedule, or
2. The Limited Demand which equals:
    a. Period One - (Monthly Billed kWh) / [20%*Days*24 hours]
    b. Period Two - (Monthly Billed kWh) / [15%*Days*24 hours]

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule, other than those specifically modified here, continue to apply.

2. Qualifying direct current fast chargers have a discharge capacity of 50 kW or greater and are available for use by the general public and not restricted.

DRAFT