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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JIM O'CONNOR – CHAIRMAN
LEA MÁRQUEZ PETERSON
ANNA TOVAR
KEVIN THOMPSON
NICK MYERS

Arizona Corporation Commission
DOCKETED
MAR 5 2024
DOCKETED BY

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01345A-22-0144 DECISION NO. 79293 **OPINION AND ORDER**

DATES OF HEARING: August 10-11, 14-18, 21-23, 25, and 28-31; September 1, 5-8, 11, 13, and 15; and October 3, 2023

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Sarah N. Harpring

APPEARANCES:[1]

Melissa M. Krueger, Jeffrey S. Allmon, Scott Hesla, Theresa Dwyer, and Lauren Ferrigni, PINNACLE WEST CAPITAL CORPORATION, on behalf of Arizona Public Service Company;

Nicholas J. Enoch, Morgan L. Bigelow, and Clara S. Bustamante, LUBIN & ENOCH, PC, on behalf of the International Brotherhood of Electrical Workers, AFL-CIO Locals 387, 640, and 769;

Justina A. Caviglia, PARSONS BEHLE & LATIMER, on behalf of Walmart, Inc.;

Patrick J. Black and Kaitlyn Smith, FENNEMORE, on behalf of Freeport Minerals Corporation;

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

CPT Marcus Duffy, MAJ Leslie Newton, CPT Ashley George, and Thomas Jernigan, U.S. AIR FORCE, on behalf of the Federal Executive Agencies;

[1] Intervenor Brookfield Renewables Trading and Marketing LP indicated though a filing that it would not participate in the hearing. Intervenors Tucson Electric Power Company and Arizona Competitive Power Alliance requested and were granted excusal from participating at the prehearing and hearing.

Thorvald A. Nelson and Austen W. Jensen, HOLLAND & HART LLP, on behalf of the Arizona Large Customer Group;

Nathan D. Schott, GUST ROSENFELD, P.L.C., on behalf of the Joseph City Unified School District;

Todd F. Kimbrough, BALCH & BINGHAM, LLP, on behalf of the Navajo Nation;

Amy Mignella, HOPI TRIBE OFFICE OF GENERAL COUNSEL, on behalf of the Hopi Tribe;

Chanele N. Reyes, ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST, on behalf of San Juan Citizens Alliance, Tó Nizhoni Áni, Diné C.A.R.E., Black Mesa Trust, Southwest Energy Efficiency Project, Western Resource Advocates, and Vote Solar;

George Cavros, WESTERN RESOURCE ADVOCATES, on behalf of Western Resource Advocates;

Timothy M. Hogan, ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST, on behalf of Wildfire, Arizona School Boards Association, Arizona Association of School Business Officials, and Arizona School Administrators;

Gregory M. Adams, RICHARDSON ADAMS, PLLC, on behalf of Calpine Energy Solutions, LLC;

Court S. Rich, ROSE LAW GROUP, PC, on behalf of NRG Energy, Inc.; EVgo Services LLC; Tesla, Inc.; and Arizona Solar Energy Industries Association and Solar Energy Industries Association;

Autumn T. Johnson, TIERRA STRATEGY, on behalf of Arizona Solar Energy Industries Association and Solar Energy Industries Association;

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

Patrick Woolsey and Nihal Shrinath, SIERRA CLUB ENVIRONMENTAL LAW PROGRAM, on behalf of Sierra Club;

Kristin Nelson, pro se;

John B. Coffman, JOHN B. COFFMAN LLC, and Ayensa Milan, CIMA LAW GROUP, PC, on behalf of AARP;

Daniel Pozefsky, Chief Counsel, and Jon McCarty, Attorney III, RESIDENTIAL UTILITY CONSUMER OFFICE, on behalf of the RESIDENTIAL UTILITY CONSUMER OFFICE; and

Maureen Scott, Deputy Chief of Litigation and Appeals, and Samantha Egan, Kate Kane, and Carolyn Keist-Gilbert, Staff Attorneys, LEGAL DIVISION, on behalf of the Arizona Corporation Commission's Utilities Division.

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BY THE COMMISSION:

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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 to this case along with their shortened and, as applicable, group names:

Party	Group Name
Arizona Public Service Company ("APS")	
International Brotherhood of Electrical Workers, AFL-CIO Local 387	"IBEW Locals"[2]
International Brotherhood of Electrical Workers, AFL-CIO Local 640	
International Brotherhood of Electrical Workers, AFL-CIO Local 769	
Walmart, Inc. ("Walmart")	
Freeport Minerals Corporation ("Freeport")	
Kroger Co. ("Kroger")	
Federal Executive Agencies ("FEA")	
Arizona Large Customer Group ("AZLCG")	
Joseph City Unified School District ("JCUSD")	
Navajo Nation ("Nation")	
Hopi Tribe ("Tribe")	
San Juan Citizens Alliance	"Citizen Groups"
Tó Nizhoní Ání,	
Diné C.A.R.E.	
Black Mesa Trust	
Wildfire	
Southwest Energy Efficiency Project ("SWEEP")	
Western Resource Advocates ("WRA")	
Arizona School Board Association ("ASBA")	"School Groups"
Arizona Association of School Business Officials ("AASBO")	
Arizona School Administrators ("ASA")	
Vote Solar	
Brookfield Renewables Trading and Marketing LP ("Brookfield")	
Tucson Electric Power Company ("TEP")	
Arizona Competitive Power Alliance ("AZCPA")	
Calpine Energy Solutions, LLC ("Calpine")	

[2] IBEW Local 387 is the certified bargaining representative for approximately 1,210 APS employees, and IBEW Locals 640 and 769 have collective bargaining agreements with contractors for APS. (Tr. at 149.)

NRG Energy, Inc. ("NRG")	
EVgo Services LLC ("EVgo")	
Tesla, Inc. ("Tesla")	
Arizona Solar Energy Industries Association	"AriSEIA/SEIA"
Solar Energy Industries Association	
Arizona Solar Deployment Alliance ("ASDA")	
Sierra Club	
Kristin Nelson	
AARP	
Residential Utility Consumers Office ("RUCO")	
Utilities Division ("Staff")	

II. **Procedural History**

On June 1, 2022, 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 June 2, 2022, then-Chairwoman Lea Márquez Peterson filed a letter in the docket requesting that APS and other parties provide evidence on the impact on APS's cost of capital of the parties' positions on enumerated issues.[3]

On June 6, 2022, a Procedural Order Regarding Consent to Email Service was filed in this docket.[4]

On June 9, 2022, APS filed an Amended Notice of Intent to File a Rate Case, stating that it intended to file its rate application on or about October 28, 2022, using a test year of July 1, 2021, through June 30, 2022.

On June 21, 2022, then-Chairwoman Lea Márquez Peterson filed in the docket a letter that had been filed on the same date in Docket No. E-01345A-21-0348, requesting that APS and interested parties address specific attached information and discuss and propose methods by which the Commission can put non-utility-owned resources on equal footing with utility-owned resources.

On October 28, 2022, APS filed its Rate Application, which uses a TY of July 1, 2021, through

[3] The issues were (1) plant retirements, depreciation, and stranded assets; (2) new plant additions, expansions, procurements, conversions, and upgrades; (3) pollution controls and environmental compliance; (4) ongoing plant operations and maintenance; (5) coal community transition and funding; (6) regional markets and regional transmission organizations; (7) transmission and distribution system upgrades and expansions; (8) energy efficiency and transportation/building electrification; and (9) all other issues related to APS's clean energy transition. Official notice is taken of this letter. Both Mr. Cooper and Dr. Morin addressed aspects of the letter in their testimony. (*See* Ex. APS-5 at 16-22, Att. AC-03DR; Ex. APS-33 at 36-42.)

[4] Subsequent party filings and Procedural Orders related to consent to email service are not listed herein. Each party to this matter has consented to email service in this matter.

June 30, 2022, and sought a net increase in base rates of $460 million, or 13.6%, to become effective on December 1, 2023.

On November 4, 2022, Walmart filed a Petition for Leave to Intervene, and Freeport filed an Application for Leave to Intervene.

On November 7, 2022, a Procedural Order was issued explaining the Arizona Supreme Court Rules prohibitions on the practice of law by out-of-state attorneys who have not been granted admission pro hac vice and the need for party filings to be signed by authorized legal representatives.

On November 8, 2022, RUCO filed an Application to Intervene.

On November 9, 2022, Wildfire filed a Motion for Leave to Intervene, and the Citizen Groups filed a Motion for Leave to Intervene.

On November 14, 2022, SWEEP filed a Motion for Leave to Intervene, and Kroger filed a Petition for Leave to Intervene.

On November 15, 2022, FEA filed an Application for Leave to Intervene.

On November 17, 2022, by Procedural Order, intervention was granted to Walmart, Freeport, RUCO, Wildfire, and the Citizen Groups.

On November 28, 2022, 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 and classifying APS as a Class A utility.

Also on November 28, 2022, as requested in Decision No. 78317 (November 9, 2021), APS filed separate jurisdictional rate case Standard Filing Requirements schedules.

On December 1, 2022, by Procedural Order, intervention was granted to SWEEP, Kroger, and FEA.

On December 2, 2022, a Procedural Order was issued establishing a schedule and procedural requirements for this matter, including a hearing to commence on July 31, 2023, and public comment sessions to be held on the afternoon of June 1, the evenings of June 7 and 20, and the mornings of June 20 and July 31, 2023. Also on December 2, 2022, a second Procedural Order was issued correcting the deadline for Staff and intervenors to file direct testimony and associated exhibits on rate design issues.

On December 7, 2022, Brookfield filed a Petition for Leave to Intervene, and APS filed a Request for Clarification and Modification to Procedural Order, requesting permission to add language to the prescribed public notice and that the deadline for mailing and newspaper publication of the notice be extended.

On December 8, 2022, by Procedural Order, APS's Motion was denied in part and granted in part. APS was ordered to provide alternate additional language to its public notice and was granted its requested deadline extension. Additionally, the intervention deadline was extended to March 3, 2023; APS was ordered to replace the intervention deadline in its public notice; and APS's deadline to file a certification of mailing and publication was extended to March 3, 2023.

On December 9, 2022, Applications to Intervene were filed by TEP and jointly by AriSEIA/SEIA.

On December 13, 2022, Staff filed a Motion for Modification of Procedural Schedule, requesting extensions of the dates for Staff/Intervenor rate design testimony, APS rebuttal testimony, Staff/Intervenor surrebuttal testimony, APS rejoinder testimony, and commencement of the hearing. Staff proposed a first hearing date of August 2, 2023.

On December 14, 2022, by Procedural Order, the Staff Motion was granted and the procedural schedule was modified, with the hearing rescheduled to commence on August 2, 2023, and to continue until September 6, 2023; the original July 31, 2023, hearing date retained for taking public comment; and the timeclock deadline in this matter extended by two days.

On December 15, 2022, by Procedural Order, intervention was granted to Brookfield.

On the same date, APS filed a Notice of Delivering to the Hearing Division a USB Flash Drive containing Plans of Administration attachments and schedules and Excel versions of the jurisdictional-only Standard Filing Requirement schedules filed on November 28, 2022. APS stated that the files had also been uploaded to the APS 2022 Rate Case Extranet Site.[5]

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[5] In the Procedural Orders issued on December 2, 2022, APS was ordered to establish an APS-hosted Hearing Extranet Site and an APS-hosted Discovery Extranet Site to be used by the parties in this matter for exchanging exhibits and sharing discovery documents. Further, APS was ordered to ensure that each party representative and witness had an opportunity to complete any agreement required by APS to access the Extranet Sites and that each representative and witness completing a Protective Agreement was able to access confidential information. APS hosted an Extranet Site for parties in the 2019 rate case.

On December 19, 2022, by Procedural Order, TEP and AriSEIA/SEIA were granted intervention.

On December 20, 2022, APS filed a Notice stating that the public notice it provided had included the revised August 2, 2023, hearing date.

On January 3, 2023, the IBEW Locals jointly filed a Motion for Leave to Intervene.

On January 5, 2023, local counsel for Walmart filed a Motion for Pro Hac Vice Admission requesting that Vicki Baldwin be permitted to appear before the Commission as counsel pro hac vice for Walmart in this matter.

On the same date, local counsel for Kroger filed a Motion to Associate Counsel Pro Hac Vice requesting that Kurt J. Boehm and Jody Kyler Cohn be permitted to appear before the Commission as counsel pro hac vice for Kroger in this matter.

On January 6, 2023, by Procedural Order, Ms. Baldwin, Mr. Boehm, and Mr. Cohn were granted admission pro hac vice.

On January 9, 2023, an Application for Leave to Intervene for the Nation was filed by an out-of-state attorney who had not been admitted pro hac vice in this matter.

On January 12, 2023, by Procedural Order, intervention was granted to the IBEW Locals.

Also on January 12, 2023, a Procedural Order was issued ordering that the Nation's Application for Leave to Intervene could not be approved because it had been signed by an out-of-state attorney not authorized to practice law in Arizona and that if the Nation desired to intervene, the Nation must file another Application for Leave to Intervene signed and filed by an authorized legal representative.

On January 12, 2023, a Motion for Leave to Intervene was jointly filed by the School Groups.

On January 12, 2023, the Nation filed an amended Application for Leave to Intervene signed and filed by a different attorney for whom the Application showed an Arizona Bar number.

On January 13, 2023, a Procedural Order was issued ordering that the Nation's Application for Leave to Intervene signed by the second attorney could not be approved because the second attorney was, according to the Arizona State Bar website, an inactive member of the Arizona State Bar and thus not authorized to practice law in Arizona. The Procedural Order provided that if the Nation desired to intervene, the Nation must file another Application for Leave to Intervene signed and filed by an authorized legal representative and including documentation establishing the legal representative's authority to engage in the practice of law in Arizona.

Also on January 13, 2023, APS filed an invitation for all interested parties to join a collaborative meeting with stakeholders to discuss AG-X program topics, scheduled to be held on January 19, 2023.

On January 19, 2023, the Nation filed a Re-Filed Application for Leave to Intervene, which included a copy of an email from the State Bar of Arizona stating that the second attorney's return to active status was effective January 17, 2023.

On January 20, 2023, by Procedural Order, the Nation was granted intervention.

On January 26, 2023, local counsel for AriSEIA/SEIA filed a Motion to Associate Counsel Pro Hac Vice requesting that Autumn T. Johnson be permitted to appear before the Commission as counsel pro hac vice for AriSEIA/SEIA in this matter.

Also on January 26, 2023, by Procedural Order, the School Groups were granted intervention, and Ms. Johnson was granted admission pro hac vice.

On January 30, 2023, AZCPA filed an Application for Leave to Intervene.

On January 31, 2023, NRG filed an Application for Leave to Intervene.

On January 31, 2023, local counsel for Brookfield filed a Motion to Associate Counsel Pro Hac Vice requesting that Laura K. Granier and Amber L. Rudnick be permitted to appear before the Commission as counsel pro hac vice for Brookfield in this matter.

On February 1, 2023, local counsel for FEA filed a Motion to Associate Counsel Pro Hac Vice requesting that Major Holly L. Buchanan, Captain Marcus Duffy, and Thomas A. Jernigan be permitted to appear before the Commission as counsel pro hac vice for FEA in this matter.

On February 2, 2023, Vote Solar filed a Motion for Leave to Intervene

Also on February 2, 2023, by Procedural Order, admission pro hac vice was granted to Ms. Granier, Ms. Rudnick, Major Buchanan, Captain Duffy, and Mr. Jernigan.

On February 7, 2023, JCUSD filed a Motion for Leave to Intervene.

On February 8, 2023, by Procedural Order, intervention was granted to AZCPA and NRG.

On February 9, 2023, Tesla filed an Application for Leave to Intervene.

On February 10, 2023, by Procedural Order, Vote Solar was granted intervention.

On February 14, 2023, AZLCG filed an Application for Leave to Intervene.

Also on February 14, 2023, APS filed a Notice that it was hosting a rate case technical conference for parties on March 14, 2023.

On February 15, 2023, by Procedural Order, JCUSD was granted intervention.

Also on February 15, 2023, a Procedural Order was issued requiring AZLCG to make a filing addressing issues related to the legal entities comprising its membership and whether it would be appropriate for those legal entities to intervene in their own right but participate together as a group.

On February 16, 2023, APS filed a letter stating that the prescribed notice of this matter had been included as an addition to each customer's bill by mail or email (according to customer preference) between January 4 and 31, 2023; that the prescribed notice had been added as a link on the main page of APS's website on December 30, 2022, and would remain there until a decision is issued in this matter; and that the prescribed notice had been published in a newspaper of general circulation in each county in which APS provides service between January 18 and 29, 2023. APS included a screenshot of the main page of its website showing the link to the notice and Affidavits of Publication from the newspapers.[6]

On February 17, 2023, by Procedural Order, intervention was granted to Tesla.

On February 17, 2023, AZLCG filed Responses to Procedural Order Requesting Additional Information, identifying AZLCG's members as Microsoft Corporation, Target Corporation, Google LLC, and Freeport and stating that all AZLCG members either receive electricity and electric service from APS or indirectly rely on APS as a service provider.

On February 21, 2023, APS filed a Notice inviting interested parties to join its next collaborative meeting to discuss the AG-X program, to be held on February 28, 2023.

On February 22, 2023, Calpine filed an Application to Intervene.

On February 23, 2023, by Procedural Order, intervention was granted to AZLCG.

On February 28, 2023, Sierra Club filed an Application for Leave to Intervene.

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[6] The newspapers were *The Arizona Republic*, the *West Valley View*, the *Arizona Daily Sun* (Flagstaff), the *Sedona Red Rock News*, the *Navajo-Hopi Observer*, the *White Mountain Independent*, *The Tribune* (Holbrook), *the Payson Roundup*, *Globe Miami Times*, *The Parker Pioneer*, the *Casa Grande Dispatch*, the *Tri-Valley Dispatch* (Casa Grande), the *Yuma Sun*, the *Sierra Vista Herald Review*, *The Daily Courier* (Prescott Valley), the *Ajo Copper News*, and the *Arizona Daily Star* (Tucson).

On March 2, 2023, by Procedural Order, intervention was granted to Calpine.

Also on March 2, 2023, WRA filed a Motion for Leave to Intervene, and Ms. Kristin Nelson filed an Individual Intervention Request.

On March 3, 2023, EVgo filed an Application for Leave to Intervene. Additionally, after business hours on March 3, 2023, ASDA filed an Application for Leave to Intervene.

On March 6, 2023, APS filed a copy of a presentation made at the January 19, 2023, AG-X collaborative meeting and, separately, a copy of a presentation made at the February 28, 2023, AG-X collaborative meeting.

On March 7, 2023, IBEW Locals filed a Notice of Appearance for Clara S. Acosta.[7]

On March 7, 2023, at its Open Meeting, the Commission considered, in Docket No. E-00000A-22-0103 ("Community Solar Docket"), both (1) a Staff-proposed Commission Policy for the Development and Integration of Competitive Community Solar and Community Energy Storage Projects in Arizona ("Community Solar Policy") and (2) a Motion to Amend Decision No. 78784[8] pursuant to A.R.S. § 40-252. The Commission voted to modify Decision No. 78784, *inter alia*, by requiring that any evidentiary hearing related to implementing a community solar program take place in the context of a rate case and that any proposed community solar programs must comply with the Commission's policy statement on Community Solar Programs.[9]

Also on March 7, 2023, local counsel for the Nation filed a Motion to Associate Counsel Pro Hac Vice requesting that Todd F. Kimbrough be permitted to appear before the Commission as counsel pro hac vice for the Nation in this matter.

On March 8, 2023, by Procedural Order, intervention was granted to Sierra Club.

Also on March 8, 2023, a Procedural Order was issued (1) directing APS to make a filing in this docket indicating whether it intended to request approval of its Community Solar Program Proposal

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[7] Ms. Acosta has since changed her name to Clara S. Bustamante. Official notice is taken of the Notice of IBEW Locals' Attorney's Name Change filed on November 3, 2023.

[8] In Decision No. 78784 (November 22, 2022), the Commission did not adopt APS's proposed Community Solar Plan and deferred the matter to the Hearing Division for a formal evidentiary hearing on the issues. Official notice is taken of this decision.

[9] These requirements were adopted in Decision No. 78900 (March 23, 2023). Official notice is taken of this decision. The Commission's Policy Statement Regarding Statewide Community Solar and Storage was adopted in Decision No. 78899 (March 23, 2023), which was included as an attachment to Ms. Carnes's testimony in this matter, as Attachment KC-01RB to Exhibit APS-27.

in this docket and, if so, including the Community Solar Program Proposal and the proposed date by which APS would file direct testimony supporting the Community Solar Program Proposal, and (2) granting admission pro hac vice to Mr. Kimbrough.

On March 10, 2023, by Procedural Order, intervention was granted to WRA.

On March 14, 2023, by Procedural Order, intervention was granted to Ms. Nelson, EVgo, and ASDA.

On March 15, 2023, APS filed a copy of the presentation from its 2022 rate case technical conference held on March 14, 2023.

On March 20, 2023, APS filed a Notice as to Community Solar, stating that the Community Solar Program Proposal APS docketed in the Community Solar Docket did not comply with the Commission's adopted policy and that APS would not be proposing its approval in this docket.

On March 23, 2023, APS filed a Notice of Errata to supplement EAB-01DR to the Direct Testimony of Elizabeth Blankenship.

On March 24, 2023, Freeport filed a Notice of Withdrawal of Counsel as to Lauren A. Ferrigni.

On March 28, 2023, local counsel for Calpine filed a Motion for Pro Hac Vice Admission requesting that Gregory M. Adams be permitted to appear before the Commission as counsel pro hac vice for Calpine in this matter.

On March 29, 2023, by Procedural Order, admission pro hac vice was granted to Mr. Adams.

On April 10, 2023, FEA filed its First Data Request to APS.[10]

On April 18, 2023, AARP filed an Application to Intervene.

On April 20, 2023, local counsel for Sierra Club filed a Motion to Associate Counsel Pro Hac Vice requesting that Patrick Woolsey and Nihal Shrinath be permitted to appear before the Commission as counsel pro hac vice for Sierra Club in this matter.

On April 21, 2023, by Procedural Order, admission pro hac vice was granted to Mr. Woolsey and Mr. Shrinath.

On April 26, 2023, the Tribe filed an Application for Leave to Intervene.

[10] Discovery documents such as this are not required to be filed.

Also on April 26, 2023, by Procedural Order, intervention was granted to AARP.

On May 3, 2023, local counsel for Walmart filed a Motion for Pro Hac Vice Admission requesting that Justina A. Caviglia be permitted to appear before the Commission as counsel pro hac vice for Walmart in this matter.

On May 4, 2023, by Procedural Order, intervention was granted to the Tribe.

On the same date, by Procedural Order, admission pro hac vice was granted to Ms. Caviglia.

On May 5, 2023, Staff filed a Motion for Modification of Procedural Schedule, requesting that all of the established filing deadlines, the prehearing conference date, and the first day of hearing in this matter be extended by between 8 and 14 days. Staff stated that APS and RUCO had been consulted and were amenable to the changes.

Also on May 5, 2023, local counsel for AZLCG filed a Motion for Pro Hac Vice Admission requesting that Thorvald A. Nelson and Michelle Brandt King be permitted to appear before the Commission as counsel pro hac vice for AZLCG in this matter.

Also on May 5, 2023, SWEEP, Vote Solar, and WRA filed a Response in Support of Staff's Motion for Modification of Procedural Order.

On May 9, 2023, by Procedural Order, admission pro hac vice was granted to Mr. Nelson and Ms. Brandt King.

On May 10, 2023, by Procedural Order, in response to Staff's Motion for Modification of Procedural Order, the hearing was rescheduled to commence on August 10 and to continue on most days through September 15, 2023; the prehearing was rescheduled to be held on August 7, 2023; the deadlines for filing testimony were adjusted consistent with Staff's request; other procedural dates were adjusted accordingly; and the timeclock for this matter was extended by an additional 10 days.

On May 18, 2023, local counsel for AARP filed a Motion to Associate Counsel Pro Hac Vice requesting that John B. Coffman be permitted to appear before the Commission as counsel pro hac vice for AARP in this matter.

Also on May 18, 2023, by Procedural Order, admission pro hac vice was granted to Mr. Coffman.

On May 22, 2023, the Citizen Groups, Sierra Club, AriSEIA/SEIA, SWEEP, Vote Solar, Wildfire, and WRA filed a Joint Motion for Modification of Procedural Schedule, requesting that the deadline to issue discovery requests be extended from July 25 to August 7, 2023, and that the last public comment session be moved to August 10, 2023, the first day of hearing.

On May 24, 2023, APS filed a Response to the Joint Motion, not opposing the Joint Motion provided that any discovery request served on August 7, 2023, be directly related to matters first raised in rejoinder and be served on APS no later than 1:00 p.m., and that the existing and widely publicized public comment schedule not be changed. APS suggested that additional public comment could be taken on the first day of hearing.

On May 31, 2023, in response to the Joint Motion, a Procedural Order was issued establishing August 7, 2023, at 1:00 p.m. as the deadline for serving a discovery request and requiring that such a request be related to matters first raised in rejoinder; scheduling a public comment meeting to be held on August 10, 2023, at 10:00 a.m.; and ordering that the evidentiary hearing commence at 1:00 p.m. on August 10, 2023.

On June 1, 2023, by Procedural Order, an additional public comment meeting was scheduled to be held at 10:00 a.m. on August 2, 2023.

Also on the afternoon of June 1, 2023, a public comment meeting was held, during which 10 speakers provided comment on the APS application.

On June 5, 2023, FEA and AZLCG jointly filed the Direct Testimony and Exhibits of Christopher C. Walters; FEA filed the Redacted Direct Testimony and Exhibit of Michael P. Gorman; the Citizen Groups filed the Direct Testimonies of Nicole Horseherder, Eric Frankowski, and Mike Eisenfeld; SWEEP and WRA jointly filed the Direct Non-Rate Design Testimony of Brendon J. Baatz; WRA filed the Direct Non-Rate Design Testimony of Vijay Satyal; Vote Solar filed the Direct Non-Rate Design Testimony and Exhibits of Kate Bowman; the Tribe filed the Direct Testimonies of Timothy L. Nuvangyaoma and Kendrick Lomayestewa; the Nation filed the Direct Testimony and Exhibits of James W. Daniel; the IBEW Locals filed the Direct Testimony of Joseph Gable (Except Rate Design); AZLCG filed the Non-Confidential Direct Testimony of Kevin C. Higgins (Revenue Requirement); Sierra Club filed the Public Version Direct Testimony of Devi Glick; and JCUSD filed the Direct Testimonies of Bryan Field and Jeremy Calles.

Shortly after business hours on June 5, 2023, Staff filed the Direct Testimonies of David C. Parcell and Randell M. Johnson and the Redacted Direct Testimony of Ralph C. Smith; and RUCO filed the Redacted Direct Testimony of Frank W. Radigan and the Direct Testimony of David J. Garrett.

On June 6, 2023, RUCO filed the replacement Direct Testimony of David J Garrett, to correct pagination issues in the originally filed Direct Testimony.

On June 7, 2023, Commissioner Lea Márquez Peterson filed a letter referencing her June 21, 2022, letter filed in Docket No. E-01345A-21-0348 and this docket, requesting that APS and any other interested party file answers in this docket to a number of specific inquiries regarding APS's Power Supply Adjustor ("PSA").

Also, on the evening of June 7, 2023, a public comment hearing was held, during which 26 speakers provided comment on the APS application.

On June 8, 2023, Commissioner Lea Márquez Peterson filed a letter withdrawing the letter of June 7, 2023, because she had determined after additional review of the record in this matter that the issues raised in her letter had been addressed in filed testimony.

On June 14, 2023, RUCO filed a Motion for an Enlargement of Time to File Rate Design Testimony, requesting that RUCO be allowed to file its rate design testimony one day late, on June 16, 2023, due to counsel scheduling constraints.

On June 15, 2023, FEA filed the Direct Testimony and Exhibit of Michael P. Gorman; Wildfire filed the Direct Testimony of Claire Michael; the School Groups filed the Direct Testimony of Travis Sarver; Vote Solar filed the Direct Testimony and Exhibits of Kate Bowman; Kroger filed the Direst Testimony and Exhibits of Stephen J. Baron (Cost of Service and Rate Design); Walmart filed the Direct Testimony and Exhibits of Steve W. Chriss; EVgo filed the Direct Testimony of Lindsey R. Stegall; AriSEIA/SEIA jointly filed the Direct Testimony of Kevin Lucas – Redacted Public Version; Calpine and NRG jointly filed the Direct Testimonies (Rate Design) of Greg Bass and William B. Goddard; AZLCG filed the Non-Confidential Direct Testimony of Kevin C. Higgins; NRG filed the Direct Testimonies of Lance D. Kaufman and Travis Kavulla; and Staff filed the Redacted Direct Testimony of Ralph C. Smith, the Direct Testimony of David E. Dismukes, and the Redacted Direct Testimony of Emily S. Medine.

On June 16, 2023, RUCO filed the Rate Design Testimony of Frank W. Radigan.

On the morning of June 20, 2023, a public comment meeting was held, during which seven speakers provided comment on the APS application. During this public comment meeting, a speaker pointed out that APS had not provided notice of either the August 2 or August 10 public comment meetings. An APS representative stated that notice of both public comment meetings had been posted on APS's website.

Subsequently, also on June 20, 2023, a Procedural Order was issued ordering APS to provide prescribed public notice of the remaining public comment meetings in this matter (July 31, August 2, and August 10, 2023) as a bill insert by mail or email (depending on customer billing method), by posting the prescribed notice through a link on the main page of APS's website; and through APS's social media accounts on at least three occasions (the week of July 24, on July 31 before 9 a.m., and on August 7, 2023).

On the evening of June 20, 2023, a public comment meeting was held, during which 12 speakers provided comment regarding the APS application.

On June 22, 2023, Walmart filed an Application for Withdrawal and Substitution of Counsel for Walmart, requesting approval for Ms. Baldwin to withdraw as counsel of record.

Also on June 22, 2023, by Procedural Order, Ms. Baldwin's withdrawal as counsel of record for Walmart was approved.

On June 23, 2023, the Arizona Free Enterprise Club ("AFEC") filed a Motion for Leave to Intervene, which did not identify its interests in this matter or explain why it had not requested intervention by the intervention deadline of March 3, 2023.

On June 23, 2023, by Procedural Order, the AFEC Motion was held in abeyance, and AFEC was ordered, by July 3, 2023, to file supplemental information addressing the issues identified in the Procedural Order.[11]

On June 28, 2023, Sierra Club filed a Notice of Errata providing corrections to the Direct

[11] These issues were identification of its interests, why those interests could not be adequately represented by the numerous existing parties, the extent to which it desired to participate, and why its Motion was filed almost four months after the intervention deadline and after the deadline for intervenor direct testimony.

Testimony of Ms. Glick.

On July 5, 2023, APS filed an Opposition to AFEC's Motion for Leave to Intervene, which, *inter alia*, noted that AFEC had not filed the supplemental information required by the Procedural Order.

On July 6, 2023, by Procedural Order, AFEC's Motion for Leave to Intervene was denied.

On July 7, 2023, AFEC filed a Motion to Reconsider.[12]

On July 7, 2023, Sierra Club and AriSEIA/SEIA filed a Joinder in Opposition to AFEC's Motion for Leave to Intervene and Opposition to the Motion to Reconsider.

Between July 7 and 11, 2023, the IBEW Locals, ASDA, RUCO, the Nation, Walmart, Wildfire, the School Groups, AZLCG, the Tribe, the Citizen Groups, SWEEP and WRA (jointly), Sierra Club, FEA, JCUSD, Calpine, Kroger, Vote Solar, AriSEIA/SEIA, Calpine, Freeport, APS, Tesla, EVgo, NRG, Brookfield, Staff, AARP, and AZCPA filed Notices regarding their intended manner/s of participation (in-person or remote via WebEx) for their representatives and witnesses at the hearing and, for some, prehearing conference. Ms. Nelson made her filing regarding manner of participation on July 26, 2023. Several parties subsequently filed updates to these Notices, which are not recounted here but may be viewed on eDocket.

On July 10, 2023, TEP filed a Notice Re Hearing Participation stating that TEP had not submitted prefiled testimony, did not intend to present any witnesses in this matter, and did not intend to participate actively in the hearing for this matter by providing an opening statement, cross-examining other parties' witnesses, or otherwise. TEP requested to be excused from participating at both the prehearing and the hearing for this matter.

On July 11, 2023, by Procedural Order, TEP was excused from participating in the prehearing and hearing for this matter.

On July 12, 2023, APS filed the Rebuttal Testimonies of Theodore Geisler, Jacob Tetlow, Kerri Carnes, Monica Whiting, Andrew Cooper, Justin Joiner, Jessica Hobbick, Jamie Moe, Elizabeth Blankenship, Dr. Ron White, and Dr. Roger Morin.

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[12] The Motion to Reconsider was deemed denied after 20 calendar days by operation of language in the prior Procedural Orders issued in this matter.

On July 14, 2023, APS filed a Notice of Filing Updated Jurisdictional Only Schedules, which were based on APS witnesses' rebuttal testimonies.

On July 17, 2023, Brookfield filed an Amended Notice of Non-Participation, stating that it would not participate in the hearing for this matter.

On July 24, 2023, by Procedural Order, the hearing date of August 24, 2023, was vacated due to the Commission's determination that it would be holding a Contingency Open Meeting on that date.

On July 25, 2023, APS filed a letter stating that APS had distributed public notice of the remaining public comment meetings in this matter by mail or email issued between July 11 and 21, 2023, and by posting a link to the notice on the main page of APS's website. APS provided copies of the mail and email notice and the pertinent website pages.

On July 26, 2023, FEA filed the Surrebuttal Testimony of Michael P. Gorman; FEA and AZLCG jointly filed the Surrebuttal Testimony of Christopher C. Walters; Sierra Club filed the Surrebuttal Testimonies of Devi Glick and Sandy Bahr; the IBEW Locals filed the Surrebuttal Testimony of Joseph Gable (Except Rate Design); AriSEIA/SEIA filed the Surrebuttal Testimony of Kevin Lucas; the School Groups filed the Surrebuttal Testimony of Travis Sarver; Wildfire filed the Surrebuttal Testimony of Claire Michael; RUCO filed the Surrebuttal Testimonies of Frank Radigan and David Garrett; the Citizen Groups filed the Surrebuttal Testimony of Nicole Horseherder; Vote Solar filed the Surrebuttal Testimony of Kate Bowman; Calpine and NRG jointly filed the Surrebuttal Testimonies of Greg Bass and William B. Goddard; SWEEP and WRA jointly filed the Surrebuttal Testimony of Brendon J. Baatz; WRA filed the Surrebuttal Testimony of Vijay Satyal, Ph.D; AZLCG filed the Redacted Surrebuttal Testimony of Kevin C. Higgins; NRG filed the Surrebuttal Testimony of Travis Kavulla; the Tribe filed the Surrebuttal Testimony of Timothy Nuvangyaoma; EVgo filed the Surrebuttal Testimony of Lindsey R. Stegall; NRG filed the Surrebuttal Testimony of Lance D. Kaufman; JCUSD filed the Surrebuttal Testimony of Bryan Fields; Staff filed the Surrebuttal Testimonies of David C. Parcell, Ralph C. Smith, David E. Dismukes, Ph.D., and Emily Medine.

Also on July 26, 2023, the Nation, FEA, the Tribe, APS, ASDA, AriSEIA/SEIA, Tesla, NRG, EVgo, AZLCG, RUCO, the School Groups, Wildfire, Kroger, Walmart, Citizen Groups, SWEEP and

WRA (jointly),[13] Calpine, Vote Solar, Freeport, the IBEW Locals, Ms. Nelson, JCUSD, Sierra Club, and Staff filed lists of the witnesses each intended to cross examine at hearing. Several parties subsequently filed or requested in person at hearing to have their lists modified.

Also on July 26, 2023, AZCPA filed a Notice stating that it had not submitted any prefiled testimony, did not intend to present any witnesses, and did not intend to participate actively in the hearing and requesting to be excused from participating at the prehearing conference and the hearing.

On July 27, 2023, a Procedural Order was issued excusing AZCPA from participating in the prehearing and hearing for this matter.

On the morning of July 31, 2023, a public comment meeting was held, during which 17 speakers provided comment regarding the APS application.

On August 1, 2023, AARP filed a Notice stating that it did not at that time intend to cross examine any witnesses at hearing.

On the morning of August 2, 2023, a public comment meeting was held, during which 14 speakers provided comment regarding the APS application.

On August 2 through 4, 2023, parties filed summaries of their witnesses' testimony.

From August 2, 2023, through October 3, 2023, the parties who participated actively at hearing filed exhibits lists, exhibits, updated exhibits lists, and updated exhibits.[14] The parties also had hard copies of the exhibits delivered to the Hearing Division.

On August 3, 2023, APS filed a Notice of Errata to correct the Rebuttal Testimony of Jessica Hobbick.

On August 3, 2023, Staff filed a Notice of Errata to correct the Direct Testimony of Dr. Randell Johnson.

On August 3, 2023, APS filed a Notice of Joint Proposed Witness and Hearing Schedule, including a proposed calendar for the testimony of all identified witnesses, some of whom were designated as needing to testify on specific dates certain.

On August 4, 2023, local counsel for FEA filed a Motion to Associate Counsel Pro Hac Vice

[13] SWEEP and WRA jointly made an additional filing on July 27, 2023.
[14] This procedural history does not list these individual filings, but all of the individual filings are viewable on eDocket.

and Application for Withdrawal of Counsel, requesting admission pro hac vice for Major Leslie R. Newton and Captain Ashley N. George as counsel for FEA in this matter and approval of Major Holly L. Buchanan's withdrawal as counsel for FEA in this matter.

On August 4, 2023, by Procedural Order, admission pro hac vice was granted to Major Newton and Captain George, and Major Buchanan's withdrawal as counsel for FEA was approved.

On August 4, 2023, APS Filed the Rejoinder Testimonies of Mr. Geisler, Mr. Tetlow, Ms. Carnes, Mr. Cooper, Mr. Joiner, Ms. Hobbick, Mr. Moe, Ms. Blankenship, Dr. White, and Dr. Morin.

On August 7, 2023, several parties filed individual Issues Matrices. Additionally, Staff filed a Notice of Requesting an Extension of Time to File Issues Matrix ("Motion"), stating that Staff, APS, RUCO, and other intervenors were in the process of developing a Joint Issues Matrix and requesting an extension of the filing deadline to August 9, 2023, at 3:00 p.m.

On August 7, 2023, APS filed a letter stating that APS had provided notice of the remaining public comment proceedings via social media platforms Facebook, Instagram, LinkedIn, and X (formerly Twitter) once the week of July 24, 2023; once before 9 a.m. on July 31, 2023; and once on August 7, 2023. APS included screenshots of the notices provided.

Also on August 7, 2023, the prehearing conference for this matter was held, with APS, the IBEW Locals, Walmart, Freeport, Kroger, FEA, AZLCG, JCUSD, the Nation, the Tribe, the Citizen Groups, SWEEP, WRA, Vote Solar, Wildfire, the School Groups, Calpine, NRG, EVgo, Tesla, AriSEIA/SEIA, ASDA, Sierra Club, AARP, RUCO, and Staff appearing through counsel.[15] A number of procedural issues were discussed, most of which were resolved, and the Citizen Groups agreed to make a filing concerning a request for permission to have additional public comment occur on September 5, 2023, for members of the Nation.[16] Additionally, it was determined that the

[15] It was noted for the record that Brookfield has indicated it would not be participating in the hearing and that both TEP and ACPA had been excused from participating at both the prehearing and the hearing.

[16] It was determined that the joint proposed schedule filed by the parties would generally be followed for the order of witnesses and that the requested dates certain for witnesses would be accommodated. The parties were informed how they could review and obtain transcripts, that they would be permitted to cite to the videorecording rather than transcripts if desired for their briefs, and that APS would not be required to purchase read-only transcripts for the use of other parties. The Motion filed by Staff related to the filing of the joint issues matrix was granted. The Tribe requested to have the record from the 2019 rate case (Docket No. E-01345A-19-0236) admitted into this matter but was told that although this would not be appropriate, the Tribe could provide specific exhibits from the 2019 rate case as exhibits in this matter if it chose to do so. The Citizen Groups requested permission to have additional public comment taken on September 5, 2023, the date its witness Nicole Horseherder was set to testify, as Ms. Horseherder intended to bring several members of the Nation with

Administrative Law Judge ("ALJ") would file her prepared list of witnesses and those parties who desired to cross-examine each for the parties to review.

Also on August 7, 2023, a Hearing Division Memorandum was filed with the ALJ's list of witnesses and cross-examining parties attached.

Also on August 7, 2023, Freeport filed a Notice of Errata to its Issues Matrix.

On August 9, 2023, local counsel for WRA filed a Motion for Pro Hac Vice Admission of George Cavros.

Also on August 9, 2023, a Procedural Order was issued Granting Admission Pro Hac Vice to Mr. Cavros.

Also on August 9, 2023, APS filed a Notice of Joint Issues Matrix, stating that the attached Joint Issues Matrix included information provided by APS, Staff, RUCO, AZLCG, FEA, SWEEP, WRA, Wildfire, the School Groups, NRG, Calpine, AriSEIA/SEIA, Vote Solar, the Citizen Groups, Sierra Club, JCUSD, and the Tribe. In addition to the Joint Issues Matrix, APS included as attachments a more extensive "Staff's Issues List" received from Staff and a separate table of "Fully Resolve Issues."

Also on August 9, 2023, the Citizens Group filed a Request for Limited Additional Public Comment Period, requesting that additional public comment for approximately three to five individuals from the Navajo Nation be permitted on September 5, 2023, before Ms. Horseherder's testimony, and that either Ms. Horseherder or a Commission-supplied Diné interpreter provide translation for comments provided in Diné.

On the morning of August 10, 2023, a public comment meeting was held, during which 39 speakers provided comment regarding the APS application.

Also on August 10, 2023, SWEEP and WRA filed Notice of Issue to Add to Issue Matrix.

On the afternoon of August 10, 2023, the evidentiary hearing for this matter convened before a duly authorized ALJ of the Commission at the Commission's offices in Phoenix, with APS, the IBEW

her to the hearing, at least a couple of whom desired to provide spoken comment in Diné. AriSEIA/SEIA requested that each day of hearing be recorded on WebEx as a backup in case of technical issues with the normal videorecording. An ASDA request to be excused from the first day of hearing (including not making an opening statement) was approved. Additionally, several additional dates certain were approved for witnesses for the Tribe, JCUSD, and NRG.

Locals, Walmart, Freeport, Kroger, FEA, AZLCG, JCUSD, the Nation, the Tribe, the Citizen Groups, Wildfire, SWEEP, WRA, the School Groups, Vote Solar, Calpine, NRG, AriSEIA/SEIA, Tesla, EVgo, ASDA, Sierra Club, AARP, RUCO, and Staff appearing through counsel and Ms. Nelson appearing pro se. On the first day of hearing, the Citizen Group's Request for Limited Additional Public Comment Period was granted, and opening statements were provided. The evidentiary portion of the hearing occurred on August 11, 14-18, 21-23, 25, and 28-31; September 1, 5-8, 11, 13, and 15; and October 3, 2023. During the hearing, the following witnesses appeared on behalf of the parties shown:

Party/Parties	Witness	Witness Organization &Title
APS	Theodore Geisler	APS, President
	Andrew Cooper	APS, Chief Financial Officer
	Jacob Tetlow	APS, Executive Vice President of Non-Nuclear Operations
	Justin Joiner	APS, Vice President of Resource Management
	Jamie Moe	APS, Manager of Regulatory Affairs
	Monica Whiting	APS, Vice President of Customer Experience and Communications
	Dr. Ron White	Foster Associates Consultants, LLC, President
	Elizabeth Blankenship	APS, Vice President, Controller, and Chief Accounting Officer
	Kerri Carnes	APS, Director of Customer Grid Solutions
	Jessica Hobbick	APS, Director of Rates and Rate Strategy
	Dr. Roger Morin	Utility Research International, Principal; Emeritus Professor of Finance and Distinguished Professor of Finance for Regulated Industry at the Center for Regulated Industry at Robinson College of Business, Georgia State University
	Patrick Bogle (rebuttal case)	APS, Director of Financial Control
Wildfire	Claire Michael	Wildfire, Climate Equity Director
IBEW Locals	Joseph Gable	IBEW Local 387, Business Manager/Financial Secretary
Kroger	Steve Baron	J.P. Kennedy and Associates Inc., President
Calpine & NRG	Greg Bass	Calpine, Western Regulatory and Legislative Director
	William Goddard	WBG Consulting, Technical and Management Consultant for Electricity and Energy-Related Matters
NRG	Travis Kavulla	NRG, Vice President of Regulatory Affairs
	Dr. Lance Kaufman	Western Economics, Consultant
WRA	Dr. Vijay Satyal	WRA, Deputy Director of Regional Markets
Tribe	Timothy Nuvangyaoma	Tribe, Chairman
	Kendrick Lomayestewa	Tribe, Renewable Energy Office Manager
AZLCG	Kevin Higgins	Energy Strategies, Principal

Walmart	Steve Chriss	Walmart, Senior Director of Utility Partnerships
FEA	Michael Gorman	Brubaker & Associates, Managing Principal
SWEEP & WRA	Brendon Baatz	Gabel Associates, Vice President
School Groups	Travis Sarver	AES Defined, President
FEA & AZLCG	Christopher Walters	Brubaker & Associates, Associate
Sierra Club	Devi Glick	Synapse Energy Economics, Senior Principal
Vote Solar	Kate Bowman	Vote Solar, Interior West Regulatory Director
AriSEIA/SEIA	Kevin Lucas	SEIA, Senior Director of Utility Regulation and Policy
Citizen Groups	Nicole Horseherder	Tó Nizhóni Ání, Executive Director
	Eric Frankowski	Western Clean Energy Campaign, Executive Director
	Mike Eisenfeld	San Juan Citizens Alliance, Energy and Climate Program Manager
Nation	James Daniel	GDS Associates, Executive Consultant
JCUSD	Jeremy Calles	True Professionals, LLC, Principal; NGSB, LLC, Principal; Tolleson Union High School District, Superintendent
	Bryan Fields	JCUSD, Superintendent
Sierra Club	Sandy Bahr	Sierra Club Grand Canyon Chapter, Director
RUCO	David Garrett	Resolve Utility Consulting, Managing Member
	Frank Radigan	Hudson River Energy Group, Principal
Staff	David Parcell	Technical Associates, Incorporated, Consulting Economist and Principal
	Dr. Randell Johnson	Acelerex, CEO
	Dr. David Dismukes	Acadian Consulting Group, Consulting Economist
	Emily Medine	Energy Ventures Analysis, Inc., Principal
	Ralph Smith	Larkin & Associates, Senior Regulatory Consultant

The parties stipulated to the admissibility of the prefiled testimony of EVgo witness Lindsey Stegall, and Ms. Stegall did not testify at hearing.

On August 21, 2023, APS filed a Notice of Errata to correct the Direct Testimony of Jamie Moe.

Also on August 21, 2023, Calpine and NRG jointly filed a Notice of Errata to correct the Surrebuttal Testimony of Greg Bass.

Also on August 21, 2023, NRG filed a Notice of Errata to correct Exhibit LK-5 in the Surrebuttal Testimony of Lance Kaufman.

On August 23, 2023, APS filed a Notice of Errata to correct the Rebuttal Testimony of Jessica Hobbick.

On August 25, 2023, AriSEIA/SEIA, WRA, Vote Solar, Wildfire, SWEEP, the Citizen Groups, the Tribe, Sierra Club, and JCUSD filed a Motion for Order for Read-Only Transcript Access ("Motion Regarding Transcripts"), requesting that APS be ordered to purchase a read-only copy of the hearing transcript for this matter and to provide it to intervenors at no cost.

On August 28, 2023, APS filed a Notice of Errata to correct the Rebuttal Testimony of Dr. Roger Morin.

After hours on August 28, 2023, the Tribe filed a Notice of Withdrawal of Counsel, stating that Amy Mignella was terminating her representation of the Tribe on August 30, 2023.

On August 30, 2023, a Procedural Order was issued denying with prejudice the Motion Regarding Transcripts and ordering that Ms. Mignella's name be substituted with the name of the General Counsel for the Tribe, Fred Lomayesva, in the service list for this matter.

On August 30, 2023, AZLCG and FEA filled a Notice of Errata to correct the Direct Testimony of Christopher Walters.

On September 5, 2023, AriSEIA/SEIA filed a Notice of Filing Updated Unredacted Testimony of Kevin Lucas, providing two pages from that testimony showing information that previously had been redacted because it was originally designated confidential by APS.

On September 6, 2023, the Nation filed a Notice of Errata to correct the Direct Testimony of James Daniel.

On September 8, 2023, APS filed Notice that all Plans of Administration and AG-X Program Guidelines had been posted on their website under Service Schedules and Plans of Administration.

On September 11, 2023, Staff filed a Notice of Errata to correct the Direct Testimony of Dr. Randell Johnson.

On September 12, 2023, RUCO filed a Notice of Errata to correct Attachments A and B to the Surrebuttal Testimony of Frank Radigan.

On September 12, 2023, APS filed a Notice of Rebuttal Witness, stating that APS would be calling Patrick Bogle as a rebuttal witness on the narrow issue of recent amendments to the coal contracts for the Cholla and Four Corners Power Plants.

On September 13, 2023, Staff filed a Notice of Errata to correct the Supplemental Direct

Testimony and Surrebuttal Testimony of Ralph Smith.

On September 13, 2023, RUCO filed a Supplemental Notice of Errata to correct Attachments A and B to the Surrebuttal Testimony of Frank Radigan.

On September 15, 2023, APS filed a Notice of Errata to correct the Rejoinder Testimony of Theodore Geisler.

On September 20, 2023, FEA filed an Application for Withdrawal of Counsel, requesting that Captain Marcus Duffy be permitted to withdraw as counsel of record for FEA and noting that FEA would still be represented by Major Leslie Newton, Captain Ashley George, Thomas A. Jernigan, and Karen White.

Also on September 20, 2023, a Procedural Order was issued approving Captain Duffy's withdrawal as counsel of record for FEA and ordering that his name be removed from the service list.

On October 3, 2023, Staff filed a Notice of Errata to correct the Direct Testimony and Supplemental Direct Testimony of Ralph Smith.

Also on October 3, 2023, the hearing in this matter concluded. Before the hearing was adjourned, the parties were asked whether they had been provided a full and fair opportunity to present their cases, and no party made an indication to the contrary. It was determined that initial briefs and final schedules in this matter would be due on November 6, 2023, and that responsive briefs would be due on November 21, 2023.

On October 4, 2023, Brookfield filed a Notice of Withdrawal of Attorney, advising that Laura Granier was withdrawing as counsel of record for Brookfield and that Amber Rudnick would continue to represent Brookfield.

Also on October 4, 2023, a Procedural Order was issued approving the withdrawal of Laura Granier as counsel for Brookfield and requiring that all service upon Brookfield be made upon remaining counsel Amber Rudnick and Cory Talbot.

Also on October 4, 2023, APS filed a new Exhibit APS-117 and an Amended Exhibit APS-111, stating that Exhibit APS-117 included the non-confidential appendices that had previously been included in highly confidential Exhibit APS-111. APS stated that the Amended Exhibit APS-111 included only highly confidential material. APS requested that both Exhibit APS-117 and Amended

Exhibit APS-111 be admitted into evidence in this matter.

Also on October 4, 2023, by Procedural Order, Exhibit APS-117 and Amended Exhibit APS-111 were admitted.

Between October 31, 2022, and October 20, 2023, approximately 1,053 public comment filings, representing approximately 2,600 individuals,[17] were filed in this docket. The vast majority of public comments opposed APS's proposed rate increase. Most of the comments in favor of the rate increase specifically supported providing CCT to the coal-impacted communities.

On October 31, 2023, RUCO filed notice that its expert witness on revenue requirement and rate design, Frank Radigan, had died.

On November 1, 2023, in Docket No. E-99999A-22-0046, APS filed its 2023 Integrated Resource Plan ("2023 IRP").[18]

On November 3 and 6, 2023, post-hearing briefs[19] were filed by AARP, Wildfire, the School Groups, FEA, Vote Solar, SWEEP and WRA (jointly), RUCO, Walmart, AriSEIA/SEIA, the Citizen Groups, Kroger, the IBEW Locals, the Nation, NRG, Calpine, Tesla, APS, Staff, Sierra Club, JCUSD, AZLCG, and Ms. Nelson.[20] Additionally, RUCO separately filed its final schedules, and APS filed a notice that a USB drive containing APS's final schedules and associated workpapers had been delivered to the Hearing Division and uploaded to the 2022 Rate Case Extranet Site. AriSEIA/SEIA included in their Brief a request for the ALJ to take administrative notice of APS's 2023 IRP.

On November 7, 2023, Staff filed a Notice of Errata concerning its post-hearing brief, along with a copy of the corrected brief and a redline document showing the changes made.

On November 21, 2023, responsive briefs[21] were filed by the School Groups, Wildfire, RUCO, the Citizen Groups, SWEEP, the Nation, WRA, FEA, Vote Solar, Walmart, AriSEIA/SEIA, Calpine, NRG, Kroger, Sierra Club, APS, JCUSD, AZLCG, and Staff. Sierra Club in its Responsive Brief

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[17] Some commenters filed multiple comments, some filings included a number of different names, and some filings made by Commissioner offices included representative copies of numerous similar emails received directly by the offices.

[18] Pursuant to the requests made by AriSEIA/SEIA and Sierra Club, as described below, official notice is taken of the 2023 IRP and the assertions made by APS therein under A.A.C. R14-3-109(K) and (T)(5) and Arizona Rules of Evidence Rule 201.

[19] These filings had various names but each is referred to herein as "Brief" and in citations as "Br."

[20] Parties' final schedules are deemed admitted in this matter and are cited herein according to whether they were filed with a party's brief or separately.

[21] These filings had various names but each is referred to herein as "Responsive Brief" and in citations as "RBr."

joined in AriSEIA/SEIA's request for the ALJ to take administrative notice of APS's 2023 IRP.

III. Background

APS is a wholly owned subsidiary of Pinnacle West Capital Corporation ("PNW"), which is a publicly traded holding company that receives essentially all of its revenues and earnings from APS. (Ex. RUCO-7 at 45.) APS serves more than 1.3 million customers in 11 Arizona counties and has a service area of approximately 35,000 square miles. (Tr. at 143.) APS has approximately 33,000 miles of distribution lines, more than 6,000 miles of transmission lines, almost 500 substations, approximately 300,000 transformers, and more than 550,000 power poles and structures. (Ex. APS-8 at 7.) APS states that its 2021 generation resource mix was 29% gas, 25% nuclear, 16% coal, 15% demand side management ("DSM"), 10% renewables, and 5% market purchases, representing a portfolio that is 50% clean. (Ex. APS-11 at 6.) APS's coal fleet includes the Four Corners Power Plant ("4CPP") and the Cholla Power Plant ("Cholla"), both of which are currently operational but due to be retired, with Cholla to be retired in 2025 and the 4CPP to be retired in 2031. (Ex. APS-8 at 28.) The Navajo Generation Station ("NGS"), in which APS also had an ownership interest, retired in 2019. (Ex. APS-8 at 28.)

APS's current rates were set in Decision No. 78317 (November 9, 2021),[22] which used a test year ending June 30, 2019. APS appealed certain aspects of Decision No. 78317, resulting in a Court of Appeals Opinion Affirming in Part, Vacating in Part, and Remanding in Part to the Commission. (Ex. S-65 at 2.) The Commission filed a Petition for Review with the Arizona Supreme Court and subsequently requested suspension of the Arizona Supreme Court's procedural schedule so that Staff and APS could engage in settlement discussions. (Ex. S-65 at 2.) Staff and APS reached a Joint Resolution, approved by the Commission in Decision No. 78979 (June 28, 2023),[23] that authorizes APS to assess a court resolution surcharge of \$0.00175/kWh on all customer bills beginning on July 1, 2023, based on the following:[24]

- APS's being authorized to include in rate base, in the next rate case after the conclusion

[22] Decision No. 78317 was admitted herein as Exhibit RUCO-7.
[23] Decision No. 78979 was admitted herein as Exhibit S-65.
[24] Ex. S-65 at 4, Joint Resolution at 3-4.

of this matter, the remaining costs attributable to the $215.5 million in Selective Catalytic Reduction ("SCR") equipment at the Four Corners Power Plant disallowed in Decision No. 78317, which resulted in an additional annual revenue requirement of $25 million;[25]

- Reversal of the 20-basis point reduction to APS's return on equity ("ROE") in Decision No. 78317, which resulted in an additional annual revenue requirement of $12.6 million; and
- The lost revenue experienced by APS between December 2021 and June 20, 2023, as to both the SCRs being recovered through rate base and the addition of 20 basis points in ROE, which resulted in a total of $59.6 million, to be amortized over 48 months (i.e., an additional annual revenue requirement of $14.9 million for four years).

The Joint Resolution authorizes APS to collect the court resolution surcharge until the conclusion of APS's next general rate case after this matter, but requires that the court resolution surcharge be reduced (1) by the $12.6 million portion attributable to reversal of the 20-basis point reduction upon conclusion of this matter and (2) upon APS's collection of the total $59.6 million attributable to lost revenue from the SCRs between December 2021 and June 20, 2023. (Ex. S-65 at Joint Resolution at 5.)

APS's system has been experiencing consistent and substantial customer and load growth, and APS anticipates even greater growth in the next few years. (Tr. at 145, 152-153.) APS estimates that it will see a 60% increase in energy usage and a 40% increase in peak demand from 2023 to the turn of the decade, which will necessitate the addition of substantial new generation, transmission, and distribution infrastructure. (Tr. at 169-171, 360.) APS's service area experienced a record-breaking heat wave in July 2023 of 31 consecutive days with temperatures over 110° F, during which APS reached an all-time peak demand of 8,200 MW. (Tr. at 144-145, 210.) As of APS's application in this matter, the historical all-time peak had been 7,660 MW, reached in 2020. (Ex. APS-10 at 11.) During the summer of 2023, APS exceeded this historical all-time peak on 14 days. (Ex. APS-10 at 11.)

[25] The Joint Resolution stated that this calculation was based on an 8.9% return on equity and the cost of the SCRs, using a 2038 end of life for depreciation purposes for both the previously disallowed $215.5 million and the portion of SCR costs already in rate base. (Ex. S-65 at Joint Resolution at 4.)

APS plans to acquire more than 2,300 MW of on-peak resource capacity by 2026. (Tr. at 170.) APS states that it will be unable to add the substantial infrastructure to its system necessary to meet expected growth without the requested rate increase because APS has not yet recovered the capital for its assets already in service for customers, its credit ratings with all three credit agencies have dropped since the 2019 rate case, it has been put on negative watch by the credit rating agencies, its stock price has underperformed all utilities in the utility index by more than 50% over the last three years, and its net income decreased by 22% in 2022 and is anticipated to decrease again in 2023. (Tr. at 296-297.) According to APS, its requested rate increase is necessary to ensure reliability and resiliency, to secure a clean and balanced energy supply, and to improve customer support. (Tr. at 145.)

APS asserts that the requested rate increase is necessary to restore its financial stability so that it can cost-effectively access the capital needed to meet customer needs. (Tr. at 145, 148.) Mr. Geisler testified that APS recently was unable to borrow the full $500 million of debt that it sought at a competitive rate and had to settle for $400 million at an interest rate that is now the highest interest rate in APS's portfolio. (Tr. at 297, 306.) Likewise, Mr. Cooper testified that although APS has not been unable to finance any infrastructure project sought to serve its customers, it has only been able to obtain the financing at a higher cost than is desirable for APS and its ratepayers. (Tr. at 591-592.) Mr. Geisler testified that one of the things that keeps him up at night is worrying about whether APS can build the grid fast enough to keep up with growth while maintaining reliable service. (Tr. at 147-148, 393.)

IV. APS's Application as Amended

APS's rate application uses a test year ("TY") ending June 30, 2022. As amended, APS's application reports the following adjusted TY results for APS's jurisdictional operations and requests the following ($ amounts are in thousands):[26]

Original Cost Rate Base ("OCRB")	$10,359,616
Reconstruction Cost New Depreciated Rate Base ("RCND")	$22,497,874
Fair Value Rate Base ("FVRB")	$16,428,745
Fair Value Increment ("FVI")	$6,069,129
Operating Revenues from Base Rates	$3,377,773

[26] APS Post-Hearing Brief ("Br.) at Att. B at sched. A-1, sched. C-1. Hereinafter, references to a party's initial post-hearing brief are designated as "Br." and references to a party's responsive brief are designated as "RBr."

Operating Revenues from Surcharges	$209,412[27]
Other Electric Revenues	$251,851
Operating Income	$256,436
Current Rate of Return on OCRB	2.48%
Required Operating Income	$742,784
Required Rate of Return on OCRB	7.17%
Operating Income Deficiency on OCRB	$486,348
Gross Revenue Conversion Factor ("GRCF")	1.3345
Increase in Base Revenue Requirement Based on OCRB	$649,047
After Tax Return on FVI	$41,383
Requested Increase in Base Revenue Requirement	$690,430
Required Rate of Return with FVI	4.71%

APS's proposed adjusted capital structure, cost of long-term debt, and cost of equity ("COE") result in the following weighted average cost of capital ("WACC") ($ amounts are in thousands):[28]

Invested Capital	$ Amount	% Amount	Cost Rate	Composite Cost
Long-Term Debt	$4,979,867	48.07%	3.85%	1.85%
Preferred Stock	0	-	-	-
Common Equity	$5,379,749	51.93%	10.25%	5.32%
Short-Term Debt	0	-	-	-
Total	$10,359,616	100.00%		**WACC: 7.17%**

APS has requested that its rates be set based on its FVRB and using a return of 0.50% on its FVI, which would result in the following fair value rate of return ("FVROR"), assuming acceptance of APS's requested 10.25% COE ($ amounts are in thousands):[29]

Capitalization	$ Amount	% Amount	Cost Rate	Composite Cost
Long-Term Debt	$4,979,867	30.31%	3.85%	1.17
Common Equity	$5,379,749	32.75%	10.25%	3.36
FVI	$6,069,129	36.94%	0.50%	0.18
	$16,428,745			**FVROR: 4.71%**

In addition to requesting the FVRB, FVROR, and base revenue increase reflected above, APS's application, as amended, requests the following:

- Approval to implement a new System Reliability Benefit Mechanism ("SRB") that would allow APS to recover, between rate cases, the carrying costs for new APS-owned generation resource

[27] When calculating its TY operating income, APS includes a pro forma adjustment to deduct these TY surcharge revenues. (APS Br. at Att. B at sched. C-1.)
[28] *See* APS Br. at Att. B at sched. D-1, sched. A-1.
[29] APS Br. at Att. B at Sched. A-1, Sched. D-1.

projects with costs exceeding $50 million that are obtained through all source RFPs ("ASRFPs") and placed into service, with coal-fired generation resources excluded;[30]

- Approval to revise the Power Supply Adjustor Mechanism ("PSA") by increasing the annual limit on PSA increases from $0.004/kWh to $0.006/kWh and requiring APS to notify Commission Staff if the under-collected PSA balance exceeds $150 million;[31]
- Approval to maintain the Lost Fixed Cost Recovery Mechanism ("LFCR") as an independent adjustment mechanism, to modify the LFCR Plan of Administration ("POA") to change the earnings test, and to include $58.5 million in reported TY lost fixed costs in base rates while removing the same amount from the LFCR;[32]
- Approval of the following related to the Demand Side Management Adjustment Charge ("DSMAC"):
  - Waiver of A.A.C. R14-2-2411 and R14-2-2419 so that DSM performance incentives for APS are not calculated solely based on energy efficiency ("EE") and instead include energy savings achieved through both EE and demand response ("DR"),
  - Revision of the DSMAC POA to reflect that the performance incentive calculation allows DR program savings to be included with EE program savings, and
  - Inclusion in base rates of the $39.4 million collected in the DSMAC during the TY while removing the same amount from the DSMAC;[33]
- Approval to maintain the Renewable Energy Standard Adjustment Charge ("REAC") in its current form and to include in base rates $1.9 million in Solar Communities costs collected in the REAC while removing the same amount from the REAC;[34]
- Approval to eliminate the Environmental Improvement Surcharge Mechanism ("EIS") and transfer $10.3 million into base rates;[35]
- Approval to retain the Transmission Cost Adjustment Mechanism ("TCA") in its current

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[30] APS Br. at 34, Att. C.
[31] APS Br. at 40, 43, 139; Ex. APS-30 at 7; Ex. APS-6 at 17.
[32] APS Br. at 48; Ex. APS-29 at 5, 7-8; Ex. APS-30 at 9; Tr. at 2808.
[33] APS Br. at 51-52, 138; Tr. at 2364, 2405-2406; Ex. APS-99. APS desires to continue collecting in base rates the $20 million of DSM expenses currently included in base rates. (APS Br. at 138.)
[34] APS Br. at 54, 138.
[35] APS Br. at 54, 138; Ex. APS-29 at 5.

form;[36]

- Approval to retain the Tax Expense Adjustment Mechanism ("TEAM") in its current form and with its current zero rate;[37]
- Approval to use the Average and Excess – Four Coincident Peak ("A&E-4CP") method to allocate production demand costs in its Cost of Service Study ("COSS") in its next rate case rather than the Average and Peak – Four Coincident Peak ("A&P-4CP") method supported by Staff in its last rate case (and this rate case), which APS was required to use in its COSS in this matter;[38]
- Approval to continue allocating production demand costs to customers enrolled in the AG-X program in the same manner as those costs are allocated to non-AG-X customers;[39]
- Approval to continue allocating secondary distribution costs using the sum of individual max ("SIM") allocator;[40]
- Approval of APS's solar COSS methodology for use in future rate case proceedings;[41]
- Approval of an even distribution for revenue allocation that results in equivalent average base rate increases for both the residential and general service customer classes;[42]
- Approval of modifications to the AG-X program to require resource adequacy for AG-X electricity supplies, to expand AG-X eligibility to smaller aggregated general service customers without expanding the 400 MW program cap, and to require notice within specified periods for leaving the AG-X program or changing the means of obtaining resource adequacy for the AG-X program;[43]
- Approval to retain its three residential rate plan options without introducing seasonality to its Residential Fixed Energy Charge plan, although APS designed two seasonal versions of this

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[36] APS Br. at 139.
[37] APS Br. at 139.
[38] APS Br. at 55, 58; Ex. APS-24 at 18.
[39] APS Br. at 58-59; Ex. APS-11 at 29-30; Ex. APS-25 at 9.
[40] APS Br. at 59-60; Ex. APS-25 at 11-12.
[41] APS Br. at 63; Ex. APS-25 at 16. As APS completed two separate solar COSS, using different methodologies, it is not altogether clear which solar COSS methodology APS desires to have approved for future usage. (*See* APS Br. at 60-63.)
[42] APS Br. at 63-64, Att. B at sched. A-1.
[43] APS Br. at 65-66; Ex. APS-98 Amended.

rate as required by Decision No. 78317;[44]

- Approval to increase the basic service charge ("BSC") for residential customers to recover a larger portion of fixed costs through the BSC;[45]
- Approval of modifications to the Energy Support Program and Medical Care Equipment Support Program rate riders to provide two tiers of discounts based on income level, with significantly higher discounts provided to those customers with incomes of 0% to 75.99% of the Federal Poverty Level and with monthly dollar caps at each tier;[46]
- Approval to continue the accounting order allowing APS to defer the limited income programs' discounts (fees or credits) to the extent that they are higher or lower than TY levels, as previously approved in Decision No. 78317, for reconciliation in APS's next rate case;[47]
- Approval to continue funding APS's Crisis Bill Assistance program at $2.5 million per year, as approved in Decision No. 78317;[48]
- Approval to add two new off-peak holidays for residential customers on the TOU 4 p.m. to 7 p.m. Weekdays and TOU 4 p.m. to 7 p.m. Weekdays with Demand Charge rate plans and customers on the frozen Saver Choice Plus demand rate—Juneteenth and Indigenous People's Day/Columbus Day;[49]
- Approval to cancel or freeze the R-Tech rate;[50]
- Rejection of NRG's Residential Buy-Through Pilot program;[51]
- Approval to continue APS's Solar Communities Program for another three years at its existing annual funding level and to expand program eligibility to include all municipal governments within APS's service territory;[52]
- Rejection of AriSEIA/SEIA proposals to require APS to adopt a community solar program;[53]

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[44] APS Br. at 83-84; Ex. APS-29 at 14; Ex. APS-30 at 16.
[45] APS Br. at 84; Ex. APS-30 at 15-16; Ex. APS-32 at 6-7.
[46] APS Br. at 87-88; Ex. APS-16 at 7; Ex. APS-17 at 4; Tr. at 1799-1800, 1845-1846.
[47] APS Br. at 88, 139; Ex. APS-29 at 19-20, 27-28.
[48] APS Br. at 88-89; Ex. APS-16 at 9.
[49] APS Br. at 89-90; Ex. APS-16 at 15.
[50] APS Br. at 90; Ex. APS-32 at 9.
[51] APS Br. at 91-96.
[52] APS Br. at 96-97; Ex. APS-27 at 24-25.
[53] APS Br. at 97-99.

- Rejection of AriSEIA/SEIA's proposed Bring-Your-Own-Device ("BYOD") program;[54]
- Rejection of proposals for APS to be required to meet specified formal requirements for future procedures or to obtain Commission approvals associated with its potential involvement in western regional wholesale day-ahead markets;[55]
- Approval of the ratepayer-funded Coal Community Transition support proposed by APS in the 2019 rate case and not approved in Decision No. 78317, with the total of $106.5 million to be collected through the REAC over nine years, with the first year collection to be approximately $16 million;[56]
- Approval of APS's proposed base fuel rate of 3.8321¢/kWh, which is an increase of 0.687¢/kWh over the base fuel rate approved in Decision No. 78317, with a corresponding reduction to the PSA;[57]
- Approval of a requirement for APS to work with parties through its Resource Planning Advisory Committee to examine whether and how DSM and EE measures can be evaluated in resource planning to reflect their value for risk reduction and as a hedge;[58]
- A determination that APS's coal procurement costs, including liquidated damages costs, for the 4CPP and Cholla have been reasonable and in the best interest of customers;[59]
- Elimination or waiver of the following compliance filings and requirements:
  - The two compliance requirements related to the E-32 L Storage Pilot included in Decision No. 76295, as those have been superseded by Decision No. 78317;[60]
  - The compliance requirement in Decision No. 68741 (June 5, 2006)[61] concerning annual filings relating to Competitive Electric Affiliates;[62]
  - The compliance requirement in Decision No. 77270 (June 27, 2019)[63] for tracking and

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[54] APS Br. at 100-103.
[55] APS Br. at 114-115.
[56] APS Br. at 115-117, 139.
[57] APS Br. at 119, 139; Ex. APS-24 at 5.
[58] APS Br. at 120; Ex. APS-14 at 23-24.
[59] APS Br. at 120-127.
[60] APS Br. at 127; Ex. APS-29 at Att. JEH-19DR.
[61] Official notice is taken of this decision.
[62] APS Br. at 127-128; Ex. APS-29 at Att. JEH-19DR.
[63] Official notice is taken of this decision.

quarterly reporting of gross margins from higher-than-projected revenues;[64] and

- The compliance requirement in Decision No. 76295 concerning APS being required to meet with interested parties once a specified number of customers are signed up for an Optional R-Tech Pilot Rate Program;[65]

- Approval to keep the overall Palo Verde Generating Station ("Palo Verde") decommissioning funding level the same as reflected in the TY but to allocate the entire amount to Palo Verde Unit 2 going forward, as follows:
  - By having the Commission include specific language[66] in its final decision, and
  - By having the Commission include as an appendix to the final decision in this case Attachment EAB-02DR, which was part of admitted Exhibit APS-20;[67]
- Rejection of AriSEIA/SEIA's request that APS be prohibited from continuing its microgrid program, under which it plans, constructs, and monitors microgrids to provide backup power for critical infrastructure customers that require high levels of reliability;[68]
- Rejection of the IBEW Locals' request that APS be required to retain outside experts to generate a report regarding potential projects to improve system resiliency;[69] and
- Approval of APS's proposed modifications to Service Schedules 1, 3, and 9.[70]

V. **Uncontested Issues**

The following requests made by APS in its application, as amended, are uncontested:

- Elimination of the EIS and transfer of $10.3 million collected in the EIS into base rates;[71]
- Retention of the TCA in its current form;[72]
- Retention of the TEAM in its current form and with its current zero rate;[73]
- Retention of APS's three residential rate plan options without introducing seasonality to the

[64] APS Br. at 128; Ex. APS-29 at Att. JEH-19DR.
[65] APS Br. at 128; Ex. APS-29 at Att. JEH-19DR.
[66] The specific language reads: "The decommissioning costs as recommend[ed] by APS are adopted as set forth in the decommissioning contribution schedule at Appendix [*X*] to this Decision." (APS Br. at 129; Ex. APS-20 at 45.)
[67] APS Br. at 129, 139; Ex. APS-20 at 44-45.
[68] APS Br. at 129-134.
[69] APS Br. at 136.
[70] APS Br. at 137.
[71] APS Br. at 54, 138; Ex. APS-29 at 5; Ex. RUCO-1 at 7; Ex. S-21 at 11, 31-33.
[72] APS Br. at 139; Ex. RUCO-1 at 7; Ex. S-21 at 30-31.
[73] APS Br. at 139; Ex. RUCO-1 at 7; Ex. S-21 at 42-43.

Residential Fixed Energy Charge plan;[74]

- Modification to the Energy Support Program and Medical Support Program rate rider to provide two tiers of discounts based on income level, with significantly higher discounts provided to those customers with incomes of 0% to 75.99% of the Federal Poverty Level and with monthly dollar caps at each tier;[75]
- Continuation of the accounting order allowing APS to defer the limited income programs' discounts (fees or credits) to the extent that they are higher or lower than TY levels, as previously approved in Decision No. 78317, for reconciliation in APS's next rate case;[76]
- Continuation of the \$2.5 million per year funding for APS's Crisis Bill Assistance program;[77]
- Addition of two new off-peak holidays for residential customers on the TOU 4 p.m. to 7 p.m. Weekdays and TOU 4 p.m. to 7 p.m. Weekdays with Demand Charge rate plans and customers on the frozen Saver Choice Plus demand rate—Juneteenth and Indigenous People's Day/Columbus Day;[78]
- A requirement for APS to work with parties through its Resource Planning Advisory Committee ("RPAC") to examine whether and how DSM and EE measures can be evaluated in resource planning to reflect their value for risk reduction and as a hedge;[79]
- Elimination or waiver of the following compliance filings and requirements:
    - The two compliance requirements related to the E-32 L Storage Pilot included in Decision No. 76295, as those have been superseded by Decision No. 78317 and Decision No. 78966 (May 9, 2023);[80]
    - The compliance requirement in Decision No. 68741 (June 5, 2006)[81] concerning annual filings relating to Competitive Electric Affiliates;[82]

[74] APS Br. at 83-84; Ex. APS-29 at 14; Ex. APS-30 at 16; Ex. RUCO-3 at 11-12; Ex. S-12 at 3, 38-39.
[75] APS Br. at 87-88; Ex. APS-16 at 7; Ex. APS-17 at 4; Tr. at 1799-1800, 1845-1846; Ex. RUCO-3 at 15-17; Ex. WF-2 at 3; Ex. S-12 at 42-45.
[76] APS Br. at 88, 139; Ex. APS-29 at 19-20, 27-28; Ex. WF-1 at 18-21; Ex. WF-2 at 4; *see* Ex. S-24 at 42.
[77] APS Br. at 88-89; Ex. APS-16 at 9; Ex. S-12 at 41.
[78] APS Br. at 89-90; Ex. APS-16 at 15; Ex. RUCO-3 at 13-14; Ex. S-12 at 40.
[79] APS Br. at 120; Ex. APS-14 at 23-24; Ex. SWEEP-2 at 8-10.
[80] APS Br. at 127; Ex. APS-29 at Att. JEH-19DR; Ex. S-21 at 43-47.
[81] Official notice is taken of this decision.
[82] APS Br. at 127-128; Ex. APS-29 at Att. JEH-19DR; Ex. S-21 at 47-48.

- The compliance requirement in Decision No. 77270 (June 27, 2019)[83] for tracking and quarterly reporting of gross margins from higher-than-projected revenues;[84] and
- The compliance requirement in Decision No. 76295 concerning APS being required to meet with interested parties once a specified number of customers are signed up for an Optional R-Tech Pilot Rate Program;[85]

- Maintaining the overall Palo Verde decommissioning funding level as reflected in the TY but allocating the entire amount to Palo Verde Unit 2 going forward, as follows:
  - By having the Commission include specific language[86] in its final decision, and
  - By having the Commission include as an appendix to the final decision in this case Attachment EAB-02DR, which was part of admitted Exhibit APS-20;[87] and
- Approval of APS's proposed modifications to Service Schedules 1, 3, and 9.[88]

Resolution of each of the above uncontested issues as requested by APS is supported by substantial evidence in the record for this matter, as cited herein. It is just, reasonable, and in the public interest to approve them and to include in the ordering paragraphs herein the specific provisions to bring each to fruition.

VI. Contested Issues Other Than Cost of Capital[89]

A. Rate Base Issues (Unrelated to the 4CPP)

1. Post-Test-Year Plant ("PTYP") Allowed & Method of Calculation

APS Proposal

APS is requesting to have \$613.5 million[90] in net PTYP added to rate base. (APS Br. at 3, Att.

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[83] Official notice is taken of this decision.
[84] APS Br. at 128; Ex. APS-29 at Att. JEH-19DR; Ex. S-21 at 48-49.
[85] APS Br. at 128; Ex. APS-29 at Att. JEH-19DR; Ex. S-21 at 49-50.
[86] The specific language reads: "The decommissioning costs as recommended by APS are adopted as set forth in the decommissioning contribution schedule at Appendix X to this Decision." (APS Br. at 129; Ex. APS-20 at 45.)
[87] APS Br. at 129, 139; Ex. APS-20 at 41-45, Att. EAB-02DR.
[88] APS Br. at 137; Ex. APS-29 at 25-26; Ex. APS-30 at 31-32; Ex. S-21 at 3.
[89] For each contested issue included in this Section, other than the issue of coal-impacted community transition, a party's argument is presented only if the party briefed the contested issue. Because the Tribe participated in the hearing for this matter but did not file a post-hearing brief, possibly due to the loss of its primary legal representative, the Tribe's arguments presented at hearing are included. Also, in some instances, a Staff or RUCO position taken at hearing is mentioned for clarity even though Staff or RUCO did not brief the issue.
[90] This amount total, which was first proposed in APS's Brief and thus was not expressly included in the evidentiary record for this matter, represents a decrease from APS's rejoinder position of \$634.3 million, which APS attributed to an update to the 4CPP Effluent Limitation Guidelines Plant Modifications project costs and a credit recently received through a

B at sched. B-2 at 1-2.) The net PTYP represents $1.273 billion in PTYP, reduced by rolled forward TY amounts of accumulated depreciation and taxes. (*See* APS Br. at Att. B at sched. B-2;[91] Ex. APS-10 at 2; Ex. APS-9 at 6; Tr. at 971.) With the exception of one project, the 4CPP Effluent Limitation Guidelines Plant Modifications ("ELG Project"), discussed further below, all of the PTYP was placed into service by June 30, 2023, i.e., within 12 months after the TY. (Ex. APS-10 at 1-2, Att. JT-01RJ through Att. JT-06RJ.) APS removed from PTYP a total of $132,852,961, which it stated represented growth-related plant, all of which was distribution-related plant that hooks up new customers to the grid. (Tr. at 605-606, 967-968; Ex. APS-9 at att. JT-01RB at 2.) APS does not report capital budgets for distribution, production, or transmission by growth and non-growth related plant projects; thus, when there is a rate case, APS's accounting and operations teams review the capital investments and determine which plant was needed for future growth. (Tr. at 970, 1974.) Ms. Blankenship testified that APS erred on the side of excluding potentially growth-related PTYP projects when there was doubt. (Tr. at 1975-1976.) According to APS, all of the PTYP projects were necessary and useful to serve customers who existed at the end of the TY, not future customers. (APS Br. at 6.)

APS asserts that including PTYP in rate base is in ratepayers' best interests because it reduces regulatory lag inherent with the use of a historical TY and helps to minimize the frequency of rate cases. (Tr. at 974; Ex. APS-9 at 2; Ex. APS-6 at 11-12.) APS also claims that allowing PTYP is

manufacturer's warranty. (APS Br. at 4; *see* Ex. APS-10 at 2.) APS's PTYP additions are broken down into broad categories and at the rejoinder stage included $14,400,041 for Customer Technology Innovation; $232,607,803 for Information Technology and Facilities; $256,290,151 for Distribution; $56,093,611 for Nuclear Generation; $219,398,773 for Other Generation; and $528,301,325 for Renewable Generation. (Ex. APS-10 at att. JT-01RJ, JT-02RJ, JT-03RJ, JT-04RJ, JT-05RJ, and JT-06RJ.) The Customer Technology Innovation category includes approximately 600 Level 2 EV chargers with a total cost of $6,702,716, and five Direct Current Fast Charging EV charging stations with a total cost of $7,697,326. (Ex. APS-10 at att. JT-01RB.) APS owns the charging equipment and the infrastructure feeding it, and the charging equipment is in service, but APS does not operate the charging equipment. (Tr. at 992-994, 1065; Ex. APS-10 at Att. JT-01RB.) APS believes these investments allow APS to support the electrification of transportation, that they also allow APS to learn about charging behaviors and habits and how best to build such infrastructure, and that the Commission has supported APS's transportation electrification plan. (Tr. at 995.) When asked why APS did not assign these costs only to ratepayers with EVs, Mr. Tetlow stated that APS does not know who those ratepayers are or where they charge their vehicles and that he does not see in practical terms how APS would be able to do that. (Tr. at 995-996.) Additionally, Mr. Tetlow stated, APS considers these investments to be for the future of serving everyone, as the transportation sector is moving away from combustion engines. (Tr. at 996.)

[91] Although Schedule B-2 included in Attachment B to APS's Brief includes notes suggesting that the PTYP included in rate base by APS represents only 9 months, APS has consistently stated throughout this matter that the PTYP (with the exception of the 4CPP Effluent Limitation Guidelines Plant Modifications) represents plant additions made through June 30, 2023, which is 12 months after the end of the TY. (*See* APS Br. at Att. B at Sched. B-2 at 1-2; Ex. APS-1; Ex. APS-2 at 10.)

standard practice at the Commission, not special ratemaking treatment, and that the Commission's not allowing PTYP in rate base in this matter would not be well received by the credit, debt, and equity markets.[92] (Tr. at 978; Ex. APS-6 at 12.) Mr. Tetlow testified that allowing the PTYP to go into rate base is important because APS desires to create space between rate cases, the PTYP is in service already, APS's system is experiencing record growth, APS anticipates the addition of a large number of "mega customers" who will use upwards of 10,000 MW, APS needs a robust system,[93] and APS cannot compromise on reliability. (Tr. at 990-991.) Mr. Cooper added that while APS is planning for and addressing growth in its service area, the types of investments that are at stake in this case include spending to replace aging infrastructure and make infrastructure more resilient for existing customers due to the age of the infrastructure, increasing needs, and the impacts of extreme heat, not spending to serve new customers or new growth. (Tr. at 765-766, 779.)

Further, APS opposes AZLCG's proposal to have PTYP depreciation expense established using the expected per-book expense for the PTY period rather than using an annualized amount, stating that AZLCG's proposal does not adhere to Generally Accepted Accounting Principles ("GAAP") or the matching principle. (APS Br. at 8; Ex. APS-22 at 10-11.) APS asserts that its annualization method is consistent with GAAP and the matching principle and ensures that the costs of the asset are allocated over the period in which the asset contributes to revenue generation. (APS Br. at 8; Ex. APS-22 at 10-11.)

<u>AZLCG</u>

AZLCG argues that because the Commission's rules do not prescribe the manner in which the Commission must measure PTYP, only requiring that OCRB be calculated based on end-of-TY values, PTYP may be measured based on an alternate methodology. (AZLCG Br. at 10; *see* Tr. at 2018-2019; A.A.C. R14-2-103(A)(3).) AZLCG proposes that the Commission require APS's PTYP to be valued

[92] Mr. Tetlow acknowledged that the inclusion of more than $717 million of PTYP in APS's rate base in the last APS rate case did not prevent APS's credit rating from being downgraded, APS's being placed on negative watch with credit rating agencies, or APS's filing its application in this matter less than one year after Decision No. 78317 was issued. (Tr. at 975-978.)

[93] Part of the PTYP is for advanced grid technologies that allow APS to see what is happening on the distribution grid (power quality, frequency, voltage) and to start automating the grid such as through fault location, isolation, and service restoration, which allows APS to remotely open and close switches to reroute power. (Tr. at 989.) The advanced grid technologies allow for a more dynamic distribution grid that can accommodate more technology layered onto it. (Tr. at 989-990.)

using an average-of-period methodology rather than an end-of-period methodology, stating that the average-of-period methodology is commonly used and more accurate, APS uses the average-of-period methodology to measure its transmission plant consistent with FERC requirements,[94] and the average-of-period methodology better balances APS and ratepayer interests. (AZLCG Br. at 10-16.) AZLCG asserts that other public utility regulators ("PUCs") have required use of an average rate base methodology for plant that goes into service after a utility's rate case application and quotes an "authoritative text" characterizing the use of an end-of-period rate base as "exceptional" and stating that the use of an average rate base "accurately reflects the relationship between test year investment, revenues, and expenses." (AZLCG Br. at 11-12 (citing decisions from the Wyoming PUC and Colorado PUC and quoting Leonard Saul Goodman, *The Process of Ratemaking* (1998) at 736-737).) Mr. Higgins testified that APS's PTYP should be determined by averaging each month's plant and depreciation values, which change each month, so that APS only earns a return on the typical value over the course of the PTY period. (AZLCG Br. at 13-14; Ex. AZLCG-1 at 16-18; Tr. at 3022.) AZLCG further argues that it is "unreasonably aggressive" "doubling up" of regulatory lag mitigation methods for APS to be allowed to include PTYP in rate base (one method) and to set the value of PTYP based on end-of-period measurement (another method). (AZLCG Br. at 14; Ex. AZLCG-1 at 15-16; *see* Ex. APS-6 at 12; Ex. APS-22 at 9.) AZLCG argues that APS's unjust and unreasonable request for 12 months of PTYP valued at end-of-PTY period values should not be approved just because the Commission has previously allowed it. (AZLCG Br. at 15; Ex. AZLCG-1 at 15; *see* Ex. RUCO-1 at 10-13.) Further, AZLCG adds, regulatory lag provides an incentive for APS to operate efficiently. (AZLCG Br. at 15; Tr. at 3089.) AZLCG notes that if its proposal is approved by the Commission, "several other adjustments" must also be made. (AZLCG Br. at 16 n.79, ex. KCH-3-F, ex. KCH-4-F, ex. KCH-5-F; Ex. AZLCG-1 at 24-25; AZLCG-5 at 15-16.)

In its Responsive Brief, AZLCG states that one of the "several other adjustments" necessary to carry out its average rate base adjustment is to set depreciation expense for PTYP at the expected per-

[94] FERC regulations (18 CFR § 35.13(h)(4)(i) and (ii)) require utilities to present their plant-in-service costs using a 13-month average for the current test year. (Ex. AZLCG-15 at 7.) APS acknowledged that it uses an average-of-period methodology to project current year transmission plant additions, that FERC regulations require it to set the transmission rate base using an average-of-period methodology, and that APS used the average-of-period transmission rate base to set its transmission rate base in this matter. (APS Br. at 13; Tr. at 1891, 1895, 1898.)

book expense for the PTY period rather than using an annualized amount as APS has done. (AZLCG RBr. at 4; *see* AZLCG Br. at 16 n.79.) AZLCG clarified that it is not recommending this method of setting depreciation expense for PTYP independent of other adjustments, only to effectuate AZLCG's recommendation to value PTYP using an average-of-period method. (AZLCG RBr. at 4.) AZLCG states that using per-books depreciation expense rather than annualized depreciation expense is the standard method when using average rate base and conforms to the matching principle. (AZLCG RBr. at 4; Ex. AZLCG-5 at 16.)

Because RUCO's proposal to allow only 6 months of PTYP in rate base results in treatment comparable to AZLCG's proposal to value PTYP using an average-of-period method, AZLCG supports RUCO's proposal as the second best option to balance shareholder and ratepayer interests should the Commission not adopt AZLCG's position. (AZLCG Br. at 15-16; *see* Ex. RUCO-1 at 13; Tr. at 1889, 4367, 4721.)

AZLCG also criticizes APS's ad hoc method for determining whether PTYP is growth-related and asserts that it would be simpler and consistent with the matching principle for APS to include all PTYP in rate base and also recognize PTY revenues to match the PTYP. (AZLCG Br. at 17; AZLCG RBr. at 3.) AZLCG argues that APS's failure to include any additional revenues collected from ratepayers in the PTY period violates the matching principle because APS will be using mismatched historical TY billing determinants to recover its PTYP from ratepayers, which AZLCG states will overstate APS's revenue deficiency and result in increased costs for ratepayers and a "windfall" for APS. (AZLCG Br. at 18; Ex. AZLCG-1 at 25-26; Ex. RUCO-4 at 3; Tr. at 3022.) AZLCG also states that APS's claim that no incremental or current growth will be served by any of the energy produced from the PTYP generation investments does not pass muster, questioning APS's categorization of only distribution plant as growth-related and asserting that APS's claim that all growth-related plant has been removed should be rejected because APS provided no evidence demonstrating that the PTYP investments will not be used to serve at least some load growth; APS does not categorize or report capital budgets for distribution, production, or transmission projects as growth-related or non-growth-related; and APS projected high growth rates in its 2020 IRP and in this matter.[95] (AZLCG Br. at 19-20; Ex. RUCO-1 at 13-14; Ex. RUCO-4 at 4-5; Tr. at 970, 1156, 4876, 4888.) AZLCG cites with approval RUCO's analysis on the growth-related plant issue. (AZLCG Br. at 21; *see* Ex. RUCO-1 at 13-16; Tr. at 4876, 4888.) According to AZLCG, APS has excluded from PTYP only those investments that exclusively serve customer growth and, as a result, current customers will be required to pay the full price of assets that will be partially offset by customer growth, which is unjust and unreasonable and will lead to over-recovery of APS's revenue requirement and unreasonable regulatory lag for customers. (AZLCG Br. at 21-22; Ex. AZLCG-1 at 26-28.) AZLCG further argues that APS should not be permitted to argue that including PTY period revenues as an offset violates the Commission's historical TY framework while also requesting inclusion of PTYP, which can also be viewed as violating this framework. (AZLCG Br. at 22.) AZLCG asserts that APS's PTY period revenues are at least $50 million[96] and that recognizing $50 million in PTY revenue would more than offset the additional revenue requirement associated with including the growth-related PTYP, resulting in a better deal for ratepayers. (AZLCG Br. at 23-24, ex. KCH-6-F; Ex. AZLCG-1 at 26.) The Commission should adopt this compromise position advocated by AZLCG, it argues, because APS has "signaled . . . it would be amenable to recognizing revenues in the post-test-year period" if growth-related PTYP were also included. (AZLCG Br. at 23-24; Ex. AZLCG-5 at 18; Ex. APS-6 at 12; Tr. at 606.)

<u>RUCO</u>

RUCO argues that APS should be allowed to include in rate base only 6 months of PTYP, which should be reduced by also rolling forward 6 months of TY accumulated depreciation and by removing all growth-related PTYP. (RUCO Br. at 20-21.) RUCO states that its position on PTYP for this case was determined using criteria developed by Staff in Docket No. AU-00000A-19-0080 ("PTYP Generic Docket"), which provided that PTYP must: (1) be prudently invested; (2) reflect appropriate, efficient, effective, and timely decision-making; (3) be of a magnitude relative to the utility's total investment

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[95] AZLCG cites Mr. Geisler's testimony that APS's expected growth is requiring investments in generation and transmission infrastructure and that the Evans Churchill substation included in PTYP was needed to keep up with growth in the downtown Phoenix area, as well as Dr. Johnson's testimony that the Evans Churchill substation will be used to serve existing and future customers. (AZLCG Br. at 21; Tr. at 170, 4350, 4357, 4360; Ex. APS-91 at 3.)

[96] AZLCG asserts that APS did not dispute Mr. Higgins's calculation of PTY revenues, that RUCO estimated the additional revenues to be as much as $100 million annually, and that Mr. Smith agreed that APS's sales and revenues continued to grow during the PTY period. (AZLCG Br. at 23; Ex. AZLCG-1 at 26; Ex. RUCO-4 at 3; Tr. at 4370, 5037, 5041-5042.)

such that excluding the PTYP from cost of service would jeopardize the utility's financial health; (4) be revenue neutral and not made to generate or support system growth or new customers; and (5) be in service and used and useful. (RUCO Br. at 21; Ex. RUCO-1 at 10.) RUCO asserts that APS's PTYP proposal meets the first two criteria but does not meet the third criteria because APS does not need any assistance to build the plant. (RUCO Br. at 21; Ex. RUCO-1 at 11.) In support, RUCO points to a number of presentations made by PNW to the investment community in which PNW stated that APS's capital expenditures, shown as being in the range of $1 to $1.3 billion per year,[97] are funded primarily through internally generated cash flow. (RUCO Br. at 21-22; Ex. RUCO-1 at 11-12, ex. FWR-2 through ex. FWR-11.) RUCO asserts that since June 2020, APS has spent approximately $3.5 billion on plant additions with no help from ratepayers. (RUCO Br. at 22; Ex. RUCO-1 at 12, ex. FWR-12.) RUCO concedes that 2021 and 2022 capital expenditure figures were lower, but attributes this to an abnormally high fuel and purchased power deferral, and asserts that APS nonetheless funded 83% of its construction expenditures from internally generated funds in years 2016 through 2022. (RUCO Br. at 22; Ex. RUCO-1 at 12-13, ex. FWR-13.)

Additionally, RUCO argues, APS has not supported its assertion that all growth-related plant has been removed from its PTYP proposal, primarily because APS's capital projects and capital budgets do not include a growth category, with the result being that growth-related PTYP "remains a mystery." (RUCO Br. at 23; Ex. RUCO-1 at 13, ex. FWR-14.) RUCO asserts that utilities typically separate growth- and non-growth-related plant. (RUCO Br. at 23; Tr. at 4378-4379.) Mr. Radigan testified that in its next rate case, APS should be required to make a better presentation of its growth-related revenues and growth-related expenditures, with the values tied to APS's corporate budget and workpapers provided so that parties can review the information. (RUCO Br. at 24; Tr. at 4377-4378.)

Consistent with its 6-month PTYP proposal, RUCO recommends a total pro forma accumulated depreciation reserve for PTYP of $231.9 million and a total pro forma depreciation expense for PTYP of $24.346 million. (RUCO Br. at 25; Ex. RUCO-1 at 17-19, sched. B-1, sched. C-2.)

[97] Although RUCO used "million," as had Mr. Radigan in his prefiled testimony, the excerpts from the presentations to investors clearly show that "billion" is the appropriate term. (*See* RUCO Br. at 22; Ex. RUCO-1 at 12, ex. FWR-2 through FWR-11.)

In its Responsive Brief, RUCO points out that the Commission has not adopted a policy of including 12 months of PTYP in rate base and instead determines PTYP issues on a case-by-case basis. (RUCO RBr. at 1-2.) Thus, RUCO argues, APS's proposal diverges from policy and itself is arbitrary. (RUCO RBr. at 2.) RUCO states that its own recommendation is not arbitrary because it provided lengthy testimony and support for its PTYP recommendation. (RUCO RBr. at 2; *see* RUCO Br. at 21-23; Ex. RUCO-2 at 10-13.) Further, RUCO characterizes APS's position on removal of growth-related plant from PTYP as one of "trust but don't verify," because APS has made it clear that it does not categorize plant projects as growth-related or non-growth-related or report capital additions or capital budgets based on such categorization, making it suspect that APS was not able to identify and remove all growth-related plant. (RUCO RBr. at 2; Ex. RUCO-2 at 14, ex. FWR-14 at 4-5.)

<u>Staff</u>

In its Brief, Staff states that it agrees with APS's proposed 12 months of PTYP, including APS's pro forma adjustments and amounts. (Staff Br. at 7, 9, 11; Ex. S-73.) Staff asserts that it evaluated APS's proposed PTYP using the following criteria: (1) the plant was verified as having been placed into service by June 30, 2023, and (2) the plant was non-growth related. (Staff Br. at 8; Ex. S-18 at 19; Tr. at 1591.) Staff states that it also supports APS's "rolling forward" of TY accumulated depreciation and ADIT as a reduction to PTYP and notes that APS made the same type of adjustment to PTYP in its last rate case. (Staff Br. at 9.)

In its Responsive Brief, Staff notes that APS's Brief made two updates to its requested PTYP request that resulted in a \$13.8 million reduction from its rejoinder position. (Staff RBr. at 1-2.) Staff apparently queried APS concerning the specifics of the two updates and identifies them as a reduction of approximately \$15.36 million to Other Generation attributable to a manufacturer warranty credit received from APS, and an estimated increase of approximately \$1.56 million to the cost of the 4CPP ELG Project.[98] (Staff RBr. at 2-3.) Staff recommends that APS's updated amount for Other Generation be accepted by the Commission. (Staff RBr. at 3.) Staff's recommendation regarding the ELG Project is discussed below in Section (VI)(B)(2).

[98] These amounts are not included in the evidentiary record for this matter.

Staff states that APS's end-of-year method to measure PTYP should be adopted because it is the Commission's usual practice, will assist in minimizing regulatory lag, may delay APS's next rate case, and "is preferrable to customers."[99] (Staff RBr. at 3-4; Tr. at 5044.)

APS Response

APS opposes making any adjustments to PTYP to account for revenue from customer growth during the PTY period, asserting that if this were done, the excluded growth-related PTYP would also need to be included, and numerous other expenses that changed during the PTY period (both capital and operating) would need to be considered. (APS Br. at 6-7; Ex. APS-6 at 12-13; Ex. APS-9 at 5; Tr. at 606-607.) APS asserts that the PTYP docket established by Commissioner Myers[100] is the most appropriate place to have conversations about making forward-looking adjustments for customer growth and expenses during the PTY period. (Tr. at 607.) APS further states that the arguments made by AZLCG and RUCO are based on a false assumption that load growth is proportionate to rate base growth. (APS Br. at 7; Ex. APS-6 at 12-13.)

APS also opposes AZLCG's proposal to have APS's PTYP calculated based on average-of-period values rather than end-of-period values, asserting that because PTYP comprises rate base components, they should be measured at a specific point in time rather than based on an average. (APS Br. at 7; Ex. APS-22 at 10.) APS asserts that calculating PTYP using end-of-period values is consistent with the Commission's prior treatment of PTYP in rate cases and, further, that using average-of-period values would inappropriately disallow rate base adjustments for investments that are in service and used and useful as of the effective date of the rates established in this matter. (APS Br. at 7; Ex. APS-23 at 8; Ex. RUCO-7 at 127-129.) Additionally, in response to AZLCG's use of FERC's approach to support its argument that PTYP should be measured using an average-of-period method rather than an end-of-period method, APS points out that FERC ratemaking is done using formulas rather than a

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[99] To support this last assertion, Staff cites testimony of Mr. Smith in which he stated that he thought "the Arizona framework of using a historical test year with post test year plant and other limited pro forma adjustments . . . is actually much preferable for customers." (Tr. at 5044.) The Commission understands this to mean that Mr. Smith considers it to be more advantageous for customers, not that customers have been asked about their preferences. This understanding is bolstered by Mr. Smith's subsequent testimony (in reference to including PTY revenues as an offset of PTYP) that making changes to the regulatory paradigm has not, in his experience, produced better results for ratepayers. (*See* Tr. at 5041-5046.)

[100] This docket is AU-00000A-23-0012, and it was established for an inquiry into possible modifications to the Commission's TY rules. (Ex. APS-7 at 7.)

historical TY and, further, that the Commission consistently has used end-of-period values to measure PTYP. (APS RBr. at 5.) APS characterizes AZLCG's "doubling up" argument as "disingenuous" and states that it ignores the Commission's definition of OCRB and long-standing practice and also fails to consider that APS is the only Arizona utility that rolls forward accumulated depreciation on all of its plant in service to offset its PTYP. (APS RBr. at 5; Ex. APS-22 at 9.)

APS argues that RUCO's six-month PTYP recommendation is based on a RUCO position taken in a generic docket from more than four years ago, was never approved or adopted by the Commission, is arbitrary, and contradicts RUCO's acknowledgment that all of the PTYP represents prudent investments reflective of appropriate decision-making. (APS RBr. at 1; *see* RUCO Br. at 21.) APS further asserts that RUCO has failed to provide any evidence that APS has included any growth-related plant in PTYP and emphasizes that APS removed entire growth-related projects from PTYP, erring on the side of exclusion. (APS RBr. at 2; Ex. APS-20 at 19; Ex. APS-9 at 5; Tr. at 1976.)

<u>Resolution</u>

The Commission does not currently have a formal policy governing the treatment of PTYP. Nonetheless, as APS observed, it has not been uncommon for the Commission to grant a Class A investor-owned electric utility's proposal for inclusion of PTYP in rate base. In the 2022 TEP rate case,[101] in which TEP requested to have 6 months of PTYP included in rate base, the Commission approved TEP's request. (Ex. APS-84.) In the last APS rate case, in which APS requested to have 12 months of PTYP included in rate base, the Commission approved APS's request. (Ex. RUCO-7.) There are numerous other examples of decisions in which PTYP has been awarded to other utilities.

While the Commission has not consistently awarded a specific period of PTYP, it has consistently required that the PTYP include only non-growth-related or revenue-neutral plant projects and that the PTYP projects all be in service and used and useful by the end of the PTY period, consistent with the criteria used by Staff to formulate its recommendation herein. This approach is also consistent with the first, second, fourth, and fifth criteria used by RUCO in its analysis based on the criteria

[101] The 2022 TEP rate case was in Docket No. E-01933A-22-0107. The Recommended Opinion and Order for that case was admitted as Exhibit RUCO-12, and the resulting decision, Decision No. 79065 (August 25, 2023), was admitted as Exhibit APS-84.

recommended by Staff but not adopted by the Commission in the PTYP Generic Docket.

RUCO has questioned whether APS has removed all growth-related plant from its requested PTYP but has not been able to provide more than speculation that APS has failed to do so, largely based on RUCO's displeasure with APS's failure to categorize plant projects up front as growth-related or non-growth-related. When questioned, Mr. Tetlow testified that APS would have made all of the PTYP expenditures, other than those categorized as growth-related, even if there had been no growth during the PTY period, because APS has a very large system with a lot of aged infrastructure, and it takes significant investment to keep the system working. (Tr. at 1056.) Likewise, as noted above, Mr. Cooper testified that the plant projects at issue in this case were to replace aging infrastructure, improve resiliency of infrastructure, address existing customers' increasing needs, and address the impacts of extreme heat. (Tr. at 765-766, 779.) No evidence has been provided to support RUCO's assertion that growth-related plant has not been removed from PTYP.[102] Nonetheless, Mr. Radigan's recommendation that APS be required to categorize its plant projects up front as growth-related or non-growth-related, with such categorization documented consistently and reflected in APS's budgeting, has merit. Such up-front categorization would alleviate the need for APS's multiple teams to scrutinize and make judgment calls to determine after the fact which projects fall within each category and would allow the parties in future rate cases to review APS's requested PTYP more thoroughly. We will adopt this recommendation.

AZLCG argues that the PTYP allowed in rate base should not be measured using end-of-period values because such measurement is not required by Commission rules, and it is overly preferential to APS to allow such end-of-period measurement. AZLCG is correct that the Commission's ratemaking rule does not include a requirement for how PTYP should be measured, only for how TY plant should

[102] The closest thing was Dr. Johnson's testimony about the Evans Churchill Substation project, which was designed to enhance APS's circuit capacity and improve reliability and includes, *inter alia*, 69 Kilo Volt (kV) Gas Insulated Switchgear (GIS), Substation Transformers, capacitor banks, a double bus bar and breaker scheme, and capacity improvement for control equipment and ultimately will have three sets of three-phase GIS circuit bays, not all of which were expected to be in use by June 30, 2023. (Ex. S-3 at 9; Tr. at 4317-4319, 4347-4348, 4350, 4353-4360.) Dr. Johnson testified that the unused bays were not yet connected with cables and that additional investment will be required to make them used and useful in providing electric service to customers. (Ex. S-3 at 9; *see* Tr. at 4317, 4347-4348.) APS stated that there were three unused circuit bays and that each of the unused GIS circuit bays would need an additional $100,000 investment for a line relay plus additional investment for any underground or overhead line costs in order to be used. (Ex. APS-91 at 3.) The cost of the unused circuit bays themselves was not provided, and no party has asserted that the Evans Churchill Substation project should be removed from PTYP due to the unused circuit bays.

be measured. (*See* A.A.C. R14-2-103.) This is probably true because the Commission's ratemaking rule does not mention PTYP at all. Nor does the rule expressly mention FVI, FVRB, FVROR, or numerous other elements of ratemaking used by the Commission. The rule does, however, consistently require information to be provided by an applicant based on the end of a given period. (*See, e.g.,* A.A.C. R14-2-103(A)(3)(h), (n), (p), App. A, App. B, App. D, App. E.) Coupled with the Commission's never before having determined that it is appropriate to use average-of-period measurement for PTYP, this strongly indicates that the Commission considers end-of-period measurement to be just and reasonable and in the public interest in ratemaking.

Allowing PTYP in rate base for a Class A investor-owned electric utility is a means of mitigating the regulatory lag inherent in a regulatory ratemaking process that must use a historical TY and that, of necessity, takes approximately one year (sometimes more) to complete. With the exception of the ELG Project discussed below and the unused bays at the Evans Churchill Substation, the PTYP plant for which APS requests recovery has already been serving APS's customers since at least June 30, 2023. If the Commission were to deny inclusion of that PTYP in rate base in this rate case, APS would not be able to begin recovering for that PTYP for more than 24 months after it was placed into service.[103] This could prove problematic in light of APS's much higher than normal anticipated capital needs in the next few years based on projected levels of growth in load and demand, which will be exacerbated by the impending closure of Cholla. Additionally, the Commission is cognizant that APS's voluntary roll forward of TY accumulated depreciation and taxes benefits ratepayers greatly by reducing the net amount of PTYP included in rate base. It is the Commission's job to determine the appropriate balance between the interests of APS and ratepayers. In this matter, it is just and reasonable and in the public interest to approve inclusion in rate base of the PTYP placed into service by June 30, 2023, at its end-of-period value, net of the rolled forward TY accumulated depreciation and taxes.[104]

Additionally, although the Commission can appreciate the logic of AZLCG's argument that it

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[103] This assumes a decision in this case by January 31, 2024, a new rate application filed on July 29, 2024 (180 days later, approximately half the time APS used to prepare and file the application in this matter), and a decision issued on August 23, 2025 (390 days later, which includes the minimum period of 30 days for sufficiency and 360 days from sufficiency for a decision, with no allowance for the number of hearing days).

[104] The Commission will also allow recovery for the extra bays of the Evans Churchill Substation because it is not possible based on the evidentiary record to remove them from PTYP, and no party has advocated for their removal.

is appropriate to require APS to recognize PTY revenues along with its PTY plant, the evidentiary record in this matter does not establish the actual PTY revenues and instead provides an estimated range of $50 million[105] to $100 million.[106] The Commission is also cognizant that recognition of PTY revenues would reduce the regulatory lag mitigation that allowing for PTYP provides. Thus, the Commission declines to make the AZLCG's proposed adjustment for estimated PTY revenues.

2. Pension & Other Post-Employment Benefits ("OPEB")

APS Proposal

APS proposes to include in rate base a $524.5 million net prepaid pension asset (comprised of the TY qualified pension balance of $781.2 million reduced by the Supplemental Employee Retirement Benefit Plan ("SERBP") balance of $89.2 million and the pension accumulated deferred income taxes ("ADIT") balance of $167.4 million). (APS Br. at 8; Ex. APS-23 at Att. EAB-03RJ.) APS asserts that the revenue requirement impact of including the net prepaid pension asset in rate base is $45.8 million, assuming its requested WACC and exclusive of the FVI. (Ex. APS-23 at Att. EAB-01RJ.) APS also proposes to include in rate base $40.6 million of net OPEB liabilities. (APS Br. at 8.) According to APS, no party disputes that payment of pension benefits is a generally accepted business practice and properly included in cost of service or that including pension and OPEB assets and liabilities in rate base is appropriate. (APS Br. at 8; *see* Ex. RUCO-7 at 182.)

Ms. Blankenship testified that a prepaid pension asset arises when the cumulative contributions to the pension plan trust exceed the cumulative pension costs.[107] (Ex. APS-22 at 14.) She further stated that when recovery is based on pension expense, the contributions made in excess of expenses are funded by shareholders.[108] (Ex. APS-22 at 14-15.) APS asserts that because the net prepaid pension asset represents contributions of shareholder capital, not ratepayer-provided funds, the difference between the cumulative contributions and the cumulative costs should be included in rate base, net of ADIT. (APS Br. at 9-10; Ex. APS-22 at 14-15; Ex. APS-23 at 3-4.) Since 2010, APS has made significant contributions to the qualified pension plan to ensure that it is adequately funded, resulting

[105] Ex. AZLCG-1 at 25-29, ex. KCH-6-S.

[106] Ex. RUCO-4 at 3. Here, Mr. Radigan specifically estimated the net annual revenues to APS based on annual sales growth projections for 2023 to 2024 and 2024 to 2025, not for the PTY period. (*See id.*)

[107] In the opposite scenario, an accrued pension liability arises. (Ex. APS-22 at 14.)

[108] Likewise, she stated, any expense recognized in excess of contributions is funded by ratepayers. (Ex. APS-22 at 14.)

in annual company contributions that greatly exceed annual pension costs and in a cumulative qualified pension balance of $781.2 million. (Ex. APS-22 at 14-16, 17.) APS claims that the higher shareholder contributions to the pension asset benefit ratepayers because they reduce the pension unfunded liability upon which Pension Benefit Guarantee Corporation ("PBGC") premiums are based, thereby reducing those premiums, and result in a higher expected return on assets ("EROA"),[109] which offsets pension expense. (APS Br. at 10; Ex. APS-22 at 15, 20-21; Ex. APS-23 at 3-4, 6-7.)

APS argues that because the net prepaid pension asset represents APS's capitalized cumulative cash contributions, less the cumulative amounts charged to pension expense, it should be measured at a point in time like any other rate base item—i.e., it should not be normalized as it was in Decision No. 78317. (APS Br. at 9; Ex. APS-22 at 13; Ex. APS-23 at 5; *see* Ex. RUCO-7 at 182.) APS states that normalizing any portion of the prepaid pension asset would prevent APS's equitable recovery of a fair and reasonable return on the shareholder capital that funded the cumulative contributions in excess of expenses. (APS Br. at 9; Ex. APS-23 at 5.) Additionally, APS argues, although normalization could potentially benefit customers today, it would result in future customers facing additional costs that would offset that benefit. (APS Br. at 9; Ex. APS-23 at 5; Tr. at 1995.) APS also asserts that if normalization is ordered as it was in Decision No. 78317, a corresponding increase to customer costs would need to be made as a result, as it was in Decision No. 78317. (Ex. APS-23 at 6.)

In addition, APS argues, the return rate to be applied to the prepaid pension asset must be the WACC, not the EROA, because Decision No. 78317 authorized a WACC return, and authorizing a different rate of return would be inconsistent with that decision and with standard ratemaking principles. (APS Br. at 10; Ex. RUCO-7 at 183; Ex. APS-22 at 20; Ex. APS-23 at 6.) Ms. Blankenship testified that the WACC is applied to net rate base while the EROA is applied to gross pension and OPEB rate base assets and that both of these economic variables reflect the investor-required rate of return for the risks to which the respective investments are exposed. (Ex. APS-23 at 6.) According to APS, it would be inequitable and unreasonable to deny APS a WACC return on the prepaid pension asset. (Ex. APS-23 at 7.)

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[109] The EROA is applied to the entire value of assets in the pension trust, and the return amount is subtracted from the annual pension cost. (Ex. APS-23 at 6-7.)

Ms. Blankenship acknowledged that the funded position component of APS's prepaid pension asset went from an unfunded liability of $207.6 million on June 30, 2019, to a funded asset of $266.8 million on June 30, 2022, primarily due to discretionary contributions of $260 million made by APS during that period. (Tr. at 1916-1918; Ex. AZLCG-1 at 39.) Ms. Blankenship stated that this was done to ensure APS's ability to meet its obligations to its retirees and to save money by not having to pay PBCG premiums. (Tr. at 1917, 1919.) According to APS, APS's pension plan is important because it allows APS to attract and retain talented employees to ensure its ability to serve its customers. (Tr. at 1920.) Additionally, Ms. Blankenship asserted, because the contributions to the pension trust cannot be used for any purposes other than to pay pension retirees and plan fees, APS has no incentive to make those contributions. (Tr. at 1919.) Ms. Blankenship acknowledged, however, that the return obtained from having the prepaid pension asset included in rate base can be used for any shareholder purpose. (Tr. at 1919.)

<u>AZLCG</u>

AZLCG states that although there are sound policy and ratemaking reasons to exclude the prepaid pension asset from rate base altogether, AZLCG does not recommend such a disallowance in this case but instead recommends that the Commission set the return on the prepaid pension asset at the EROA (5.0%) rather than APS's requested WACC (7.17%). (ALCG Br. at 28-29; Ex. AZLCG-1 at 40.) AZLCG characterizes its argument as a cost-benefit analysis, stating that APS is requesting to have ratepayers, who ultimately fund the pension plan, compensate APS at 7.17% so that the proceeds can be invested at an expected return of only 5.00%,[110] which is "obviously not a good proposition for customers." (AZLCG Br. at 30; Ex. AZLCG-1 at 40; Ex. AZLCG-5 at 24.) AZLCG asserts that other PUCs have limited the return on a prepaid pension asset to balance the utility's right to earn a return on its investment with the ratepayers' right to be charged just and reasonable rates. (AZLCG Br. at 30; Ex. AZLCG-1 at 41 (citing Colorado PUC Decision No. C20-0505 (May 13, 2020)). AZLCG argues that the pension trust includes both shareholder ($760.2 million) and ratepayer ($279.9 million) funds

[110] AZLCG states that when shareholder funds invested in the pension trust exceed the pension cost, the funds earn a return, which is then reduced by the amount of any pension premium costs to obtain the EROA. (AZLCG Br. at 29; Ex. AZLCG-1 at 37; Tr. at 1901-1903, 1997.) The EROA is applied to both shareholder and ratepayer funds in the pension trust, AZLCG states, and is the amount APS expects to earn on the asset. (AZLCG Br. at 29; Ex. AZLCG-1 at 40, ex. KCH-12; Tr. at 1905, 1907, 1911.)

and characterizes APS's argument that ratepayer benefits should be evaluated based on the return on the entire pension trust as "conflat[ing] benefits between wholly different funding sources." (AZLCG Br. at 30; *see* Tr. at 1906; Ex. APS-22 at 17.) AZLCG acknowledges that the EROA is applied to the entire pension trust amount but argues that APS should not be permitted to earn a return on the ratepayer contributions therein. (AZLCG Br. at 30.) AZLCG further argues that the return on ratepayer contributions to the pension trust "is immaterial for evaluating APS's return on shareholder funded contributions to the *prepaid pension asset*" because each dollar contributed to the pension trust earns only the EROA. (AZLCG Br. at 30-31; *see* Tr. at 1915.) According to AZLCG, allowing APS a WACC return on the prepaid pension asset creates a perverse incentive for APS to overfund the pension trust. (*See* AZLCG Br. at 31; Ex. AZLCG-5 at 24.) AZLCG points out that APS has made significant discretionary contributions[111] to its pension trust since the 2019 rate case, growing its gross balance of \$505.3 million on June 30, 2019, to \$781.2 million on June 30, 2022, thereby increasing its proposed rate base and anticipated return. (AZLCG Br. at 31; Ex. AZLCG-1 at 37, 39, ex. KCH-14 at 4; Tr. at 1916-1918.) AZLCG states that its EROA return proposal is a compromise approach that protects ratepayers by allowing APS to earn a return at the same level that ratepayers earn a benefit, rather than disallowing APS's excess discretionary contributions. (AZLCG Br. at 32, ex. KCH-12-F.) In its Responsive Brief, AZLCG argues that because the only benefit ratepayers obtain from the pension prepayments is the EROA, APS's benefit from the prepaid pension asset likewise should be set at the EROA, nothing more; otherwise, ratepayers would be rewarding shareholders with a return at a level higher than the benefits generated in returns from the contributions. (AZLCG RBr. at 5.)

Similarly, AZLCG argues that the return on APS's OPEB liability should be set at the 2022 EROA for the OPEB plan, which is 5.35%. (AZLCG Br. at 32; Ex. AZLCG-1 at 41.) According to AZLCG, the OPEB plans provide post-retirement benefits such as medical benefits and are not subject to the same federally mandated minimum funding requirements as prepaid pensions. (AZLCG Br. at 32; Ex. AZLCG-1 at 38.) Because APS's cumulative accounting cost for its OPEB plan exceeds APS's cumulative contributions to the plan, AZLCG states, APS has an OPEB liability. (AZLCG Br. at 32;

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[111] The federal government has established minimum contribution levels for qualified pension plans as well as maximum levels of tax deductibility for qualified pension plan contributions. (*See* Tr. at 1917.)

Ex. AZLCG-1 at 38.) AZLCG argues that the same rationale for providing only an EROA return to the prepaid pension asset applies to the return on the OPEB liability and recommends that the Commission set the allowed return on the accrued OPEB liability at 5.35%. (AZLCG Br. at 32, ex. KCH-12-F.) AZLCG shows that the combined impact of the Commission's approving a 5.00% EROA return on the prepaid pension asset and a 5.35% EROA return on the OPEB liability, assuming the 9.55% ROE recommended by Mr. Walters, would be a reduction to APS's revenue requirement of approximately $12 million. (AZLCG Br. at ex. KCH-12-F; Ex. AZLCG-1 at 42.)

FEA

FEA argues that consistent with Decision No. 78317, APS should be allowed to include only a normalized prepaid pension asset in rate base rather than the full prepaid pension asset APS requests. (FEA Br. at 3; Ex. FEA-1 at 8-9.) A prepaid pension asset that is funded by investor capital may be included in rate base, FEA asserts, but it should be excluded from rate base if APS has already recovered the asset funding from customers through pension expenses collected in base rates exceeding the pension expense amount recorded by APS during the period the rates are in effect and the prepaid pension asset is recorded. (FEA Br. at 3-1; Ex. FEA-1 at 10.) Including the prepaid pension asset in rate base is only fair if the prepaid pension asset is funded by investors, FEA argues, and the evidence of record in this matter shows that APS has been reimbursed for its pension trust contributions through the pension expense recovered from customers in cost of service over the last several years. (FEA Br. at 4; Ex. FEA-1 at 11-12.) FEA asserts that contrary to Ms. Blankenship's testimony, the prepaid pension asset is funded by a combination of shareholder funds and ratepayer funds, not solely shareholder funds.[112] (FEA Br. at 5; Ex. FEA-3 at 4-5; Tr. at 3388, 3401.) Because of this, FEA concludes, it would be appropriate to exclude the prepaid pension asset from rate base, although that is not FEA's recommendation. (FEA Br. at 4.) Rather, FEA argues, the Commission should include only a normalized prepaid pension asset, as it did in Decision No. 78317, which would reduce the prepaid pension asset in rate base by $77.6 million and lower APS's revenue requirement by approximately

[112] Mr. Gorman testified that there is uncertainty about what is creating the prepaid pension asset (cash outlays or trust fund returns) and that for this reason as well as the annual variation in the asset due to many variables, it is fair and reasonable to normalize the pension asset as the Commission required in the 2019 rate case. (Ex. FEA-3 at 3-4; *see* Tr. at 3388, 3398-3399.)

$6.8 million. (FEA Br. at 4, 5; Ex. FEA-1 at 13; Tr. at 3388, 3402-3403.) Requiring this normalization, Mr. Gorman testified, would recognize that the prepaid pension asset is funded by a combination of cash contributions from APS as well as other factors that have no cost to APS, would ensure that APS's costs do not vary based on non-cash outlays of the company and on a pension asset that the company can grow intentionally to increase its rate base, and would be more fair and balanced than assuming (as APS did) that the prepaid pension asset is fully funded by cash contributions from APS. (Ex. FEA-3 at 6; Tr. at 3399.) Because the amount of the prepaid pension asset does not get reset between rate cases, Mr. Gorman stated, the amount of pension expense included in cost of service may be different than the actual pension expense during the periods rates are in effect. (Tr. at 3403.) In fact, Mr. Gorman stated, Ms. Blankenship's exhibit shows that the amount of pension expense included in rates has exceeded the actual amount that APS has recorded while the rates set in the 2019 rate case have been in effect. (Tr. at 3403, 3413.)

Further, while Mr. Gorman agrees that ADIT needed to be adjusted as asserted by APS due to the normalization of prepaid pension expense in Decision No. 78317, he does not agree that pension expense also needed to be adjusted as asserted by APS and adopted by the Commission. (Tr. at 3413-3414.) Rather, Mr. Gorman stated, TY pension expense should be based on the actual pension expense in the TY unless there are exceptional circumstances showing that the pension expense was abnormal for some reason. (Tr. at 3413-3414.)

Ms. Nelson

Ms. Nelson argues that APS's prepaid pension asset should not be a ratepayer cost. (KN Br. at 3.) Further, Ms. Nelson states, the Commission should not allow shareholders to contribute to the prepaid pension asset without restriction because those increased contributions add unnecessary costs to ratepayers while only benefiting shareholders. (*Id.*) Ms. Nelson argues that the Commission should regulate how often contributions can be made and how much can be contributed. (*Id.*)

Staff

In its Responsive Brief, Staff states that it does not recommend removal of APS's prepaid pension asset from rate base because the prepaid pension asset has been reduced by income generated from the pension trust assets. (Staff RBr. at 4.) Staff states that its continued support of including the prepaid pension asset in rate base is contingent, however, on the Commission rejecting APS's attempt to increase TY pension and OPEB expense by approximately $20.8 million through averaging actual 2022 and estimated 2023 pension and OPEB costs, a proposal that APS included on rebuttal but not in its original application. (Staff RBr. at 4.) Staff states that allowing APS to increase TY pension and OPEB expense by approximately $20.8 million would be inconsistent with the net benefit amounts that underly Staff's support for including the prepaid pension asset in rate base.[113] (Staff RBr. at 4; *see* Ex. S-24 at Att. RCS-12 at 38-39.)

<u>APS Response</u>

In its Reply Brief, APS observes that Staff agrees with the proposed prepaid pension rate base asset and that only AZLCG and FEA disagree, although their recommendations differ. (APS RBr. at 6.) APS asserts that neither AZLCG's nor FEA's recommended treatment is appropriate or in the public interest, stating that Mr. Gorman has not established through evidence that any portion of the TY prepaid pension asset balance has been funded by customers, while Ms. Blankenship has clearly established that the TY prepaid pension asset has been funded by shareholders only, and that AZLCG's EROA return recommendation is inconsistent with standard ratemaking principles. (APS RBr. at 6-8.) Further, APS argues, the benefit that customers are receiving from returns on amounts customers have not yet paid through recognized pension costs (that is, the shareholder-funded contributions) and the lower PBGC premium expenses exceed the return APS would be allowed to earn from inclusion of the prepaid pension asset in rate base with a WACC return. (APS RBr. at 8; Ex. APS-22 at 20-21.) APS did not respond to Ms. Nelson's arguments.

<u>Resolution</u>

In Decision No. 78317, the Commission determined that APS's proposed inclusion of pension and OPEB assets and liabilities in rate base was appropriate but that because the amount of APS's prepaid pension asset, net of changes in SERBP liability, was significantly higher in the TY than in the four preceding years, the prepaid pension asset should be normalized to represent the typical level of

[113] In response to a data request, APS stated that the revenue requirement impact from including the net prepaid pension asset in rate base is approximately $45.8 million and that the reduction to pension expense related to the EROA is approximately $136.7 million. (Ex. S-24 at Att. RCS-12 at 38.)

investment in pension costs by APS. (Ex. RUCO-7 at 182.) After the Recommended Opinion and Order ("ROO") in the 2019 rate case was issued, APS provided exceptions that identified adjustments APS stated were necessary to reflect jurisdictional rather than total company amounts, reflect normalization of ADIT, and increase TY pension expense consistent with the normalization. (Ex. RUCO-7 at 182.) The Commission adopted these adjustments. (*Id.*) The Commission also concluded that there was no compelling reason to depart from the normal treatment of the return allowed on assets included in rate base by adopting a separate rate of return. (Ex. RUCO-7 at 183.)

In this matter, APS's net prepaid pension asset again is higher than it has been for the prior several years, because APS continues to make discretionary pension trust contributions, and its TY pension expenses do not offset those discretionary contributions. The following shows APS's contribution, net periodic cost/benefit, gross prepaid pension asset, pension ADIT, and net prepaid pension asset for each year since 2019 (all $ in millions):[114]

Year	Annual Employer Contribution (Jurisdictional)	Annual Net Periodic Cost/(Benefit)	Gross Prepaid Pension Asset[115]	Pension ADIT	Net Prepaid Pension Asset
2019	$149.5	$43.4	$444.4	($106.9)	$337.6
2020	$99.7	$8.8	$539.7	($130.1)	$409.5
2021	$99.1	($39.1)	$680.5	($164.6)	$515.9
TY as of 6/31/22	-	($8.8)	$691.9	($167.4)	$524.5
Four-Year Average Net Prepaid Pension Asset:					$446.9

Because the prepaid pension asset is a rate base item, and the Commission concedes that normalization of a rate base item is unusual, the Commission will not normalize the prepaid pension asset in this matter. In addition, consistent with Decision No. 78317, we conclude that it is appropriate to allow APS a return set at the Company's WACC on its net prepaid pension asset and its net OPEB liability. Although the Commission recognizes the facts discussed above, we conclude that there is no compelling reason to depart from the normal treatment of the return allowed on assets included in rate base by adopting a separate rate of return as proposed by some of the parties in this case.

[114] Ex. FEA-1 at ex. MPG-1 at 4, 5.

[115] This figure reflects deduction of the annual SERBP balance. (Ex. FEA-1 at ex. MPG-1 at 4.)

3. Cash Working Capital

APS Proposal

APS proposes an adjusted allowance for working capital of $462.224 million, which reflects a reduction of $8.853 million from APS's reported TY allowance for working capital of $471.077. (APS Br. at Att. B at Sched. B-1 at 1.) Ms. Blankenship testified that the allowance for working capital is a measure of investor funding of daily operating expenditures and non-plant investments necessary for ongoing operations and includes materials and supplies, fuel inventories, prepayments, and cash working capital. (Ex. APS-20 at 11.) Because it is an investment like other capital requirements, Ms. Blankenship stated, it is included in rate base. (Ex. APS-20 at 11-12.) Ms. Blankenship stated that the cash working capital component was determining using a lead/lag study[116] showing the amount of investor funds used to maintain operations from the time expenditures are made to the time revenues are collected to reimburse for those expenditures. (Ex. APS-20 at 12.) On rebuttal, Ms. Blankenship testified that APS agreed with Staff's methodology for cash working capital but that their numbers are different because of other pro forma adjustments. (Ex. APS-22 at 3.)

Staff

Mr. Smith testified that APS's working capital is categorized into six components: (1) cash working capital balance, (2) year-end materials and supplies balance, (3) year-end fuel (coal and oil) balance, (4) year-end fuel (nuclear) balance, (5) year-end prepayments balance, and (6) year-end special deposits and working funds balance. (Ex. S-18 at 32.) According to Mr. Smith, APS has a negative cash working capital requirement, which is a reduction to rate base, because its lead/lag study shows that revenues are typically received from ratepayers before expenditures are made. (Ex. S-18 at 33.) Staff recommends revising APS's cash working capital request by synchronizing the calculation of cash working capital with Staff's recommended revenue increase in terms of updating the cash expenses for income taxes and interest, which increases cash working capital by approximately $1.929 million.[117] (Ex. S-18 at 34; Ex. S-24 at 17.) Staff's final schedules reflect an adjusted allowance for

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[116] APS asserts that this was pursuant to a requirement in Decision No. 55931 (April 1, 1988).

[117] Staff's Brief identified the necessary adjustment using the $2.818 million number from Mr. Smith's surrebuttal testimony, the $2.928 million included in Mr. Smith's direct testimony, and a reference to Exhibit S-73 (which included a cash working capital adjustment of $1.929 million). (*See* Staff Br. at 12-13; Ex. S-73 at Att. RCS-15 at 22.) Because Staff included Exhibit S-73 as an attachment to its Brief, the Commission understands Staff to be proposing an adjustment of

working capital of $459.155 million, which is an increase of $1.929 million from the adjusted allowance for working capital included in APS's application of $457.226 million. (Staff Br. at Att. B at Att. RCS-15 at 5 (Sched. B); *see* Ex. APS-37 at Sched. B-1.)

APS Response

APS does not address Staff's cash working capital argument in its Brief or Responsive Brief.

Resolution

Although Staff characterizes cash working capital as a disputed issue, the evidence does not support that APS and Staff are using different methods to calculate cash working capital.

B. 4CPP-Related Issues

The two remaining operational units of the 4CPP, Units 4 and 5, are owned by APS (63%), Salt River Project ("SRP") (10%), TEP (7%), Navajo Transitional Energy Company ("NTEC") (7%), and Public Service Company of New Mexico ("PNM") (13%). (*See* Ex. RUCO-7 at 47; Ex. APS-84 at 14; Ex. S-14 at 17-18.) NTEC has agreed to acquire PNM's interest, but the sale has been rejected by the New Mexico PUC and is now the subject of litigation. (Ex. S-14 at 17-19.) NTEC is also the owner of the Navajo Mine, which is the sole source of coal for the 4CPP. (Ex. S-14 at 17; Ex. RUCO-7 at 47.) Currently, APS, SRP, TEP, and NTEC have committed to ensuring 4CPP operations through 2031. (Ex. APS-11 at 29.) APS cannot unilaterally force the retirement of the 4CPP because decommissioning requires a unanimous vote of the plant owners other than NTEC. (Ex. APS-11 at 29.)

The agreements between the 4CPP owners, as amended in 2021, allow for transfer of PNM's rights and obligations to NTEC and also for seasonal operations at the 4CPP. (*See* Ex. APS-11 at 27-28.) In the 2019 rate case, APS notified the Commission that seasonal operations would begin in fall 2023. (Ex. RUCO-7 at 47.) Subsequently, in July 2022, APS determined that it was not economical to implement seasonal operations at the 4CPP in fall 2023 due to high forecasted gas prices and notified the other owners that it intended to request normal operations at the 4CPP for the period of November 1, 2023, through May 31, 2024, as permitted under the 2021 amendment. (Ex. APS-12 at 27; Ex. SC-

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$1.929 million, as included in Exhibit S-73. This is also consistent with Mr. Smith's testimony at hearing. (*See* Tr. at 4921.)

1 at Att. DG-2 at 96.)

1. Recovery of Costs Other than for ELG Project

APS Proposal

APS includes in rate base the end-of-TY plant value of its ownership portion of the 4CPP, other than the $215.5 million from the SCRs excluded from rate base in the last rate case and subsequently addressed separately through the Joint Resolution settling the remand case.[118] Additionally, APS includes in O&M expenses APS's ownership portion of the TY expenditures for operating and maintaining the 4CPP. (*See* APS Br. at 106.)

The 4CPP currently provides APS approximately 970 MW of capacity when both Units 4 and 5 are operating. (Ex. APS-12 at 12; Ex. S-14 at 4.) APS has emphasized the importance of the 4CPP to providing reliable service during the summer 2023 heatwave, noting that on the 14 days when customer demand was at its highest, 4CPP Unit 4 was online each day, and Unit 5 was online 11 days. (Ex. APS-10 at 11.) During the period of June 1 through July 30, 2023, the 4CPP had an Equivalent Availability Factor ("EAF"[119]) of 95.24%, which Mr. Tetlow described as impressive and critical to the region and for keeping on customers' air conditioners during the record-breaking heat. (Ex. APS-10 at 11.)

According to Mr. Joiner, the 4CPP provided customers a net energy value/customer cost savings in the hundreds of millions of dollars in 2021 and 2022, and the hedge value of the 4CPP greatly exceeds its outage replacement costs. (Ex. APS-12 at 23.) APS provided a comparison of actual historical and estimated market replacement costs based on actual day-ahead clearing prices that would have been incurred to replace the 4CPP's capacity during 2020, 2021, and 2022 and up to May 31 in 2023. (Ex. APS-47; Tr. at 1114-1116.) The comparison showed the following ($ are in millions):[120]

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[118] As described in Section III above, the previously disallowed $215.5 million of the SCRs will be included in rate base, with its accumulated depreciation, in APS's next rate case.

[119] EAF measures the percentage of time a unit was available during all the hours in a period, including those hours in which the unit was planned to be unavailable. (Ex. SC-1 at 19.)

[120] Ex. APS-47.

Period	Total Actual Cost (includes O&M, capital, and fuel costs[121])	Estimated Market Replacement Cost
2020	$321.32	$518.00
2021	$345.84	$565.00
2022	$371.66	$903.00
2023 (up to 5/31)	$150.17	$423.00
Total	$1,188.99	$2,409.00
Savings:	$1,220.01	

Mr. Joiner testified that APS had Energy+Environmental Economics, Inc. ("E3") analyze the economics of continued operations of the 4CPP after its 2020 IRP, with the Inflation Reduction Act ("IRA") factored in, based on recommendations using replacement scenarios from Sierra Club and the Strategen study cited by Sierra Club in the 2019 rate case. (Tr. at 1353-1354; Ex. APS-14 at 9-11.) Mr. Joiner acknowledged that the E3 analyses performed were not resource optimization analyses (such as would be done in an IRP) but instead were based on Sierra Club's and Strategen's recommendation to replace the 4CPP capacity with renewables, batteries, and market purchases. (Tr. at 1354-1355; Ex. APS-14 at 11.) Mr. Joiner testified that to replace the 970 MW capacity of the 4CPP reliably, APS would need to build 3,000 to 4,000 MW of battery storage and 2,300 MW of solar and, if the solar and storage were built in the same area as the 4CPP, at least one additional high-voltage transmission line in parallel to the existing transmission line at the 4CPP. (Tr. at 1360-1362.) Mr. Joiner conceded that these estimates are not part of a resource optimization analysis and that other replacement portfolios might require a smaller quantity of replacement resources, but emphasized the importance of dispatchability to ensure reliability and that the analyses performed showed that ratepayers would incur higher costs from early retirement of the 4CPP and that the costs would be higher the earlier the 4CPP were retired.[122] (Tr. at 1362-1363, 1367.) Mr. Joiner testified that if natural gas resources were included, APS would be able to reduce the quantity of replacement resources. (Tr. at 1363.)

Mr. Joiner further testified that if the 4CPP were retired in the next two to three years, APS would need to rely entirely on market purchases to replace the 4CPP's capacity, and if the 4CPP were

[121] Actual fuel costs include liquidated damages payments as applicable.

[122] The E3 analysis showed a cost increase of $165 million for retirement in 2029 and of $648 million for retirement in 2026. (Ex. APS-14 at 10.)

retired in 2028, APS would need to rely primarily on market purchases to replace its capacity, because no other resource could be brought online to replace the 4CPP's capacity within that time. (Tr. at 1369-1371, 1373.) APS has consistently maintained that it would not be economical to replace the capacity from the 4CPP earlier than 2031, if sufficient resources could even be obtained, especially without exposing customers to unacceptable reliability risks. (Ex. APS-12 at 20-22; APS Br. at 109-110.) According to Mr. Joiner, APS needs until 2031 to replace the 4CPP's capacity with resources other than market purchases because all of the resources APS is contracting for in its RFPs will be exhausted due to load growth, the Cholla retirement, and other factors. (Tr. at 1370-1371.) APS further argues that retiring the 4CPP in 2028 or earlier by relying exclusively on zero-emitting renewable generation, storage resources, and wholesale market purchases would lead to increased costs for APS customers and resource adequacy challenges. (APS Br. at 111-112.) APS asserted that its 2023 IRP would evaluate numerous exit scenarios for the 4CPP, with dates ranging from 2027 through 2031, as well as alternative scenarios for the 4CPP, including considering carbon capture on the 4CPP and the impacts on the 4CPP if the EPA-proposed greenhouse gas rules[123] are adopted. (Ex. APS-12 at 19-20; Tr. at 1009; *see* Ex. S-14 at 26.) In its 2023 IRP, APS maintains its plan to exit the 4CPP in 2031, presenting a preferred portfolio that could save customers $357 million as compared to a reference case described as "an optimized, least-cost portfolio of resources to meet rapidly growing customer demands and replace currently planned resource retirements . . . while satisfying reliability needs."[124] (2023 IRP at 71.) The 2023 IRP shows that an exit from the 4CPP in 2027, 2028, 2029, or 2030 could result in more moderate cost savings as compared to the reference case, ranging from $26 million to $139 million. (2023 IRP at 71.) APS states in the 2023 IRP that "the actual development of the resources (along with

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[123] The proposed greenhouse gas rules categorize existing coal-fired steam generating units into long-term (not committed to cease operations by January 1, 2040), medium-term (committed to cease operations after December 31, 2031, and before January 1, 2040, and not meeting the near-term definition), near-term (committed to cease operations after December 31, 2031, and before January 1, 2035, and to adopt an annual capacity factor limit of 20%), and imminent-term (committed to cease operations before January 1, 2032). (Ex. S-30 at 88 Fed. Reg. 33359.) Under the proposed greenhouse gas rules, imminent-term coal-fired steam generating units are essentially permitted to maintain their normal operations, provided that they do not increase their emissions. (*See id.*) APS believes that the proposed greenhouse gas rules would not have any impact on the cost to operate the 4CPP because APS does not intend to increase emissions from the plant. (Tr. at 897-900, 1008.)

[124] APS compares this to the "truly 'least cost' portfolio" labeled as the technology neutral portfolio, which does not consider carbon emission standards or any voluntary goals for emission reductions and renewable energy and for which the 2023 IRP shows cost savings of $96 million from the reference case. (2023 IRP at 71.)

delivery of electricity) from these [early exit] scenarios is unlikely to be executable while maintaining reliable service to customers" due to the necessary development timeframes for resources and the necessary electricity transmission and gas transportation infrastructure to accommodate the new resources, which likely cannot be built soon enough to accommodate the early exit scenarios. (2023 IRP at 74-75.)

Sierra Club

Sierra Club argues that APS's requested approval of more than \$180 million in spending at the 4CPP, including \$29.2 million in TY capital spending, \$98.9 million in TY O&M spending, and \$52 million in PTY spending for the ELG Project, should be disallowed because the 4CPP is no longer economical, is increasingly unreliable, and should be replaced with lower-cost clean energy as soon as possible.[125] (SC Br. at 5-6; Ex. SC-1 at 9; Ex SC-2 at 11.) Further, Sierra Club argues, APS has not justified its spending at the 4CPP, which is unreasonable and/or obviously wasteful (i.e., imprudent) based on the information available at the time APS made the investments. (SC Br. at 5, 18; SC RBr. at 4; *see* A.A.C. R14-2-103(A)(3)(l).)

Sierra Club's argument essentially boils down to these elements:

- The Commission's ratemaking rule (A.A.C. R14-2-103) does not mandate a presumption that operating expenses have been prudently incurred, APS as the applicant has the burden of proof on the issue under A.A.C. R14-3-103(A)(3)(l),[126] and APS has failed to carry its burden of proof.[127]
- Rather than performing a thorough analysis to identify a resource-optimized portfolio that could reliably replace the 4CPP before 2031, APS relied on its outdated 2020 IRP[128] and other "narrow

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[125] The ELG Project issue is discussed and resolved below.

[126] In its Responsive Brief, Sierra Club points out APS's argument that its 4CPP O&M expenses are presumed to be prudent and that the presumption can only be set aside by clear and convincing evidence, which Sierra Club argues wrongly places the burden of proof on intervenors. (SC RBr. at 2; *see* APS Br. at 106.) Sierra Club also argues that clear and convincing evidence in this matter shows APS's spending at the 4CPP was imprudent, including the \$98.9 million in TY O&M expenses and the \$29.2 million in TY capital expenditures. (SC RBr. at 2-3.)

[127] SC Br. at 4-5, 18; Ex. SC-1 at 6; *see* A.A.C. R14-2-103(A)(3)(l); A.A.C. R14-3-109(G); Decision No. 77130 (March 13, 2019) at 10. Official notice is taken of Decision No. 77130.

[128] Sierra Club criticizes the 2020 IRP because it assumed a 2031 4CPP retirement in each scenario therein and did not analyze whether earlier retirement was feasible and does not reflect any of the significant market changes that have occurred since it was issued in 2021. (SC Br. at 11-12, 18-19; Ex. SC-1 at 46, 50-51; Ex. SC-26 at 133, 136; Tr. at 1352, 1553-1555.) As examples of these changes, Sierra Club points to the August 2022 passage of the IRA; changes in the prices of renewables, gas, and wholesale power; recent increases in coal prices and liquidated damage obligations for shortfalls at the 4CPP; and newly enacted or proposed environmental regulations that Sierra Club states are likely to increase the cost of operating coal-fired power plants. (SC Br. at 12-14; Ex. SC-1 at 51-54, 57, 60; Ex. S-14 at 15, 21; Tr. at 4635-4636; *see*

analyses"[129] to support its position in this case, only finally completing a thorough and resource-optimized analysis in its 2023 IRP issued in November 2023.[130]

- The prudency of APS's spending on the 4CPP must be evaluated in light of all relevant conditions known or which in the exercise of reasonable judgment should have been known by APS at the time the investments were made, and APS reasonably should have known of the 4CPP's "economic troubles" well before the end of the TY, because solar and wind costs were already lower than the costs of energy from the 4CPP in 2020 and 2021,[131] the 4CPP's forced outage rates in 2018 through 2021 were well above average,[132] and the 2019 Strategen coal study found that utilities could achieve large savings by retiring the 4CPP in 2023.[133]
- APS cannot justify continued operation of the 4CPP based on its reliability benefits because it is

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26 U.S.C. §§ 45, 45Y, 48, 48E; Tr. at 4573.) Sierra Club notes that Ms. Medine testified at hearing that the increasing coal prices at the 4CPP and Cholla caused "concern[] about the fact that they were becoming uneconomic." (SC Br. at 13; *see* Tr. at 4573.) Sierra Club did not note that Ms. Medine subsequently backtracked on that characterization and said that she did not think she had made that conclusion. (*See* SC Br. at 13; Tr. at 4635-4636.)

[129] Sierra Club states that APS's "narrow analyses" conducted between 2020 and 2023, upon which APS relies, did not include resource-optimized analyses, evaluated only a narrow set of predetermined portfolios, relied on unrealistic assumptions calling for excessive reliance on market power, and in one instance did not consider the effects of the IRA. (SC Br. at 14-15; Ex. APS-12 at 17-18; Ex. APS-14 at 10-11.)

[130] SC Br. at 6, 11, 14, 18-19; Ex. SC-1 at 46-47, 50; Tr. at 1353-1355.

[131] According to Sierra Club, APS's own data shows that the 4CPP is no longer economical to operate, and Ms. Glick's testimony provided clear and convincing evidence that APS's spending at the 4CPP is not economically justified because the 4CPP is more expensive to operate than alternative renewable energy resources. (SC Br. at 5-6; *see* Ex. SC-1 at 46-47; Ex. SC-2 at 2-14.) APS calculated the levelized cost of energy ("LCOE") for the 4CPP at $89.20/MWh, a figure that Ms. Glick testified likely underestimates the true costs to operate the 4CPP because it does not include the shortfall costs APS could incur under its coal contract with NTEC, particularly if the 4CPP moves to seasonal operations, and also assumes that the 4CPP will maintain historic levels of operation. (SC Br. at 6, 8; Ex. SC-1 at 23-25.) Ms. Glick also testified that APS's LCOE calculation did not include any costs associated with the ELG Project, but this contradicts the data response cited by Ms. Glick in support, which states that "[f]orecasted costs for the ELG upgrade at Four Corners were included in the IRP analysis." (Ex. SC-1 at 24-25, Att. DG-2 at 95.) In contrast, Ms. Glick cited regional solar photovoltaic ("PV") project costs at $15-$30/MWh, regional solar PV plus battery storage project costs at $24.50-$30/MWh for the solar PV and $5.36-$10.99/kW-month for the battery storage component, and APS's own standalone battery storage projects and wind projects that reflect similar pricing. (SC Br. at 6; Ex. SC-1 at 23-24, 28, Att. DG-8 through DG-10.) (Sierra Club also cited material that is not part of the evidentiary record in this matter and is not available to the ALJ: (1) portions of Attachment DG-2 to Exhibit SC-1 that are described as provided on the APS Extranet Site, and (2) Attachment DG-4 to Exhibit SC-1HC, which states that the highly confidential APS responses to data requests are available on USB and the APS Extranet Site. The APS Extranet Site is not part of the evidentiary record, and the ALJ does not have access to it. As provided in the scheduling Procedural Order issued on December 2, 2022, at page 7, in notes 7 and 8, the ALJ "will not access the APS Hearing Extranet Site" and "will not access the APS Discovery Extranet Site." Sierra Club was asked to provide hard copies of the documents it had attempted to provide on USB but declined due to the nature of the documents.)

[132] Ex. SC-1 at 18.

[133] SC Br. at 18-19; Ex. SC-1 at 18, 28, Att. DG-15 at 11, 12, 32; Ex. SC-1HC at Att. DG-10; A.A.C. R14-3-103(A)(3)(l). Sierra Club argues that APS's 2023 IRP finds substantial cost savings from replacing the 4CPP with a combination of solar and gas resources in 2028, cost savings that would have been apparent to APS during the TY if APS had conducted a resource-optimized analysis of the costs and benefits of retiring and replacing the 4CPP, as Sierra Club and other parties recommended in the 2020 IRP process. (SC RBr. at 6.)

increasingly unreliable:

- From 2018 through 2022, 4CPP Units 4 and 5 had annual equivalent forced outage rates ("EFORs")[134] ranging from 7.95%[135] to 28.2%, while the national average EFOR for coal units between 2017 and 2021 was approximately 10% and for all resources was approximately 7.25%. (SC Br. at 9; Ex. SC-1 at 18-19, 34.)
- During the period of 2018 through 2022, 4CPP Units 4 and 5 also had EAFs ranging from 51.55% to 83.72%.[136] (Ex. SC-1 at 19.)
- The 4CPP's reliability is likely to degrade in its final years as spending ramps down, something acknowledged by APS. (SC Br. at 9, 10-11; Tr. at 875.)

- Ms. Glick is an expert witness whose qualifications have not been questioned by any party, and APS has not responded to or provided contemporary evidence to rebut most of the evidence provided by Ms. Glick.[137]
- Ms. Glick determined that the 4CPP is more expensive to operate than alternative energy sources like solar, wind and storage; that APS underestimates the continuing costs to operate the 4CPP; that APS could reduce costs by retiring the 4CPP and replacing it with alternative resources before 2031; that this is possible even considering supply chain issues, project development delays, and the timeline for transmission development; and that APS did not adequately evaluate pre-2031 4CPP retirement before making its TY spending decisions.[138]
- A portfolio of clean energy resources plus limited amounts of market energy can provide reliability equal to or better than APS's fossil-fueled plants, and APS has acknowledged it can replace the

[134] EFOR measures the percentage of time a unit was unavailable during the hours it was expected to be available, thus excluding hours when it was planned to be offline. (Ex. SC-1 at 18.)

[135] In Ms. Glick's testimony and Sierra Club's brief, this low-end number was misstated as 9.5%, although Ms. Glick's Table 5 shows a low-end number of 7.95% in 2022. (*See* SC Br. at 9; Ex. SC-1 at 18-19.)

[136] Sierra Club acknowledged that Mr. Tetlow asserted the EAFs at the 4CPP were low from 2017 to 2021 because of years of underinvestment at the plant due to uncertainty after APS acquired Units 4 and 5, which necessitated greater investment in the last couple of years. (*See* SC Br. at 9; Tr. at 872-873.) Mr. Tetlow also testified that APS considers summer EAF to be the most important metric because in summer, a lack of reliability could impact life and safety, whereas in spring and fall, a lack of reliability causes costs. (Tr. at 873.) Mr. Tetlow testified that the 4CPP's EAF for the last three summers averaged 92%. (Tr. at 873.)

[137] SC RBr. at 3-4.

[138] SC RBr. at 3-4, 6-7. Sierra Club argues that APS's Brief did not dispute that retiring the 4CPP before 2031 could result in cost savings and further states that APS's 2023 IRP finds that APS would save $139 million by retiring the 4CPP in 2028, $91 million by retiring it in 2029, or $57 million by retiring it in 2030. (SC RBr. at 5.)

4CPP with resources providing equivalent reliability by the 2031 retirement date. (SC Br. at 9, 11; Ex. SC-1 at 33-34; Ex. AP-12 at 15-16; SC RBr. at 6-7.)

- APS's "self-fulfilling" contention that APS could not acquire replacement resources before 2031, along with its "inaction and imprudence," have made it more difficult to procure the resources needed to enable earlier retirement, and APS should not be permitted to "rely on its earlier inaction to justify claims that it is infeasible to acquire replacement resources before 2031."[139]

In its Responsive Brief, Sierra Club adds that the outcome of the TEP rate case does not dictate the outcome of this case because TEP is only a minority owner, while APS is the majority owner and operator of the plant, with the power to decide when the 4CPP closes and the responsibility to evaluate the economics of the 4CPP on an ongoing basis. (SC RBr. at 14; *see* Ex. APS-84 at 14, 17; Ex. SC-1 at 8.) Sierra Club also clarifies that it is not recommending that the Commission disallow all PTYP spending at the 4CPP, only the PTYP spending on the ELG Project. (SC RBr. at 14; Ex. SC-1 at 6; *see* SC Br. at 3.)

WRA

In its Responsive Brief, WRA appears to suggest for the first time that the Commission should deny recovery of APS's TY capital expenditures and O&M costs at the 4CPP. (*See* WRA RBr. at 7.) WRA states that the 4CPP cost recovery depends on an outdated analysis that assumes 2019 operations, assumes APS will exit the 4CPP in 2031, and fails to include new cost savings opportunities such as the IRA. (WRA RBr. at 6.) Without a more current evaluation using earlier retirement dates, WRA states, the study cannot economically justify continued operation of the 4CPP and, thus, APS has failed to meet its burden of proof in showing that it is prudent to continue using customer dollars to operate the 4CPP through 2031. (WRA RBr. at 6.) WRA argues that by filing an updated study in the 2023 IRP matter, APS has itself abandoned the outdated study used in this matter. (WRA RBr. at 6.) WRA argues that without "an updated analysis on the record,"[140] the Commission cannot verify that operating the 4CPP until 2031 is the best economic choice. (WRA RBr. at 6-7.) WRA adds that if the

[139] SC RBr. at 6-7.

[140] The Commission has taken official notice of the 2023 IRP in this matter, pursuant to the requests made by AriSEIA/SEIA and the Sierra Club.

Commission approves APS's request for recovery in this matter, the Commission should "provide guidance" to APS and "caution" APS that if updated studies, including the 2023 IRP, show cost savings from early retirement of the 4CPP, "future requests for customer-funded investments, and costs to maintain the operation of an un-economic plant will be closely scrutinized and may be denied." (WRA RBr. at 7.) WRA then states: "In other words, the Commission's decision in this case should clarify that future investment and expenditures on the [4CPP] would not be prudent if any APS study demonstrates ongoing operation of the plant is not economic or that earlier retirement would provide savings to customers." (WRA RBr. at 7.)

APS Response

APS characterizes Sierra Club's arguments as "meritless" and asserts that they have already been rejected by the Commission in the 2022 TEP rate case. (APS RBr. at 79; *see* Ex. APS-84 at 18-19.) APS maintains that the investments and expenditures necessary to ensure 4CPP operations through 2031 are prudent because the 4CPP is "a vital asset for regional grid reliability that provides numerous cost-effective values for customers." (APS RBr. at 79.) According to APS, the record shows that it is responsibly transitioning away from coal-fired generation in a manner that will ensure sufficient resources to replace the 4CPP in 2031 and grid reliability, and there is "no credible evidence" that the 4CPP can feasibly be replaced before 2031 without compromising resource adequacy and thus reliability. (APS RBr. at 79.) APS argues that Sierra Club provides "pure speculation, rather than credible analysis" to oppose APS's position. (APS RBr. at 79.) APS further argues that Sierra Club has failed to provide any evidence to contest APS's undisputed evidence concerning resource development delays and cancellations, the timeframes needed to develop additional transmission assets or natural gas pipeline capacity, and the dramatic load growth on APS's system. (APS RBr. at 80; Ex. APS-14 at 12-14; Tr. at 3701-3702; Ex. APS-76.) To rebut Sierra Club's argument that APS is not taking adequate steps to develop replacement capacity for the 4CPP, APS points to the 291 MW of new renewable energy generation and storage resources that went into service by June 30, 2023, and for which APS seeks cost recovery herein; the fact that APS has at least 3,500 MW of new renewable generation and energy storage resources actively under development to be placed in service by 2025; and APS's 2023 ASRFP that seeks an additional 1,000 MW of new generation resources (including

700 MW of renewables). (APS RBr. at 80; Ex. APS-14 at 7-9; Ex. APS-8 at 25-27; Ex. APS-10 at 1, 3, Att. JT-07RJ at 3.) APS also points to its need to fill an additional 3,500 MW gap in growing peak demand by 2031 and the steps it is taking to implement a year-round procurement process to accelerate additional resources. (APS RBr. at 81; Ex. APS-76 at 2; APS Br. at 105-106.)

APS adds that Sierra Club does not address the fact that because of the 4CPP's shared ownership, APS cannot make unilateral decisions on plant retirement and plant-sustaining capital investments such as the ELG Project. (APS RBr. at 82-83; Ex. APS-12 at 29.) APS points out that both TEP and SRP are planning to use the 4CPP plant capacity through 2031 and, further, that NTEC is exploring opportunities to continue operating the 4CPP by installing carbon capture. (APS RBr. at 82; Ex. APS-12 at 29; Tr. at 835-836, 1007.)

Further, while APS acknowledges that it is "explor[ing] opportunities for modest acceleration of its 2031 exit from [the 4CPP] as part of its . . . 2023 [IRP]," provided that the opportunities are affordable and ensure reliability, APS maintains that seeking to replace the 4CPP with only clean energy resources and market purchases would not save customers money and would put reliability at risk. (APS RBr. at 83-85.) APS defends the E3 analysis, stating that it built upon the 2020 IRP analysis, included data used in APS's 2023 IRP, explicitly included IRA tax benefits, and was conducted specifically to provide "a realistic depiction of exactly what Sierra Club is advocating," which APS states is only a portfolio with zero-emitting renewable energy generation, battery storage, and market purchases, not a resource optimized portfolio. (APS RBr. at 83-84; Ex. APS-14 at 9-11; Ex. APS-12 at 18-19; Tr. at 1515-1516.) APS also rejects Sierra Club's contention that the E3 analysis relied on excessive market energy purchases, pointing out that it was Mr. Joiner who stated that APS would need to rely primarily on market purchases to replace the 4CPP by 2028. (APS RBr. at 84-85; Ex. APS-12 at 18; *see* Tr. at 1369-1371.)

Finally, APS criticizes Sierra Club for relying on the 2019 Strategen analysis, which APS states is outdated and significantly flawed; depending almost exclusively on LCOE, which undervalues the 4CPP as a 24-hour capacity resource; failing to recognize the resource diversity value of the 4CPP, which enhances reliability; relying on forced outages to demonstrate that the 4CPP is increasingly unreliable, when the 4CPP provided critical capacity during the summer 2023 heat wave; failing to acknowledge Mr. Tetlow's testimony that the historic capital spending at the 4CPP was not indicative of future projections; and failing to recognize that APS's planning efforts take into account proposed environmental regulations and that the 4CPP is well positioned to manage the obligations of such regulations in a cost-effective manner. (APS RBr. at 85-86; Ex. APS-12 at 12-22; Ex. APS-10 at 11-16; Ex. APS-9 at 12-16, 19; Tr. at 1520.)

Resolution

Sierra Club and WRA are correct that APS has the burden of proof concerning the prudence of its TY capital and O&M expenditures for the 4CPP, and Sierra Club is correct that there is no presumption of prudence for O&M expenditures.[141] Sierra Club is also correct that APS's burden of proof concerning the prudence of its O&M expenditures is a preponderance of the evidence,[142] not clear and convincing evidence. Concerning capital investments at the 4CPP, however, there is a presumption of prudence, which can be overcome by clear and convincing evidence that the investments were imprudent when viewed in light of all relevant conditions known or that in the exercise of reasonable judgment should have been known when the investments were made.[143]

APS has established that the 4CPP was used and useful during the TY and, for the past three summers, has served as a dispatchable and reliable capacity resource with an average summer EAF of 92%. According to the E3 analysis completed in 2020, prior to the TY, exiting the 4CPP before 2031 by using renewables, storage, and market purchases would have increased costs to customers and posed a reliability risk. The E3 analysis was not resource optimized, as Sierra Club emphasizes, but it would have served as contemporary information available to APS when it made its decisions about TY expenditures for the 4CPP. APS also would have been aware that Western U.S. balancing authorities had declared multiple Emergency Energy Alert Level 3 emergencies during summer 2020[144] when balancing authorities were unable to meet minimum contingency reserve requirements and load interruption was in progress or imminent, Arizona had experienced its hottest summer recorded in 2020, and APS had been able to continue providing reliable service throughout these events because

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[141] *See* A.A.C. R14-2-103(A)(3)(l); A.A.C. R14-3-109(G); Decision No. 77130 at 10.
[142] *See, e.g.,* Decision No. 67279 (October 5, 2004).
[143] A.A.C. R14-2-103(A)(3)(l).
[144] This also happened in summer 2021 and 2022. (Ex. APS-11 at 11.)

of its diverse portfolio that includes the 4CPP. (Ex. APS-11 at 11-12.) Additionally, and importantly, APS cannot make unilateral decisions about retiring the 4CPP; it must have the support of the other 4CPP owners, all of whom (other than PNM) have been and are currently planning for the 4CPP to continue operations until 2031. For these reasons, APS's TY O&M expenditures were prudent, and they should be recoverable through base rates. Additionally, APS's TY capital expenditures, other than the ELG Project (discussed below) were prudent, and they should be included in rate base.

2. Inclusion of ELG Project in PTYP

APS Proposal

APS asserts that it is appropriate to include the ELG Project in PTYP because it is federally mandated to be installed by the end of 2023,[145] APS cannot operate the 4CPP beyond 2028 without it, the 4CPP provides economic base load generation, gas prices are still high, and the ELG Project will be in service well before the rates set herein are in effect. (Tr. at 377, 801, 1068; Ex. APS-12 at 20.) APS originally expected the ELG Project to be completed by June 30, 2023, but it was delayed due to supply chain issues in obtaining the large amount of concrete needed to make the containment ponds, which span the size of three football fields. (Tr. at 377, 940-941.) Additionally, APS chose not to construct the ELG Project during the summer months because the tie-in of the ELG Project at the 4CPP necessitated a 45-day outage, and APS desired to ensure reliability to serve summer loads.[146] (Tr. at 941.) Further, the ELG Project would qualify for recovery under the EIS, which is being eliminated in this matter at APS's request (Tr. at 1005.) APS also asserts that it has no unilateral ability to exit the 4CPP to avoid the ELG Project expense, as the other owners of the 4CPP[147] are unified in their plans to exit the 4CPP in 2031. (Ex. APS-12 at 21, 29.)

As of April 21, 2023, APS had made the following investments in the ELG Project in 2021, 2022, and 2023:[148]

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[145] The purpose of the EPA's ELG requirement is to minimize or eliminate waters that touch coal combustion residuals from being discharged from the plant site; some people refer to this as "zero liquid discharge" because water that enters the site is not allowed to leave the site. (Tr. at 814.)

[146] APS states that it chose not to construct the ELG in 2021 or 2022 because of the time value of money and not wanting customers to pay for the ELG to go into service more than a reasonable margin before the required deadline. (Tr. at 942.)

[147] This statement assumes that PNM's interest is sold to NTEC.

[148] Ex. SC-1 at Att. DG-2 at 104.

2021	2022	2023	Total as of April 21, 2023
$3,293,336	$20,182,363	$8,733,833	$32,209,532

As of June 30, 2023, APS had spent $42 million on the ELG Project and expected the ELG Project to be in service by the end of November 2023. (Tr. at 815, 942-943.) As of the hearing in this matter, APS estimated that the ELG Project would have a total cost of $52,596,551. (Ex. APS-10 at Att. JT-05RJ at 2; Tr. at 940-941.) In its Brief, APS asserts that the ELG Project cost has been updated but did not provide the new figure, which is included in the $613.5 million of net PTYP for which recovery is requested. (APS Br. at 3-4.) APS also states that it will provide final cost information to Staff once the ELG Project is completed and "will postpone any additional trailing costs of the project to its next rate case." (APS Br. at 4.)

AZLCG

AZLCG argues that the ELG Project should be excluded from PTYP because it was not completed, in service, and used and useful by June 30, 2023, and should not be afforded special and unique treatment. (AZLCG Br. at 6.) AZLCG observes that APS removed from its PTYP request $161.7 million in plant projects that were expected to be placed into service by June 30, 2023, but were not, and asserts that the ELG Project is no different from these projects and is not certain to be placed into service even by November 2023. (AZLCG Br. at 7; *see* Ex. APS-10 at 2; Ex. APS-23 at 7; Tr. at 1980-1981, 4439.) The ELG Project's being federally mandated does not necessitate that it be included in rate base in this matter, AZLCG states, because all utility plant investments have to be necessary to avoid being determined imprudent, and there must be a cut-off date for determining rate base so that there is as much synchronization as possible between revenues, expenses, and investment. (AZLCG Br. at 7; Ex. AZLCG-5 at 12; A.A.C. R14-2-103(A)(3)(l); Ex. AZLCG-1 at 12; Ex. RUCO-1 at 11; Tr. at 3021.) AZLCG argues that APS's proposed rates herein would not reflect the revenue growth in the PTY period or as of the ELG Project's placement into service, and asserts that APS acknowledged both that it has typically been awarded only 12 months of PTYP and that there is no Commission policy or precedent to support including a plant project from outside of the PTY period in rate base because it is federally mandated. (AZLCG Br. at 8; Tr. at 816.)

AZLCG further asserts that if the Commission allows the ELG Project to be included in rate base in this matter, the Commission should require APS to roll forward accumulated depreciation for the rest of the 4CPP through the date the ELG Project is placed into service. (AZLCG Br. at 6, 8, 9-10.) AZLCG states that accumulated depreciation is rolled forward for the PTY period to ensure that rate base is offset to reflect the depreciation expense paid by ratepayers during the PTY period and that APS agrees that this treatment aligns with the matching principle. (AZLCG Br. at 8-9; Tr. at 1877, 1956, 1960; *see* Tr. at 5227.) APS's treatment of the ELG Project is inconsistent, AZLCG states, because although the 4CPP will continue to experience depreciation between June 30, 2023, and the date the ELG Project is placed into service, that additional accumulated depreciation will not be reflected in rate base, resulting in a higher rate base and revenue requirement to be paid by ratepayers. (AZLCG Br. at 9; Tr. at 1877-1878, 1881-1882, 1884, 1886-1887.)

In its Responsive Brief, AZLCG took issue with APS's statement in its Brief that the projected cost of the ELG Project had been updated, without quantification of the change, which AZLCG inferred to mean that the ELG Project cost had increased. (AZLCG RBr. at 2; *see* APS Br. at 4.) Additionally, AZLCG expressed concern about APS's statement that APS "will postpone any additional trailing costs of the project to its next rate case." (AZLCG RBr. at 2; *see* APS Br. at 4.) AZLCG argues that both of these APS statements demonstrate that the ELG Project costs are uncertain and support its exclusion from rate base in this matter, as the updated costs and "implicit deferral request" both appeared for the first time in APS's Brief and were not evaluated by the parties to this matter through discovery and cross-examination. (AZLCG RBr. at 2.) AZLCG quotes Mr. Smith's testimony to the effect that if the actual costs of the ELG Project were lower, APS should be required to adjust the number down, and if the actual costs were higher, APS's recovery should be capped at the number in its rejoinder testimony. (AZLCG RBr. at 2-3; Tr. at 5332.) AZLCG concludes that the ELG Project costs are not currently known and measurable and that it should not be included in rate base in this matter. (AZLCG RBr. at 3.)

<u>Sierra Club</u>

Sierra Club asserts that APS's spending on the ELG Project should not be included in PTYP because the ELG Project was not completed and in service by June 30, 2023; APS has not demonstrated that the ELG Project was prudent; and evidence indicates that the costs of the ELG Project could have been avoided or reduced if APS retired the 4CPP by 2028. (SC Br. at 16.) Sierra Club argues that because APS never considered retiring the 4CPP before 2031 when making its decision to move forward with the ELG Project investment, APS failed to perform adequate analysis to support its decision and failed to evaluate whether ratepayers would have been better served by retiring the 4CPP in 2028 and thus avoiding the ELG Project. (SC Br. at 15; Ex. SC-1 at 44.) According to Sierra Club, if APS had committed to retiring the 4CPP by 2028, the 4CPP would be subject to less stringent effluent discharge standards, and APS "likely" would have incurred lower ELG Project costs. (SC Br. at 16; Ex. SC-1 at 27; *see* 40 CFR Part 423.) Sierra Club disagrees with APS's assessment that it would be unable to procure replacement capacity by 2028, instead asserting that APS did not adequately attempt to obtain replacement capacity to retire the 4CPP before 2031 and that retirement before 2031, probably by 2028, is feasible. (SC Br. at 16; Ex. SC-1 at 27, 34, Att. DG-2; Ex. SC-2 at 10-11.) Ms. Glick testified that the $52 million ELG Project is an example of the type of environmental compliance costs that APS ratepayers will bear if APS continues to operate the 4CPP and pointed out that it is only part of the cost of extending the life of the 4CPP beyond 2028, as ratepayers will also continue to pay ongoing capital costs and O&M costs that could be avoided by a 2028 closure. (Ex. SC-2 at 11-12.) Sierra Club denies that it is recommending that APS rely heavily on market purchases to obtain replacement capacity to allow for a pre-2031 closure of the 4CPP, but also asserts that APS should not "conservatively plan[] its system to operate like an isolated island." (Ex. SC-2 at 13.)

In its Responsive Brief, Sierra Club reiterates the arguments from its Brief and, additionally, asserts that clear and convincing evidence shows the ELG Project spending was imprudent. (SC RBr. at 9.) Sierra Club notes that Staff acknowledged merely finding PTYP to be used and useful cannot justify its recovery in rates, as the Commission must also find that the PTYP investments were prudent. (SC RBr. at 10; Ex. S-24 at 17-18; A.A.C. R14-2-103(A)(3)(l).) Sierra Club also cites with approval AZLCG's argument that allowing recovery of PTYP completed 17 months after the end of the TY would be inconsistent with the Commission's established practice of limiting PTYP to a 12-month period and would depart from the matching principle. (SC RBr. at 10; AZLCG Br. at 7-8; Ex. AZLCG-1 at 12; Ex. RUCO-1 at 4, 11, 15.) Sierra Club also questions the proposition that a plant project should be included in rate base simply because it is federally mandated, asserting that there is no such

Commission policy and that the Commission must evaluate whether the spending was prudent, reasonable, and not wasteful. (SC RBr. at 11; AZLCG Br. at 7; Ex. AZLCG-4 at 12; A.A.C. R14-2-103(A)(3)(l); Tr. at 816.)

To support its assertion that clear and convincing evidence shows the ELG Project spending was imprudent, Sierra Club reiterates Ms. Glick's testimony that APS's ELG Project spending could have been reduced or avoided if APS had planned to retire the 4CPP by 2028, notes Mr. Smith's testimony that APS could continue to operate the 4CPP until 2028 without installing the ELG Project, and asserts that APS has not disputed that retiring the 4CPP in 2028 would reduce ELG Project compliance costs and instead asserts that it must operate the 4CPP until 2031 because a 2028 retirement would be costly and infeasible. (SC RBr. at 11-12; Ex. SC-1 at 5-6, 27; Ex. APS-12 at 20-21; Ex. APS-9 at 8-9; Ex. APS-14 at 12; Tr. at 883, 3687, 3691, 3756-3757, 5192; *see* 40 CFR §§ 423.11(w), 423.13, 423.18, 423.19 (2023); 85 Fed. Reg. 64650, 64681 (Oct. 13, 2020)[149].) Sierra Club states that APS admitted it never evaluated whether it could have avoided or reduced the ELG Project costs by retiring the 4CPP in 2028.[150] (SC RBr. at 12; Ex. SC-1 at 27, Att. DG-2.) In addition, Sierra Club newly asserts that APS's 2023 IRP confirms that retiring the 4CPP in 2028 could save $139 million. (SC RBr. at 13.) Sierra Club argues that APS decided to spend more than $52 million on the ELG Project

[149] In its Responsive Brief, Sierra Club requests that official notice be taken of the effluent limitation guidelines final rule published at 85 Fed. Reg. 64,650 (October 13, 2020) and codified at 40 CFR Part 423. This is the Final Rulemaking published in the *Federal Register* showing that the EPA adopted the revised Effluent Limitations Guidelines and Standards for the steam electric power generating point source category applicable to flue gas desulfurization wastewater and bottom ash transport water effective December 14, 2020. Official notice is taken of this Final Rulemaking and of the codified rule changes in 40 CFR Part 423. The final rule included separate requirements for electric generating units that will permanently cease the combustion of coal by 2028. EPA states the following in the notice: "EPA concludes that premature closure of some plants and/or [electric generating units ("EGUs")] is an unacceptable non-water quality environmental impact because it could impact reliability. Therefore the avoidance of these premature closures weighs in favor of subcategorization [of EGUs that will permanently cease coal combustion by 2028]." (85 Fed. Reg. 64650, 64680.) EPA noted a North American Electric Reliability Corp ("NERC") "aggressive stress test scenario" that determined "significant reliability problems" could occur if the projected retirement dates for large baseload coal and nuclear plants were moved forward such that well-planned replacement generation capacity is not in place, along with inadequate reserve margins in some regions, as support for "EPA's view that marginal plants should not be forced into retirement while they still have a useful role to play in ensuring electric reliability." (*Id.* at 64681.)

[150] APS acknowledged that it did not conduct an analysis regarding whether the ELG Project investments could have been reduced or avoided if the 4CPP were closed by 2028 because APS had determined that it would not be feasible to replace the 4CPP with equivalent dispatchable capacity by 2028 due to the "incredibly tight" western market for capacity resources and the lead time needed to develop large-scale capacity resources. (Ex. SC-1 at Att. DG-2 at 98.) APS had included forecasted capital and incremental O&M costs for the ELG Project in its 2020 IRP analysis. (Ex. SC-1 at Att. DG-2 at 95.) In a data response dated February 16, 2023, Mr. Joiner acknowledged that APS had not performed an updated economic analysis related to the 4CPP retirement date since its last rate case but stated that it was required to include an analysis in its upcoming 2023 IRP. (Ex. SC-1 at Att. DG-2 at 93-94.)

to keep the 4CPP online from 2028 to 2031 without evaluating whether it could avoid the need for the ELG Project or meet the ELG compliance requirements in a less costly manner by retiring the 4CPP by 2028, that retirement and replacement of the 4CPP by 2028 was feasible when APS decided to pursue the ELG Project, and that retiring the 4CPP before 2031 remains feasible. (SC RBr. at 13; Ex. SC-1 at 34; Ex. SC-2 at 11; Tr. at 3687, 3756-3758.)

<u>WRA</u>

In its Responsive Brief, WRA appears to suggest that the Commission should deny recovery for the ELG Project in PTYP. (*See* WRA RBr. at 6-7.) WRA's arguments and recommendation are identical to what has been set forth above concerning recovery of costs other than for the ELG Project.

<u>RUCO</u>

Under the unique facts and circumstances in this case, RUCO supports allowing APS to defer the costs of the ELG Project, with carrying costs set at APS's weighted cost of debt in this matter, from the time it is placed into service until APS's next rate case. (RUCO Br. at 24; Ex. RUCO-4 at 2.) RUCO states that the 4CPP "is a critical resource that is needed to keep the lights on and ensure reliability for APS customers" and that APS has asserted that failure to complete the ELG Project by the end of 2023 would result in violation of APS's National Pollutant Discharge Elimination System ("NPDES") permit for the 4CPP and in APS not being able to operate the plant after 2028. (RUCO Br. at 24; Ex. APS-9 at 8-9; 85 Fed. Reg. 64650 (October 13, 2020).) RUCO asserts that its position on including the 4CPP ELG Project shows that its approach to pro forma adjustments like PTYP is fair and balanced, flexible, and aligned with the facts and circumstances of a given case. (RUCO Br. at 25.)

<u>Staff</u>

Staff asserts that absent compelling circumstances, it would be inappropriate to include the ELG Project in rate base in this matter because it was not in service by June 30, 2023. (Staff Br. at 10; Ex. S-24 at 17.) However, Staff determined that there are compelling circumstances in this matter based on all of the related facts and circumstances. (Staff Br. at 10; Ex. S-24 at 17.) Specifically, Staff states, the ELG Project will be in service and used and useful on November 28, 2023, before the rates from this matter become effective; the ELG Project was required by the EPA and must be completed by the end of 2023 to allow the 4CPP to continue operations through 2031; the total cost of the ELG Project has been allocated among APS and the other 4CPP owners, and the amount to be included in rate base is the amount corresponding to APS's ownership share; and the ELG Project would have qualified for cost recovery under the EIS, which is proposed to be eliminated in this case but is currently still in effect. (Staff Br. at 10-11; Tr. at 5191-5192; Ex. S-24 at 19-21; Ex. APS-10 at 7.) Staff recommends that the jurisdictional amount of APS's cost for the ELG Project be included in rate base. (Staff Br. at 11.)

In its Responsive Brief, Staff reveals that the update to the cost of the ELG Project referenced by APS in its Brief was an increase of approximately $1.56 million, resulting in a total ELG Project cost of $54.16 million[151] rather than the $52.60 million identified by APS on rejoinder. (Staff RBr. at 2.) Additionally, Staff states that the amount appears to be an updated estimate rather than the final actual as-recorded cost for the ELG Project. (Staff RBr. at 2.) Staff recommends recognition in rate base of the ELG Project cost that APS identified through the conclusion of the hearing in this matter.[152] (Staff RBr. at 2.) Staff further recommends that APS be required to report to the Commission when the ELG Project is placed into service and to file with the Commission, within 60 days after the in-service date, a report providing the final as-recorded costs of the ELG Project and how the costs were allocated among APS and the other 4CPP owners. (Staff RBr. at 2 (quoting Ex. S-24 at 21).) Staff concludes by stating that while it stands by its recommendation, it does not object to using the updated final as-recorded cost for the ELG Project as long as the final cost can be verified by the Commission before its decision is issued in this matter. (Staff RBr. at 2.)

<u>APS Response</u>

APS argues that RUCO's recommendation to defer the costs of the ELG Project until APS's next rate case at a carrying cost equal to APS's weighted cost of debt once placed in service should be rejected because as of November 21, 2023, the ELG was operational and undergoing final commissioning.[153] (APS RBr. at 2.) APS asserts that the system tie-in outage would end and the ELG

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[151] This figure is not included in the evidentiary record for this matter.

[152] Staff misidentifies this amount as $52.037 million but also recognizes in its Responsive Brief that the cost amount identified by APS through the end of the hearing was $52.60 million. (Staff RBr. at 2 (quoting Ex. S-24 at 21); *see* Ex. APS-10 at Att. JT-05RJ at 2; Tr. at 940-941.)

[153] This is not in the evidentiary record.

Project would become used and useful on November 26, 2023.[154] (APS RBr. at 2.) APS includes in its Responsive Brief photos of ELG Project flush and sluice vertical turbine pumps and water tanks.[155] (APS RBr. at 3.) Further, APS argues, RUCO's recommended deferral is inconsistent with the purpose of PTYP, which is to reduce regulatory lag. (APS RBr. at 3.)

APS argues that the Commission should reject AZLCG's argument that the ELG Project should not be provided special treatment through inclusion in PTYP despite its post-June 30, 2023, in-service date because the ELG Project is federally mandated, and the EPA will require shutdown of the 4CPP if the ELG Project is not completed; the ELG Project would have been eligible for recovery under the EIS that APS has requested to eliminate in this matter, and thus APS would not be able to include the ELG Project in rate base until its next rate case if it is not included in PTYP herein; and AZLCG is incorrect that the Commission has not previously allowed a PTY period beyond 12 months.[156] Regarding AZLCG's argument that APS should be required to roll forward accumulated depreciation for the 4CPP through the in-service date of the ELG Project if the ELG Project is included in PTYP, APS states that AZLCG has cited no legitimate basis or Commission precedent for rolling forward the depreciation for an entire asset based on a single improvement to that asset, and there is none.[157] (APS RBr. at 4-5.)

APS argues that Sierra Club's position also should be rejected because the EPA's NPDES regulations are "extremely inflexible" about compliance timing and would require "permanent cessation" of operations at the 4CPP by the end of 2028 if APS did not complete the ELG Project and instead tried and failed to obtain sufficient replacement resources by the end of 2028, regardless of whether APS customers could not be served. (APS RBr. at 81; 85 Fed. Reg. 64650, 64681.) According to APS, the EPA explicitly ruled out compliance flexibility associated with market conditions, the availability of natural gas pipelines, and other situations that could delay developing sufficient

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[154] This is not in the evidentiary record.

[155] This is not in the evidentiary record.

[156] APS states that in its 2008 rate case, the Commission approved an 18-month PTY period and that in its 2011 rate case, the Commission approved a 15-month PTY period. (APS RBr. at 4 (citing Decision No. 71448 (December 30, 2009) and Decision No. 73183 (May 24, 2012)).) Official notice is taken of Decision No. 71448. Decision No. 73183 was admitted as Exhibit RUCO-13. The Commission notes that both of these decisions approved settlement agreements.

[157] APS asserts that AZLCG disingenuously cites Ms. Blankenship's hearing testimony to support its argument, although Mr. Blankenship disagreed with AZLCG's position in that testimony. (APS RBr. at 5; *see* Tr. at 1880-1884.)

resources to retire a coal-fired plant and warned that it was necessary to plan carefully how to comply with the ELG requirements. (APS RBr. at 81-82; 85 Fed. Reg. 64650, 64709.) Finally, APS argues, forgoing the ELG Project would create serious reliability risks for its customers. (APS RBr. at 82; Ex. APS-12 at 22.)

Resolution

AZLCG is correct that there should generally be a cut-off point beyond which PTYP projects are excluded from rate base. In this case, that cut-off point is June 30, 2023, and the ELG Project was not completed and in service by that cut-off point. Rather, the ELG Project was not due to be completed until almost five months after the end of the 12-month PTY period. In spite of this, APS and Staff desire to make an exception for the ELG Project. Even RUCO recommends that the ELG Project receive special treatment, albeit not through inclusion in PTYP and rate base in this case. APS, RUCO, and Staff use as justification the federal mandate for the ELG Project, the unexpected delays that occurred in obtaining the materials for and construction of the ELG Project, and the ELG Project's eligibility otherwise to be included in the EIS (which is being eliminated in this case).

The 4CPP served as a critical resource during the past three summers, and the ELG Project is mandated by the EPA and necessary for APS to continue to operate the 4CPP beyond 2028 (as it and the other 4CPP owners intend to do). APS has provided ample testimony concerning its inability to acquire or construct alternative generating resources to replace the capacity of the 4CPP before 2031 and its concerns that relying on market purchases to replace the 4CPP's capacity before 2031 would be both uneconomical and risky in terms of reliability, and this testimony has not been rebutted with sufficient evidence to establish that the 4CPP capacity could be economically and reliably replaced before 2028, which is the relevant date in this scenario.[158] (*See, e.g.,* Tr. at 1350-1355, 1369-1371, 1373, 3713-3725.)

The Commission considers it reasonable and appropriate to consider extenuating circumstances when determining whether a PTYP project that did not make the general cut-off date should

[158] APS apparently has planned for the ELG Project since at least 2020 and began making expenditures for the ELG Project in 2021. When APS planned and began making expenditures for the ELG Project, the APS analysis available was that in the 2020 IRP, which assumed operations of the 4CPP until 2031.

nonetheless be included in rate base as PTYP.[159] In this case, the ELG Project almost certainly would have been completed before June 30, 2023, if not for difficulties obtaining the necessary supplies to construct the project and APS's responsible decision not to take the 4CPP offline for 45 days during the summer months to install the ELG Project. For this reason, because the ELG Project is reasonably expected to be in service and used and useful before the effective date of the rates in this matter, because the ELG Project is federally mandated to allow continuing operation of the 4CPP beyond 2028, because there is insufficient evidence to establish that the capacity from the 4CPP could be economically and reliably replaced before 2028, because APS cannot unilaterally opt out of paying its share of the ELG Project costs, and because the ELG Project would have been eligible for recovery through the EIS if the EIS were not eliminated in this matter, it is just and reasonable to include the ELG Project in rate base as PTYP in this matter. Because the final cost of the ELG Project is not yet known and the updated estimate is not part of the evidentiary record for this matter, it is just and reasonable to limit the cost of the ELG Project included in PTYP to APS's rejoinder position of $52,596,551. Additionally, it is just and reasonable to require APS to report on the ELG Project consistent with Staff's recommendation but with a modified timeline: APS will be required to file a report within 30 days after the effective date of this Decision providing the final as-recorded costs of the ELG Project and the breakdown of those costs among APS and the other owners of the 4CPP.

3. Seasonal Operations

APS Proposal

APS states that for economic reasons, it no longer proposes to initiate seasonal operations at the 4CPP in late 2023 or pre-summer 2024, although it maintains the flexibility to initiate seasonal

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[159] For example, in the 2019 TEP rate case, which had a TY ending December 31, 2018, and a PTY period general cut-off date of June 30, 2019, the Commission nonetheless allowed in rate base as PTYP several projects that had not been completed until late 2019 or even February 2020. (Ex. AZLCG-28 at 12, 14, 18, 27, 36, 39-40, 45.) (Exhibit AZLCG-28 is Decision No. 77856 (December 30, 2020), issued in TEP's 2019 rate case, Docket No. E-01933A-19-0028.) In Decision No. 77856, the Commission noted that the Irvington Facilities modernization project had been touted by TEP as improving operational efficiency, enhancing security, improving safety, and keeping pace with advances in communication and field technology; concluded that the acquisition of Gila River Unit 2 (550 MW capacity) saved ratepayers millions of dollars as compared to the Tolling Agreement TEP had in place prior to the purchase; and concluded that the addition of 10 Reciprocating Internal Combustion Engines ("RICE Units") (each with a capacity of 18.2 MW) at its Sundt facilities in Tucson was necessary to support the addition of renewables onto TEP's system. (Ex. AZLCG-28 at 17, 19-20, 27, 45.) The Commission determined that because the projects were reasonable and prudent and the facilities used and useful, it was reasonable to include them in rate base as PTYP. (Ex. AZLCG-28 at 45.)

operations in future years. (APS Br. at 108-109; Tr. at 840, 887, 895, 1029; Ex. APS-10 at 12-13[160].) APS asserts that the forward natural gas prices for the San Juan Basin, from which APS procures its gas, are higher than the costs needed to justify seasonal operations, so if APS were to initiate seasonal operations in the coming winter and spring, customers would pay more for electricity. (APS Br. at 108; Ex. APS-143 at 27-28; Ex. APS-14 at 7; Ex. SC-2 at 14-15; Ex. SC-1 at 7; Ex. APS-10 at 12-13.) Mr. Tetlow testified that if APS can maintain reliability and save customers money by moving to seasonal operations at the 4CPP, APS will do so, but that moving to seasonal operations would require a scenario such as $2/MMBtu natural gas prices, which have not existed since before COVID. (Tr. at 840, 885-887, 889, 1067-1068.) Mr. Tetlow also testified that APS continuously analyzes current forward-looking gas prices and that the 2021 Amendment to the 4CPP Agreement requires the 4CPP owners to decide whether to opt out of seasonal operations before the summer months each year. (Tr. at 887, 889.)

As explained thoroughly above, APS also maintains that it is infeasible to replace the 4CPP with sufficient resource adequate replacement resources, and the infrastructure to deliver their energy to customers, before 2031, and that accelerating APS's exit from the 4CPP (assuming that it could be done in light of the ownership model) would significantly risk continued reliable service to APS's customers. (APS Br. at 109-110.)

Sierra Club

Sierra Club argues that the Commission should order APS to evaluate moving the 4CPP to seasonal operations beginning in 2024 because the evidence shows that switching to seasonal operations would save customers money by reducing APS's spending on coal and exposure to coal price volatility. (SC Br. at 17, 20; Ex. SC-1 at 5-6, 48, Att. DG-2 at 96.) According to Sierra Club, APS's decision to postpone seasonal operations was shortsighted because gas prices have dropped to a level similar to the level at which APS originally decided to move to seasonal operations in 2021 and below the level APS previously cited as a threshold to re-review the seasonal operations decision.[161]

[160] APS also cited Exhibit APS-110, which was not admitted, is thus not a part of the evidentiary record in this matter, and will not be considered by the Commission.

[161] Sierra Club states that APS subsequently "mov[ed] the goalposts" by referencing a different threshold number. (SC Br. at 17 n.85; *see* Tr. at 885-886, 889-890.)

(SC Br. at 17; Ex. SC-1HC at 49[162]; Ex. SC-2 at 4.) Sierra Club states that APS can save ratepayers money by moving the 4CPP to seasonal operations in fall 2023 or winter 2024 because gas prices are projected to decrease and stabilize, and APS is only required to provide seven days' notice to invoke seasonal operations. (SC Br. at 17; Ex. SC-1 at 5-7, 49, 62; Ex. SC-2 at 6.)

Staff

Staff states that APS has not been able to take advantage of seasonal operations at the 4CPP both because natural gas prices have risen since the seasonal operations contract provision was negotiated, making use of the 4CPP's generation a more economic option, and because the 2021 Amendment is dependent on the sale of PNM's share of the 4CPP to NTEC, which was denied by the New Mexico PUC, a decision that was upheld by the New Mexico Supreme Court. (Staff Br. at 66.) Staff states that if the PNM sale is not completed, the seasonal operations contract provision is of "questionable viability." (Staff Br. at 66.)

APS Response

APS disputes Sierra Club's assertion that customer costs would decrease if seasonal operations were implemented in 2024, stating that Sierra Club relies entirely on Henry Hub pricing information although APS procures its gas from the San Juan Basin. (APS RBr. at 87; *see* Ex. SC-1 at 48-50; Tr. at 3725-3726.) APS asserts that the undisputed evidence of record shows that San Juan Basin forward natural gas prices are forecasted to be higher than $3.50/MMBtu in winter 2023 and higher than $4.00/MMBtu into 2024, levels significantly higher than the level APS has established for considering seasonal operations at the 4CPP. (APS RBr. at 87; Ex. APS-12 at 27-28.)

APS further states that Staff is incorrect that APS does not have the flexibility to initiate seasonal operations when it becomes cost effective to do so. (APS RBr. at 88; Ex. APS-10 at 12-13; *see* Staff Br. at 66.) APS asserts that the decision not to initiate seasonal operations is economical based on energy market conditions and has nothing to do with uncertainty concerning the PNM sale.[163]

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[162] Sierra Club also again referenced Attachment DG-4 to Exhibit SC-1, which is not part of the record in this matter.

[163] The evidence shows that the 2021 amendments to the Operating Agreement and Co-Tenancy Agreement terminate by their own terms if the PNM sale is not finalized by the end of 2024 but that the 4CPP owners are required to negotiate in good faith to discuss new amendments to the Agreements regarding seasonal operations if termination should occur. (*See* Tr. at 5413-5414; Ex. S-24 at 5758.) APS reports that the other owners are open to continuing the seasonal operations provisions if the sale does not go forward. (*See* Tr. at 5414.)

(APS RBr. at 88; Ex. APS-10 at 12-13; Tr. at 5413-5415.) APS adds that all of the current 4CPP owners, including PNM and NTEC, are committed to ensuring seasonal operations flexibility can be preserved in the 4CPP operating agreements. (APS RBr. at 88; Tr. at 5413-5415.)

Resolution

According to APS's data responses set forth in Mr. Smith's testimony, the seasonal flexibility provision remains in effect until the end of 2024, when it may terminate automatically, though the 4CPP owners would be required to negotiate in good faith regarding seasonal operations. (Ex. S-24 at 57.) Thus, APS and the other owners of the 4CPP currently have the ability to invoke seasonal operations when they see fit.

Sierra Club requests that the Commission require APS to invoke seasonal operations now. Contrary to Sierra Club's vehement assertions, the preponderance of the evidence does not establish that implementing seasonal operations now would result in reduced costs being passed on to ratepayers. Rather, the San Juan Basin gas pricing information is at best inconclusive concerning pricing trends, and the Henry Hub gas pricing information is inapt. Thus, it would not be in ratepayers' best interest for the Commission to impose such an order.

4. Future Expenditures at the 4CPP

WRA has recommended that the Commission clarify in this matter "that future investment and expenditures on the [4CPP] would not be prudent if any APS study demonstrates ongoing operation of the plant is not economic or that earlier retirement would provide savings to customers." (WRA RBr. at 7.) APS has not had an opportunity to respond to this recommendation because it was made for the first time in WRA's Responsive Brief.

The Commission is aware that the 2023 IRP shows APS could save money by retiring the 4CPP earlier than 2031. If the Commission were to adopt WRA's recommendation, that would mean that no future investments or expenditures for the 4CPP could be prudent. WRA's recommendation oversimplifies what is a complicated situation and does not contemplate whether APS could actually timely obtain the resources, or the 4CPP owner support, necessary to implement the earlier retirement scenarios. The Commission will not adopt WRA's recommendation. The Commission will, however, direct APS to explore thoroughly and in good faith with the other 4CPP owners the issue of earlier retirement and to submit to the Commission, within six months after the effective date of this Decision, a report concerning the outcome of those efforts. Additionally, the Commission directs APS to explore thoroughly and in good faith the extent to which it would be able to obtain the resources identified in the earlier retirement scenarios included in its 2023 IRP and to submit to the Commission, within six months after the effective date of this Decision, a report that details the following for each early retirement scenario: (1) APS's projected ability to obtain the resources and any needed associated infrastructure, (2) the timeline to obtain the resources and associated infrastructure, (3) whether the pricing would be consistent with the pricing assumed in the 2023 IRP, (4) any reliability issues foreseen by APS as a result of implementing any of the scenarios, (5) factual information supporting APS's assertions as to the first four items, and (6) any additional relevant information of which APS believes the Commission should be aware. To the extent that either of the reports required herein includes information APS deems to be confidential, APS shall redact the information before filing the report in this docket. APS shall provide Staff and any other party to this matter the opportunity to review the confidential information from each report subject to a protective agreement previously executed by the party for this matter or a new protective agreement. APS shall provide a hard copy of the confidential report to each Commissioner's office and to the Utilities Division Director under seal.

5. SCRs

<u>APS Proposal</u>

Pursuant to Decision No. 78317 and the Joint Resolution, APS has removed from rate base in this matter the $215.5 million in previously disallowed SCRs. (Staff Br. at 11; *see* Ex. APS-20 at 35; Ex. S-24 at 52-54.) Additionally, APS has made an operating income pro forma adjustment related to the $215.5 million previously disallowed and the depreciation of the SCRs through 2031 [164] as ordered in Decision No. 78317. (Ex. APS-20 at 35.)

Decision No. 78317 authorized APS to recover an annual level of amortization of the SCRs deferred costs through 2031 (10 years); to continue deferring SCRs costs incurred after December 31,

[164] APS's 2019 Depreciation Study prepared for the last rate case reflected a 2038 end of life for the SCRs. (Ex. APS-20 at 35.) This adjustment increases depreciation and amortization expense by $779,000. (APS Br. at Att. B at Sched. C-2 at 16.)

2020, and until December 1, 2021; and to request recovery for the additional SCRs deferral in this rate case at the cost of debt established in the last rate case. (Ex. APS-20 at 36; Ex. RUCO-7 at 116-117.) To reflect these authorizations, APS made one pro forma adjustment to reflect the annual level of amortization,[165] because the TY included only seven months of the amortization period, and a second pro forma adjustment to reflect the annual level of amortization requested in this case for the additional deferred amount using an amortization period through 2031[166] to align with APS's planned exit from the 4CPP. (Ex. APS-20 at 36.) In total, APS requests recovery in base rates of an $11.256 million annual amortization expense for the deferrals.[167] (APS Br. at 34; Ex. S-24 at 49, Att. RCS-11 at 42.)

APS argues that the 10-year amortization period approved in Decision No. 78317 for the SCRs deferrals remains appropriate because it aligns cost recovery more closely with the timing of the expenditures than Staff's proposal to extend amortization to 2038 and strikes a reasonable balance between customer impacts and APS's ability to obtain timely recovery. (APS Br. at 34; Ex. APS-23 at 12-13, Att. EAB-06RJ, Att. EAB-07RJ.)

Staff

Staff argues that APS has been using a retirement date of 2038 for depreciation expense purposes for the 4CPP SCRs and non-SCRs assets.[168] (Staff Br. at 15; Ex. S-24 at 48.) Staff states that although Decision No. 78317 required both the allowed portion of the SCRs and the allowed portion of the SCRs deferrals to be recovered based on the retirement date of 2031, both the allowed and disallowed SCRs costs are now being depreciated using a retirement date of 2038.[169] (Staff Br. at 16;

[165] This adjustment increases depreciation and amortization expense by $3.390 million. (APS Br. at Att. B at Sched. C-2 at 17.)

[166] This adjustment increases depreciation and amortization expense by $3.119 million. (APS Br. at Att. B at Sched. C-2 at 17.)

[167] As of December 31, 2020, the jurisdictional SCRs deferrals recorded were $81.370 million, which result in an annual amortization of $8.137 million using a 10-year amortization period. (Ex. S-24 at 49.) Between January 1, 2021, and December 1, 2021, APS recorded an additional $24.981 million in jurisdictional SCRs deferrals, which APS proposes to amortize over 8 years, resulting in an annual amortization of $3.119 million. (Ex. S-24 at 49.)

[168] This does not appear to be consistent with Staff's evidence, which showed that APS used a retirement date of June 2031 for the SCRs based on Decision No. 78317 and after that decision began accruing depreciation expense on the SCRs and amortizing the SCRs deferrals using the 2031 date (Ex. S-24 at 45), that APS has used a retirement date of June 2038 for the 4CPP other than the SCRs (Ex. S-24 at 46, Att. RCS-12 at 20), and that APS has not used consistent retirement dates for calculating the depreciation expense on the 4CPP SCRs and 4CPP non-SCRs plant. (Ex. S-24 at 47.)

[169] This does not appear to be consistent with Staff's evidence, which shows that APS used an end of life of July 2031, as required by Decision No. 78317, to determine the amount of depreciation expense for the SCRs currently in base rates and proposed to be included in base rates in this case (Ex. S-24 at 46) and that APS acknowledged in a data response that Decision No. 78979, which approved the Joint Resolution, ordered APS to use a 2038 end of life for depreciation on the

Ex. S-24 at 50.) Staff does not believe that there is a need to adjust the 4CPP SCRs depreciation expense in this matter to use a 2038 retirement date "if that adjustment has already been reflected in the development of the surcharge that was approved by the Commission" in the Joint Resolution. (Ex. S-24 at 48-49.) Staff does not recommend such an adjustment in this matter.

Staff does, however, recommend that the SCRs deferral amounts be amortized using the 2038 end of life rather than the 2031 end of life proposed by APS. (Staff Br. at 16; Ex. S-24 at 49, Att. RCS-11 at 42.) Staff states that having the 4CPP plant depreciation (SCRs and non-SCRs) and the SCRs deferrals amortization computed using 2038 would properly synchronize depreciation and amortization through the same period. (Staff Br. at 16-17.) Staff states that the 2038 end-of-life date is consistent with the 2019 Depreciation Study and has consistently been used for depreciation of the 4CPP non-SCRs plant and, further, that the Joint Resolution uses the 2038 retirement date for recognition of depreciation expense for the previous SCRs plant disallowance from Decision No. 78317. (Staff Br. at 17; Ex. S-65 at 4.) Staff states that consistently using a 2038 retirement date for the 4CPP's depreciation and amortization is appropriate to match the recovery period for the costs and help mitigate the annual revenue requirement impact on ratepayers related to the SCRs costs. (Staff Br. at 17.) Staff's proposal to extend the amortization period for the 4CPP SCRs deferrals results in an annual amortization expense of $6.450 million, a reduction of $4.806 million from APS's proposal. (Ex. S-24 at 50.)

APS Response

APS did not further respond to Staff's argument in its Responsive Brief.

Resolution

APS and Staff do not appear to agree on the depreciation rates that have been used to determine the depreciation expense proposed to be recovered in this matter for the portion of the SCRs allowed in rate base in the last rate case and the $215.5 million portion of the SCRs disallowed from rate base

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$215.5 million of SCRs costs previously disallowed and to align the depreciation of the SCRs already included in rate base to a 2038 end of life for depreciation purposes, but stated that these changes were implemented in the surcharge approved by the Joint Resolution and that, for purposes of this matter, the portion of SCRs in rates uses an end of life of 2031 (Ex. S-24 at 46-47, Att. RCS-12 at 9-10). Interestingly, Staff's evidence also included a data response from APS stating that the "SCR and the non-SCR assets are both using an estimated retirement date of 2038" for depreciation. (Ex. S-24 at 48, Att. RCS-12 at 52-54.)

in the last rate case. The preponderance of the evidence provided in this matter indicates that both the portions of the SCRs allowed in rate base in the last rate case and the $215.5 million portion of the SCRs disallowed from rate base in the last rate case have been depreciated by APS, for purposes of this matter, using an end of life of 2031.[170] The evidence further indicates that the non-SCRs portion of the 4CPP has been depreciated using an end of life of 2038.[171]

In Decision No. 78317, the Commission ordered APS to depreciate the SCRs (allowed and disallowed portions) and to amortize the SCRs deferral and debt deferral using an end of life of July 2031. (Ex. RUCO-7 at 117, 429-430.) Subsequently, in Decision No. 78979, the Commission ordered APS to use a 2038 end of life for depreciation on the previously disallowed $215.5 million portion of the SCRs and to align the depreciation on the portion of the SCRs already included in rate base to a 2038 end of life. (Ex. S-65 at Joint Resolution at 4.) Because Decision No. 78979 was issued on June 28, 2023, shortly before APS's submission of rebuttal testimony in this matter, one would expect APS to identify clearly in its rebuttal testimony, rejoinder testimony, or final schedules any adjustments made to the 4CPP SCRs plant balances and depreciation expense resulting from Decision No. 78979, but no such adjustments were identified.[172] This supports a conclusion, inconsistent with Staff's conclusion and with one of the data responses from APS upon which Staff relied, that APS has continued to use the 2031 end of life for depreciation of the SCRs in this matter.

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[170] To be clear, it appears that APS had been using depreciation rates consistent with a 2038 end of life to record depreciation expense on the SCRs in rate base and the SCRs portion previously disallowed in rate base and has made pro forma adjustments in this matter to convert the depreciation rates to a 2031 end of life. In her direct testimony, Ms. Blankenship stated that APS used the depreciation rates from the 2019 Depreciation Study conducted by Dr. White and approved and authorized in Decision No. 78317 for this matter and proposed to continue depreciating the 4CPP until 2038. (Ex. APS-20 at 23-24.) Ms. Blankenship further stated that an adjustment was made to depreciation expense related to the $215.5 million SCRs rate base disallowance and the acceleration of the depreciation on the SCRs based on an end of life of 2031 (versus the 2038 end of life reflected in the 2019 Depreciation Study), as ordered by Decision No. 78317. (Ex. APS-20 at 35.) In her rebuttal testimony, Ms. Blankenship included an adjustment of the 4CPP depreciation expense "to correct and reflect depreciation expense of the allowed remaining Four Corners SCR plant balance based on an end of life of 2031 ordered in Decision No. 78317." (Ex. APS-22 at Att. EAB-04RB at Sched. C-2 at 16.) This rebuttal adjustment to reflect an end of life of 2031 for the depreciation expense on the allowed 4CPP SCRs balance is retained in APS's final schedules. (APS Br. at Att. B at Sched. C-2 at 16.) This indicates that APS has used a 2031 end of life for depreciation on the 4CPP SCRs plant and a 2038 end of life for depreciation on the 4CPP non-SCRs plant, contrary to Staff's conclusion.

[171] In her direct testimony, Ms. Blankenship stated that APS used the depreciation rates from the 2019 Depreciation Study conducted by Dr. White and approved and authorized in Decision No. 78317 for this matter and proposed to continue depreciating the 4CPP until 2038. (Ex. APS-20 at 23-24.)

[172] APS did identify an adjustment to SCRs depreciation expense made to "correct the starting net book value of the authorized plant balance utilized in calculating the accelerated straight-line depreciation expense in accordance with Decision No. 78317." (Ex. APS-22 at 6-7.) This indicates that APS maintained the use of a 2031 end of life when calculating depreciation of the SCRs for this matter.

Because the Commission has now required APS to use the 2038 end of life for the depreciation on the SCRs (allowed and disallowed portions), the Commission will require APS in this matter to make adjustments to its depreciation expense to reflect the 2038 end of life for the depreciation on the portion of SCRs included in rate base. This results in a reduction to depreciation expense of $779,000 and an increase to operating income of $1.570 million.

Additionally, the Commission will adopt Staff's recommendation for the SCRs deferral amortization periods (the existing deferral allowed in the last rate case and the new deferral amount) to be aligned with the 2038 end of life ordered by the Commission to be used for depreciation. While there was and is merit to using a depreciation period and amortization period aligned with the anticipated end of life of 2031, there is also merit to allowing recovery of the deferrals over an amortization period aligned with the depreciation period the Commission mandated in Decision No. 79879. The Commission believes that doing so establishes an appropriate balance between the interests of APS and its ratepayers, who are already paying a significant surcharge due to the Joint Resolution. This results in a decrease to depreciation and amortization expense of $3,601,911 for the preexisting 4CPP SCRs deferral and of $1,600,915 for the newly included 4CPP SCRs deferral.

C. Operating Expense Issues

1. Generation Maintenance & Outages Expense Normalization & Escalation

<u>APS Proposal</u>

APS adjusts maintenance and outage expense, separately for nuclear generation plants and fossil fuel generation plants, to normalize maintenance and outage levels for the plant in service at the end of the TY. (Ex. APS-20 at 31.) According to APS, the adjustments are needed to make the TY expense consistent with an average year because of variations in outage time for planned routine maintenance and unplanned forced outages in any given year. (*See* Ex. APS-20 at 31-32.) Because fossil fuel plants are on a six-year overhaul cycle, APS normalized using the years of 2017-2021 and the TY. (Ex. APS-20 at 31.) Because each nuclear plant unit is on an 18-month refueling cycle, APS normalized using a three-year period (2020-2021 and the TY) to ensure that each unit's maintenance time was reflected in equal proportion. (Ex. APS-20 at 32.) After normalizing the historical expenses, APS inflated labor costs to reflect historical labor cost increases and escalated non-labor maintenance costs using the relevant Handy-Whitman cost indices. (Ex. APS-20 at 32.) APS's pro forma for nuclear maintenance expense decreased operating expense by $430,000, and its adjustment for fossil maintenance expense increased operating expense by $27.974 million. (APS Br. at Att. B at Sched. C-2 at 14.)

AZLCG

AZLCG argues that the Commission should reject the escalation adjustment to APS's generation maintenance expense normalization and require APS not to double count the July through December 2021 period in its normalization calculations. (AZLCG Br. at 24.) AZLCG argues that while the use of normalization for generation maintenance expense is appropriate, so that ratepayers pay an average of actual costs incurred over the normalization period, escalating the normalized dollars is not. (AZLCG Br. at 25; Ex. AZLCG-1 at 34; Ex. AZLCG-5 at 21.) AZLCG determined that APS's calculation method[173] resulted in annual fossil fuel plant overhaul and maintenance expense of $103.012 million, while normalizing the actual expenses without escalation and without double counting would have resulted in an annual expense of $87.028 million. (AZLCG Br. at 26; Tr. at 1935-1938; *see* Ex. AZLCG-1 at ex. KCH-9 at 4; Ex. AZLCG-17; Ex. AZLCG-18.) AZLCG asserts that the proposed adjusted TY fossil fuel plant overhaul and maintenance expense is greater than the actual expense incurred in every normalization year except 2018, which Ms. Blankenship acknowledged, and is $28.03 million greater than the actual expense incurred in the TY. (*See* AZLCG Br. at 26; Tr. at 1939-1942.) AZLCG points out that the Commission has previously rejected normalization adjustments that increase TY operating expense and argues that the same principle applies to APS's use of cost escalators. (*See* AZLCG Br. at 26-27; Ex. RUCO-7 at 187-188 (concerning cash incentive expense).)

AZLCG also points out that Ms. Blankenship described the adjustments as necessary to reflect upcoming costs, and argues that this is inappropriate because Arizona is not a future test year

[173] AZLCG states that APS calculated its nuclear plant generation maintenance expense by taking the actual level of overhaul and routine maintenance expense for 2020, 2021, and the TY ending June 30, 2022; escalating each expense level to end-of-TY dollars; and then averaging the results. (AZLCG Br. at 24-25; Tr. at 1921; Ex. AZLCG-1 at 33-34.) AZLCG states that APS calculated its fossil fuel plant generation maintenance expense in the same manner, but beginning with the actual level of overhaul and routine maintenance expense for 2017, 2018, 2019, 2020, 2021, and the TY ending June 30, 2022. (AZLCG Br. at 25; Tr. at 1922; Ex. AZLCG-1 at 33-34.)

jurisdiction. (AZLCG Br. at 27; Tr. at 2008-2009.) In its Responsive Brief, AZLCG additionally observed that APS in its Brief indicated the normalization was "Necessary to Reflect *Anticipated* Actual Costs," demonstrating that APS is attempting to transform its generation maintenance expense into a future test year cost. (AZLCG Br. at 6-7; *see* APS Br. at 12-13.)

Further, AZLCG argues, the escalation cannot be justified based on inflation because the TY expenses were not higher than the expenses in the prior normalization years, as would be expected if inflation had such an impact on these expenses.[174] (AZLCG Br. at 27-28; Ex. AZLCG-5 at 21-22; Ex. AZLCG-1 at ex. KCH-4 at 4.)

AZLCG also argues that July through December 2021 should not be double counted in APS's calculations of normalized generation maintenance expense because doing so gives the expenses from this period extra weight and is "an unprincipled calculation methodology that could, in the future, operate to ratepayer detriment." (AZLCG Br. at 28; Ex. AZLCG-5 at 21; Tr. at 1930, 1932.)

AZLCG asserts that its recommended adjustments to the nuclear and fossil fuel generation maintenance expense would reduce operating expenses by $17.518 million. (AZLCG Br. at ex. KCH-9-F at 1.)

APS Response

APS argues that it uses escalation factors in its maintenance expense normalization calculation to account for the impact of inflation over time on historical costs and mitigate the inflationary pressures that can significantly impact generation maintenance costs. (APS Br. at 29; Ex. APS-23 at 12.) APS asserts that use of these factors is well established, recognized as a reliable methodology for computing maintenance expense normalization, and critical to ensuring the sufficiency of APS's revenue requirement set using a historical TY. (APS Br. at 29; Ex. APS-23 at 12.) APS opposes AZLCG's proposal to remove the inflation escalators and modify normalization so that the six month period of July through December 2021 is not double counted, noting that Mr. Higgins acknowledged the double counting benefits customers. (APS Br. at 28; *see* Ex. AZLCG-5 at 5, 21.) APS states that removal of the escalators would penalize APS and prevent it from recovering expenses necessary to its

[174] Mr. Higgins testified that there is no need to adjust maintenance expense upward for inflation when the per books expense is nearly the same as the average without the escalators. (*See* Ex. AZLCG-5 at 22.)

operations in the current high inflationary environment. (APS Br. at 28.) APS did not further address this issue in its Responsive Brief.

Resolution

The Commission determines that it is reasonable and appropriate for APS to use escalation factors to adjust its generation maintenance and outages expenses to reflect a reasonable TY value, and that it is appropriate for APS to normalize those expenses using the calendar years and TY period used. AZLCG is correct that using the TY results in double counting of the first six months of that TY. That is a shortcoming of a TY that is not a calendar year and would be concerning if the TY expenses in this area were unusually high, which they were not.[175] Rather than modify the normalization dates for this particular expense, the Commission urges APS to use a TY that is a calendar year for its next rate case, to eliminate these types of arguments.

2. Employee Cash Incentives

APS Proposal

APS has an Annual Incentive Award Plan ("Incentive Plan") that provides cash incentives to employees for meeting specified goals based on both an APS/PNW Performance Component and a Business Unit Performance Component. (*See* Ex. APS-44; Ex. RUCO-2 at ex. FWR-15.) The APS/PNW Performance Component accounts for 50% of the potential award but has threshold earnings levels for both APS and PNW that must be met for any cash incentives to be awarded. (*See* Ex. APS-44 at 3.) The Business Unit Performance Component accounts for the other 50% of the potential award; is broken down for five different business units that have different performance metrics: transmission and distribution, customer service, fossil generation, corporate resources, and Palo Verde; and allows for different award levels based on threshold, target, and maximum levels of success meeting Business Unit metrics. (*See* Ex. APS-44 at 3, 6-9; Ex. RUCO-2 at ex. FWR-15.) For the TY period, each Business Unit's metrics included approximately 40% to 55% customer-centric metrics related to reliability and/or customer satisfaction. (*See* Ex. APS-44 at 6-9; Ex. RUCO-2 at ex. FWR-15.) Assuming that the earnings threshold is met, the amount of incentive paid to an individual employee

[175] *See* AZLCG Br. at ex. KCH-9-F at 4.

ranges from 5% to more than 100% based on the thresholds met and employee position. (*See* Ex. APS-44 at 2, 10-11; Ex. RUCO-2 at ex. FWR-15.)

APS asserts that no party has argued its Incentive Plan is unreasonable; that the Incentive Plan benefits ratepayers, employees, and shareholders; and that the costs of the Incentive Plan are prudently incurred and 100% recovery would be appropriate. (APS Br. at 26.) APS proposes to normalize this cost item over a three-year period and then to accept a 50% reduction of that normalized amount, which APS states resulted in a $21.5 million reduction to APS's proposed revenue requirement. (APS Br. at 26; Ex. APS-25 at 6.) APS asserts that RUCO and FEA support its proposed adjustment and that Staff and AZLCG agree with the 50% recovery level but not the normalization. (APS Br. at 26; Ex. FEA-3 at 2; Ex. RUCO-4 at 2; Tr. at 4922-4924; Ex. S-24 at 28-30.) APS argues that normalizing incentive expenses provides stability and predictability by smoothing out fluctuations or anomalies in expenses and employee headcount and, further, states that with the exception of its last rate case, its three-year normalization has generally been accepted by the Commission. (APS Br. at 26-27; Ex. APS-23 at 10.) APS also states that the normalization approach was originally adopted pursuant to a Staff recommendation made in APS's 2011 rate case. (APS Br. at 27.[176])

<u>AZLCG</u>

AZLCG agrees with APS's proposal to recover only 50% of cash incentive expense but argues that the cash incentive expense should not be normalized because the cash incentive expense has decreased in each of the normalization years—10.81% from 2020 to 2021[177] and an additional 19.65% from 2021 to the TY.[178] (AZLCG Br. at 33, 107.) AZLCG points out that the Commission rejected normalization of this expense in Decision No. 78317 because it would have resulted in an increase in TY operating expenses for an expense that was "not guaranteed to occur in future years." (AZLCG Br. at 33; Ex. RUCO-7 at 187-188.) AZLCG argues that APS has not provided any persuasive

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[176] APS cites to the Direct Testimony of Ralph Smith from Docket No. E-01345A-11-0224, but this testimony is not part of the evidentiary record in this matter.

[177] In its Brief, AZLCG misstates the years as 2021 to 2022 and then 2022 to the TY. (*See* AZLCG Br. at 33.) This is obviously incorrect, as the TY ended June 30, 2022, and AZLCG had previously identified the years used for normalization as 2020, 2021, and the TY ended June 30, 2022, and the dates have been corrected here. (*See* AZLCG Br. at 32.)

[178] AZLCG showed total company amounts of cash incentive expenses of $58.893 million in 2020, $52.402 million in 2021, and $41.950 million in the TY. (AZLCG Br. at ex. KCH-7-F.) Averaged, these amount to $51.082 million, which when adjusted using the jurisdictional allocation factor of 91.28% is $46.627 million. (*See id.*)

justification to deviate from the result in the last rate case. (AZLCG Br. at 34; Tr. at 1989.) AZLCG reports that this would reduce APS's operating expenses by $3.291 million. (AZLCG Br. at ex. KCH-7-F at 1-2.)

FEA

FEA asserts that APS includes approximately $47.1 million of incentive compensation costs in rates. (FEA Br. at 5; Ex. APS-20 at 26-27; Ex. FEA-1 at 14.) FEA states that incentive compensation costs tied to financial incentives should not be included in cost of service because they do not produce measurable benefits for customers, and customers should not be required to pay incentive costs without proof that the financial incentives have reduced cost of service, proof that has not been provided by APS in this matter. (FEA Br. at 6; Ex. FEA-1 at 15-16.) FEA notes that the Commission allowed APS recovery of only 25% of the actual TY costs of the Incentive Plan cash incentives in Decision No. 78317 because the Business Unit performance goals gave significant weight to shareholder interests while giving less consideration to customer-related goals. (FEA Br. at 6; Ex. RUCO-7 at 188.) FEA observes that APS has proposed to recover 50% of its cash incentive expenses. (FEA Br. at 7.) FEA recommends that the Commission "reject 50% of the [Incentive Plan] cost included in APS's proposed rates."[179] (FEA Br. at 7; Ex. FEA-1 at 15.) FEA states that the Incentive Plan is "clearly a financial incentive program and incentive compensation programs that are designed to align the interests of employees with shareholders should be paid for by shareholders, not customers." (FEA Br. at 7; Ex. FEA-1 at 15.)

Ms. Nelson

Ms. Nelson asserts that the Commission should not allow Incentive Plan expenses to be a ratepayer cost because APS is a monopoly, a customer is not permitted to change to another provider regardless of whether APS's service is good or bad, and service incentives are thus irrelevant and should be ceased. (KN Br. at 3.)

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[179] Although this could be interpreted to mean that FEA recommends 75% of the Incentive Plan expenses be disallowed in this matter (i.e., 50% of the 50% APS now proposes), the Commission believes it is intended to mean 50% of the Incentive Plan expenses should be disallowed, based on Mr. Gorman's testimony to that effect, which FEA cites. (*See* Ex. FEA-1 at 15.)

RUCO

RUCO argues that, consistent with the outcome of the last rate case, APS should be allowed to recover only \$9.7 million in Incentive Plan expense (25% of the actual TY cash incentive expense of \$38.905 million, not a normalized amount), because nothing distinguishes APS's request in this case from its request in the last rate case. (RUCO Br. at 31-32; Ex. RUCO-7 at 187-188.) RUCO reports that this results in a reduction of jurisdictional O&M expenses of \$26.6 million. (RUCO Br. at 32; Ex. RUCO-1 at 20-21.)

Staff

Staff accepts APS's 50% reduction of Incentive Plan expenses but argues that APS's proposed normalization of the expense using 2020, 2021, and the TY should be rejected because the actual expense declined each year, and normalization is not appropriate for declining costs, only for costs that fluctuate up and down. (Staff Br. at 19; Ex. S-24 at 29-30.) Staff notes that normalization was rejected in Decision No. 78317, in which the Commission found that the expense was not guaranteed to occur in the future. (Staff Br. at 19; Ex. RUCO-7 at 188.) Staff argues that the Commission should reject the normalization in this matter as well and asserts that its adjustment reduces TY expense by \$25.195 million and payroll tax expense by \$1.481 million. (Staff Br. at 19; Ex. S-73 at 36 (Sched. C-8), 37 (Sched. C-9); Ex. S-24 at 31.) Staff reiterated this argument in its Responsive Brief. (Staff RBr. at 5-6.)

APS Response

APS did not address the issue further in its Responsive Brief.

Resolution

The Incentive Plan metrics appear to have become more customer-centric (reliability and customer satisfaction) since APS's last rate case. (*See* Ex. APS-44; Ex. RUCO-2 at ex. FWR-15.) This indicates that customers should be receiving more benefits from the Incentive Plan than was true for the last rate case, in which the Commission determined that shareholder interests were the primary focus of the Incentive Plan. Under the circumstances, it is just and reasonable to allow APS to recover a greater portion of the Incentive Plan expenses than in the prior rate case.

There is no guarantee that cash awards will be earned in any given year for any Business Unit under the Incentive Plan; it depends on whether the APS/PNW Performance Component, an earnings threshold at fiscal-year end, is met. Because of this, and because APS's Incentive Plan expenses decreased in each of the three years that APS used to normalize its proposed expense, it is not just and reasonable to allow APS to increase the Incentive Plan expense over what was actually incurred in the TY before it reduces the expense by 50%. The Commission finds that it is just and reasonable to allow APS to include in operating expenses 50% of the actual Incentive Plan expenses incurred during the TY and to require APS to make a corresponding reduction to TY payroll tax expense.

3. Pension and OPEB Expense

APS Proposal

APS proposes to "normalize" pension and OPEB expense by averaging 2022 actual and 2023 estimated pension and OPEB costs. (Ex. APS-22 at 6, Att. EAB-04RB.) APS reports that its proposed normalization of pension and OPEB costs increases operating expenses by $25.536 million. (APS Br. at Att. B at Sched. C-2 at 10.) APS argues that this adjustment is consistent with how the expenses were addressed in the 2019 rate case, that normalization adjustments are made to better reflect the expected level of ongoing expense during the time rates will be in effect, and that normalization adjustments are appropriate to reduce regulatory lag by allowing timely recovery for these expenses. (APS Br. at 29; Ex. RUCO-7 at 181-182; Ex. APS-20 at 17; Ex. APS-23 at 11.[180])

APS argues that Staff's opposition to normalization in this matter is inconsistent with Staff's position in the 2019 rate case, in which such a normalization reduced operating expenses, and criticizes Staff for not following Commission "precedent" for split test years. (APS Br. at 30; Ex. APS-23 at 11.) APS further argues that its proposal "reflects known and measurable changes" in the form of 2022 market forces that contributed to an "unprecedented increase in interest rates" that will continue while APS's rates set herein are in effect. (APS Br. at 30; Ex. APS-7 at 7-8; Ex. APS-23 at 11.) APS cites testimony from Mr. Cooper to the effect that APS did not have information at the end of 2021 concerning the impact on pension and OPEB expense of the rising interest rates in 2022 but did have this information by the end of 2022 and thus could capture the actual impact through averaging two

[180] APS also cites a number of testimonies from other dockets, but not the Decisions from those dockets. Those testimonies are not part of the evidentiary record in this matter.

years similar to what it did in its last rate case.[181] (APS Br. at 30; Tr. at 681-683.)

APS argues that Staff fails to appreciate the significant threat to APS's financial stability that Staff's position poses because market forces outside of APS's control (interest rate increases during the first six months of 2022) have created significant increases in APS's pension expense, and financial institutions have expressed concern about the impacts of rising interest rates on pension expenses for electric utilities and the utilities' potential inability to recover these expenses in a timely manner. (APS Br. at 31; Tr. at 586-588, 681-683; Ex. APS-7 at 7-8.) APS argues that its adjustment reflects "actual market conditions readily known and observable" and ensures APS's financial stability. (APS Br. at 31.)

Staff

Staff argues that APS's reliance on Decision No. 78317 to justify this normalization is misplaced because, Staff states, the Commission did not intend to create a methodology for adjusting retirement benefit expense beyond the specific circumstances of the last rate case. (Staff Br. at 20.) Staff recommends that the proposed normalization, which Staff states increases operating expense by approximately $20.8 million, be rejected in this matter. (Staff Br. at 20; Ex. S-24 at 44.) In its Responsive Brief, Staff points out that Decision No. 78317 did not make an adjustment to pension and OPEB expense that substantially increased it; just the opposite occurred. (Staff RBr. at 6.) Staff asserts that in the 2019 rate case, APS proposed on rebuttal an adjustment to decrease its pension and OPEB expense by averaging in an additional year, an adjustment that Staff and other parties did not oppose because it reduced the rate increase requested by APS. (Staff RBr. at 6.) Staff states that the lack of opposition to that reduction in the 2019 rate case was not intended to create a new methodology for the treatment of pension and OPEB expense in future rate cases. (Staff RBr. at 6.) Staff further asserts that APS's failure to include its proposed adjustment in its application in this matter indicates that APS itself did not consider the 2019 rate case to have created a new methodology. (Staff RBr. at 6-7.)

Staff also argues that APS's proposed normalization methodology for this expense is inconsistent with its proposed normalization methodology for Incentive Plan expense because APS is

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[181] Mr. Cooper's testimony indicated that the two years being averaged were 2021 and 2022, not the TY and a projected year, and that actual end-of-year expenses were being used. (*See* Tr. at 586-587, 755-757.)

proposing to normalize TY pension and OPEB expense using estimated 2023 amounts, not actual historic amounts, and using only two years rather than three. (Staff Br. at 7.)

Further, Staff notes, its support for rate base inclusion of APS's prepaid pension asset depends on the Commission rejecting APS's normalization proposal for pension and OPEB expense. (Staff RBr. at 7-8.)

APS Response

In its Responsive Brief, APS states that there is no dispute that pension expenses have increased since APS filed its rate application herein, as determined by actuarial calculations for calendar year 2023. (APS RBr. at 17; Tr. at 587-588; Ex. APS-7 at 7-8.[182]) APS states that because of this, APS proposes to normalize 2022 and 2023 pension expenses, thereby increasing its revenue requirement by approximately $19 million. (APS RBr. at 17; APS Br. at Att. B at Sched. C-2 at 11.) APS states that Staff offers little explanation for its opposition aside from arguing that Decision No. 78317 did not create a methodology. (APS RBr. at 17.) APS then asserts that "Decision No. 78317 offers a Commission-approved rationale for how pension expenses can be adjusted based on known and measurable changes," supporting this statement by reference to testimony from Freeport and Arizonans for Electric Choice and Competition ("AECC"), Staff, and APS in the 2019 rate case.[183] APS states that no other party addressed the issue in the 2019 rate case and that the "Commission accepted normalization of this expense without additional discussion." (APS RBr. at 17.)

APS argues that it is already incurring pension and OPEB costs higher than the level requested in this matter,[184] because these costs are sensitive to market interest rates, and that recovery of these expenses is important to APS's financial health. (APS RBr. at 18; Ex. APS-23 at 11.) APS states that the Federal Reserve increased interest rates at the end of 2022 and is expected to do so again at the end of 2023.[185] (APS RBr. at 18; Ex. APS-7 at 7-8; Tr. at 682.)

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[182] APS also cited direct testimony from Ms. Blankenship, in which she describes the original requested adjustment, which was determined by taking the "difference between the Test Year expense and the 2022 level of that expense, as determined by APS's actuaries." (Ex. APS-20 at 25.) This testimony does not support APS's statement about actuarial calculations for calendar year 2023.

[183] These testimonies cited by APS are not part of the evidentiary record in this matter.

[184] Ms. Blankenship testified on rejoinder (August 2023) that if current level 2023 amounts had been considered, operating income would have increased an additional $18 million without the two-year averaging APS requests. (Ex. APS-23 at 11.)

[185] The testimony cited by APS did not support its statement about a 2023 interest rate increase.

APS further argues that whether or not to normalize a TY expense should not be based on whether the result increases or decreases costs because the goal of normalization is to adjust a TY to reflect anticipated future years between rate cases. (APS RBr. at 18.) APS argues that normalization is an appropriate method to adjust the TY to reflect the period between rate cases, including making adjustment for known and measurable changes occurring after the TY but before rates are set, especially for costs that are "reliable and certain like the actual pension expense" incurred by APS. (APS RBr. at 18-19; *Utah Power & Light Co v. Idaho Pub. Utils. Comm'n*, 629 P.2d 678, 680 (Idaho 1982); *Mountain States Tel. & Tel. Co. v. Public Utils. Comm'n*, 513 P.2d 721, 724-725 (Colo. 1973).[186]) APS argues that the issue is whether its proposal is based on a known and measurable change and that its proposed normalization will provide a more accurate level of ongoing costs for future expected pension expense and should be approved. (APS RBr. at 19; *Ariz. Corp. Comm'n v. Ariz. Pub. Serv. Co., 113 Ariz. 368, 371* (1976); Ex. APS-23 at 11.)

<u>Resolution</u>

The Commission did not include any discussion or analysis concerning APS's normalization of pension and OPEB expense in Decision No. 78317. Thus, APS's contention that the Commission in Decision No. 78317 established a methodology to be applied going forward for this type of expense is disingenuous, as is APS's criticism of Staff for not unquestioningly accepting the purported methodology in this matter.

APS has not, nor could it have, provided in the record for this matter the actual costs it has incurred for pension and OPEB expenses in 2023, which obviously would reflect a known and measurable change. Rather, APS has provided estimated 2023 pension and OPEB expenses. Estimates by their nature are not known and measurable, and reality can differ dramatically from what is projected, as has been seen elsewhere in this matter. It is apparent that APS's proposed normalization is largely intended to address projections of dramatically increased interest costs between 2022 and 2023, which APS shows in a data response to be approximately 40.15% ($37 million) to approximately 41.48% ($51 million) higher in the estimated 2023 projection. (*See* Ex. S-24 at Att. RCS-12 at 39.)

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[186] APS also cited a number of testimonies form other dockets that are not part of the evidentiary record in this matter.

The Commission is aware that interest rates have increased dramatically since 2021, but that knowledge does not substantiate the accuracy of APS's projected 2023 pension and OPEB expenses, and APS has not provided supporting information to substantiate those projected expenses.[187] The Commission finds that it is not just and reasonable to adopt APS's proposed adjustment to pension and OPEB expense based on normalization using projected expense figures and, instead, that it is just and reasonable to allow APS to recover for the actual pension and OPEB expense incurred in calendar year 2022.

4. Board of Directors Fees

<u>APS Proposal</u>

APS proposes full recovery of $2,791,905 paid to its board of directors during the TY. (APS Br. at 32; Ex. APS-46.) APS asserts that it is required by law to have a board of directors. (APS Br. at 32; Tr. at 461, 2024.[188]) APS's board of directors has the same membership as the PNW board of directors. (Tr. at 2027-2029.) Mr. Geisler stated that the board approves APS's annual capital budget, reviews large capital projects in the budget to ensure they meet reliability requirements, and reviews risk management plans for subjects such as wildfire mitigation, reliability, and customer growth. (Tr. at 461.) Mr. Geisler added that board members have met with large customers to discuss electric infrastructure and are engaged in community outreach and public information. (Tr. at 461.) According to Mr. Geisler, APS's board not only represents the interests of shareholders but also ensures that management is doing its job to serve customers because without good customer value there is not shareholder value. (Tr. at 461.) APS argues that its board of directors expenses are a reasonable and prudent cost of service and should be approved in full. (APS Br. at 32.) APS argues that reasonable and prudently incurred costs of service are recoverable regardless of whether they benefit shareholders and, further, that the Commission has previously determined that operating expenses for board member compensation are reasonable and appropriate. (APS Br. at 33; Decision No. 77130 (March 13, 2019)

[187] For example, APS could have provided data on the actual interest expense being incurred to date in 2023 (as opposed to 2022), any increase in number of pensioners, any contractual increases from vendors, etc.

[188] Ms. Blankenship testified that APS is required to have a board of directors because it is a publicly traded company but then acknowledged that APS is not a publicly traded company, PNW is. (Tr. at 2024, 2027.) Ms. Blankenship further testified that APS files financial statements with the SEC because it has one shareholder, PNW, so APS does have a board of directors, but APS is "kind of holistically governed by" the PNW board of directors. (Tr. at 2027.)

at 14.[189])

Ms. Nelson

Although Ms. Nelson does not directly challenge APS's proposed recovery of board of directors expense, Ms. Nelson asserts that the Commission should consider whether having the same board of directors for APS and PNW represents a conflict of interest or is imprudent. (KN Br. at 4.)

RUCO

RUCO recommends that APS be allowed recovery of 50% of TY board of directors expense, which RUCO states is "fair if not generous" in light of the Commission's recent disallowance of all board of directors expense in the TEP rate case. (RUCO Br. at 32-33; *see* Ex. APS-84 at 38-39.) RUCO argues that its approach is balanced because it recognizes that ratepayers can benefit from the board of directors' responsibility for providing safe and adequate service to retail ratepayers. (RUCO Br. at 33; Ex. RUCO-1 at 22.)

Staff

Staff did not make an adjustment in its schedules for this expense item and did not address this issue in its Brief or Responsive Brief. (*See* Ex. S-73.)

APS Response

APS did not further address this issue in its Responsive Brief.

Resolution

We note that the Board of Directors is elected by the shareholders to serve the shareholders. The Board of Directors has such responsibilities as choosing the corporate officers, distributing dividends, authorizing stock issuance, determining whether to merge with another corporation, and setting strategy. As such, all expenses associated with the Board of Directors should be borne by shareholders. We will disallow the Board of Directors fees of $2,791,905 in this case; therefore, these fees shall not be borne by ratepayers

Ms. Nelson has expressed concern that PNW and APS having the same board members may represent a conflict of interest, but no party has alleged or alluded to any misconduct resulting from the

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[189] APS also cited *Tucson Elec. Power Co. v. Ariz. Corp. Comm'n*, 132 Ariz. 240, 245 (1982), but it is not apparent how the cited portion of the opinion supports APS's position.

lack of distinct board members. Thus, it is unnecessary for the Commission to explore this issue further.

5. Directors & Officers ("D&O") Insurance

APS Proposal

D&O insurance protects corporate directors and officers from personal liability for third party claims against them made based on their decisions as directors and officers. (APS Br. at 27.) APS originally requested recovery of $1,033,030 in TY D&O insurance expense,[190] which it states is a reasonable and appropriate cost of service for which full recovery is appropriate, but on rebuttal agreed to a 50% reduction in the expense as a compromise in this matter. (APS Br. at 27; Ex. APS-3 at 4-6; Tr. at 356.) APS states that D&O insurance is necessary to attract and retain qualified directors, who otherwise would not be likely to accept these positions, and that a well-managed utility benefits customers. (APS Br. at 27; Ex. APS-3 at 5-6; *see* Ex. RUCO-1 at 24-25.) APS's adjustment reduced its jurisdictional TY O&M expense by $516,515. (APS Br. at 28; Ex. S-24 at 28.) APS argues that the Commission should allow the 50% recovery and that any additional reduction would not be in the public interest. (APS Br. at 28; Ex.APS-3 at 5-6; *see* Decision No. 77850 (December 17, 2020) at 39-40; Decision No. 73142 (May 1, 2012) at 8-9.[191])

FEA

FEA argues that APS should not be allowed to recover any D&O insurance costs in base rates[192] because Decision No. 78317 found that all D&O insurance expense should be excluded from customer rates. (FEA Br. at 7; Ex. RUCO-7 at 195.) FEA argues that "APS has not provided any evidence to oppose the Commission's decision to exclude D&O insurance" and recommends that the Commission adhere to Decision No. 78317 and exclude D&O insurance expense because it benefits only shareholders, not customers. (FEA Br. at 7.)

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[190] Ex. RUCO-1 at 24, ex. FWR-20. PNW incurs the costs for D&O insurance and then charges APS for the majority of that cost (approximately 91.2% for the TY) as a corporate fee. (*See* Ex. RUCO-1 at 24, ex. FWR-20.)

[191] Official notice is taken of these decisions. APS also cited Decision No. 58497 (January 13, 1994), 1994 WL 96976 (Ariz. C.C.) at *26, but Decision No. 58497 does not appear to reflect a 50% reduction of D&O insurance costs; instead it appears to reflect acceptance of the reduced premium for a plan period different from the TY.

[192] In its Brief, FEA repeatedly referred to inclusion of these costs in "rate base," but the Commission understands this to have been in error and intended to mean "base rates." (*See* FEA Br. at 7.) In a data response in this matter, APS reported that it has not included any D&O insurance expense in rate base, which is consistent with what APS reported in its 2019 rate case. (*See* Ex. RUCO-1 at ex. FWR-20; Ex. RUCO-7 at 193.)

RUCO

Although RUCO did not address the issue of D&O insurance in its Brief, the 50% reduction is consistent with RUCO's adjustment made in this matter. (Ex. RUCO-1 at 24-27.)

Staff

Staff states that APS now accepts the Staff adjustment to remove 50% of D&O insurance expense, which results in a reduction of $516,515 and causes the expense to be shared equally between shareholders and ratepayers. (Staff Br. at 13; *see* Ex. S-24 at 28, Att. RCS-2 at Sched. C-7; Ex. APS-22 at 4.) Staff states that Staff made the same adjustment in APS's 2011, 2016, and 2019 rate cases.[193] (Staff Br. at 13; Ex. S-18 at 45.)

APS Response

APS did not address this issue further in its Responsive Brief.

Resolution

APS's proposal to have D&O insurance costs shared 50/50 between shareholders and ratepayers, which is consistent with RUCO's and Staff's recommendations, is just and reasonable. This adjustment reflects the Commission's understanding that D&O insurance is necessary for APS to obtain qualified individuals to serve in director and officer roles.

6. Industry Association Dues

APS Proposal

APS proposes to recover $3,881,031 in adjusted TY industry association dues, which include but are not limited to dues paid to the Electric Power Research Institute ("EPRI") and the Edison Electric Institute ("EEI"). (APS Br. at 33; *see* Ex. RUCO-1 at ex. FWR-18.) APS asserts that the proposed amount does not include any monies spent for lobbying or other legislative or regulatory advocacy. (APS Br. at 33; Tr. at 1972; *see* Ex. RUCO-1 at ex. FWR-18 at 6, ex. FWR-19.) APS argues that there is no evidence the association dues expenses are imprudent or unreasonable and, further, that APS's memberships are helpful to APS and its customers because they allow APS to remain current

[193] Mr. Smith noted in his testimony that the 2011 and 2016 rate cases resulted in settlement agreements and that the issue was not addressed in those settlement agreements. (Ex. S-18 at 45.) As noted above by FEA, Staff's adjustment was not adopted in Decision No. 78317.

on national industry innovations and standards and thereby to improve and innovate service to its customers. (APS Br. at 33; Tr. at 1971-1973.) APS asserts that the full amount of industry association dues is prudently incurred and should be allowed and that any disallowance of industry association dues expense is not warranted by the evidence and would be contrary to law. (APS Br. at 33.)

RUCO

RUCO recommends that APS be allowed to recover only 50% of the industry association dues, pointing out that the Commission adopted its position on the issue in the 2019 rate case and also allowed recovery of only approximately 50% of Edison Electric Institute ("EEI") dues in a 2009 rate case for UNS Electric, Inc. (RUCO Br. at 33; *see* Ex. RUCO-7 at 196-197; Decision No. 71914 (September 30, 2010) at 24-25.)

Staff

Staff did not make an adjustment in its schedules for this expense item and did not address this issue in its Brief or Responsive Brief. (*See* Ex. S-73.)

APS Response

APS characterizes RUCO's recommendation as arbitrary and punitive and points out that RUCO has acknowledged the benefits APS's involvement with these associations provide to both ratepayers and shareholders. (APS Br. at 33; Tr. at 1971-1973; *see* Ex. RUCO-1 at 23.)

Resolution

APS is facing a set of circumstances that have required APS and will require APS to be nimble and innovative to ensure reliable, safe, and affordable service to its customers—sustained population growth in its service area,[194] increased demand for load to serve the greater electrification of things by its existing customers (such as through increased adoption of electric vehicles),[195] extremely high (unprecedented) demand for load to serve new extra-high load factor ("XHLF") customers,[196] additional customer-sited distributed generation ("DG") on the grid,[197] record-setting extreme heat events and more severe storms,[198] impending closure of a baseload coal plant and a planned exit from

[194] *See, e.g.,* Ex. APS-33 at 16; Ex. APS-2 at 2, 16.
[195] *See, e.g.,* Ex APS-8 at 12; Ex. APS-2 at 18; Tr. at 408.
[196] *See, e.g.,* Ex. APS-12 at 11-12; Tr. at 206-207, 210, 288-290.
[197] *See, e.g.,* Ex. APS-24 at 18-19.
[198] *See, e.g.,* Ex. APS-2 at 18.

another,[199] and a lack of extra capacity on the western energy market.[200] To meet these challenges, APS needs to be well informed concerning the technologies that are available, what has and has not been reliable and efficient for other utilities, and what technologies may be on the horizon. APS's involvement in industry associations, which provides it with information that is not readily available from other sources, will support it in facing these circumstances. The Commission finds that it is just and reasonable to allow APS full recovery for its proposed EPRI association dues expense and to disallow the TY EEI membership dues totaling $1,126,241.[201]

7. Depreciation & Net Salvage Adjustment

<u>APS Proposal</u>

APS proposes an adjusted TY depreciation and amortization expense of $723.314 million. (APS Br. at 23, Att. B at Sched. C-1.) In calculating depreciation, APS used a straight-line method and the depreciation rates in the 2019 Depreciation Study completed by Dr. White for the 2019 rate case. (APS Br. at 23; Ex. APS-20 at 23; Ex. APS-21.) APS states that Staff accepts APS's analysis except as to retirement and negative net salvage costs and that RUCO accepts APS's analysis but disallowed depreciation and amortization expense on the depreciable plant RUCO excluded from PTYP. (APS Br. at 23; Ex. S-18 at 73-76; Ex. RUCO-1 at 19.)

APS supports recovering retirement and negative net salvage over the life of the asset using the straight-line method, which means that an asset will be depreciated equally each year of its depreciable service life. (APS Br. at 24; *see* Ex. APS-20 at Att. EAB-01DR at 6.) APS states that it has used the straight-line method for retirement and negative net salvage for decades, that the Commission has approved it in other rate cases, and that it is used by the majority of utility commissions in the U.S. (APS Br. at 24; Ex. APS-18 at 6, Att. RW-02RB at 12; Ex. RUCO-7 at 208; *see* A.A.C. R14-2-102(B)(3)[202].)

APS argues that the Statement of Financial Accounting Standards No. 143 ("SFAS 143") is a financial accounting standard used to determine the amount of an asset retirement obligation to be

[199] *See, e.g.,* Tr. at 1370-1371.
[200] *See, e.g.,* Ex. APS-2 at 19.
[201] *See* Ex. RUCO-1 at ex. FWR-18.
[202] A.A.C. R14-2-102(B)(3) states: "The cost of depreciable plant adjusted for net salvage shall be distributed in a rational and systemic manner over the estimated service life of such plant."

included on a corporation's balance sheet, not a method developed to determine depreciation expense in utility rate cases. (APS Br. at 24; Tr. at 2142-2145, 2160.) APS further argues that using the SFAS 143 method as recommended by Staff "essentially back-loads" retirement costs so that customers in later years pay more than customers in earlier years.[203] (APS Br. at 24-25; Ex. APS-18 at Att. RW-02RB at 11.) APS argues that the earlier year savings are offset by higher financing costs[204] and that there is an increased risk of larger stranded costs if the asset is retired early or the estimates made in year one and negative net salvage are too low. (APS Br. at 25.)

Dr. White testified that he firmly disagrees with the use of the Staff-recommended SFAS 143 method, which he stated serves no purpose other than to reduce current depreciation rates. (Ex. APS-18 at 5.) Dr. White testified that the Commission should allow APS to retain the straight-line method because its simplicity greatly outweighs any benefit from introducing time value of money into the computation of net salvage accruals. (Ex. APS-18 at 6.)

Staff

As in the 2019 rate case, Staff recommends in this matter that the SFAS 143 method propounded by Mr. Smith be adopted to calculate the cost of removal/negative net salvage component of depreciation expense. (Staff Br. at 17; Ex. S-18 at 69-70.) Staff argues that using the SFAS 143 method removes the impact of estimated future inflation from that portion of depreciation rates so that current ratepayers are not charged for it. (Staff Br. at 17; Ex. S-18 at 69-70.) Staff asserts that the SFAS 143 is a generally accepted accounting method for applying a discounted present value analysis to asset retirement obligations, thereby removing the impact of estimated future inflation for financial accounting and reporting purposes. (Staff Br. at 17; Ex. S-18 at 69.) According to Staff, this is believed to reflect more accurately the annual depreciation expense component associated with asset retirement obligations. (Staff Br. at 17; Tr. at 4925-4926, 4928.) Staff asserts that for a large utility like APS, the SFAS 143 approach results in more accurate depreciation rates that adjust over time as APS's plant in

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[203] A graphic example of the two methods for the 4CPP created by Dr. White for the 2019 rate case shows customers paying $6 million each year from 2019 to 2038 with the straight-line method, as opposed to paying approximately $5 million in 2019 followed by rates escalating to $6 million in 2027 and then to nearly $8 million in 2038. (Ex. APS-18 at Att. RW-02RB at 11.)

[204] According to Dr. White, the SFAS 143 method is complex and attempts to shift the timing of net salvage accruals to achieve reduced current depreciation expense, thereby increasing future depreciation expense and potentially increasing the marginal cost of external financing. (Ex. APS-18 at 6.)

service grows. (Staff Br. at 17; Tr. at 4929.)

Staff asserts that a number of jurisdictions have determined that it is inappropriate to require current ratepayers to pay for the impacts of future inflation, making adjustments using the SFAS 143[205] or other methodologies[206] to accomplish that. (Staff Br. at 18; Ex. S-18 at 66-67.) Staff acknowledges that the Commission declined to adopt the same Staff recommendation in the 2019 rate case but states that "Staff believes that this is an important issue in [this matter] and will help reduce the amount of revenue increase needed . . . in a principled manner . . . that will not be harmful prospectively to APS's net operating income." (Staff Br. at 18; Tr. at 4929-4930.) Staff states that adoption of Staff's recommended SFAS 143 method would reduce APS's prospective revenue and depreciation expense by approximately the same amount. (Staff Br. at 18.[207]) Staff compares applying a non-discounted approach to the negative net salvage component of depreciation to allowing recovery for labor cost escalations that are 20 or 30 years beyond the end of TY, which PUCs would not accept, and essentially states that the traditional treatment of negative net salvage exists because the SFAS 143 method was not yet available. (*See* Staff Br. at 18; Ex. S-18 at 69-70.) Staff states that whether to require use of the SFAS 143 method is "a policy issue subject to the Commission's discretion" and that Staff's recommended adjustment would decrease depreciation expense by approximately $8.951 million. (Staff Br. at 18; Tr. at 4930; Ex. APS-18 at Att. RW-02RB at 11.)

<u>APS Response</u>

APS did not address this issue further in its Responsive Brief.

<u>Resolution</u>

Despite Staff's efforts, the Commission remains unconvinced that the value of requiring APS to adopt Staff's recommended SFAS 143 method for calculating the cost of removal/negative net salvage component of depreciation expense is outweighed by the burden the SFAS 143 method imposes. As the Commission stated in Decision No. 78317, "[w]e are concerned that Staff's proposal

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[205] Mr. Smith cited Maryland and the District of Columbia as two jurisdictions that use the Staff-recommended SFAS 143 method. (*See* Ex. S-18 at 62.)

[206] Mr. Smith testified that Pennsylvania and Delaware PUCs have eliminated the estimated impact of future inflation in a different manner. (Tr. at 4927.)

[207] Staff also cited two pages of Mr. Smith's testimony at hearing to support this statement, but no such statement was found on those two pages or in their proximity. (*See* Tr. at 4925-4930.)

may be based . . . on current and short-term outcome . . . [and] believe that the increased costs imposed on future customers would be anachronistic as they will have benefited less from the retired plants." (Ex. RUCO-7 at 208.) Except as modified by other determinations made in this Decision (such as related to the 4CPP SCRs), APS's depreciation and amortization rates and methods are approved.

D. Coal Community Transition ("CCT") Support

In Decision No. 78317, the Commission acknowledged its prior determination, made in Decision No. 77763 (October 2, 2020),[208] that APS has a corporate obligation to support a just and equitable transition away from coal-based economies for communities impacted by early coal plant closures. (Ex. RUCO-7 at 170.) The Commission further concluded the following:[209]

- That APS's customers had already been paying the decommissioning and site restoration costs for the 4CPP and the decommissioning costs for Cholla and would be asked to pay the costs of replacing the generation no longer produced by NGS, Cholla, and the 4CPP;
- That both APS and its customers had benefited from the coal plant operations—customers through receiving the electricity generated and APS through selling the electricity at a profit that allowed APS to pay PNW an increased dividend each year;
- That the coal plant operations had resulted in economic benefits for the impacted communities as well as severe negative externalities that 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; and
- That in light of the negative externalities impacting these communities and the economic devastation that had come or was coming with closure of the coal plants, it was just and reasonable for APS customers and shareholders to share the burden of transition assistance costs.

The Commission declined to approve a CCT Memorandum of Understanding ("MOU") entered into by APS and the Nation but approved the following CCT direct financial assistance:[210]

[208] Decision No. 77763 was admitted herein as Exhibit CG-6.
[209] Ex. RUCO-7 at 171-172.
[210] Ex. RUCO-7 at 172, 303, 430.

- A total of $10 million to be paid to the Nation over a period of 3 years, to be funded by ratepayers through the REAC, with no carrying costs;
- A single payment of $1 million to be paid to the Tribe within 60 days after the effective date of the decision, to be funded by ratepayers through the REAC, with no carrying costs; and
- A single payment of $500,000 to be paid to the Navajo County Communities[211] within 60 days after the effective date of the decision, to be funded by ratepayers through the REAC, with no carrying costs.

As additional CCT assistance, the Commission ordered APS:[212]

- To provide job redeployment offers within APS organizations to all impacted APS employees at least six months before the Cholla closure, at least six months before seasonal operations at the 4CPP, and at least six months before the 4CPP closure;
- To modify the distribution line extension policy in Service Schedule 3, as applicable to residential and commercial buildings on the Navajo Nation and the Hopi reservation, to allow distribution lines to be extended up to 2,000 feet at no cost to Navajo and Hopi applicants;
- Within 12 months after the decision, to perform or pay for a census of unelectrified buildings in the Nation and authorized APS to spend up to $1.25 million toward other home and business electrification projects within the Nation, to be funded by ratepayers through the REAC, with no carrying costs; and
- Within 12 months after the decision, to perform or pay for a census of unelectrified buildings in the Hopi reservation and authorized APS to spend up to $1.25 million toward other home and business electrification projects within the Hopi reservation, to be funded by ratepayers through the REAC, with no carrying costs.

The Commission also declined to make any determinations as to the appropriateness of the remaining provisions of the CCT MOU and stated the following:

> 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

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[211] APS had identified the Navajo County Communities as the Navajo County General Fund, Northland Pioneer College, and JCUSD, the taxing districts that received direct economic benefits from Cholla. (Ex. RUCO-7 at 172 n.265.)
[212] Ex. RUCO-7 at 172-173, 430-431.

> 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 [Docket No. E-00000A-21-0010 ("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.[213]

The Commission further imposed procedural and timing obligations on Staff for the Generic Transition Docket.[214] (*See* Ex. RUCO-7 at 431-432.)

The Generic Transition Docket ended with Decision No. 78906 (April 17, 2023),[215] administratively closing the docket because the Commission had declined to adopt Staff's Proposed Order at the Open Meeting on December 6, 2022. (Ex. S-75.) Decision No. 78906 stated that the issue of CCT was open to be addressed in the 2022 TEP rate case and this matter. (Ex. S-75.)

<u>APS Proposal</u>

APS proposes to recover through its REAC a total of $106.5 million of CCT over nine years, with approximately $16.09 million of that to be recovered in the first year, representing that portion of CCT assistance proposed to be paid with ratepayer funds in the 2019 rate case and that the Commission declined to approve in Decision No. 78317. (Ex. APS-1 at 9-10; Ex. APS-29 at 13.) The CCT assistance APS proposes to provide to the Nation is that portion of the CCT assistance APS committed to provide first in the CCT MOU considered in the 2019 rate case and then in a CCT Agreement.[216] (*See* Ex. APS-8 at Att. JT-07DR; Ex. RUCO-7 at 143-146.) The CCT that APS proposes to provide to the Tribe and the Navajo County Communities is the disallowed portion that APS proposed in the 2019

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[213] Ex. RUCO-7 at 173-174.

[214] The "Generic Transition Docket" was opened on January 12, 2021, "In the Matter of Impact of the Closures of Fossil-Based Generation Plant on Impacted Communities," pursuant to a directive in Decision No. 77856 (December 31, 2020), issued in the 2019 TEP rate case and admitted herein as Exhibit AZLCG-28. (*See* Ex. AZLCG-28 at 171-172.)

[215] Decision No. 78906 was admitted herein as Exhibit S-75.

[216] The CCT Agreement was executed by Jeffrey Guldner for APS and by the then-current Nation President and Nation Attorney General in August 2021 and has an effective date of August 6, 2021. (*See* Ex. APS-8 at Att. JT-07DR.) No other entity was a party to the CCT Agreement. (*See id.*)

rate case without having an agreement in place with the planned recipients. (*See* Ex. APS-8 at 28; Ex. APS-1 at 9-10; Ex. RUCO-7 at 147.) Specifically, APS now proposes to provide and have ratepayers fund:[217]

- $90 million to the Nation, to be paid over 8.5 years, at $10,588,235 in years 1 through 8 and $5,294,118 in year 9;[218]
- $3.75 million to the Nation for home and business electrification, to be paid over three years, at $1.25 million per year;[219]
- $10.4 million to the Navajo County Communities, to be paid over three years, at $3,466,667 per year;[220] and
- $2.35 million to the Tribe, to be paid over three years, at $783,333 per year.[221]

APS characterizes the proposed CCT costs as "akin to site remediation and decommissioning costs necessary to restore the site of a coal-fired power plant back to productive economic use for a host community," and states that it determined the level of support for each recipient based on the average quantity of direct economic benefit each community received as a result of APS's ownership or operation of the coal-fired power plant in each location. (APS Br. at 115-116.) APS argues that because the CCT costs are a necessary cost of service, "as acknowledged by the Commission in APS's 2019 rate case decision," the proposed costs should be included in rates. (APS Br. at 116.)

According to APS, the issue has been exhaustively evaluated, with thorough records developed in this docket, the Generic Transition Docket, and APS's 2019 rate case, so no additional study or evaluation is needed. (APS Br. at 116; Ex. APS-9 at 22, Att. JT-05RB; Ex. APS-10 at 6.) Because the Commission declined to create a specific methodology or approach for customer-funded CCT support as part of the Generic Transition Docket, APS states, the issue is left to be resolved in rate cases. (APS

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[217] Ex. APS-29 at 13; *See* Ex. APS-8 at 28, Att. JT-07DR at 3, 5; Ex. RUCO-7 at 147, 430-431.

[218] The CCT Agreement requires payment of $100 million over 10 years, at $10 million per year. (*See* Ex. APS-8 at Att. JT-07DR at 3.)

[219] The CCT Agreement requires payment of $5 million over 10 years, at $500,000 per year. (*See* Ex. APS-8 at Att. JT-07DR at 5.)

[220] In the 2019 rate case, the proposal was payment of $10.9 million over five years, at $2.18 million per year. (*See* Ex. RUCO-7 at 147.) Mr. Tetlow testified that the breakdown of CCT assistance to the Navajo County Communities was based on the percentage paid to each on APS's 2019 property tax bills: 50% to JCUSD, 24% to the Northland Pioneer Community College, and approximately 26% to the Navajo County General Fund. (Ex. APS-9 at 26.)

[221] In the 2019 rate case, the proposal was payment of $3.35 million over five years, at $670,000 per year. (*See* Ex. RUCO-7 at 147.)

Br. at 116; *see* Ex. RUCO-10; Ex. S-32; Ex. S-75.)

APS states that although the Tribe and JCUSD argue otherwise, APS's customers should not be required to fund support at a level exceeding the impact to the affected communities specifically attributable to APS's percentage share of ownership or operation of a coal plant in the community. (APS Br. at 117; Ex. APS-10 at 10-11; *see* Ex. JCUSD-1 at 9-10; Tr. at 2967, 2976.) APS argues that the requests for higher CCT assistance made by the Tribe and JCUSD may be properly denied because the evidence each provided to support its request was speculative concerning the alleged financial impact experienced or to be experienced. (APS Br. at 117; Tr. at 3012-3014, 4224-4231.)

APS also argues that JCUSD's claim of a need for APS's DSM and solar programs that exceeds the programs' availability is incorrect and that there is sufficient existing availability in APS's DSM and Solar Communities programs to address the needs of those in JCUSD and elsewhere within rural Arizona.[222] (APS Br. at 118; Ex. APS-27 at 11; *see* Ex. JCUSD-2 at 10; Tr. at 4250-4252.) APS asserts that it would be inappropriate to provide a carveout or set aside within APS's DSM or Solar Communities programs for JCUSD, but that APS is willing to work with members of the Joseph City community to identify programs or support mechanisms that may be helpful to meet the community's energy goals. (APS Br. at 118; Ex. APS-28 at 3-4.)

<u>AARP</u>

AARP states that it supports RUCO's position that a two-year analysis should be conducted on CCT funding, during which time no CCT-related funding should be approved, because there is insufficient information to support CCT funding by ratepayers at this time. (AARP Br. at 3.)

<u>Citizen Groups</u>

The Citizen Groups note that they have been integrally involved in the CCT issue with the Commission for the past five years, during which they have presented voluminous evidence concerning the impact of closing coal plants on communities where coal plants and coal mines are the main economic drivers through jobs, tax revenues, and royalties. (CG Br. at 2.) The Citizen Groups state that only Staff has opposed CCT funding in this matter, and that Staff's "blanket rejection" was made

[222] JCUSD did not include such a request in its Brief or Responsive Brief.

"without sufficient justification." (CG Br. at 3.) The Citizen Groups argue that because the Commission has formally recognized the moral and corporate responsibility for CCT, and there is insufficient evidence to support denial of additional CCT assistance in this matter, the Commission should approve APS's CCT proposal. (CG Br. at 3-4; *see* Ex. RUCO-7 at 170; Tr. at 5170-5171.)

The Citizen Groups argue that the record in this matter does not support denial of additional CCT funding because only one Staff witness presented testimony on CCT, and his prefiled testimony devoted only 3.5 pages to the subject and did not include any substantive discussion of pros and cons, Commission jurisdiction, policy, analytical considerations, or the Commission's prior decisions on CCT. (CG Br. at 4-5; *see* Ex. S-18 at 83-85; Ex. S-24 at 54-55.) The Citizen Groups argue that despite this, and without justification, Staff "concludes unilaterally that absolutely *no* coal community funding transition should be collected from ratepayer funds in this case." (CG Br. at 5.) The Citizen Groups criticize Staff's witness for not being an expert on CCT, not being familiar with litigation related to CCT involving the Tribe and Commission, and not being familiar with the principles and policy reasons behind Staff's position. (CG Br. at 5-6; *see* Tr. at 5096-5098, 5164.) The Citizen Groups also note that Staff's witness acknowledged federal funding is difficult to obtain, that he had not thoroughly researched the federal funding available, and that federal funding might not be available to JCUSD at all. (CG Br. at 7; Tr. at 5098-5101.) The Citizen Groups also criticize Staff's witness for not recalling whether he had reviewed the economic impact study provided by JCUSD in this matter, for not being intimately familiar with the Generic Transition Docket, for not knowing the extent to which ratepayer funds were used for CCT in other jurisdictions, and for stating that the Commission should agree with Staff's recommended denial in the absence of additional economic research. (CG Br. at 8-9; *see* Tr. at 5104, 5105, 5109, 5179-5180, 5187, 5203-5206.) The Citizen Groups also criticize Staff counsel for preventing Staff's witness from providing his own opinion, as opposed to Staff's position, on the need for additional CCT funding or the existence of significant environmental harms resulting from coal plants and coal mines near the coal-impacted communities. (CG Br. at 9-10; *see* Tr. at 5208-5209.) The Citizen Groups further argue that Staff's witness showed "a disturbingly flippant attitude for the advocacy of eliminating CCT assistance for coal-impacted communities that are in desperate need of funding" when he said that he had not included examples of the most common types of CCT support he has seen because he had "a lot of issues to cover" in his testimony.[223] (CG Br. at 9; *see* Tr. at 5163.) The Citizen Groups argue that Staff has not provided sufficient justification for its recommendation regarding CCT and that if the same standards were applied to all other cost-of-service issues in this matter, "it would make a mockery of the ratemaking process."[224] (CG Br. at 10.) Thus, the Citizen Groups argue, Staff's recommendation should be disregarded, and the Commission should approve APS's CCT proposal. (CG Br. at 10-11.)

The Citizen Groups acknowledge that the Commission denied CCT funding in the 2022 TEP rate case but argue that the 2022 TEP rate case is readily distinguishable from this matter because TEP, unlike APS, has not entered into an agreement for CCT support with a coal-impacted community or tribal government, and no prior TEP rate case provided a precedent in which CCT rate recovery had been authorized with the explicit understanding that additional amounts could be awarded and APS should request them.[225] (CG Br. at 11-12; *see* Ex. APS-84 at 125-128; Ex. APS-8 at Att. JT-07DR; Tr. at 5174; Ex. RUCO-7 at 173-174.) The Citizen Groups note that the Commission has already found that it is just and reasonable for APS customers and shareholders to share the burden of CCT costs and that APS has a corporate responsibility to coal-impacted communities, and that the Commission has approved ratepayer-funded CCT assistance in the last rate case and, separately, through a ratepayer-funded DSM program.[226] (CG Br. at 12; *see* Ex. RUCO-7; Ex. CG-6; Ex. CG-7; Tr. at 5168-5173.) The Citizen Groups remind the Commission that an administrative agency should not significantly depart from its prior precedent without adequately explaining its rationale, that consistency and predictability should be prioritized, and that an agency's failure to provide sufficient explanation when

[223] Because no one, including Staff, is suggesting the elimination of CCT funding that was approved in Decision No. 78317, this criticism is inaccurate and unfairly melodramatic, especially given the Staff witness's candor about his role regarding the CCT issue (which the Citizen Groups characterized as "simply [being] a mouthpiece for Staff's recommendation"). (*See* CG Br. at 10; Tr. at 5104-5105.)

[224] This suggests that Staff bears the burden of proof on the CCT issue, which it does not; APS as the applicant and proponent of the CCT proposal bears the burden of proof. (*See* A.A.C. R14-3-109(G).)

[225] Decision No. 78317 did not direct APS to request additional ratepayer funding of CCT assistance; it authorized APS to do so in the 2019 rate case docket "[i]f the Generic Transition Docket identifie[d] additional transition assistance that should be provided to the Nation or the Tribe, and APS desire[d] authorization to recover from its customers the costs of this transition assistance" and authorized APS to do so in its next rate case (i.e., this matter), if no such request was filed by APS in the 2019 rate case docket within 12 months after the effective date of Decision No. 78317. (Ex. RUCO-7 at 174.)

[226] This refers to the Tribal Energy Efficiency Program the Commission required APS to develop in Decision No. 77763, "as part of its corporate obligations to support a just and equitable transition of communities impacted by early power plant closure," and approved in Decision No. 78052, to assist Navajo Nation and Hopi Tribe community members who are APS customers and with a budget of at least $1 million annually. (*See* Ex. CG-6; Ex. CG-7.)

changing its prior approach can result in a finding of arbitrary and capricious decision-making. (CG Br. at 12-13; *see Akebia Therapeutics, Inc. v. Azar*, 976 F.3d 86 (1st Cir. 2020); *Begay v. Off. of Navajo and Hopi Indian Relocation*, 305 F. Supp. 3d 1040 (D. Ariz. 2018); *State ex rel. Brnovich v. Ariz. Bd. of Regents*, 250 Ariz. 127 (2020).[227]) The Citizen Groups argue that the Commission should follow its "well-established principals [sic] related to APS and its corporate responsibility" and approve APS's CCT proposal in this matter. (CG Br. at 13.)

In their Responsive Brief, the Citizen Groups also advocate for Commission approval of the funding requests made by the Tribe and JCUSD, stating that JCUSD's request is firmly supported by its financial impact study and that the Tribe needs further CCT assistance. (CG RBr. at 2.)

<u>Tribe</u>

The Tribe did not provide a Brief or Responsive Brief in this matter. However, in its testimony, the Tribe asserts the following:

- The Tribe needs economic support to replace the lost revenue from NGS operations for a sufficient number of years to transition its economy.[228]
- The CCT support proposed by APS for the Tribe in this matter falls "far short" of what the Tribe needs and what is just and equitable, making the APS CCT proposal "illegitimate."[229]
- A multiplier must be applied to the APS CCT proposal, and the CCT support to the Tribe must include all categories of assistance offered to the Nation.[230]
- "CCT assistance must be based on the following criteria: (1) degree of recipient economic impact, (2) consistent treatment between recipients by assistance category, (3) on a per MW ownership basis, and (4) considering the detrimental reliance of the impacted community on continuing facility operations."[231]

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[227] The first two cases, while supportive of the broad principles for which they are cited in the context of federal administrative law, do not establish the law in Arizona, and the third case involves interpretation of a statute. The Citizen Groups also cited a treatise that is not included in the record for this matter.
[228] Ex. Hopi-1 at 3 (response to Q7).
[229] Ex. Hopi-1 at 4 (response to Q9).
[230] Ex. Hopi-1 at 4 (response to Q9).
[231] Ex. Hopi-2 at 1 (response to Q5). Mr. Lomayestewa testified that the Nation sought assistance at $100,000/MW in the 2019 rate case and that the Tribe's adjusted estimate of the value of the CCT proposed by APS for the Nation in that case was $115,424/MW, which would make that or a similar number appropriate to use in this case for the Tribe. (Ex. Hopi-2 at 2 (response to Q6).)

- When the Black Mesa portion of the Kayenta Mine closed, the Tribe lost many years of revenue on which it historically depended for as much as 90% of its total annual budget, and that loss resulted entirely from the early NGS closure, of which the Tribe did not receive notice that would realistically allow it to plan to transition away from coal dependence.[232]
- Any CCT assistance to the Tribe should reflect that the Tribe experienced an approximately three-fold greater economic impact from the NGS closure than the Nation did, meaning that the CCT support to the Tribe calculated on a per MW basis "should incorporate the appropriate scaling."[233]
- Because the Tribe would have received more than 20 years of additional financial benefits from NGS operating to almost the end of 2044, when its federal authorization was to expire, and the Tribe's annual coal revenues regularly exceeded $13 million, the Commission should factor into its CCT determination that the Tribe lost an estimated $260 million as a result of the early NGS closure.[234]
- Because the Hopi reservation is geographically surrounded by the Navajo Nation, the Tribe's land would meet the proximity criterion for locating solar generation on or within 50 miles of the Nation, but APS has not proposed use of the Tribe's land.[235]
- APS's CCT proposal fails to take into account the degree of economic impact the NGS closure had on the Tribe and fails to offer the Tribe projects that parallel those offered to the Nation in the CCT MOU.[236]
- APS assumed responsibility for paying Hopi due to the mine closure caused by the NGS closure because APS accelerated the NGS closure.[237]
- The Commission lacks authority to direct the use of CCT funds already paid through the 2019

[232] Ex. Hopi-2 at 1-2 (response to Q5); Tr. at 3005-3006. According to one exhibit, coal revenues constituted 82% of the Hopi General Fund Budget in FY2018, 53% in FY2019, and 0% in FY2020 and FY2021. (Ex. Hopi-4.) According to another exhibit, coal royalties plus water draw payments constituted 69.8% of the Hopi General Fund Budget in FY2018, 75.0% in FY2019, and 1.7% in FY2020. (Ex. Hopi-8.) Mr. Lomayestewa acknowledged that the coal royalties plus water draw payments had not constituted more than 75% of the Hopi General Fund Budget since FY2012. (Tr. at 3013-3014.)

[233] Ex. Hopi-2 at 2-3 (response to Q7).

[234] Ex. Hopi-2 at 3 (response to Q7).

[235] Ex. Hopi-3 at 1 (response to Q3).

[236] Ex. Hopi-3 at 2 (response to Q5).

[237] Ex. Hopi-3 at 2 (response to Q7). Chairman Nuvangyaoma acknowledged that APS was not the majority owner of NGS and that APS's stake in NGS was smaller than those of the other owners. (Tr. at 2965.)

rate case and has no jurisdiction to direct the use of any additional CCT funds.[238]

IBEW Locals

The IBEW Locals argue that the Commission should, pursuant to its permissive power under Arizona Constitution Article 15, § 3, "specifically incentivize . . . through specific ordering language" public service corporations to (1) develop new plant or technologies within 25 miles of a retired fossil-based generation plant; and/or (2) redeploy or retrain the employees of its retired fossil-based generation plant for future work within or outside of the public service corporations. (IBEW Br. at 11-14.) The IBEW Locals state that these proposals will minimize the impact and harm of coal plant closures going forward. (IBEW Br. at 14.) The IBEW Locals further request the Commission to adopt, in this matter and in future rate cases, an Impacted Communities Surcharge (not an adjustor mechanism) that would allow public service corporations to collect from ratepayers the funds needed to pay for development of new plants or technologies and/or redeployed or retrained employees. (IBEW Br. at 14.) The IBEW Locals assert that their proposals would assist public service corporation employees by providing new employment opportunities or training for alternate employment, provide additional employment opportunities through new plant investments, and preserve public service company employees' well-being by avoiding the detrimental impacts of unemployment. (IBEW Br. at 14-15.) Finally, the IBEW Locals argue that APS must collaborate with workers and their representatives, including unions, concerning CCT funding and workforce transition efforts. (IBEW Br. at 15.)

JCUSD

JCUSD requests the Commission to order APS to provide JCUSD CCT assistance of approximately $20 million over the next 10 years, to assist JCUSD with the impacts of the Cholla closure. (*See* JCUSD Br. at 2, 7; Tr. at 4242.) JCUSD bases its requested CCT assistance on a financial impact study performed by Jeremy Calles, which estimates that JCUSD will lose a total of approximately $20.15 million in funding between 2025 and 2035 due to a significant decline in enrolled

[238] Ex. Hopi-3 at 2 (response to Q7); *see also* Tr. at 2967-2970.

students[239] caused by the Cholla closure. (JCUSD Br. at 7; Ex. JCUSD-3 at ex. JC-1 at 3.) In addition to the CCT payments over 10 years, JCUSD requests that APS be required to provide JCUSD a one-time payment of $800,000 to pay off the balance on JCUSD's solar energy system lease-purchase agreement. (JCUSD Br. at 8; Tr. at 4261-4262.) JCUSD argues that both the Commission and APS (the majority owner and operator of Cholla) have acknowledged APS's corporate obligation to support a just and equitable transition away from coal-based economies for communities impacted by early coal plant closures. (JCUSD Br. at 1; *see* Ex. RUCO-7 at 136, 170; Ex. APS-9 at Att. JT-04RB at 3.)

JCUSD acknowledges that it received approximately $500,000 in direct CCT assistance from APS since the last rate case and that it would receive approximately $5 million in additional direct CCT assistance under APS's CCT proposal in this matter. (JCUSD Br. at 5, 6; *see* Ex. JCUSD-1 at 20.) JCUSD asserts that it is not seeking a "windfall" and that any direct financial assistance it receives is required by law to be spend educating students. (JCUSD Br. at 8.) According to JCUSD, APS's CCT proposal does not justly and equitably address the impact on JCUSD from Cholla's closure. (JCUSD Br. at 2.) JCUSD argues that it needs the requested $20 million in funds to continue providing the same level of educational services (classes, athletics, and other extracurriculars) that its students currently enjoy and that a just and equitable transition assistance package for a public school district must be based on actual financial impacts and designed to prevent the loss of educational opportunities while the community rebuilds its economy. (JCUSD Br. at 2, 9.)

JCUSD argues that it is neither just nor equitable for APS to base the CCT proposal for JCUSD on what was acceptable to the Nation (approximately two years' worth of taxes, royalties, and lease payments) because JCUSD and the Nation will experience very disparate impacts due to the extent to which their respective annual budgets will be affected by the coal plant closures.[240] (JCUSD Br. at 10.) JCUSD also points out that it, as a public school district, has only the powers and authorities expressly or impliedly provided by the Legislature, which does not include the ability to supplement budgets by

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[239] Mr. Calles assumes a 25% enrollment decline for FY2026, followed by an additional 5% decline in FY2027, followed by an additional 2% decline in each of the next three years, and then no further decline. (Ex. JCUSD-3 at ex. JC-1 at 6.) As of the hearing, JCUSD had approximately 475 students. (Tr. at 4254.)

[240] JCUSD asserts that it faces the loss of 20% of its annual budget immediately after Cholla closes and expects the annual budgetary shortfall to rise to more than 40% in the 10th year after Cholla closes, while each $10 million payment to the Nation makes up approximately 0.4% of the Nation's annual budget. (JCUSD Br. at 10.) To support the budget figure for the Nation, JCUSD cited an article that is not part of the evidentiary record in this matter.

raising funds independently. (JCUSD Br. at 10; *see Tucson Unified Sch. Dist. v. Tucson Educ. Ass'n*, 155 Ariz. 441 (App. 1987); A.R.S. §§ 15-341, 15-342.)

JCUSD argues that no party has meaningfully contested the findings and conclusions of JCUSD's financial impact study and that the study provides much of the information parties have identified as necessary to make a determination on appropriate CCT assistance. (JCUSD Br. at 11; *see* Tr. at 817-819, 4714.) JCUSD also argues that this matter is the appropriate forum in which to approve CCT assistance for JCUSD because the Commission has already recognized the urgent need for and has already authorized CCT assistance, and Cholla will close in April 2025, meaning that JCUSD's students will suffer irreparable harm if JCUSD is not provided CCT assistance now. (JCUSD Br. at 11-12; *see* Ex. CG-6; Ex. AZLCG-28 at 171; Ex. RUCO-7 at 173-174; Ex. JCUSD-1 at 17.)

JCUSD argues that the record is sufficiently developed to finalize a CCT package for JCUSD in this matter because JCUSD has provided a financial impact study, and an extensive record has been developed in past rate cases and the Generic Transition Docket.[241] (JCUSD Br. at 13.) Further, JCUSD argues, because all parties have had an opportunity to supplement the record on CCT in this matter, the Commission should give no credence to arguments that further study or analysis is required. (JCUSD Br. at 13.) JCUSD notes that it has sought additional funding mechanisms, with the assistance of the Just Energy Transition Center at Arizona State University, only to conclude that none are available. (JCUSD Br. at 14; *see* Tr. at 4244-4245.) JCUSD argues that the Commission should not decline to order APS to provide JCUSD CCT assistance in this matter due to speculation that there may be financial assistance available in the future. (JCUSD Br. at 14.) JCUSD states that it intends to work with community partners to leverage all available opportunities to rebuild its tax base and transition away from a coal-based economy and that the CCT assistance provided in this matter will help bridge the gap while those community partnerships are developed. (JCUSD Br. at 14.)

In its Responsive Brief, JCUSD addresses criticisms of its financial impact study made in APS's Brief—that JCUSD does not account for replacement generation at the Cholla site or area, that JCUSD inappropriately assumes that all APS Cholla employees will leave the area when Cholla closes, and

[241] Much of the information provided in other dockets is not part of the evidentiary record in this matter.

that JCUSD does not account for PacifiCorp's ownership of Cholla Unit 4. (JCUSD RBr. at 4; *see* APS Br. at 177.) JCUSD argues that APS has not cited any actual evidence rebutting anything in the financial impact study but instead states (without support) that the Commission should adopt APS's CCT proposal. (JCUSD RBr. at 4.) JCUSD asserts that the record includes no meaningful information on any replacement generation to be located at or near Cholla and that it thus is disingenuous for APS to critique the financial impact study for not including it.[242] (JCUSD RBr. at 4-5.) JCUSD adds that if APS had provided timely plans about repurposing Cholla so that permanent jobs and the tax base could be maintained, JCUSD would not have needed to intervene in this matter. (JCUSD RBr. at 5.) JCUSD also asserts that it appreciates APS's June 2023 ASRFP[243] but that requesting proposals does not guarantee creation of hundreds of permanent jobs[244] or replacement of tens of millions of dollars in tax base.[245] (JCUSD RBr. at 5.) Regarding the jobs lost, JCUSD argues that APS has provided no evidence suggesting that any Cholla employees would continue to reside in the area after Cholla closes, noting that Mr. Tetlow testified APS has committed to transferring Cholla employees or providing them severance, that there are no other APS facilities in the area to which the Cholla employees could be transferred, and that APS has provided no evidence concerning remote work opportunities. (JCUSD RBr. at 6; *see* Tr. at 828.) JCUSD argues that APS could have completed and submitted its own financial impact study, could have provided evidence concerning the loss of assessed valuation of Cholla attributable to PacifiCorp's Unit 4, or could have provided evidence concerning the jobs lost when Cholla Unit 4 was closed, but APS did not do so and instead "inexplicably" asserts in its Brief

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[242] JCUSD acknowledges that Mr. Calles was shown an application for a Certificate of Environmental Compatibility ("CEC") from October 2020 for a substation and three-to-four mile alternating current generation tie-in line, but argues that the impact of this would be negligible when compared to the loss of permanent jobs and assessed valuation resulting from the Cholla closure. (JCUSD Br. at 5 n.7; *see* Ex. APS-86; Ex. APS-87; Tr. at 4225-4227.) JCUSD does not note that the gen-tie project is to support a 275 MW to 400 MW solar photovoltaic power plant that may be paired with a battery energy storage system, to be located in and thus provide property tax revenue to Navajo County. (*See* Ex. APS-86; Ex. APS-87.) Official notice is taken of Decision No. 77888 (January 25, 2021) and Decision No. 77889 (January 25, 2021), which approved the CECs issued by the Arizona Power Plant and Transmission Line Siting Committee for the two components of the gen-tie project.

[243] The ASRFP specifically requests proposals for potential redevelopment of the Cholla site. (*See* Tr. at 819.)

[244] The evidence at hearing indicated that Cholla had employed 84 full-time workers, not hundreds of workers, since 2018 and that it employed 195 full-time workers before 2018. (Tr. at 4255-4256.)

[245] The financial impact study shows a loss of approximately $1 million in 2025-2026, $1.7 million in 2026-2027, and $1.9 million in 2027-2028, followed by losses of between $2 million and $2.3 million in each subsequent year. (*See* Ex. JCUSD-3 at ex. JC-1 at 16.)

that the financial impact study should be wholly disregarded.[246] (JCUSD RBr. at 7.)

Concerning the lack of reference to PacifiCorp's ownership of Cholla Unit 4, which was decommissioned in 2020, JCUSD states that the financial impact study calculates impact based on the closure of Cholla's actual operations. (JCUSD RBr. at 7.) Further, JCUSD argues, if APS's 64% ownership is applied to the financial impact calculated by Mr. Calles, a just and equitable transition package for JCUSD would provide at least $12.9 million. (JCUSD RBr. at 8; *see* Tr. at 821; Ex. JCUSD-3 at ex. JC-1 at 3.) JCUSD argues that Commission decisions must be supported by substantial evidence and that the only evidence concerning just and equitable transition assistance for JCUSD has been provided by JCUSD. (JCUSD RBr. at 9; *see Litchfield Park Serv. Co. v. Ariz. Corp. Comm'n*, 178 Ariz. 431, 434 (App. 1994).) JCUSD further argues that if the Commission decides to "disregard APS's special obligations to the community as the operator of Cholla" by reducing the CCT package based on APS's ownership percentage, the Commission must provide JCUSD at least $12.9 million over a 10-year period. (JCUSD RBr. at 9, 12.)

Finally, JCUSD responds to RUCO and Staff's recommendations for additional study and further development of a policy or framework for CCT assistance, asserting that these arguments are thoroughly rebuffed by the Briefs of the Citizen Groups and Nation, in which JCUSD joins. (JCUSD RBr. at 9-10.)

<u>Nation</u>

The Nation requests that the Commission approve APS's CCT proposal in this matter. (Nation Br. at 1.) The Nation states that the CCT funding includes quantifiable forgone revenues to the Nation related to the early closures of NGS, Cholla, and the 4CPP and that the funding is properly recoverable from ratepayers as costs of service directly caused by those early closures. (Nation Br. at 1.)

The Nation argues that Decision No. 78317 broadly acknowledged the necessity of CCT assistance to the impacted communities, determined that the Commission had jurisdiction over recovery of CCT costs from retail ratepayers, authorized partial CCT funding as an interim step, and explicitly invited future requests for CCT from APS. (Nation Br. at 2; *see* Ex. RUCO-7 at 170-174,

[246] It should be noted that APS cross-examined Mr. Calles about the first two specific items of criticism enumerated by JCUSD in its Responsive Brief. (*See* Tr. at 4224-4231.)

428.) The Nation argues that Staff's recommendation for the Commission to "reverse course" from its prior decision is "unjustified and legally problematic" because no party has provided evidence of a change in circumstances to warrant this reversal, and denial of APS's CCT proposal thus would be unsupported by substantial evidence and arbitrary and capricious. (Nation Br. at 3; *see Ariz. Pub. Serv. Co. v. Ariz. Corp. Comm'n*, 526 P.3d 914, 918 (2023); *Sierra Club—Grand Canyon Chapter v. Ariz. Corp. Comm'n*, 237 Ariz. 568, 575 (App. 2015).) The Nation argues that the basic facts and circumstances supporting the need for CCT assistance are unchanged from the 2019 rate case and that because no party challenges the calculation of the CCT proposal amount, the record lacks substantial evidence to support a lower amount of CCT assistance than that proposed by APS.[247] (Nation Br. at 3, 7.) Further, the Nation argues, because no one sought rehearing or appeal of the partial CCT relief granted to the Nation in Decision No. 78317,[248] opposing CCT relief for the Nation in this matter "amounts to an unfounded collateral attack on the Commission's decision," which "should not be countenanced and must be rejected outright." (Nation Br. at 3-4; *see Ariz. Pub. Serv. Co. v. S. Union Gas Co.*, 76 Ariz. 373, 377 (1954).[249])

According to the Nation, the trend across the country is to close coal plants and reexamine the issue of CCT compensation and its recovery through rates, which the Nation argues renders any opposition based on tradition "antiquated" and out of touch with the "uncontested truth" that the shift away from coal-fired generation creates new and unexpected costs for coal-impacted communities. (Nation Br. at 4; *see* Tr. at 4941; Ex. CG-3 at 13.) The Nation points to Mr. Daniel's testimony that the costs caused by early retirements are properly considered costs of service that should be recovered through rates and that CCT relief is being provided in other states. (Nation Br. at 4; *see* Ex. Navajo-1

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[247] The Nation asserts that the CCT proposal represents the remaining portion of quantifiable and verifiable revenues forgone by the Nation due to the early closures of the coal plants, comprising lease payments, taxes, and royalties that would otherwise have been recovered from customers through retail rates if the coal plants continued to operate. (Nation Br. at 7; *see* Tr. at 5117.)

[248] The Nation acknowledges that the Tribe appealed the amount of CCT assistance the Tribe was provided in Decision No. 78317, but asserts that the Tribe did not challenge the Commission's authority to provide ratepayer-funded CCT assistance to the Nation. (Nation Br. at 3 n.7.)

[249] The Nation also cites A.R.S. § 40-252's language that "[i]n all collateral actions or proceedings, the orders and decisions of the commission which have become final shall be conclusive." The Nation's reliance on A.R.S. § 40-252 is misplaced, however, because A.R.S. § 40-252 authorizes the Commission, upon notice to the corporation affected and after an opportunity to be heard, to "rescind, alter or amend any order or decision made by it" and renders any such rescission, alteration, or amendment "effective as an original order or decision." Thus, it is possible for a "final" Commission decision to be rescinded, altered, or amended even in the absence of an appeal.

at 15.) The Nation argues that no party challenged Mr. Daniel's testimony and that the parties opposing the CCT Agreement did not even cross-examine him about his conclusions.[250] (Nation Br. at 4-5.)

As the Commission has recognized, the Nation asserts, the coal plants were major contributors to the Nation's economy for decades, and their closures have caused and will cause significant adverse economic impacts, requiring the Nation to go in a new direction. (Nation Br. at 5.) The Nation argues that it could choose to increase property tax rates on APS to recover the lost revenues, but that this would be less stable and predictable for ratepayers than the annual CCT payments would be. (Nation Br. at 5; *see* Tr. at 5122-5127.[251]) The Nation notes that the Commission generally allows a utility to recover property tax expenses in rates without special monitoring. (Nation Br. at 5; *see* Tr. at 5129-5130.[252]) The Nation argues that using the property tax approach, as opposed to the proposed CCT approach, would be less transparent to the Commission, because the CCT Agreement describes the amounts, the payment period, and the uses for the funds. (Nation Br. at 5-6; *see* Tr. at 5127-5128.)

The Nation argues that the outcome on CCT in the 2022 TEP rate case should have no bearing on this matter because "the findings and conclusions in a rate case are specific to that record and do not extend beyond it," and because the procedural circumstances were different in the 2022 TEP rate case, with the issue of CCT not being raised until the Generic Transition Docket had closed, approximately nine months after TEP filed its application. (Nation Br. at 6; *see* Ex. APS-84 at 126.)

The Nation asserts that the amounts included in the CCT Agreement represent the average tax, royalty, and lease payments from APS to the Nation over two years and that the $10 million annual payments are only a fraction of the $60 million per year that the Nation received when all three coal plants were operating, thus posing no risk of overcompensation to the Nation. (Nation Br. at 7; *see* Ex. APS-9 at Att. JT-04RB at 2-6; Tr. at 857-859.) The Nation also argues that the tax, royalty, and lease payments were routinely included in cost of service and that the CCT assistance expenses are end-of-

[250] The Commission notes that Staff cross-examined Mr. Daniel about the New Mexico Supreme Court's July 2023 decision upholding the New Mexico PUC's denial of PNM's request to sell its share of the 4CPP, of which Mr. Daniel was not aware when he wrote his testimony. (*See* Tr. at 4180-4181; Ex. S-29.)

[251] The Commission notes that Staff's witness pushed back on the Nation's hypothetical, suggesting that a special property tax assessment on APS alone would likely result in a lawsuit by APS for discriminatory treatment and heightened scrutiny from the Commission when considering recovery through rates. (*See* Tr. at 5122-5127.) Staff's witness also stated that he did not see a value to ratepayers from paying for CCT. (Tr. at 5127.)

[252] Staff's witness clarified that this is the case with property taxes assessed in the ordinary course of business. (Tr. at 5130.)

plant-life costs similar to site reclamation and decommissioning costs that are routinely included in cost of service. (Nation Br. at 8; *see* Tr. at 853-854; Ex. Navajo-1 at 15.)

The Nation rejects Staff and RUCO's positions that further analysis is required before additional CCT should be approved, again emphasizing that the CCT proposal for the Nation is based on historic data and adding that APS has reviewed or conducted 12 distinct financial studies related to the impacts of coal plant closures and does not believe that any further analysis is needed. (Nation Br. at 8; *see* Ex. APS-9 at 22, Att. JT-05RB; Tr. at 818.) The Nation also criticizes Staff's recommendation for a two-year period to perform analysis, pointing out that NGS has already closed and that Cholla will close in spring 2025. (Nation Br. at 8.) The Nation further points out that the CCT proposal is based on the CCT Agreement, which is substantively the same as the CCT MOU considered in the 2019 rate case, meaning that Staff and RUCO have had more time to scrutinize the CCT proposal than to scrutinize any other information in this matter. (Nation Br. at 8-9; *see* Ex. RUCO-7 at 143-147.)

The Nation further argues that unlike other CCT requests in this matter that are less quantitative and based on environmental justice considerations, the CCT proposal is based solidly on the economic impacts of the early coal plant retirements and designed to address those costs. (Nation Br. at 9; *see* Ex. CG-1 at 17; Ex. CG-4 at 11; Ex. CG-3 at 23; Tr. at 849; Ex. APS-8 at 28.[253]) The Nation states that "APS's proposed CCT is not a matter of social justice or ratepayer largesse," but instead "is a fundamental cost of service that should be included in rates." (Nation Br. at 8.)

The Nation also criticizes Staff and RUCO's desire to analyze who benefited from the operation of the coal plants during their operational lives before the Commission approves any additional CCT assistance and argues that their positions should be disregarded because neither has offered a methodology to perform such an analysis, and such analysis appears to be unprecedented as a prerequisite to cost recovery in a Commission case. (Nation Br. at 10; *see* Tr. at 4386, 5103-5104.) The Nation argues that RUCO's proposal to review who paid for and benefited from the operation of each coal plant "fundamentally conflicts with the basic concepts of *res judicata* and collateral estoppel" because prior Commission decisions have established who paid for the plants and whether the plants

[253] The Nation also cited *Sun City Home Owners Ass'n v. Ariz. Corp. Comm'n*, 252 Ariz. 1, 8 (2021), for its endorsement of the Commission's use of cost-causation principles when setting rates.

were used and useful in providing service. (Nation Br. at 10-13; *see* Ex. RUCO-3 at 7; Ex. RUCO-7 at 133; Tr. at 4466.[254]) The Nation argues that the rate cases that included the coal plants in rate base also addressed the shareholder benefit from the plants, which was the return on equity, meaning that that issue also cannot be relitigated. (Nation Br. at 12; *see Ariz. Pub. Serv. Co. v. Ariz. Corp. Comm'n*, 526 P.3d 914, 921 (2023).) The Nation further argues that it would be "inconsistent and discriminatory" to use historic shareholder returns to justify opposing CCT assistance from ratepayers and that any analysis to determine the split of benefits between ratepayers and shareholders, for which RUCO has not proposed a methodology, would be inaccurate. (Nation Br. at 12.) The Nation argues that *res judicata* prohibits reassessment of whether the coal plants were used and useful in the provision of service and further claims that "denying rate recovery today related to the provision of service pursuant to a Commission-approved tariff" would be "impermissible retroactive ratemaking." (Nation Br. at 12-13; *see* Decision No. 77292 (July 19, 2019) at 66.[255])

Additionally, the Nation argues that the CCT costs caused by retirement of the coal plants have no relationship to whether and to what extent the coal plants benefited APS's customers in the past. (Nation Br. at 13.) The Nation points out that the CCT proposal is to cover forgone revenues to the Nation from lease payments, taxes, and royalties that would have been paid if not for early retirement of the coal plants; that these are "due to the Nation" regardless of the benefits the plants provided to ratepayers; and that they are no different than other end-of-life costs that APS is routinely allowed to recover from ratepayers. (Nation Br. at 13.) The Nation argues that adopting RUCO's position would constitute baseless discrimination against a particular set of costs and could result in every cost incurred by APS being subjected to a "hindsight-driven, relative benefit analysis." (Nation Br. at 13; *cf. Ariz. Pub. Serv. Co. v. Ariz. Corp. Comm'n*, 526 P.3d 914, 922-923 (2023).)

The Nation further argues that the Commission's and ratepayers' lack of involvement in the

[254] To support its legal argument that *res judicata* and collateral estoppel apply to Commission matters and that the elements of collateral estoppel have been met as to who paid for the coal plants and whether they were operated for the benefit of APS's customers because they have been included in rate base, the Nation cited *Hawkins v. State, Dept. of Economic Sec.*, 183 Ariz. 100, 103-104 (App. 1995); *JW Hancock Enters., Inc. v. Ariz. State Registrar of Contractors*, 142 Ariz. 400, 410 (App. 1984); *Simms v. Round Valley Light & Power Co.*, 80 Ariz. 145, 151 (1956); and Ariz. Const. Art. XV, § 3.

[255] Official notice is taken of Decision No. 77292, which resolved a formal complaint against APS and stated that *res judicata* prohibits attacks on rates set in prior proceedings. The Nation does not cite any authority for its retroactive ratemaking argument.

management decision to retire the coal plants early does not excuse ratepayers from bearing any of the costs resulting from such retirements, because management decisions (such as to enter into the CCT Agreement) are appropriately made by APS, not by ratepayers or the Commission. (Nation Br. at 14; *see Ariz. Pub. Serv. Co. v. Ariz. Corp. Comm'n*, 526 P.3d 914, 921 (2023).) The Nation points out that no party opposes rate recovery for decommissioning or site reclamation costs associated with the early coal plant closures, although ratepayers were not involved in the closure decisions. (Nation Br. at 14.) The Nation also points out that no one is arguing that the reductions in operating expenses resulting from the early plant closures should not be passed on to ratepayers, which the Nation states represents an illogical "have your cake and eat it too" position. (Nation Br. at 14; *see* Ex. APS-10 at 12.) The Nation argues that Staff's position that Staff and others should have been involved in the negotiations for the CCT MOU and CCT Agreement is inconsistent with Staff's normal role, as Staff's witness offered no examples of instances in which APS has sought Staff approval before entering into litigation settlements. (Nation Br. at 15.) To support its claim that the CCT Agreement is a litigation settlement, the Nation points to language in the CCT Agreement stating that it is intended to resolve the Nation's CCT claims relative to APS. (Nation Br. at 15; Ex. APS-8 at Att. JT-07DR at 2.) The Nation calls out Staff for treating the Nation differently than other parties who settle disputes with regulated utilities, asserting that there is no basis for subjecting the Nation to a more burdensome process. (Nation Br. at 15.)

In its Responsive Brief, the Nation reiterates arguments made in its Brief and additionally argues that there is no need for another CCT generic docket and that the Commission directed the parties to use this matter for consideration of CCT. (Nation RBr. at 3.) The Nation argues that the Commission can develop a statewide policy applicable to other utilities in this matter and subsequent TEP dockets, as it is common for the Commission, Staff, and RUCO to cite policies approved for one utility in the context of setting policy for another.[256] (Nation RBr. at 4; *see* RUCO RBr. at 5-6; Staff Br. at 63; Ex. RUCO-7 at 202-203.) The Nation emphasizes that the CCT Agreement is a bilateral

[256] The Nation notes that Decision No. 79065 from the 2022 TEP rate case expressly did not establish a policy standard for CCT by restricting its CCT resolution to the TEP matter and, further, expressly encouraged TEP to enter discussions with the Nation and others in an effort to reach agreement on CCT. (*See* Ex. APS-84 at 128.)

agreement between two parties. (Nation RBr. at 4-5.) The Nation argues that RUCO and Staff's position, taken to its logical end, would require the Commission to open generic dockets on the calculation of return on equity, depreciation, and numerous other issues, something that is not a viable approach to utility regulation. (Nation RBr. at 5.) The Nation also notes that although both RUCO and Staff assert that more information is needed regarding CCT, neither contacted the Nation about the CCT Agreement or conducted discovery related to it in this matter. (Nation RBr. at 6.) The Nation asserts that it is "absurd" to argue that further analysis is needed, that RUCO and Staff's positions are a delay tactic, and that Staff's study process would result in the Nation not receiving any additional CCT assistance until at least 2031, six years after retirement of Cholla and 12 years after retirement of NGS and not in time for the assistance to serve any "transition" function. (Nation RBr. at 6-7; *see* Tr. at 4483.)

The Nation characterizes RUCO's contention that the Commission should complete a review of securitization before approving APS's CCT proposal as defying logic and "another flavor of delay." (Nation RBr. at 7[257]; RUCO Br. at 35.) According to the Nation, RUCO's argument should be rejected because APS does not seek to fund the CCT proposal through securitization, and securitization is outside the scope of this matter. (Nation RBr. at 8.)

Likewise, the Nation characterizes Staff's concerns about appellate court treatment of CCT as "irrelevant," "blatantly speculative[,] and lacking in any substantive evidence." (Nation RBr. at 8; *see* Staff Br. at 63-64.) The Nation notes that Staff did not explain its response to the appellate court's question about the Commission's jurisdiction over ratepayer funding for CCT or the correctness of the finding in the last rate case that the Commission has such authority. (Nation RBr. at 8; *see* Ex. RUCO-7 at 428.) The Nation further points out that a question at oral argument does not guarantee that an issue will be addressed, or in what manner, and that Staff has not identified any party to the appeal that has raised the issue for the court's consideration. (Nation RBr. at 8.) The Nation notes that the Tribe has not entered into any agreement for CCT with APS and asserts that "it is illogical to put the brakes on approval of the [CCT] Agreement to account for the unlikely scenario that the courts might perhaps

[257] The Nation misstates RUCO's argument as stating that APS should retain a consultant to advise it on securitization. (*See* RUCO Br. at 35.)

find CCT relief outside of a settlement beyond the Commission's authority." (Nation RBr. at 9.[258]) The Nation argues that if the Commission left every issue subject to challenge unresolved, "the regulatory process would cease to function," and cites the Joint Resolution as an example of how the Commission is able to adapt to a court order. (Nation RBr. at 9; *see* Staff Br. at 2, 12, 17.)

The Nation concludes that the evidence in this matter supports adoption of the CCT Agreement, and the public interest in the coal-impacted areas would not be served by further delay. (Nation RBr. at 10.)

<u>Ms. Nelson</u>

Ms. Nelson asserts that the coal-impacted communities should be helped in reclamation by APS, its shareholders, and its ratepayers. (KN Br. at 3.) Ms. Nelson also states that the Commission should regulate the money collected annually for reclamation to ensure that it is allocated to use only for reclamation after the 4CPP closes. (KN Br. at 3.)

<u>Sierra Club</u>

Sierra Club argues that CCT assistance is urgently needed to address the economic impacts of recent and upcoming coal plant closures and "the legacy of environmental harm" from operating those coal plants. (SC Br. at 21.) Because the Commission has already recognized that CCT assistance is an obligation shared by APS ratepayers and shareholders, and because CCT assistance is a plant closure expense that is part of the cost of service using coal power, Sierra Club argues, the Commission should approve APS's CCT proposal and the additional CCT requests of the Tribe, JCUSD, and the Nation. (SC Br. at 21; *see* Ex. RUCO-7 at 172.) Sierra Club advocates for approximately $158.05 million of CCT assistance to the Nation, the Tribe, and JCUSD and states that the CCT funding should be viewed in light of the decades of "cheap coal power" and against the much-higher costs of running the coal plants. (SC Br. at 24; *see* Ex. SC-3 at 8; Ex. APS-47.) Sierra Club argues that the CCT assistance will have only a small and modest rate impact as compared to the tens of millions of dollars APS will save ratepayers by ceasing to operate the coal plants. (SC Br. at 35; *see* Ex. SC-1 at 46-47, 62; Ex. Navajo-1 at 19-20.) Sierra Club adds that if the Commission is concerned about the burden, the Commission

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[258] We note that the existence of an agreement for CCT would likely have no impact if the Commission were declared to lack the authority to approve ratepayer funding for CCT.

could exempt low-income ratepayers[259] from paying CCT assistance by providing a CCT discount on their bills. (SC Br. at 35; Ex. SC-3 at 14-15.)

Sierra Club argues that the record in this matter includes abundant information to support APS's CCT proposal and the other parties' CCT requests, with APS, the Tribe, the Nation, the Citizen Groups, JCUSD, and Sierra Club all providing testimony supporting the urgent need for CCT assistance and ratepayers' obligation to contribute to that funding. (SC Br. at 22; *see* Ex. APS-10 at 6; Ex. SC-3; Ex. Navajo-1; Ex. CG-3; Ex. CG-1; Ex. CG-2; Ex. CG-4; Ex. JCUSD-1; Ex. JCUSD-3; Ex. Hopi-2; Ex. Hopi-3.) Additionally, Sierra Club argues, there is evidence that CCT funding has been provided by utilities across the U.S. (SC Br. at 22; Ex. CG-3 at 13-17.)

Sierra Club points out the Commission's previous determinations that "APS has a corporate obligation to support just and equitable transition," that it is just and reasonable for APS ratepayers and shareholders to share the burden of CCT costs, and that the need for CCT assistance is urgent. (SC Br. at 22-23; *see* Ex. CG-6 at 38; Ex. RUCO-7 at 171-172; Ex. AZLCG-28 at 171.) Sierra Club argues that customers have an obligation to provide CCT assistance because they have benefited from low-cost and abundant coal power while coal-impacted communities were undercompensated for hosting the land, water, and coal used for the coal plants, and shareholders have an obligation to provide CCT assistance because artificially low-cost coal power was profitable. (SC Br. at 23; *see* Ex. CG-3 at 24-25; Ex. SC-3 at 11; Ex. RUCO-7 at 171.)

According to Sierra Club, the Commission has recognized that CCT assistance is an "end-of-plant-life cost." (SC Br. at 24; *see* Ex. RUCO-7 at 171.[260]) Additionally, Sierra Club asserts, APS has acknowledged that CCT costs are similar to reclamation or power plant decommissioning costs. (SC Br. at 24; *see* Ex. RUCO-7 at 167, 171.) Sierra Club argues that the Commission has routinely allowed ratepayer funding of other typical end-of-life costs, including the site restoration and decommissioning costs for the 4CPP and Cholla that ratepayers are already paying, and has not articulated any rule that

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[259] Sierra Club suggested that enrollment in the Low-Income Home Energy Assistance Program ("LIHEAP") could be used to identify low-income households. (SC Br. at 35; *see* Ex. SC-3 at 14-15.)

[260] The full sentence that is the source of the quote provided by Sierra Club states: "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 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." (Ex. RUCO-7 at 171.)

would justify treating CCT funding differently. (SC Br. at 24; *see* Ex. RUCO-7 at 171 n.262.) Also, Sierra Club notes, CCT payments can be viewed like workforce training programs for eliminated employee positions, which are considered a reasonable cost of doing business and recoverable in rates. (SC Br. at 24; *see* Ex. Navajo-1 at 15.)

Sierra Club further argues that there is undisputed evidence of the environmental harms to coal-impacted communities, the adverse public health impacts caused by the coal plant operations, the Tribe's economic dependence on NGS, the economic harm to the Tribe and Nation from the abrupt closure of NGS, and the future economic harm from the coal plant closures. (SC Br. at 24-25; *see* Ex. SC-3 at 7, 10-12; Ex. CG-1 at 13, 17-25; Ex. CG-3 at 25; Ex. CG-4 at 11-17; Ex. Navajo-1 at 5-7; Ex. Hopi-2 at 1-3.) In addition, Sierra Club argues, the mineral royalties and lease payments to the coal-impacted communities did not match the value of the natural resources and land used for the coal plant operations, and the coal industry crowded out other industries in the impacted areas, making those areas especially vulnerable upon closure of the coal plants. (SC Br. at 25-26; *see* Ex. CG-3 at 24-25; Ex. SC-3 at 12; Tr. at 4762.)

Sierra Club argues that the Commission should approve APS's CCT proposal in full because it is just and reasonable, providing the coal-impacted communities with limited compensation as a "stopgap" for lost coal revenues and as "seed money" to change their economies. (SC Br. at 26.) The CCT proposal is just, Sierra Club argues, because APS has a Commission-recognized obligation to help the coal-impacted communities, which have not been adequately compensated for their resources or the pollution caused by the coal plant operations, and the abrupt retirement of NGS left the coal-impacted communities insufficient time to develop transition plans. (SC Br. at 26-27; *see* Ex. SC-3 at 10; Ex. CG-1 at 17-25; Ex. CG-4 at 11-18.) The coal-impacted communities' need is urgent now, Sierra Club states, to allow transition planning for the upcoming Cholla and 4CPP retirements. (SC Br. at 27.)

Sierra Club further asserts that APS's CCT proposal should be approved so that APS can meet its commitments to the Nation made in the CCT Agreement, which was the result of extensive negotiation. (SC Br. at 27; *see* Ex. Navajo-1 at 14-15.) According to Sierra Club, the Commission's failure to honor the CCT Agreement "would send a message to rate case participants that efforts to find common ground and settle contested issues will be ignored and are not worth attempting."[261] (SC Br. at 27-28.)

Sierra Club argues that the CCT assistance approved in Decision No. 78317 was insufficient to cover the full extent of APS's CCT obligation and that the Commission acknowledged this in that decision. (SC Br. at 28; *see* Ex. RUCO-7 at 173.) Sierra Club further argues that the Commission approved the underlying principle that compensation to the coal-impacted communities should begin before coal plant retirement dates. (SC Br. at 29; *see* Ex. Navajo-1 at 10.[262]) According to Sierra Club, additional CCT assistance must be provided now because the coal-impacted communities are already experiencing the negative economic impacts from coal plant closures (as the Commission has acknowledged), and further delay will only exacerbate those impacts and impede transition of their economies. (SC Br. at 29; *see* Ex. APS-84 at 171.)

For the CCT assistance to the Tribe to be consistent with the CCT funding for the Nation proposed by APS, Sierra Club argues, the Commission should approve CCT assistance of $38.9 million in additional to APS's CCT proposal. (SC Br. at 29; *see* Ex. SC-3 at 7; Ex. Hopi-2 at 1.) Sierra Club characterizes the $2.35 million for the Tribe included in the APS CCT proposal as "a token amount" that is disproportionate to the impacts experienced and to be experienced by the Tribe, which Mr. Lomayestewa estimated at a $260 million loss in revenues over 20 years. (SC Br. at 29-30; *see* Ex. APS-8 at 28; Ex. Hopi-2 at 1, 3.) Sierra Club argues that the Tribe should receive CCT assistance proportional to the impacts it suffers and that APS's share should be calculated on a per-MW ownership basis because APS, the Nation, and the Commission have all recognized that CCT assistance is compensation for the coal power supplied to APS's service territory and part of the cost of doing business, and the Nation's President indicated that negotiations started with a total derived using a per-MW multiplier. (SC Br. at 30; *see* Ex. Navajo-1 at 14-16; Ex. RUCO-7 at 166-167.) Sierra Club argues that APS's ownership share of each coal plant can serve as a proxy for the amount of power

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[261] The Commission notes that all settlement agreements that depend on Commission approval receive scrutiny from the Commission and are subject to change by the Commission, something of which all parties to this matter should be well aware. The Commission is not a rubber stamp.

[262] The Commission did not make an express finding as to the appropriate timing of CCT assistance, other than that the assistance to the Tribe and the Navajo County Communities should be provided within 60 days after the effective date of the decision because NGS had already closed. (*See* Ex. RUCO-7 at 172.)

produced for APS's customers and for the environmental impacts caused by the generation of that power by each plant, and that using the Tribe's calculated $115,424/MW rate for CCT assistance and APS's 14% ownership in NGS (337 MW total capacity) results in $38.9 million in CCT funding for the Tribe. (SC Br. at 30-31; *see* Ex. SC-3 at 6-7; Ex. Hopi-2 at 2.) Sierra Club argues that there is no defensible reason to hold only plant operators responsible for CCT funding, as APS would do, and that all plant owners must share in CCT costs as they share in other plant-related costs, and further notes that APS does not dispute its role in NGS's closure. (SC Br. at 31; *see* Ex. APS-9 at 24-25; Ex. APS-10 at 10.) Sierra Club asserts that no party disputes the benefits to APS from NGS operations or the economic harm to the Tribe from closure of NGS and the Kayenta Mine and, further, argues that the $38.9 million of CCT support for which Sierra Club advocates would not meet the Tribe's full economic transition needs, just the portion reflective of APS's ownership interest in NGS. (SC Br. at 32; *see* Ex. APS-10 at 25.)

Additionally, Sierra Club argues that the Commission should approve CCT assistance of $20 million over 10 years for JCUSD[263] because that is the amount JCUSD has demonstrated it will experience from the closures of Cholla Units 1 and 2, for which APS is 100% responsible, and APS is obligated to provide CCT assistance as the owner and operator of Cholla. (SC Br. at 32; *see* Ex. JCUSD-1 at 8-10; Ex. JCUSD-3 at 6-7; Ex. SC-3 at 7.) Sierra Club cites the testimony of JCUSD witness Mr. Fields that JCUSD cannot fill its revenue shortfall before 2025 and would lose the ability to seek bonds for capital improvements and to develop a viable transition plan. (SC Br. at 33; *see* Ex. JCUSD-1 at 17-18.)

Sierra Club further argues that the Commission should order APS to issue RFPs for at least 1,000 MW in renewable energy projects to be located near the 4CPP, Cholla, and NGS. (SC Br. at 33, 34.) Sierra Club notes that APS's CCT proposal commits to issuing two RFPs for development of 250 MW of renewable energy projects on the Navajo Nation and another 350 MW of renewable energy projects within 50 miles of the Nation, but that the three coal plants together provided more than 5,000 MW at their peak with corresponding transmission facilities. (SC Br. at 33; *see* Ex. APS-9 at 19.)

[263] This is as opposed to the $5 million proposed by APS. (SC Br. at 33; *see* Ex. SC-3 at 7.)

Sierra Club cites Nation witness testimony that repurposing the transmission facilities and infrastructure in Nation and Tribe territory could result in lower-cost renewable energy resources for APS customers[264] and that the IRA includes a 10% tax credit adder for projects sited on or near "energy communities" such as those on the Navajo Nation or Hopi Reservation. (SC Br. at 33-34; *see* Ex. Navajo-1 at 21; Ex. SC-3 at 6, 9.) According to Sierra Club, requiring the additional RFPs for projects near the 4CPP, Cholla, and NGS would provide a "win-win" because they would bring jobs, revenue, and economic development to coal-impacted communities while also lowering resource costs for ratepayers through repurposed transmission assets and IRA tax credits. (SC Br. at 34.)

Finally, Sierra Club argues that there is no need for additional study related to the impacts of coal plant closures on impacted communities or the need for CCT assistance for those communities, as the issues have been extensively evaluated by APS and others. (SC Br. at 35-37; *see* Ex. APS-9 at Att. JT-05RB.) Sierra Club criticizes RUCO's witness for not studying the accounting of taxes, royalties, and lease payments provided by Mr. Tetlow and for proposing a two-year study process that would result in the Commission's inability to make a decision on CCT until the year Cholla is to close and criticizes Staff's witness for providing "no rational justification" for Staff's opposition to CCT funding and stating that the Commission has enough information to reject CCT funding but would need additional economic studies to approve CCT funding.[265] (SC Br. at 36-37; *see* Ex. RUCO-4 at 7; Tr. at 4479, 4484, 5204-5206; Ex. S-24 at 55.)

In its Responsive Brief, Sierra Club argues that only Staff opposes ratepayer contributions to CCT assistance in this matter, while APS, the Nation, the Citizen Groups, Sierra Club, and Vote Solar present evidence supporting approval of APS's CCT proposal.[266] (SC RBr. at 14-15; *see* CG Br. at 3-13; APS Br. at 115-116; Nation Br. at 1; SC Br. at 21; VS Br. at 17-18.) Sierra Club asserts that JCUSD has also supported its need for ratepayer-supported CCT assistance. (SC RBr. at 15; *see* JCUSD Br. at 2, 5, 7-8.) Sierra Club cites Vote Solar's assertions that ratepayers are already benefiting from cost reductions due to coal plant retirement. (SC RBr. at 15; *see* VS Br. at 17-18.) Sierra Club also argues

[264] Sierra Club also cited testimony from Mr. Tetlow noting that JCUSD has a lot of good infrastructure, transmission lines, water resources, and interstate access and is a good potential redevelopment site. (Tr. at 829.)
[265] Staff's witness advocated for additional CCT funding from ratepayers to be denied and said that additional economic studies could be useful if the Commission were to require additional ratepayer funding. (Tr. at 5204-5205.)
[266] Sierra Club seems to be forgetting RUCO.

that rejecting APS's CCT proposal in this matter would be inconsistent with Decision No. 78317 and also with current regulatory trends. (SC RBr. at 15; *see* Nation Br. at 3-4; CG Br. at 9; Ex. CG-3 at 13-17.) Additionally, Sierra Club notes the Nation's concerns about using an alternate method of funding CCT assistance, such as the Nation's taxing authority, which Sierra Club argues could subject APS's ratepayers to negative consequences. (SC RBr. at 15-16; *see* Nation Br. at 5-6.)

Sierra Club joins the Nation's argument that denying ratepayer-provided CCT funding would be arbitrary and capricious because there is not substantial evidence supporting such rejection and the Nation's argument that the CCT determination in the 2022 TEP rate case has no bearing on this matter. (SC RBr. at 16-17; *see* Nation Br. at 6.[267]) Sierra Club also joins the Nation's argument that relitigating the extent to which coal plant operations and retirements benefitted ratepayers is prohibited by *res judicata*. (SC RBr. at 17; *see* Nation Br. at 10-12.)

Sierra Club adds that Staff's position contradicts Commission precedent and is unsupported by the record and, further, was inadequately explained by Staff's witness. (SC RBr. at 18.) Sierra Club also argues that Staff did not meaningfully address or attempt to rebut the testimony of the parties supporting CCT assistance, instead resorting to speculation about potential court orders that would reverse the Commission's prior conclusion. (SC RBr. at 18; *see* Staff Br. at 62-64; Ex. RUCO-7 at 171-173.)

Finally, Sierra Club criticizes as unsupported APS's position on additional CCT support for the Tribe and JCUSD, arguing that the Tribe, JCUSD, and Sierra Club provided testimony supporting the additional CCT support and that APS provides only cursory arguments in opposition. (SC RBr. at 19; *see* SC Br. at 29; JCUSD Br. at 2, 7; Ex. JCUSD-1 at 8-10; Ex. JCUSD-3 at 6-7.) Sierra Club argues that APS's proposed CCT support for the Tribe and JCUSD "relies on statements unsupported by any testimonial or record evidence."[268] (SC RBr. at 19.) Sierra Club claims that APS's characterization of the Tribe's and JCUSD's calculations of the financial impacts of the NGS and Cholla closures as speculative is baseless and states that APS has not provided its own calculations or analysis of those

[267] We do not set out the specifics of the argument because they are consistent with those set forth by the Nation and based on the same cited sources.

[268] Sierra Club appears to disregard the explanation and calculations provided by APS in Mr. Tetlow's rebuttal testimony. (*See* SC RBr. at 19-20; Ex. APS-9 at Att. JT-04RB at 3-6.)

impacts or adequately explained its basis for challenging those analyses. (SC RBr. at 20; APS Br. at 117.) APS's claims that APS ratepayers would be providing disproportionate support if the Tribe's and JCUSD's proposals were approved are baseless, Sierra Club argues, because APS is the sole owner of Cholla Units 1 and 3, and the Tribe's CCT proposal accounts for APS's 14% interest in NGS and uses the same dollar-per-MW ratio as APS's proposed CCT funding for the Nation. (SC RBr. at 20-21; *see* SC Br. at 30-31.[269])

Vote Solar

Vote Solar asserts that APS's CCT proposal should be approved, stating that it is just and reasonable to allow recovery of CCT assistance costs that help mitigate the negative effects on coal-impacted communities from the early closures of coal plants, closures that at the same time benefit all customers through reduced costs and reduced risks (such as from increased environmental regulations). (VS Br. at 17-18; *see* Ex. VS-1 at 31-34.) Vote Solar notes the Commission's prior determinations that APS has a corporate obligation to support just and equitable transition and that APS's customers have benefited from coal plant operations. (VS Br. at 17; *see* Ex. RUCO-7 at 170, 171.)

In its Responsive Brief, Vote Solar also supports approval of the Tribe's and JCUSD's proposals for additional CCT assistance, which Vote Solar states are "[l]ike APS's proposal, . . . informed by an evaluation of the economic impact from closure of APS-owned and operated coal-fired power plants." (VS RBr. at 5-6; *see* Ex. Hopi-2 at 7-9; SC Br. at 31; JCUSD Br. at 2.) Additionally, Vote Solar supports resource procurement efforts focused on coal-impacted communities and recommends that the Commission direct APS to explore opportunities to take advantage of Infrastructure Investment and Jobs Act ("IIJA") and IRA provisions that could reduce costs for itself or its customers[270] and to file its findings in Docket E-99999A-22-0046.[271] (VS RBr. at 7; *see* Ex. VS-

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[269] As noted above, Sierra Club's Brief cites testimony from the Nation's witness that the starting point for negotiations was $100,000/MW. (*See* SC Br. at 30; Ex. Navajo-1 at 14.) Using $100,000/MW is not the methodology APS described for its calculations supporting the CCT Agreement. (*See* Ex. APS-9 at Att. JT-04RB at 1-2.)

[270] Vote Solar notes Sierra Club's recommendations for APS to be required to issue an RFP seeking an additional 1,000 MW of renewable energy resources in coal-impacted communities near the 4CPP, Cholla, and NGS to take advantage of the 10% adder to the Investment Tax Credit available for projects in "energy communities" and adds that energy resources that repurpose retired energy infrastructure such as the coal plants are eligible for low-cost loan guarantees through the U.S. Department of Energy's Energy Infrastructure Reinvestment Financing Program, meaning that they are likely to be very cost-effective. (VS RBr. at 7; *see* Ex. VS-1 at 23-24.)

[271] This is the docket for Resource Planning and Procurement in 2021, 2022, and 2023, in which APS recently filed its 2023 IRP.

1 at 23-25.)

RUCO

RUCO argues that the CCT issue is a matter of statewide concern, that a framework is needed around which CCT assistance can be justified and fairly implemented, and that no party has presented such a framework. (RUCO Br. at 35.) RUCO argues that the framework should fully address the questions set forth in then-Chairwoman Márquez Peterson's letter filed in the Generic Transition Docket on February 25, 2022,[272] which addressed, *inter alia*, how APS and ratepayers benefited, how ratepayers benefited compared to how shareholders benefited, how funds would be used by the Tribe or any other coal-impacted community, and how the recipients of funds would be subject to the Commission's jurisdiction. (RUCO Br. at 35; *see* Ex. RUCO-2 at 30, ex. FWR-21.)

RUCO also states that it supports requiring completion of an economic impact study of any fossil-based generation plant two years before scheduled closure of the plant, and requiring the Commission to retain consultants with expert legal and technical knowledge of securitization to advise the Commission, with the consultants to be paid by the utilities. (RUCO Br. at 35.[273]) RUCO argues that the coal-impacted communities received significant benefits from the coal plants and that circumstances requiring ratepayer responsibility for CCT have not been defined, explained, or justified. (RUCO Br. at 36.) RUCO argues that APS's CCT proposal is not supported by any cost-benefit or

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[272] The 13-page letter included 49 questions for coal-impacted communities and essentially called upon Staff, if it determined there was sufficient evidence to demonstrate the propriety of using ratepayer funds and a formula for quantifying those funds, to provide information supporting that determination, a plan for how the funds would be used and how recipients would facilitate a transition to clean energy, the identity of the entity that would be leading and administering the plan, proof of assent and a commitment by fund recipients to be accountable to the Commission and ratepayers, and a description of protections to ensure ratepayer funds could be used only within Arizona and for Arizonans. (*See* Ex. RUCO-2 at ex. FWR-21.) We note that RUCO filed comments in the Generic Transition Docket supporting the Chairwoman's letter and expressing doubt that the Commission had legal authority to authorize CCT support, which RUCO stated was "clearly not a cost of service." (Ex. CG-5.)

[273] RUCO states that this is consistent with Staff recommendations made in the Generic Transition Docket. (RUCO Br. at 35.) RUCO also cites to Staff's Revised Staff Report and Proposed Order in the Generic Transition Docket, which was not admitted as part of the evidentiary record in this matter. We note Mr. Radigan's testimony that Staff recommended in the Generic Transition Docket for APS and/or TEP to provide all economic impact studies performed, at least two years before commencing early closure of a fossil-based generation plant, to demonstrate economic impact on customers. (*See* Ex. RUCO-1 at 32-33.) Mr. Radigan subsequently testified that he had reviewed the list of studies cited by Mr. Tetlow and that none of them satisfied RUCO's concern. (Ex. RUCO-4 at 7.) We further note Mr. Radigan's testimony that RUCO endorsed Staff's securitization recommendation from the last APS rate case—that the Commission retain expert consultants with legal and technical knowledge in the area of securitization to advise and assist the Commission in navigating securitization issues, that the Commission require utilities to pay for the consultants, that Staff direct and control the consultants' work, and that the Commission order utilities to submit securitization plans for the Commission to review. (Ex. RUCO-1 at 34-35.)

other cost-based analysis and that the Commission needs such information to account to ratepayers for any level of CCT funding for which they are to be held responsible. (RUCO Br. at 36.) RUCO argues that an economic analysis examining who paid and who benefited from the operation of the coal plants should be performed before any CCT assistance is approved and that APS's CCT proposal should be rejected in this matter. (RUCO Br. at 36; *see* Ex. RUCO-4 at 7.)

Additionally, RUCO argues that securitization could be used to reduce costs to ratepayers for a fixed set of assets, such as the costs of providing transition assistance to coal-impacted communities. (RUCO Br. at 36.)

RUCO did not further address the CCT issue in its Responsive Brief.

<u>Staff</u>

Staff argues that the Commission should not award any further CCT assistance at this time because the Commission has not developed a policy for CCT assistance using ratepayer funds, and federal and state funding may become available for CCT assistance. (Staff Br. at 63.) Additionally, Staff cautions, the Arizona Court of Appeals recently asked all parties in the Tribe's appeal of Decision No. 78317 to identify the source of the Commission's authority to award ratepayer-funded CCT assistance, which Staff asserts makes it possible that the Court will opine on the Commission's ability to award CCT assistance funded by ratepayers as a component of utility rates. (Staff Br. at 63-64.)

In its Responsive Brief, Staff addresses the Nation's argument that it is unprecedented for Staff to review and opine on the CCT Agreement, stating that Staff and the Commission frequently review agreements that impact ratepayers because they can be a vehicle for ratepayer funding of items that the Commission otherwise would not approve. (Staff RBr. at 32.) Staff states that such settlements and agreements are subject to Commission review in rate cases such as this matter. (Staff RBr. at 32.) Staff further states that the Nation's arguments concerning *res judicata* and collateral attacks are baseless and rely upon language in Decision No. 78317 as a commitment for more CCT funding from APS and its ratepayers, although the Decision did not make such a commitment and instead stated that additional funding could be awarded based on the findings of the Generic Transition Docket. (Staff RBr. at 32,33; *see* Navajo Br. at 2, n.4.) Staff argues that its position in this matter—that ratepayers should not be charged any additional CCT costs—is consistent with Decision No. 78317 and with the more recent

Commission decision in the 2022 TEP rate case. (Staff RBr. at 32-33.)

Staff further reiterates its concern that the Court of Appeals, in the Tribe's appeal of Decision No. 78317, could find that the Commission lacks authority to require ratepayer funding of CCT. (Staff RBr. at 33.) Additionally, Staff asserts that since Decision No. 78317, the Commission has not required any additional ratepayer funding of CCT assistance.[274] (Staff RBr. at 33.)

Staff disagrees with the Citizen Groups' assertion that there is insufficient evidence in the record to deny ratepayer-funded CCT and notes that while other jurisdictions have provided CCT assistance, the funding amounts and what they covered varied in each case, with many situations involving specific enabling legislation. (Staff RBr. at 34; *see* CG Br. at 4; ex. CG-3 at 13-17; Tr. at 4151-4153.) Staff acknowledges that Sierra Club discusses in its Brief various bases for awarding ratepayer-funded CCT assistance, but argues that these methods would need to be evaluated with the goal of developing a CCT policy. (Staff RBr. at 35; *see* SC Br. at 29-32.)

Staff argues that both the Nation and the Citizen Groups make more of the language in Decision No. 78317 than was intended because the Commission did not state therein "that it was going to charge APS ratepayers for large amounts of additional CCT funding, without additional fact finding, the development of a generic CCT policy, and the funding sources available at the federal and state levels." (Staff RBr. at 35.) Staff notes that it recommended in an earlier TEP rate case that economic impact studies be undertaken by the utilities at least two years before each plant closure, and that the Commission addressed in the decision for that matter many of the points raised by the parties supporting CCT in this matter. (Staff RBr. at 35; *see* Ex. APS-84 at 114-128.)

Staff expresses doubt that the Nation could raise its tax rates to recover the lost revenues from the early closures of the three coal plants and questions whether the Nation needs the significant portion of CCT assistance attributable to the 4CPP closure, as the 4CPP will continue to operate until 2031.

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[274] This is inconsistent with the Commission's approval in Decision No. 78781 (November 21, 2022) to continue APS's Tribal Communities Energy Efficiency Program, ordered in Decision No. 77763, to serve the Tribe and Nation by providing free weatherization and energy efficiency equipment upgrades to tribal member homes and businesses and do-it-yourself weatherization training for community members, with funding of at least $1 million annually and no requirement for a cost-benefit analysis, which was subsequently expanded to include community solar, storage, electrification, and energy efficiency projects designed to benefit the community as a whole. (*See* Decision No. 78781 at 24-25, 29, 36, 38, 39.) Official notice is taken of this decision. In Decision No. 77763, the Commission stated that the Tribal Energy Efficiency Program was part of APS's corporation obligation to support a just and equitable transition of communities impacted by early power plant closures. (Ex. CG-6 at 38-39.)

(Staff RBr. at 34.)

Staff notes that the Tribe's request in the 2019 rate case was $19 million and that the Tribe's Chairman in this matter was unable to identify an amount.[275] (Staff RBr. at 34; *see* Ex. RUCO-7 at 163; Tr. at 2981.) Staff also identifies Sierra Club's brief as the source of the $38.5 million CCT amount for the Tribe. (Staff RBr. at 34-35; *see* SC Br. at 29.)

Regarding JCUSD, Staff states that no additional ratepayer-provided CCT assistance should be provided because although JCUSD provided a financial impact study, Mr. Calles acknowledged that the true impact on JCUSD is unknown and currently impossible to determine and that a number of assumptions had to be made to complete the financial impact study. (Staff RBr. at 35-36; *see* Ex. JCUSD-3 at 6; Tr. at 4224-4233.)

APS Response

In its Responsive Brief, APS asserts that the Commission should reject the arguments of those who seek to delay implementation of APS's CCT proposal, because no additional study is needed, and should reject the arguments of parties advocating for Commission approval of CCT assistance beyond APS's CCT proposal because substantial evidence does not support the additional assistance, and approving it would be inequitable to APS's ratepayers. (APS RBr. at 88-89.) APS agrees with the Citizen Groups and Nation that the evidentiary record supports a determination that CCT is an appropriate cost of service associated with retiring coal plants, similar to decommissioning or remediation, and argues that neither RUCO nor Staff has offered evidence to the contrary. (APS RBr. at 89; *see* Navajo Br. at 4-6; CG Br. at 11-13.) APS asserts that arguments about the need for additional study or a Commission policy do not justify delaying the provision of CCT support to the coal-impacted communities. (APS RBr. at 89; *see* Staff Br. at 62-64; RUCO Br. at 35-36.) APS argues that the Commission's approval of ratepayer funding for CCT in Decision No. 78317 was a determination by the Commission that the use of ratepayer funds for CCT was appropriate. (APS RBr. at 89; *see* Ex. RUCO-7 at 430-431.) APS notes that Decision No. 78317 made a number of directives related to evaluation of CCT in the Generic Transition Docket, that the Commission subsequently considered

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[275] Staff appears to have concluded that Chairman Nuvangyaoma's $500 million number was not a sincere request. (*See* Tr. at 2976.)

numerous proposals and a comprehensive report from Staff in the Generic Transition Docket, and that the Commission ultimately directed that the decision whether to adopt specific CCT proposals should be left to individual utility rate cases. (APS RBr. at 89-90; *see* Ex. RUCO-7 at 431-432; Ex. S-75.[276]) APS argues that in light of the extensive proceedings to evaluate CCT since the 2019 rate case, it is unnecessary and unreasonable to conduct further study that would delay the provision of CCT support to the coal-impacted communities. (APS RBr. at 90.)

APS argues that the Tribe and JCUSD fail to recognize that APS's CCT proposal is not intended to have customers fund nearly total replacement for the loss of revenues resulting from coal plant closures, but only to serve as a bridge to help the communities develop their economies. (APS RBr. at 90.) APS argues that the method APS used to determine its proposed CCT support, which will provide approximately two years of direct financial support corresponding to APS's ownership and operation of a coal plant, is fair and reasonable to the communities and APS's customers. (APS RBr. at 90; *see* Ex. APS-9 at 23-24, Att. JT-04RB; APS Br. at 117.) APS argues that providing the level of CCT support requested by the Tribe or JCUSD would be unfair to APS's customers and to the other community beneficiaries of APS's CCT proposal, because such support would fully replace JCUSD's funding for 10 years and, by APS's calculation, would fully replace the revenue corresponding to APS's ownership share of NGS for more than 19 years.[277] (APS RBr. at 90-91; *see* Ex. JCUSD-3 at 7; Ex. APS-9 at 3-5; Nation Br. at 7; Ex. Hopi-8.) APS reiterates that the JCUSD CCT request fails to account for PacifiCorp's ownership of Cholla Unit 4 and potential replacement generation resources at or near the Cholla site and assumes that all APS employees will leave the area upon Cholla's closure. (APS RBr. at 91; Tr. at 4224-4231.) APS also notes that the Tribe did not make a specific CCT amount request itself, although Chairman Nuvangyaoma at one point stated that the Tribe was requesting $500 million.[278] (APS RBr. at 91; *see* Tr. at 2976.) APS also argues that both the Tribe's and JCUSD's

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[276] APS also cited Staff's CCT Report and Recommendations from the Generic Transition Docket, which is not part of the evidentiary record herein.

[277] APS averaged the coal royalty and water draw payments information provided by the Tribe for 2011 through 2018 (because 2019 appeared to be an unexplained outlier), multiplied this amount by 14% to coincide with APS's ownership of NGS, and produced an annual amount just over $2 million. (APS RBr. at 91, n.505.)

[278] Due to the way this was said, the Commission does not consider this to be a sincere request from the Tribe. When asked to quantify the Tribe's request, Chairman Nuvangyaoma stated: "I'll throw 500 million out there, but I'm not sure if it will be received." (Tr. at 2976.)

CCT requests would rely entirely on APS and its ratepayers for CCT support, without regard to other potentially responsible entities. (APS RBr. at 92.)

Resolution

The issue of CCT support for coal-impacted communities is as difficult now as it was in the 2019 rate case, perhaps more so because of the lackluster outcome of the Generic Transition Docket.[279] There is no question that the coal-impacted communities have experienced both adverse environmental impacts and sustained economic benefits as a result of the coal plant operations. Nor is there any question that APS, PNW and its shareholders, and ratepayers have benefited from the coal plant operations—the coal plant operations have been profitable for APS and PNW and its shareholders, and APS ratepayers have received significant baseload electric service from the coal plants over many years. Likewise, there is no question that each of the coal-impacted communities that has requested CCT assistance in this matter has lost or will be losing a significant revenue stream as a result of early coal plant closures and has or will have a need for financial assistance to transition away from a coal-based economy.

Additionally, the Commission has determined and continues to believe that it has the legal authority, under Arizona Constitution, Article 15, § 3, to require ratepayer funding of CCT assistance, as it does to require ratepayer funding for reclamation and decommissioning costs and the costs of what are essentially welfare programs to benefit utility ratepayers (such as APS's limited income discount and crisis bill assistance programs).

What the Commission has been unable to resolve, however, is the extent to which ratepayer funds should be used to support CCT assistance. This issue was raised in the 2019 rate case, and it continues to exist in this matter, in spite of the extensive evidence and argument presented on the CCT issue. Effectively, nothing has changed since the Commission stated in Decision No. 78317 that "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)." (Ex. RUCO-7 at 170.) None of the evidence presented in this matter, regardless of by whom, establishes why it is fair for ratepayers to

[279] We are also disappointed that there has been no apparent progress in additional funding sources being provided by Congress or the Arizona State Legislature.

bear the brunt of the financial assistance to the coal-impacted communities (in the 2019 rate case, the proposed ratepayer-funded share was approximately 80% of the financial assistance to the Nation and approximately 91% of the financial assistance to the Navajo County Communities and the Tribe). (*See* Ex. RUCO-7 at 170.) The Commission views RUCO's and Staff's recommendations as reflective of a desire to obtain justification for ratepayers to bear the vast majority of the burden. Those parties who argue that *res judicata* and collateral estoppel would be violated by requiring further examination of these issues are mischaracterizing the Commission's determinations in Decision No. 78317 and missing the point (intentionally or not)—the Commission has been and continues to be unable to determine what is a fair share of CCT financial assistance to impose upon ratepayers. The issue was not resolved in Decision No. 78317 for any situation beyond what was approved in Decision No. 78317. As we reminded in the 2022 TEP rate case, the resolution of an issue in a rate case decision does not create a precedent or amount to adoption of a statewide policy; it is specific to the facts and evidence in that rate case. (*See* Ex. APS-84 at 126.)

In the end, the Commission concludes, because it must under the circumstances, APS has not established by a preponderance of the evidence that its ratepayers should be held responsible for payment of the CCT assistance in the CCT proposal. Likewise, neither the Tribe nor JCUSD has established by a preponderance of the evidence that APS's ratepayers should be held responsible for the CCT assistance each proposes (assuming that the Tribe can be characterized as having proposed a specific amount of CCT assistance).[280] The Commission finds that it would be unjust and unreasonable for the Commission to require APS ratepayers to fund additional CCT assistance at this time. This resolution will please no one, the Commission included, but it is the only resolution supported by the evidentiary record herein.

E. Liquidated Damages Costs from Coal Purchase Agreements

<u>The 4CPP</u>

The coal supply for the 4CPP is obtained from NTEC's Navajo Mine, which is a mine mouth operation, meaning that the mine is directly adjacent to the 4CPP and no external transportation is

[280] As to their separate requests for CCT assistance, the Tribe and JCUSD are effectively applicants and thus bear the burden of proof. (*See* A.A.C. R14-3-103(B); A.A.C. R14-3-109(G).)

required or available for coal delivery. (Staff Br. at 64-65; *see* Tr. at 5406-5407; Ex. APS-93.) Under the 4CPP Coal Supply Agreement ("4CPP CSA"), as amended in 2021,[281] APS is obligated to pay for a specified minimum quantity of coal for the 4CPP each year whether the coal is delivered to and burned at the plant or not.[282] (Tr. at 1441-1442.) Mr. Joiner testified that having a minimum purchase obligation for coal is "very standard" when a plant is nearing end of life, because the coal producer needs to be able to rely on a level of income to operate, and APS has not had any trouble meeting its minimum purchase obligation in recent years because of the need for energy from the 4CPP. (Tr. at 1442-1444, 1446, 1524-1525.) Likewise, Mr. Bogle testified that the minimum take obligation in the 4CPP CSA is meant to provide the Navajo Mine a stable level of revenue to sustain its day-to-day mining operations and ongoing reclamation,[283] which ensures that APS has a long-term and stable fuel supply.[284] (Tr. at 5417.) To meet the minimum take obligation, the 4CPP Units need to be operated with approximately a 67% capacity factor, which Mr. Bogle stated is realistic and has been achievable in most years. (Tr. at 5417-5418.) In 2021, APS paid a substantial liquidated damages payment to NTEC for the 2020/2021 contract year (June 1, 2020, through May 31, 2021).[285] (Tr. at 1447, 5424, 5498, 5528, 5547; Ex. S-25 at 6-9.) Mr. Bogle attributed the liquidated damages to unplanned outages in the 2020/2021 contract year, stating that the COVID pandemic impacted 4CPP by making unplanned outages longer,[286] due to labor shortages and restrictions imposed to ensure worker health and safety. (Tr. at 5425-5426, 5481, 5530.) APS reports that the Navajo Mine is the lowest cost source of coal for the 4CPP and that the 4CPP has been a vital resource for APS customers over the past three summers.

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[281] A summary of the changes made to the CSA through the 2021 amendment is included in Exhibit APS-106, which has been designated highly confidential. The 4CPP CSA, with amendments, is included in Exhibit S-34, which has been designated highly confidential.

[282] Mr. Bogle verified that the CSA has had a "minimum take" provision going back to at least 2010; coworkers have informed him that there was such a provision even before 2010. (Tr. at 5416-5417.)

[283] There are two levels of reclamation that occur and will occur at the 4CPP—ongoing reclamation that is done as mining is conducted, and a final reclamation once all mining is done. (Tr. at 5419.) APS audits the ongoing reclamation at the Navajo Mine to ensure that the final reclamation costs are minimized. (Tr. at 5499, 5561.)

[284] In 2018, APS participated in a study with NTEC to determine the actual mining operational costs at the 4CPP, and the minimum take levels were based on those actual costs. (Tr. at 5418-5419.)

[285] The amount paid in liquidated damages was identified by APS in Exhibit APS-105, which has been designated highly confidential. It is also included in the highly confidential portion of Exhibit S-25. The liquidated damages for the 2020/2021 contract year were recorded in Account 501, which is one of the accounts included in the PSA, and would have been included in the associated annual PSA calculation for that period. (Tr. at 5530, 5541.)

[286] The unplanned outages did not result in the 4CPP having an EAF outside of Department of Energy guidelines. (Tr. at 5426-5427, 5463, 5481; *see* Ex. S-70 at 1-13, 1-14.) The most recent Fuel and Purchased Power Audit also found that equivalent forced outage factors for the 4CPP Units were generally in line with industry experience. (Ex. S-70 at 1-12.)

(Tr. at 1461, 1524-1525, 5407-5408.) APS further asserts that it is not feasible for APS to mitigate the potential liquidated damages for the 4CPP by selling off any extra Navajo Mine coal because there is no rail line to transport the coal elsewhere. (Tr. at 5459.)

Cholla

APS is the owner of Cholla Units 1, 2, and 3, and PacifiCorp is the owner of Cholla Unit 4; only Cholla Unit 3 is still operating, as Units 1, 2, and 4 have been retired.[287] (Ex. S-14 at 11.) APS obtains coal for Cholla Unit 3 from the El Segundo Mine owned by Peabody COALSALES, LLC ("Peabody"), an affiliate of Peabody Energy Corporation, under a 2005 CSA[288] amended in 2013,[289] 2017,[290] and 2018.[291] (*See* Ex. S-14 at 11-12; Ex. S-37; Tr. at 5428.) The El Segundo Mine is located in New Mexico, not in the vicinity of Cholla, so the coal from the mine is transported by train to Cholla. (Tr. at 5428-5429.) The CSA, as amended, provides for APS to make liquidated damages payments to Peabody if APS fails to take specified minimum amounts of coal each year.[292] (Ex. S-37 at 45-46.)

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[287] APS closed Unit 2 in October 2015 to meet EPA emissions reduction mandates; APS was also required by the EPA to commit to closing Cholla Units 1 and 3 by 2025. (Tr. at 5440.) APS could have opted to reduce emissions by installing additional emissions equipment at an estimated cost of approximately $200 million. (Tr. at 5440-5441.) PacifiCorp closed Cholla Unit 4 in 2020. (Ex. RUCO-7 at 136.)

[288] The Cholla CSA, with amendments, is included in Exhibit S-37, which has been designated highly confidential. Peabody set the original 2005 CSA costs and shortfall amounts based on the operations of Cholla Units 1 through 4. (Ex. S-37 at 1; *see* Tr. at 5433-5436.) The 2006 Fuel and Purchased Power Audit reviewed the CSA and determined that the El Segundo Mine provided the least cost coal supply for Cholla and that the provisions of the CSA were reasonable and standard for the industry. (Tr. at 5434-5436; Ex. APS-113.)

[289] APS was able to obtain lower shortfall volumes related to liquidated damages in the 2013 amendment, and those shortfall volumes have been maintained in the current CSA as amended. (Tr. at 5437, 5439.) A 2017 Fuel and Purchased Power Report concluded that the Cholla CSA with the 2013 amendment provided the lowest cost option for customers at the time and was reasonable and in line with industry standards. (Tr. at 5438-5439; Ex. APS-114 at ex. A.)

[290] APS entered into negotiations for the 2017 CSA Amendment because the Unit 2 closure would reduce coal consumption at Cholla and because Peabody had declared bankruptcy. (Tr. at 5441-5442.) Before entering into the 2017 CSA Amendment, APS evaluated alternative potential sources of coal for Cholla and determined that of the six different mines that could potentially serve Cholla, the El Segundo Mine had the lowest total delivered cost. (Tr. at 5443-5444; *see* Ex. APS-116 (highly confidential).) Exhibit APS-107 summarizes the changes in the 2017 CSA Amendment, which was entered into as the result of a settlement agreement, and has been designated highly confidential. Exhibit APS-115 recounts the offers made by both sides during negotiation of the 2017 CSA Amendment and has also been designated highly confidential. Mr. Bogle testified that if the CSA had been terminated instead of renegotiated, APS would have been required under the CSA to pay final reclamation costs and also would have needed to procure coal under a new contract, which combined did not provide a realistic economic option. (Tr. at 5549.)

[291] The 2018 amendment involved a price adjustment initiated by Peabody pursuant to the terms of the CSA. (*See* Ex. S-37.)

[292] Under the 2017 CSA Amendment, liquidated damages can arise from not meeting an annual minimum take obligation of 850,000 tons, which approximates a 47% capacity factor and is achievable on an annual basis, and from not meeting the separate shortfall volume, which is set at a level that cannot be met by the plant. (Tr. at 5451-5452, 5493-5496, 5504.) APS has not incurred any liquidated damages associated with the minimum take obligation. (Tr. at 5452, 5510, 5547.) In the 2017 CSA Amendment, APS obtained a 25% decrease in the liquidated damages amount to be paid due to not meeting the shortfall volume. (Tr. at 5453, 5549.)

APS incurred liquidated damages related to Cholla coal purchases in 2020, 2021, 2022, and 2023.[293] (Ex. S-46; Ex. S-47; Tr. at 1459-1460.) Mr. Joiner testified that the amounts paid were required by the CSA and were necessary for the continued reliable and safe operations of the El Segundo Mine. (Tr. at 1461.) Mr. Joiner and Mr. Bogle both testified that the Cholla Plant has been a vital resource for APS customers during recent summers. (Tr. at 1461, 5455.) APS reports that the El Segundo Mine is the lowest cost source of coal for Cholla because the next most appropriate coal supply would need to be transported by train from Wyoming and could only be used in a blend with El Segundo Mine coal unless engineering charges were made at Cholla.[294] (*See* Tr. at 1525, 5429-5430, 5456.) The costs included in the CSA for El Segundo Mine coal are designed to cover not only ongoing costs but also reclamation costs; APS has no obligation for final reclamation costs after the end of the CSA.[295] (Tr. at 5433, 5494-5495.) When compared to the reclamation costs APS experienced with the NGS, Mr. Bogle stated, the Cholla shortfall costs represent reasonable reclamation costs.[296] (Tr. at 5454.) Mr. Bogle further stated that APS's decision to close Cholla Unit 2 early even though that would result in shortfall volume charges was an economic decision that saved ratepayers money based on the $200 million capital improvement necessary to keep Cholla Unit 2 open, as compared to reclamation costs in the range of $60 million, and that APS's entering into the 2017 CSA Amendment was a prudent decision that has benefitted APS customers. (Tr. at 5454-5457.)

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[293] APS provided the invoices showing the liquidated damages amounts for 2021 and 2022, and an estimated amount of liquidated damages for 2023, in Exhibit APS-104, which has been designated highly confidential. The liquidated damages amounts incurred in 2020 through 2022 were provided in Exhibit S-46, which is designated confidential, and the liquidated damages amounts recorded for the first two quarters of 2023 were provided in Exhibit S-47, also designated confidential. (*See* Ex. S-46; Ex. S-47.) APS expects to pay liquidated damages associated with the shortfall volume again in 2024 and 2025. (*See* Tr. at 5509-5510.) The liquidated damages incurred and to be incurred are associated with the shortfall volume, not the annual minimum take obligation, and are intended to cover final reclamation costs. (Tr. at 5453, 5505, 5547.) Mr. Bogle acknowledged that the liquidated damages amounts paid in 2020 and 2021 were substantial and that those to be paid in 2023 are also likely to be substantial, in the amount of several million dollars. (Tr. at 5505, 5512.) The liquidated damages payments for any year in which they are incurred are recorded as a purchased power expense, in Account 501, which is one of the accounts included in the PSA. (Tr. at 5506, 5514, 5541; Ex. S-46; Ex. S-47.)

[294] APS periodically evaluates whether there are other coal supplies that would be more economic but has found that there are not. (*See* Ex. APS-93; Tr. at 5428-5430.)

[295] Mr. Bogle testified that the tonnage included as the shortfall amount is more than Units 1 and 3 could burn in a year, which demonstrates that the shortfall provisions are intended to cover reclamation costs for Units 1, 2, and 3. (Tr. at 5449, 5553-5558.) At the end of the CSA, APS has no final reclamation cost obligation. (Tr. at 5559.) If APS had terminated the CSA rather than renegotiating to attain the 2017 CSA Amendment, APS would have incurred termination damages, effectively having those shortfall amounts transitioned into termination damages. (Tr. at 5450, 5455-5456.)

[296] Final reclamation costs for the 4CPP are handled very differently; they are not built into the CSA but instead are collected in a "bucket of accrued dollars." (Tr. at 5496-5497.)

APS asserts that there is currently no opportunity to sell off extra El Segundo Mine coal that cannot be used at Cholla because TEP is the only entity also using El Segundo Mine coal,[297] TEP has its own contract minimum volume for the coal, and the plant at which TEP uses the coal (Springerville) is similarly situated to Cholla in terms of impending retirement. (Tr. at 5459-5460.) Nonetheless, APS communicates with TEP about any sale opportunities and also monitors the market to see if it is possible to liquidate coal. (Tr. at 5460.) Additionally, once APS meets its minimum take obligation for a current year, as it did in 2022, APS pulls forward coal deliveries that count toward the shortfall volume for the next year, to avoid back-loaded obligations under the contract, which could be exacerbated by any future operational issues at Cholla that result in the use of less coal. (Tr. at 5460-5462.) Also, until the minimum take obligation is met for each plant, APS includes the liquidated damages forecast for the plant when making its economic dispatch decisions. (Tr. at 5464-5466; *see* Ex. APS-108.)

<u>APS Position</u>

APS asserts that the Cholla 2017 CSA Amendment created significant benefits for ratepayers because (1) it separated the CSA minimum purchase obligations into the minimum take, which addresses mine operating and capital costs, and the shortfall volume, which is intended to recover long-term reclamation expenses for the El Segundo Mine; (2) it substantially reduced the payments associated with not meeting the shortfall volume obligation; and (3) it capped the extent of future price increases resulting from any future contract price reopening processes. (APS Br. at 122-123; *see* Ex. APS-115; Ex. APS-107; Tr. at 5448-5449, 5453-5454.) APS argues that it could not have avoided these reclamation costs in CSA renegotiations or through CSA termination because the costs would have been included in contract termination penalties. (APS Br. at 123; *see* Tr. at 5449.) Further, APS asserts, it has benchmarked the liquidated damages and determined that they represent reasonable mine reclamation expenses associated with comparable coal volumes. (APS Br. at 123-124; Tr. at 5454.) APS notes that the minimum take provisions at Cholla have never triggered liquidated damages and

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[297] Staff asserts that Arizona Electric Power Cooperative, Inc. ("AEPCO") also uses El Segundo Mine coal in its operations. (Staff Br. at 69; Tr. at 4961.) AEPCO is a Class A generation and transmission cooperative that serves six Class A distribution cooperative members. (Decision No. 78965 (May 9, 2023) at 7.) Most of the energy supplied by AEPCO is generated at the Apache Generating Station, which has both coal-fired and natural gas-fired capacity. (*Id.* at 8.) Official notice is taken of Decision No. 78965. Mr. Bogle testified that he believed the Apache Generating Station had closed. (*See* Tr. at 5511-5513.)

argues that the reclamation costs included in the liquidated damages triggered by the shortfall volumes are an appropriate and necessary cost of service associated with coal-fired power plants and that the 2017 CSA Amendment was reasonable and in the best interest of customers. (APS Br. at 124; *see* Tr. at 4962-4963, 5452.)

APS also asserts that the 2021 Amendments to the 4CPP CSA, made to accommodate the sale of PNM's interest to NTEC, created significant and tangible customer benefits because of the increased plant operating flexibility available through seasonal operations.[298] (APS Br. at 124-125; *see* Tr. at 5409-5410.) The 2021 amendments did not change contract pricing, minimum purchase terms, or liquidated damage expenses. (APS Br. at 124-125; *see* Tr. at 5409-5410; Ex. APS-106.) APS states that the operational flexibility from seasonal operations at the 4CPP has the potential to save customers substantial costs in future years when natural gas and purchased power costs are lower and less volatile, even when the liquidated damage payment obligation is taken into account. (APS Br. at 125; *see* Ex. APS-109; Ex. APS-110; Tr. at 5410-5412.) Further, APS argues, the 4CPP coal supply costs have been reasonable and consistent with increased plant output over the last few years. (APS Br. at 125.) The 4CPP CSA uses a defined set of U.S. Bureau of Labor Statistics pricing indices to set pricing, and a third-party audit of those indices in 2021 found that the production costs associated with actual Navajo Mine operations are within 1% of the pricing dictated by the indices in the 4CPP CSA. (APS Br. at 125; *see* Ex. APS-111; Tr. at 5420-5421, 5539-5540.) APS attributes the higher 4CPP fuel costs in 2022 to increased plant operation (because it was a more economic option compared to alternatives) as well as the high levels of inflation captured in the pricing indices. (APS Br. at 125-126; *see* Ex. APS-47; Tr. at 5422-5424.) APS argues that the minimum take obligations and the associated liquidated damages charges in the 4CPP CSA are reasonable and appropriate, and points out that APS has been able to meet the minimum take obligations except in the 2020/2021 contract year. (APS Br. at 126; *see* Tr. at 5417-5420, 5424-5426.)

Mr. Bogle testified that if the Commission were to determine that ratepayers should not be required to pay some of the liquidated damages expenses, the appropriate place to make any adjustment

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[298] The Commission's understanding is that it is the 4CPP operating agreement, not the CSA, that allows for seasonal operations.

would be in the uncollected PSA balance in the next PSA annual update in February, not in the base cost of fuel to be set in this matter,[299] because the base cost of fuel is more of a forward-looking mechanism while the PSA balance recovers expenses that have already been incurred. (Tr. at 5533-5535.)

Staff Position

Staff's position is that unless there is a compelling reason for ratepayers to pay liquidated damages (described by Staff as "costs for coal that was not delivered or utilized in the provision of providing electric utility service"), the costs should be disallowed. (Staff Br. at 64; Ex. S-24 at 58.) Staff acknowledges that APS incurred liquidated damages for the 4CPP 2020/2021 contract year but has not incurred any liquidated damages for the 4CPP since; that APS periodically evaluates whether it is possible to obtain coal from an alternative source and has concluded that a more economic source for coal does not exist because coal cannot be transported to the 4CPP by rail; that the minimum take provision in the 4CPP CSA dates back to at least 2010; that Mr. Bogle testified the minimum take provision is meant to provide the Navajo Mine a stable level of revenue to sustain its day-to-day operations and ongoing reclamation; that the pricing indices used to escalate the 4CPP clean coal prices in the CSA were determined in a third-party audit report to be accurate in relation to actual production costs; and that APS's analysis shows the actual costs to operate the 4CPP and Cholla in 2020 through 2022 and partial year 2023 were significantly lower than the market replacement costs, underscoring the physical hedge value of both the 4CPP and Cholla. (Staff Br. at 65-67; *see* Ex. APS-24 at 58, Att. RCS-12 at 3; Ex. APS-47; Tr.at 5407-5408, 5416-5417, 5421-5422.) Staff seems to take issue with APS not taking steps to avoid incurring liquidated damages for the 4CPP during the 2020/2021 contract year due to the COVID pandemic, which Staff suggests "would . . . represent an extreme and unusual event that could have provided a basis for avoiding substantial amounts of liquidated damage charges during that coal contract year." (Staff Br. at 68; *see* Tr. at 5425, 5481, 5498.) Further, Staff asserts that when the 4CPP CSA is being amended to deal with the transfer of PNM's ownership share to

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[299] Mr. Bogle was not sure what amount of liquidated damages were included in APS's proposed base cost of fuel in this matter but believed that some level of forecasted damages were included. (Tr. at 5530-5531, 5541.)

NTEC,[300] APS and the other non-NTEC owners should proactively address the minimum take provision to ensure that seasonal operation would not trigger liquidated damages. (Staff Br. at 68.) Staff does not recommend any disallowance of the 4CPP liquidated damages expense, instead stating that "if the Commission believes . . . APS has failed to justify . . . some or all of the liquidated damages amounts that APS paid to coal supplies for coal that was contracted for but not required, Staff recommends that those amounts be removed from APS's deferred fuel balance and not charged to ratepayers."[301] (Staff Br. at 69.)

Staff asserts that concerns regarding liquidated damages under the Cholla CSA were first raised in a prior fuel audit conducted by Larkin & Associates and Energy Ventures Analysis, because the auditors were unable to obtain the economic analyses performed by APS before it entered into the 2017 CSA Amendment. (Staff Br. at 70; *see* Tr. at 4951.) According to Staff, the auditors concluded, based on the contract minimums, that the liquidated damages represented a buy-down from the original contract volumes. (Staff Br. at 70; *see* Tr. at 4951-4952.) Staff asserts that the auditors were not concerned about the buy-down itself, because a buy-down is not unusual, but were concerned by APS's failure to justify to the Commission the negotiated coal delivery quantities and liquidated damages in 2021 and 2022 and to be incurred in 2023. (Staff Br. at 71; *see* Tr. at 4955-4956.) Staff argues that APS's two-part explanation (that the liquidated damages amounts are intended to ensure Peabody has enough money to continue operating the mine and cover additional costs, and that APS uses economic dispatch for its generating fleet and PPAs[302]), did not satisfy the auditors' concern that APS had not maintained documentation concerning the economic analysis relating to the 2017 CSA Amendment and the resultant costs and minimum quantities, including how APS evaluated the buy-down and the annual quantities of coal APS reasonably expected to burn at Cholla each year through the life of the plant. (Staff Br. at 72; *see* Tr. at 4954.) According to Staff, Mr. Joiner acknowledged that APS was shouldering a disproportionate share of the buy-down costs in the Cholla CSA as compared to

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[300] This seems to assume that the 2021 CSA amendments will become void and that PNM will once again attempt to gain regulatory approval for the sale to NTEC after that.

[301] Although Staff's recommendation does not clarify how its recommendation should be realized if adopted, we understand Staff's recommendation to be for any such disallowance to be made in a PSA proceeding, not in this matter.

[302] Economic dispatch means that the least cost unit is called on first to meet load requirement at any given time. (Staff Br. at 71; *see* Tr. at 4954.)

PacifiCorp, meaning that APS ratepayers are paying a portion of PacifiCorp's buy-down costs.[303] (Staff Br. at 72; *see* Tr. at 5493-5494.) Staff also criticizes Mr. Joiner for not addressing to what extent mitigating factors were considered[304] and Mr. Bogle for failing to explain what efforts APS took to investigate whether APS could have sold to another buyer coal that APS knew it could not use at Cholla.[305] (Staff Br. at 72-73; *see* Tr. at 4956-4957.) Staff also appears to criticize APS for not shifting coal deliveries into a future year to avoid incurring liquidated damages in a given year, but also acknowledges that this probably would have been unrealistic due to the Cholla closure date. (Staff Br. at 74; *see* Tr. at 4958.) Staff states: "If justification is not provided that shows what [APS] tried to do and the results of those attempts to mitigate the impact of the liquidated damages and that those payments were not wasteful, Arizona ratepayers should not absorb all of these costs." (Staff Br. at 73; *see* Tr. at 4959.) Staff states that APS has the burden of proof to show that it reasonably evaluated the minimum take obligations in the CSA and how and whether it considered the likelihood of incurring liquidated damages when entering into the CSA. (Staff Br. at 73-74.) Staff argues that APS has failed to show that the costs for the Cholla coal have been economical during the period reviewed, when the liquidated damages amounts are considered. (Staff Br. at 74.) Staff acknowledges that APS used an RFP process to solicit the original 2005 CSA for Cholla; that the Fuel Audit Report completed in 2006 found that the 2005 CSA provisions were reasonable and the lowest cost option for customers; and that a subsequent Fuel Audit Report completed in 2017 found that the CSA with the 2013 CSA amendment provided the lowest cost option at the time and was reasonable and in line with industry standards. (Staff Br. at 73-74; *see* Ex. APS-113; Ex. APS-114; Tr. at 5434-5439.) Regarding the 2017 CSA Amendment, Staff acknowledges that APS compared prices with delivery from six different mines, all of which would have cost more than El Segundo Mine; that APS evaluated additional risks posed by the next cheapest option, which were significant enough to eliminate it from consideration; that APS provided a breakdown of the offers made between APS and PacifiCorp vs. Peabody concerning the 2017 CSA Amendment; and that Mr. Bogle cited three benefits to customers obtained by APS in the

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[303] We note that the testimony cited by Staff is from Mr. Bogle and did not include this type of statement or information that could cause one clearly to reach this conclusion. (*See* Tr. at 5493-5494.)

[304] We note that Mr. Bogle addressed questions related to mitigation of liquidated damages costs. (*See* Tr. at 5458-5467.)

[305] Staff asserts that the BNSF rail line that serves Cholla also serves TEP's Springerville plant and AEPCO's Apache plant. (Staff Br. at 73; *see* Tr. at 4957-4958.)

2017 CSA Amendment.[306] (Staff Br. at 75; *see* Tr. at 5443-5446, 5448; Ex. APS-115; Ex. APS-116.)

Staff appears to dispute Mr. Bogle's characterization of the shortfall-related liquidated damages as being for reclamation costs, noting that the CSA itself does not state this. (Staff Br. at 75; *see* Tr. at 5505.) Staff also asserts that it first raised issues about the 2017 CSA Amendment in 2021, "at which time APS declined to provide any justifications," and that although Mr. Bogle provided more justification and information in line with what Staff desired to see, his testimony "ultimately did not justify the full Cholla liquidated damage amounts as being prudently incurred." (Staff Br. at 76.) Additionally, Staff doubles down on its prior statement that Mr. Bogle "confirmed . . . that APS customers were paying a disproportionate share of the liquidate[d] damages that appropriately were the responsibility of PacifiCorp." (Staff Br. at 76.[307]) Staff expresses concern that APS cannot avoid paying liquidated damages under the Cholla CSA even if Units 1 and 3 are run continually at maximum capacity and that APS will continue to incur significant amounts of liquidated damages in 2023 and 2024 and until Cholla is retired in 2025. (Staff Br. at 76.) Staff erroneously states that the two minimum coal purchase levels in the 2017 CSA amendment correspond to a 47% capacity factor and a 67% capacity factor. (Staff Br. at 76-77; *see* Tr. at 5493,[308] 5546.) Staff repeatedly asserts that PacifiCorp negotiated a higher proportional reduction in its shortfall volume obligation than APS did in the 2017 CSA Amendment and provides numbers intended to support that and that PaciCorp negotiated different and more favorable terms than APS did. (Staff Br. at 77-79; *see* Tr. at 5493;[309] Ex. APS-115.[310])

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[306] These three benefits were (1) that the shortfall volume was separated into a separate minimum take amount and a shortfall volume, (2) a discount on the shortfall volume liquidated damages price of 25%, and (3) capping the maximum increase for the 2018 price reopener at 7%. (Tr. at 5448.) The 2017 CSA Amendment also expressly set forth the separate minimum take amounts and shortfall volumes for APS and PacifiCorp. (*See* Ex. S-37 at 40, 46.)

[307] This time, Staff does not provide a citation for this statement. Our review of Mr. Bogle's testimony revealed no such statement.

[308] Mr. Bogle misspoke at page 5493, attributing the 67% capacity factor to Cholla, and subsequently corrected himself at page 5546, clarifying that he was actually talking about the 4CPP. (*See* Tr. at 5493, 5546.)

[309] As stated previously, Mr. Bogle did not say this. The numbers cited by Staff, which came directly from Mr. Bogle's testimony, do not support Staff's conclusion. (*See* Staff Br. at 78; Tr. at 5493-5494.) Mr. Bogle testified that APS ended up with an obligation for 2.25 million tons or "2.3 million-ish approximately" tons of the 3.55 million tons. (*See* Tr. at 5493, 5522.) Additionally, Exhibit S-37 shows the breakdown of the 3.55 million tons and does not support that APS's share is disproportionate to its ownership share or disadvantageous when compared to what was allocated to PacifiCorp. (*See* Ex. S-37 at 46.)

[310] Exhibit APS-115 does not support Staff's assertion that PacifiCorp negotiated different and more favorable terms because the summary shows the same terms applicable to both owners. (*See* Ex. APS-115.)

Staff concludes that APS has not adequately justified why the Cholla liquidated damages represent a reasonable and prudently incurred cost that should be paid by ratepayers. (Staff Br. at 79.) "Staff recommends that only the liquidated damages based upon APS's pro-rata share, rather than based upon the additional minimum quantity obligation that shifted to APS upon PacifiCorp's retirement of Cholla unit 4, be recoverable."[311] (Staff Br. at 79.) Staff states that if the Commission agrees that APS has failed to justify some or all of the liquidated damages amounts paid to coal suppliers for coal that was contracted for but not required, those amounts should be removed from APS's deferred fuel balance and not charged to ratepayers.[312] (Staff Br. at 79.)

In its Responsive Brief, Staff reiterates its arguments related to the Cholla liquidated damages, although Staff focuses more heavily on the annual minimum take provision than it had in its Brief and asserts that any liquidated damages incurred by APS for the additional annual minimum take obligation of 100,000 tons per year are "patently unreasonable and under no circumstances should be borne by APS's ratepayers."[313] (*See* Staff RBr. at 12-15.) Staff recommends that some or all of the amounts APS paid to Peabody for Cholla liquidated damages, particularly amounts for liquidated damages related to the additional 100,000 tons minimum take obligation, be found unreasonable or wasteful and be removed from APS's deferred fuel balance and not charged to ratepayers. (Staff RBr. at 16.)

<u>APS Response</u>

In its Responsive Brief, APS asserts that there is no support in the record for Staff's position that costs were shifted to APS upon PacifiCorp's retirement of Cholla Unit 4 or that any of the liquidated damages costs under the Cholla CSA should be disallowed. (APS RBr. at 94.) According to APS, all of the costs incurred by APS under the Cholla CSA were reasonable and prudent, and none should have been allocated or attributed to PacifiCorp. (APS RBr. at 94-95.) APS argues that Staff's assertion that APS ratepayers are paying for coal that is not being used to provide them service is false

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[311] Staff does not identify what amount Staff believes this to be.

[312] Although Staff did not say so, we believe that Staff intends for this to happen through an adjustment to the PSA deferred balance in a PSA matter, not through an adjustment that would impact base rates set in this matter.

[313] The 2017 CSA Amendment provided that if PacifiCorp were to terminate its obligation under the Agreement for Unit 4, APS's annual minimum take would increase by 100,000 tons, from 750,000 tons to 850,000 tons. (*See* Ex. S-37 at 40.) This occurred when PacifiCorp retired Unit 4, resulting in an 850,000 ton annual minimum take for APS. (Tr. at 5522.) We note that the 2017 CSA Amendment also calls for APS's annual minimum take to be reduced by specified percentages in the event APS terminates Unit 1 and/or 3 and that the two percentages add up to 100%. (*See* Ex. S-37 at 40.) Further, we note that the annual minimum take provision has not resulted in any liquidated damages for APS. (Tr. at 5510.)

and that Staff appears to misunderstand the structure of the Cholla CSA, which involves both shortfall volumes tied to mine reclamation expenses and separate minimum take obligations that are tied to minimum mine operating expenses needed to ensure a stable fuel supply for Cholla. (APS RBr. at 95; *see* Tr. at 5449-5452.) APS explains that APS's shortfall volume is 2,248,570 tons[314] and that its minimum take obligation is 850,000 tons and reiterates that it has not incurred any liquidated damages associated with the minimum take obligation, which represents an achievable 47% capacity factor. (APS RBr. at 95-96; *see* Tr. at 5449-5452, 5493-5494.) APS also argues that the liquidated damages incurred, which relate to the shortfall volume, represent reclamation costs associated with coal purchased by APS and consumed at Cholla throughout the life of the CSA that dates back to 2005. (APS RBr. at 95.) APS further claims that Staff's proposals for mitigation of the liquidated damages expenses were infeasible, as Staff acknowledged for pushing back purchase obligations to future years, and argues that Staff disregarded Mr. Bogle's testimony about APS's actual mitigation efforts, which include accelerating purchases from future years to reduce liquidated damages and using economic dispatch that takes into account liquidated damages. (APS RBr. at 96-97; *see* Tr. at 5458-5462; Staff Br. at 72-73.) Additionally, APS characterizes as meritless Staff's argument that APS has been required to pay liquidated damages from shortfall volumes that should have been attributed to PacifiCorp, pointing out that the 2017 CSA Amendment separated the shortfall volume obligations by utility and that APS's and PacifiCorp's shares of the shortfall volumes were determined based on their respective capacity ownership at Cholla—with APS owning and being allocated 63% (i.e., 2,248,570 tons) and PacifiCorp owning and being allocated 37% (i.e., 1,301,430 tons). (APS RBr. at 97-98; *see* Tr. at 5551-5552; Ex. S-37 at 46.) APS argues that there is no evidence in the record to indicate that PacifiCorp received more favorable terms under the 2017 CSA Amendment. (APS RBr. at 98.) Further, APS argues, Staff's concern with the additional 100,000 tons added to APS's minimum take obligation after PacifiCorp retired Unit 4 is misplaced because the minimum take is intended to cover El Segundo Mine operating expenses, and APS has never incurred liquidated damages associated with this minimum take obligation, meaning that it has had no impact whatsoever on APS or its customers.

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[314] Mr. Bogle rounded this to 2.25 million tons or "2.3 million-ish approximately" tons in his testimony at hearing. (*See* Tr. at 5494, 5522.)

(APS RBr. at 98-99; *see* Ex. S-37 at 40; Tr. at 5447-5448, 5451-5452.) Finally, APS argues, the record does not support disallowing costs associated with the Cholla CSA, and Staff's concerns are "little more than hindsight second-guessing," because the El Segundo Mine has consistently been the most economic option for Cholla's coal supply; APS could not have avoided paying mine reclamation costs in some manner, in this case through the shortfall volumes; and Staff has not contested that APS saved ratepayers $200 million in capital costs by closing Unit 2 early and preserving the generation capacity from Units 1 and 3 through the end of the Cholla CSA term. (APS RBr. at 99-100; *see* Ex. APS-116; Tr. at 5449-5450, 5454-5456.)

Resolution

Staff appears to have misunderstood the Cholla 2017 CSA Amendment and to have mischaracterized the fairness of the terms of the 2017 CSA Amendment. The evidence does not support a conclusion that APS negotiated disadvantageous terms for itself while PacifiCorp negotiated advantageous terms for itself or that the 100,000 ton addition to the minimum take requirement for APS has resulted or is likely to result in liquidated damages to be paid by APS. The evidence does establish that the Navajo Mine is the least cost coal supply alternative for the 4CPP and that the El Segundo Mine is the least cost coal supply alternative for Cholla. The evidence also establishes that the liquidated damages incurred for the 4CPP 2020/2021 CSA plan year were reasonable under the circumstances and should be included in cost of service. The evidence also establishes that the liquidated damages incurred for the Cholla plant in 2020, 2021, 2022, and 2023 were mitigated by APS to the extent possible, through the methods described by Mr. Bogle, and represent final reclamation costs that APS cannot avoid and that should be included in cost of service. We will not direct any disallowance of the liquidated damages incurred by APS and previously included in PSA calculations.

Staff has expressed frustration with APS's failure, during the 2021 Fuel and Purchased Power Audit and during discovery in this matter, to provide documentation justifying APS's contemporaneous decision-making in relation to the liquidated damages provisions included in the CSAs. APS ultimately provided the information in its rebuttal case in this matter, and Staff made a point of capturing on the record that the supportive documents had not been provided to Staff previously. Much, if not all, of the dispute over the liquidated damages in this matter could have been avoided if APS had provided

Staff's consultants in the prior Fuel and Purchased Power Audit and Staff in this matter with the documents demonstrating the analysis that supported APS's contemporaneous decision-making concerning the negotiation of the CSA Amendments and specifically the provisions related to liquidated damages. The Commission directs APS, in future Fuel and Purchased Power Audits, and in future rate cases, to provide Staff and Staff's consultants with all available documentation supporting APS's contemporaneous decision-making concerning potentially disputed issues and APS's efforts to mitigate any potentially harmful impacts to ratepayers arising from contract provisions. It is not in APS's best interests, or the public interest, for APS to hold back the information that explains and supports its choices and demonstrates its efforts to mitigate harms to ratepayers.

F. Base Cost of Fuel and Purchased Power

APS Proposal

APS proposes to increase its base cost of fuel and purchased power ("base fuel rate")[315] by 0.687¢/kWh, from 3.1451¢/kWh to 3.8321¢/kWh, and to decrease the PSA by the same amount at the same time so that the changes are a net zero impact to customers when the new rates become effective. (Ex. APS-14 at 17; Ex. APS-24 at 5; Tr. at 1193-1195, 1636, 1677.) APS calculated its base fuel rate by using the TY fuel rate (3.8281¢/kWh) as a baseline and the 2023 fuel forecast[316] discounted by 4% to stay near the TY baseline and minimize bill impacts. (Ex. APS-24 at 5; Tr. at 1638-1639.) The 2023 fuel forecast includes removal of the $15 million in off-system sales mitigation for the AG-X program.[317] (Ex. APS-24 at 6.) Mr. Moe testified that the forecasts did not greatly impact the proposed base fuel rate in this matter.[318] (Tr. at 1639.) As of the application, APS projected that the annual average price of gas from the San Juan Basin[319] in 2022 would be $5.93/MMBtu and that the southwest

[315] The base fuel rate includes the base cost of fuel and purchased power, the base chemical costs, and the base net margins on the sale of emission allowances. (*See* Ex. APS-30 at Att. JEH-11RB at 6.)

[316] The 2023 forecasted delivered fuel cost was 3.9918¢/kWh. (Ex. S-21 at 9.)

[317] Mr. Joiner characterized the off-system sales mitigation as a cost shift to non-AG-X customers, and it is described in the PSA POA essentially as compensation for capacity and energy displaced by AG-X. (*See* Ex. APS-11 at 31; Ex. APS-30 at Att. JEH-11RB at 8.)

[318] The forward natural gas price projections used by APS came from the Intercontinental Exchange, S&P Global, some financial institutions, and counterparties. (Tr. at 1197, 1200-1201.)

[319] The San Juan Basin provides approximately 80% of the natural gas used by APS's generating units. (Ex. APS-11 at 26; Tr. at 1198.)

would continue to experience increased natural gas prices for several years.[320] (Ex. APS-11 at 26; Tr. at 1199.) As of the hearing in this matter, APS had paid an average price (undelivered) for natural gas of approximately \$3.50/MMBtu to \$3.99/MMBtu in 2023. (*See* Tr. at 1202-1203.) In mid-August 2023, during the hearing, the undelivered price for gas from the San Juan Basin was around \$2.50/MMBtu, and the undelivered Henry Hub price was a little higher in the range of \$2.77/MMBtu to \$2.80/MMBtu. (*See* Tr. at 1204.) Mr. Joiner acknowledged that the Henry Hub prices had been in the \$2/MMBtu range since February 2023. (Tr. at 1209.)

APS states that the only parties to raise concerns about APS's proposed base fuel rate are the School Groups, which base their position on reduced natural gas prices in 2022. (APS Br. at 119; *see* Ex. ASBA-1 at 15-16.) APS asserts that although 2022 natural gas prices were lower as compared to the peak pricing in 2020 and 2021, the current and near-term forecasted rates for the San Juan Basin remain significantly elevated above pre-COVID pricing. (APS Br. at 119; *see* Ex. APS-12 at 27-28.) Further, APS asserts, if APS were to recalculate a new base fuel rate using forward projections from July 2023, the base fuel rate proposal would likely be higher than the current proposal because of the higher, sustained forward gas price forecasts for the San Juan Basin. (APS Br. at 119; Ex. APS-14 at 17.) APS urges the Commission to approve its proposed base fuel rate of 3.8321¢/kWh, which APS states is reasonable and in the best interest of its customers. (APS Br. at 119.)

IBEW Locals

The IBEW Locals support APS's proposed base fuel rate and the equivalent transfer of PSA revenues into base rates. (IBEW Br. at 9.)

School Groups

The School Groups argue that the base fuel rate should not be based on the extraordinarily increased natural gas prices experienced in 2022 because in 2023 natural gas prices have decreased dramatically, returning to pre-2020 levels, and are substantially lower than APS's fuel price forecasts for 2023 and 2024. (SG Br. at 8-9; *see* Ex. ASBA-1 at 14-16.) The School Groups assert that current

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[320] According to Mr. Joiner, the increased prices experienced by APS in 2022 were attributable to the Ukraine war (due to global competition and interrupted fuel supplies) as well as one of APS's feeds being out (since fixed by the pipeline company). (Tr. at 1208.)

natural gas supplies are strong and near all-time highs, that natural gas storage levels are above five-year average levels and approaching five-year maximums, and that the U.S. Energy Information Administration ("EIA") has shown the spot price for natural gas at Henry Hub to be less than \$3/MMBtu since February 2023. (SG Br. at 8-9; *see* Ex. ASBA-1 at 15; Ex. ASBA-2 at 11.) According to the School Groups, APS's proposed base fuel rate is based on circumstances that have since changed, and the Commission should consider a more modest increase to the base fuel rate in the range of 0.25¢/kWh, increasing the current base fuel rate to 3.39¢/kWh. (SG Br. at 9; *see* Ex. ASBA-1 at 16.)

RUCO

RUCO did not brief the base fuel rate issue. At hearing, Mr. Radigan testified that RUCO was not proposing an adjustment to APS's base fuel rate in this matter. (Tr. at 4451-4452.) Mr. Radigan acknowledged that the base fuel rate is only reset in general rate cases in Arizona, but opined that APS could ask permission to have the base fuel rate changed when the PSA POA is changed and that it should be "adjudicated between parties." (Tr. at 4452.) RUCO's final schedules show that RUCO accepted APS's adjustment to electric fuel and purchased power costs "to reflect a modified 2023 forecasted base fuel and purchased power ¢/kWh rate at adjusted [TY] consumption levels" but increased revenues from surcharges by \$204.5 million to "Reflect rejection of Base Fuel Roll In." (*See* RUCO Final Sched. C-2 at 2, 20; APS Br. at Att. B at Sched. C-2 at 2.) In his direct testimony, Mr. Radigan stated that allowing APS to roll the PSA revenues into base rates would make the PSA smaller and seemingly less important although the PSA in the recent past has gotten much larger and needs more rather than less review. (Ex. RUCO-1 at 40.)

Staff

Staff accepts APS's proposed base fuel rate increase. (Staff Br. at 20-21; *see* Ex. S-24 at 51.) Staff states that the increased base fuel rate results in an increase in fuel and purchased power costs of \$1.177 million. (Staff Br. at 20; *see* Ex. S-21 at 10.)

APS Response

In its Responsive Brief, APS asserts that the undisputed evidence of record shows that forward natural gas prices in the San Juan Basin, from which APS obtains its fuel, are forecasted to be higher than \$3.50/MMBtu in winter 2023 and higher than \$4.00/MMBtu into 2024. (APS RBr. at 87.) APS argues that the School Groups' use of pricing forecasts from the Henry Hub to support its position are misplaced, because APS does not obtain its fuel from the Henry Hub, and that San Juan Basin prices have not returned to pre-2020 levels. (APS RBr. at 87 n.482.)

Resolution

APS proposes to increase its base fuel rate to a rate that is 0.004¢/kWh higher than its actual TY base fuel rate of 3.8281¢/kWh and 0.1597¢/kWh lower than its 2023 forecasted delivered fuel cost. At the same time, APS proposes to reduce PSA revenues by $220.59 million,[321] which APS states will completely offset the base fuel rate increase so that the bill impact for customers is neutral. (Ex. APS-29 at 2; Ex. APS-30 at 12.) The School Groups refute APS's proposal but in doing so rely entirely on Henry Hub pricing, which is inapt because APS obtains the vast majority of its gas from the San Juan Basin. Based on the evidence of record in this matter, it is just and reasonable to approve APS's proposed base fuel rate of 3.8321¢/kWh. Additionally, in spite of RUCO's testimony that it is inappropriate to transfer the PSA revenues into base rates, the evidence establishes that the PSA revenues reflect actual costs of service incurred and likely to continue being incurred by APS, making it appropriate to allow the associated transfer to reduce PSA revenues. The Commission discusses the PSA further below in Section (VI)(G)(4).

G. Adjustor Mechanism Issues

1. DSMAC

APS Proposal

APS proposes to have the $39.4 million collected within the DSMAC during the TY[322] transferred into base rates, to modify the performance incentive ("PI") structure within the DSMAC POA so that savings from demand response ("DR") programs can be counted for the DSM PI, and to have the Commission approve a waiver of A.A.C. R14-2-2411 (pursuant to A.A.C. R14-2-2419) because A.A.C. R14-2-2411 requires that PI calculations consider only the savings from energy

[321] As reflected by APS, the $220.59 breaks down into three pro forma adjustments--$1.18 million in base fuel and purchased power, $212.28 million in retail deferred fuel expense and non-cash mark-to-market accrual, and $7.14 million in chemicals and O&M expense. (Ex. APS-30 at 12.)

[322] APS has been authorized to collect $20 million in DSM costs through base rates since the 2016 rate case. (*See* Ex. RUCO-7 at 213.)

efficiency ("EE") measures.[323] (APS Br. at 51-52; *see* A.A.C. R14-2-2411;[324] A.A.C. R14-2-2419.[325]) APS states that the change to allow DR savings to be captured within the PI mechanism is important because APS, consistent with Commission orders about focusing more on peak demand reductions, has been making strides to deliver meaningful and dispatchable reductions in peak demand through its DR-based Virtual Power Plant ("VPP") programs. (APS Br. at 51-52; *see* Tr. at 2250-2251; Decision No. 75679 (August 5, 2016)[326] at 17-18; Ex. APS-27 at 3-5.) APS states that there is good cause to waive the provisions of the DSM PI rules that restrict the PI to EE impacts. (APS Br. at 52; Ex. APS-27 at 6.)

APS states that WRA and SWEEP support modification of the PI provision but desire to impose a PI cap based on overall program spending and to add multiple PI tiers,[327] both of which APS opposes because, APS states, total kWh saved is a more meaningful metric due to its focus on outcomes that deliver value to customers, and PI tiers would be inconsistent with prior Commission-approved applications of the PI. (APS Br. at 51-52; *see* Ex. SWEEP-1 at 13; Ex. APS-99 at 3; Ex. APS-28 at 2; Tr. at 3435-3436; Decision No. 78781[328] at 29-31.)

APS argues that transferring the $39.4 million of TY DSMAC collections into base rates is appropriate because APS's DSM programs (both EE and DR) are core functions of cost of service and a necessary and expanding part of how APS serves its customers. (APS Br. at 53; *see* Ex. APS-30 at

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[323] APS initially proposed having the DSMAC expanded to collect lost fixed cost revenues because APS also initially proposed to eliminate the LFCR, but APS discarded those proposals in its prefiled rebuttal testimony. (*See* Ex. APS-2 at 25; Ex. APS-3 at 7.)

[324] A.A.C. R14-2-2411 states: "In the implementation plans required by R14-2-2405, an affected utility may propose for Commission review a performance incentive to assist in achieving the energy efficiency standard set forth in R14-2-2404. The Commission may also consider performance incentives in a general rate case." A.A.C. R14-2-2404(A) requires an affected utility, through EE programs, to achieve cumulative annual energy savings measured in kWh equivalent to at least 22% of the affected utility's retail electric energy sales for 2019. A.A.C. R14-2-2404(C) allows an affected utility's measured reductions in peak demand from DR and load management programs to comprise up to two percentage points of the 22% EE standard and prohibits the credit for DR and load management peak demand reductions from exceeding 10% of the EE standard for any year.

[325] A.A.C. R14-2-2419 states that the "Commission may waive compliance with any provision of this Article for good cause" and that an affected utility may petition for such a waiver.

[326] Official notice is taken of this decision, which was issued in the docket for consideration of APS's 2016 DSM Implementation Plan. The decision directed APS, *inter alia*, to make its best effort to increase the peak demand reduction capability from DR and load management programs in 2016 by 15% (as compared to 2015 results) and to modify its 2017 DSM Plan if necessary to increase peak demand reduction capability from DR and load management programs in 2017 by 30% (as compared to 2015 results). (Decision No. 75679 at 17-18.)

[327] WRA and SWEEP did not advocate for these modifications in their Brief or separate Responsive Briefs.

[328] Official notice has already been taken of this decision.

8; Ex. APS-27 at 3-5.) APS states that SWEEP, WRA, and RUCO all support the proposed transfer, with SWEEP and WRA stating that the transfer provides continuity for important DSM programs that rely upon "trade allies, vendors and program participants." (APS Br. at 53; *see* Tr. at 3436; Ex. SWEEP-1 at 5; Ex. RUCO-1 at 39.)

AARP

AARP asserts that RUCO recommended eliminating or reducing the DSMAC,[329] something that AARP seemingly supports.[330] (*See* AARP Br. at 3-4.)

AZLCG

AZLCG opposes APS's request to transfer the $39.4 million collected through the DSMAC into base rates, arguing that it would reduce transparency for ratepayers, would fail to recognize that DSM program costs are variable each year, and would result in the payment of DSM program costs by customers who are not subject to the DSMAC and cannot benefit from DSM programs. (AZLCG Br. at 72; *see* Ex. AZLCG-3 at 44-45; Ex. RUCO-7 at 212-213; Ex. APS-84 at 54.) AZLCG asserts that the Commission denied the transfer of DSMAC revenues into base rates in Decision No. 78317, for reasons including the speculative nature of the costs each year, and that had the Commission approved the transfer, APS could have collected $45 million in the TY although it spent only $39.4 million. (AZLCG Br. at 73; *see* Ex. RUCO-7 at 212-213.) AZLCG notes that the Commission also more recently denied TEP recovery of EE/DSM costs through base rates because doing so would make the charges less transparent to ratepayers, and splitting the costs between a DSM surcharge and base rates would be unnecessarily complex and burdensome. (AZLCG Br. at 73; *see* Ex. APS-84 at 54.[331]) AZLCG also points to Mr. Higgins's testimony that the Bagdad Mine owned and operated by Freeport

[329] In its Rate Application, APS had originally proposed to modify the DSMAC to include collection of costs currently eligible to be collected in the LFCR, which would have been eliminated. (*See* Ex. APS-2 at 25.) As it does currently, APS also proposed to have the TY DSMAC amount of $39.4 million transferred into base rates, so that base rate collections for DSM would be $59.4 million going forward, and to refine the existing DSMAC PI. (*See* Ex. APS-29 at 5.)

[330] AARP does not appear to acknowledge that RUCO's position concerning the DSMAC was for the DSMAC to be retained and the transfer of DSMAC revenues into base rates to be approved because the transfer would reduce the amount collected through the DSMAC. (*See id.*; Ex. RUCO-1 at 7, Sched. C-2 at 6.)

[331] We note that in Decision No. 79065, TEP's concerns about splitting recovery for EE and DSM costs between the DSM surcharge and base rates (adopted by the Commission) were premised upon recovery in base rates through a regulatory asset included in rate base and amortized over seven years, not the transfer into base rates of the amount of EE and DSM costs collected during the TY through the DSM surcharge. (*See* Ex. APS-84 at 53-54.) TEP stated that inclusion of the regulatory asset in rate base and using the DSM surcharge for all other annual costs would be unnecessarily complex and an administrative burden. (*See id.* at 54.)

(a member of AZLCG) was exempted from paying the DSMAC in 2014[332] based on the size of its load and its already having a self-funded DSM program in place for which it had historically budgeted approximately $10 million annually. (AZLCG Br. at 73; *see* Ex. AZLCG-3 at 45.) In return for this exemption, Mr. Higgins testified, the Bagdad Mine was made ineligible to receive DSM funding from APS, which means that requiring Freeport to pay for DSM program costs through base rates would be unreasonable. (*See* Ex. AZLCG-3 at 45.)

AZLCG asserts that SWEEP's first argument—that rolling DSM costs into base rates should be done because it would be consistent with the treatment of other energy resources—was addressed and rejected in Decision No. 78317, in which the Commission stated that to be consistent with the treatment of other resources would mean waiting until a rate case to have costs included in base rates (as plant in service added to rate base) rather than receiving up-front funding through base rates. (AZLCG Br. at 74; *see* Ex. SWEEP-2 at 4-5; Ex. RUCO-7 at 213.) AZLCG further asserts that SWEEP's second argument—that including a DSMAC line item on a customer bill is prejudicial—does not support the transfer because approval of the transfer would not eliminate the DSMAC or the billing line item. (AZLCG Br. at 74; *see* Ex. SWEEP-2 at 5; Tr. at 3453; Ex. APS-29 at 5.) AZLCG argues that the Commission should be consistent and reject rolling the $39.4 million in DSMAC costs into base rates. (AZLCG Br. at 74.)

<u>Sierra Club</u>

Sierra Club supports the use of DSM to manage projected load growth and states that it is disappointed that APS underspent DSM program budgets from 2018 to 2022 and in its 2023 DSM Implementation Plan showed a decrease in peak demand savings compared to previous years in both the residential and commercial sectors. (SC Br. at 45-46; Tr. at 254-255; Ex. SC-1 at 66-67, 72-73.) Sierra Club argues that the Commission should push APS to expand its DSM offerings. (SC Br. at 46.) Additionally, Sierra Club asserts that the Commission should approve APS's proposal to collect $59.4 million in DSM costs through base rates (i.e., the transfer of the $39.4 million collected through the

[332] Mr. Higgins cited Decision No. 74813 (November 13, 2014). (*See* Ex. AZLCG-3 at 45.) *Inter alia*, Decision No. 74813 exempted Freeport's Bagdad Mine from the DSMAC and the calculation of APS's EE savings goal, estimated DSM budget, and the DSMAC revenue requirement on a going forward basis and prohibited APS from providing the Bagdad Mine any incentives for any DSM program during the exemption. (Decision No. 74813 at 6.) Official notice is taken of this decision.

DSMAC in the TY into base rates). (SC Br. at 47; SC RBr. at 26.)

SWEEP & WRA

SWEEP and WRA recommend approval of APS's proposal to transfer $39.4 million from the DSMAC to base rates as an annual operating expense because (1) DSMAC reconciliation will hold customers harmless if APS does not spend all of the $59.4 million collected through base rates on DSM; (2) APS is not proposing to change the structure of DSM cost recovery, just to shift a portion of DSM expenses from the DSMAC to base rates, and will not earn additional revenue through capitalization of DSM investments; (3) EE cost recovery should be recovered in base rates because EE is a core resource and because the Commission has expressed a preference for eliminating cost recovery through adjustors; and (4) APS's risk of cost recovery for DSM programs would be mitigated by the transfer without imposing any rate impact on customers. (SWEEP/WRA Br. at 17-18.) SWEEP and WRA note Mr. Baatz's testimony that singling out DSM costs presents an unclear picture of APS's costs to serve customers when other resources are not also listed. (SWEEP/WRA Br. at 17; *see* Tr. at 3453.) SWEEP and WRA further assert that Freeport's DSMAC exemption can be maintained even if DSM program costs are collected through base rates and that one customer's request to avoid DSMAC charges should not override the public benefit of having DSM program costs recovered in base rates. (SWEEP/WRA Br. at 17.) In its Responsive Brief, in response to AZLCG's concerns that DSM costs are variable, SWEEP asserts that APS's DSM spending has significantly improved in recent years,[333] which SWEEP attributes to a predictable schedule for DSM Plan review and the Commission's directive for APS to collect up to $20 million of DSM program costs through base rates. (SWEEP RBr. at 4-5; *see* AZLCG Br. at 72; Ex. AZLCG-30.) SWEEP also asserts that the Bagdad Mine exemption can be maintained and that Decision No. 78317 rejected recovering DSM costs exclusively through the DSMAC. (SWEEP RBr. at 5-6; *see* Ex. RUCO-7 at 214.) SWEEP further suggests that if the Bagdad

[333] To support this, SWEEP provides a graph showing that APS's DSM spending has increased year over year in 2020, 2021, and 2022, which SWEEP states it compiled by comparing APS's Annual DSM Reports in Docket No. E-00000U-18-0055 against the annual DSM budgets approved in Decision No. 76313, Decision No. 77631, Decision No. 78164, and Decision No. 78781. (SWEEP RBr. at 5.) This graph was not included in the evidentiary record herein; nor were the Annual DSM Reports upon which it is based. We note, however, Table 15 included in Exhibit SC-1, which appears to show that APS's spending on two DR programs increased from 2021 to 2022, that APS newly spent on two additional DR programs in 2021, and that APS newly spent on another additional DR program in 2022. (*See* Ex. SC-1 at 67.) Further, we note Ms. Carnes's testimony showing that APS's peak demand savings increased each year from 2019 through 2022. (*See* Ex. APS-27 at 4-5.)

Mine were to lose its exemption through having the DSM charges recovered through base rates, Freeport could request another exemption from the Commission. (SWEEP RBr. at 6.)

RUCO

In its Brief, RUCO supports APS's proposal to transfer $39.4 million collected in the DSMAC into base rates because it makes the adjustor smaller and recovers more expenditures in base rates. (RUCO Br. at 37; *see* Ex. RUCO-1 at 39.) RUCO's final schedules show that RUCO made this transfer. (*See* Ex. RUCO-1 at 7, Sched. C-2 at 6.)

Staff

Staff opposes APS's proposal to revise the DSMAC PI provisions. (Staff Br. at 58; *see* Ex. S-21 at 37-38.[334]) Mr. Smith testified on direct that APS had indicated the modifications to the PI would have added an additional $763,000 to the DSMAC revenue requirement if applied in 2022. (Ex. S-21 at 38.) Mr. Smith further testified that the DSMAC in its current form appeared to be functioning as intended and that Staff recommended it be continued in its present form. (Ex. S-21 at 38.) Mr. Smith stated on direct that Staff had not yet reached a conclusion concerning the transfer of the $39.4 million. (*See* Ex. S-18 at 89.) Staff did not subsequently address the transfer of the $39.4 million into base rates in testimony or its Brief or Responsive Brief. Staff's schedules do not show any adjustment to reject the transfer.

APS Response

In its Responsive Brief, APS argues that the changes proposed to the DSMAC PI provisions are in the best interest of customers and that no party has provided compelling evidence to the contrary. (APS RBr. at 32; *see* APS Br. at 51-53.) APS argues that Staff's Brief and testimony in this matter have provided "no substantive reason whatsoever to justify or explain" Staff's opposition to the PI revision, while APS's Brief described extensive and undisputed evidence supporting the PI revision, which APS states would be consistent with Commission orders encouraging peak-reducing DR and is responsive to Commissioner interest in adjusting the financial incentives that support DR measures

[334] Staff cited Exhibit S-18 at 37 to support this position, but the testimony there is unrelated to the DSMAC. It appears that Staff intended to cite Exhibit S-21.

focused on peak demand reduction. (APS RBr. at 32; *see* APS Br. at 51-52; Ex. S-54 at 17.[335]) APS argues that Staff has provided no reason why the PI for DSM programs should be focused solely on savings from EE as opposed to peak reduction from DR and that, based on the evidence, the Commission should adopt APS's proposed modification to the DSMAC PI.

APS argues that AZLCG is the only party opposing APS's proposal to transfer $39.4 million collected through the DSMAC into base rates and characterizes AZLCG's arguments as "specious at best," asserting that the transfer would not reduce transparency and that the DSM programs would still be subject to Commission review and approval. (APS RBr. at 33.) APS argues that it would not be able to collect from customers more than authorized DSM measures cost because the DSMAC POA allows for reconciliation of program costs against collections so that customers are held harmless if APS spends less than the $59.4 million collected through base rates for DSM programs. (APS RBr. at 33; *see* SWEEP/WRA Br. at 16; Ex. APS-30 at Att. JEH-04RB at 3.) Further, APS argues, it is unlikely for APS to over-collect because APS has proposed an $88 million budget for the 2023 DSM program year[336] and is continually growing its DSM portfolio, particularly with respect to peak-reducing DR. (Ex. APS-27 at 4-5, 8-9.) Additionally, APS agrees with SWEEP and WRA that the individual customer exemption from the DSMAC does not justify "needlessly keeping funds within the DSMAC." (APS RBr. at 34; *see* SWEEP/WRA Br. at 17-18.) APS states that all APS customers, large and small, benefit from reductions in peak demand and load within APS's balancing area achieved through cost-effective DR and EE measures and that APS has a number of DSM program measures focused on large customers (such as Peak Solutions and the Existing Facilities Program) that enable them to participate in DSM programs. (APS RBr. at 34; *see* Ex. APS-27 at 3-4; Tr. at 479-483; Decision No. 78781 at 12.)

<u>Resolution</u>

APS is facing unprecedented growth in both energy usage and peak demand, projecting 60%

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[335] Exhibit S-54 is Decision No. 78499 (March 2, 2022), issued in the docket for Resource Planning and Procurement in 2019, 2020, and 2021. In the decision, the Commission directed APS, TEP, and UNS Electric, Inc. to "include in their next rate cases one or more proposals to rate base Demand-Side Resources investments," which were to be developed with the input of interested stakeholders, for potential consideration by the Commission. (*See* Ex. S-54 at 17.) We note that the PI modification proposal is not a proposal to rate base demand-side resources, but that the directive in Decision No. 78499 was supportive of potentially providing new financial incentives for DSM investments.

[336] Ms. Carnes testified that APS's actual DSM spending in 2022 was $57.5 million. (Ex. APS-27 at 8.)

growth in energy usage and 40% growth in peak demand from now until the end of the decade and having set a new demand record in July 2023 during a sustained extreme heat event.[337] Cost-effective DSM programs (both EE and DR) will only become more important resources to reduce both energy consumption and peak demand during this period of growth. APS's focus on more peak-demand-reducing DR measures, in response to Commission direction, should be encouraged because of the benefits that peak-demand-reducing DR programs will present for all customers, including large general service customers, by reducing fuel and purchased power costs, particularly during times of extreme need, when market power is least available and most expensive.

As APS has pointed out, customers are increasingly adopting connected distributed energy resources that provide opportunities for savings from cost-effective DR measures, and APS has increased its focus on DR programs and the peak demand savings from those programs.[338] (*See* Ex. APS-27 at 4-6; Ex. APS-29 at 10.) Opportunities for cost-effective DR measures will only increase with additional customer adoption of distributed energy resources, and the current DSMAC PI structure (coupled with the Commission's Electric EE Standards rules) does not incentivize investing in DR measures as it does investing in EE measures. The PI effectively helps to remove the financial disparity between investing in DSM versus investment in conventional generation resources,[339] but currently only does this for EE program investments. Both EE and DR measures are important resources to save customers money, and no evidence has been provided in this matter to substantiate a compelling reason to treat them differently in relation to APS's DSMAC PI. Thus, we will approve APS's modified DSMAC POA, which includes revised language to allow inclusion of cost-effective DR program savings in the calculation of the PI.[340]

Because APS has established good cause to allow its DSMAC PI calculations to include the savings from cost-effective and Commission-approved DR programs, we will also provide APS a waiver, under A.A.C. R14-2-2419, of the language in A.A.C. R14-2-2404, A.A.C. R14-2-2405, and

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[337] *See* Tr. at 144-145, 169-171, 210, 360.

[338] APS reports that its DSM portfolio of 16 residential and non-residential DSM programs, pilots, and initiatives delivered 322.5 MW of peak demand savings (150 MWs from DR) in 2022 and that APS plans to deliver 397 MW of peak demand savings (220 MW from dispatchable DR programs) in 2023. (*See* Ex. APS-29 at 10; Ex. APS-27 at 4.)

[339] *See* Ex. APS-27 at 5.

[340] The revised DSMAC POA is included as Attachment JEH-04RB to Exhibit APS-30.

A.A.C. R14-2-2411 restricting PI provisions to EE programs and providing a cap on the amount of DR that can be counted toward achieving cumulative annual energy savings.

Finally, the Commission declines to allow APS to collect $59.4 million annually to fund Commission-approved DSM investments through base rates.

2. REAC

APS Proposal

APS proposes that the REAC be maintained in its current form and that $1.9 million of investments in the Solar Communities program collected in the REAC be transferred into base rates. (APS Br. at 54, 138; Tr. at 341-342.) APS states that an earnings test for the REAC is unnecessary because the REAC is working as intended to support compliance with the Commission's Renewable Energy Standard, something APS says Staff has acknowledged.[341] (APS Br. at 54; *see* Ex. APS-30 at 10; Ex. S-21 at 35.)

AARP

AARP cites with apparent approval RUCO's recommendation for the Commission to reject APS's proposal to revise the REAC. (AARP Br. at 4.) AARP does not appear to recognize that APS no longer proposes to revise the REAC.

RUCO

In its Brief, RUCO discussed its opposition to the originally proposed expansion of the REAC, which RUCO acknowledged APS had discarded on rebuttal. (*See* RUCO Br. at 3-5.) RUCO did not discuss the REAC further in its Responsive Brief.

Staff

In its Brief, Staff discussed its opposition to the originally proposed expansion of the REAC and did not acknowledge that APS had abandoned that original proposal on rebuttal. (*See* Staff Br. at 59.) Staff states that it supports an earnings test for the REAC similar to the earnings test used for the LFCR and that it proposes no other changes to the REAC. (Staff Br. at 59.) Staff did not discuss the

[341] APS's original proposal, discarded on rebuttal, was for the REAC to be expanded to allow recovery of capital carrying costs on new APS-owned clean energy resources and energy storage facilities, provided that they were acquired through an ASRFP and were consistent with APS's IRP Action Plan, and to include an earnings test. (*See* Ex. APS-2 at 25, 27-28; Ex. APS-3 at 7, 11-12.)

REAC further in its Responsive Brief.

APS Response

In its Responsive Brief, APS argues that Staff has neither explained nor justified its recommendation that an earnings test be added to the REAC, which APS states appears to be rooted in a concern that APS is proposing for the REAC to be expanded as originally proposed by APS herein. (APS RBr. at 34; *see* Staff Br. at 59.) APS states that because APS is no longer proposing expansion of the REAC, and Staff has provided no reason or explanation for recommending an earnings test, Staff's recommendation should be rejected, and the REAC should be permitted to continue in its present form. (APS RBr. at 35.)

Resolution

No party other than Staff opposes allowing the REAC to continue in its current form, and Staff's opposition and earnings test recommendation appear to be based on a misunderstanding of APS's current proposal for the REAC rather than on any concern for the operation of the REAC in its current form, which Mr. Smith testified was working. Thus, we will allow the REAC to continue in its current form.

Due to the Commission's concerns with the Solar Communities program, however, which are discussed in Section (VI)(K)(1) below, we will not transfer the $1.9 million of Solar Communities program costs from the REAC into base rates.

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3. LFCR

APS Proposal

APS proposes (1) to maintain the current LFCR POA language except for a modification to the earnings test language APS states is "to clarify the level of recovery," (2) to transfer the $58.5 million TY LFCR amount into base rates, which APS states "is customary . . . (with the exception of APS's last rate case)," and (3) to have $58.5 million removed from the LFCR adjustor mechanism. (APS Br. at 47, 51; *see* Ex. APS-29 at 5; Ex. AZLCG-30 at ex. A, Section VIII;[342] Ex. APS-84 at 101.[343]) The modification to the earnings test language would make the following replacement, which APS asserts is unopposed:[344]

Current Language	Proposed Language
If the Earnings Test Period's rate of return is higher than the Earnings Test Threshold, the LFCR Adjustment for the coming year will be set to zero.	If the Earnings Test Period's rate of return is higher than the Earnings Test Threshold, the Lost Fixed Cost Revenue will be limited to the amount corresponding to the Earnings Test Threshold[.] The amount above the Earnings Test Threshold, if any, will be held [in] the Balancing Account for recovery through Adjustment Schedule LFCR in a future year.

APS states that it had lost fixed costs of $58.5 million in the TY due to EE and DG, with the amount based on verified EE reporting and meter data from DG systems, and proposes to have this amount transferred into base rates, while contemporaneously removing the amount from the LFCR. (APS Br. at 48; *see* Ex. APS-29 at 5, 7-8; Ex. APS-30 at 9, Att. JEH-04RB; Tr. at 2808, 5066.) According to APS, Staff and RUCO support the transfer and have included it in their revenue

[342] Exhibit AZLCG-30 is an excerpt of Decision No. 76295 (August 18, 2017), which approved a settlement agreement in APS's 2016 rate case. The excerpt includes all of the Commission's discussion, conclusion, and ordering paragraph pages as well as the pages of the settlement agreement (exhibit A) but excludes the appendices attached to the decision following exhibit A. The settlement agreement approved therein specifically provided that "certain revenue requirements" collected in the REAC, DSMAC, LFCR, TCA, EIS, Four Corners Rate Rider, and System Benefits Charge were to be transferred to base rates and the adjustor rates "zeroed out or reduced." (Ex. ALCG-30 at ex. A at 11.)

[343] Exhibit APS-84 is Decision No. 79065 (August 25, 2023), issued in the 2022 TEP rate case. The page cited by APS states that TEP was not proposing any modifications to the current structures of POAs for several adjustors, including its LFCR, and that no party had suggested changes to these adjustors. (*See* Ex. APS-84 at 101.) It is unclear how this supports APS's contention that LFCR revenues are routinely transferred into base rates.

[344] *See* APS Br. at 51; Ex. APS-100 at 59-66; Ex. APS-30 at Att. JEH-07RB at 2. The proposed revision to the earnings test language in the LFCR POA in Exhibit APS-100 includes a couple of typos that have been corrected as shown.

requirement calculations, and AZLCG's opposition to the transfer is without merit. (APS Br. at 48;[345] *see* Tr. at 4457-4458, 4838-4840,[346] 5053, 5084-5090.[347]) APS asserts that the $58.5 million is comprised of $27.1 million in accrued LFCR revenue that existed as of November 30, 2021, and $31.4 million in lost fixed costs that were experienced from December 1, 2021, through June 30, 2022 (i.e., from the effective date of the rates set in Decision No. 78317 to the end of the TY in this matter). (APS Br. at 49.) APS asserts that to transfer the $58.5 million into base rates, APS must reduce operating revenues by $27.1 million (the amount booked as accrued revenue under the alternative revenue program) and increase operating expenses by $31.4 million, thereby increasing APS's base revenue deficiency by $58.5 million. (APS Br. at 49; *see* Ex. APS-37 at Sched. C-2 at 5; Tr. at 2420.) APS states that the differences between how the LFCR transfer must be accomplished in this matter, as compared to how transfers were completed in prior APS and TEP cases, are necessary because Decision No. 78317's addition of an earnings test for the LFCR (effective December 1, 2021) made the LFCR ineligible for alternative revenue program treatment under GAAP. (APS Br. at 49; *see* Tr. at 2864.) Had the complete LFCR amount been eligible for the alternative revenue program, APS states, the

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[345] APS also cited Exhibit AZLCG-1 at 46, but there is no such page. APS may have meant to cite Exhibit AZLCG-3 at 49, where Mr. Higgins testified that the LFCR revenue should not be transferred into base rates.

[346] Mr. Radigan testified that while he had included the transfer of revenue in preparing RUCO's schedules, "an issue has been presented" that "RUCO would like to see . . . thoroughly investigated," and that he was not sure whether AZLCG or APS was correct as there were "conflicting arguments on either side." (Tr. at 4457-4459.) Mr. Radigan further stated: "RUCO hasn't had time or the ability to dig into the LFCR issue as its been presented in this case." (Tr. at 4459; *see also* Tr. at 4839-4840.) Mr. Radigan further stated the following:

> I think there might be some alternative solutions for this rate case, for instance, keep the LFCR and keep the 58 million in there for now and leave base rates alone. But, as you've, you know, so meticulously went through, we have a statement saying that sales should be reset every rate case, but we see that sales are being used over several LFCR filings after rates have been reset, and we have, you know, we have sales figures that are not footnoted to source. All other numbers would have to be checked and verified to determine if these numbers are correct.

Tr. at 4840.

[347] Mr. Smith testified that Staff had accepted the $58.5 million transfer in its schedules. (Tr. at 5053.) But Mr. Smith also testified that the current period level of DG savings and EE savings did not appear to be calculated in a manner consistent with the LFCR POA because the calculations referred back to the 2015 test year, and it looked to him like the LFCR POA should have been modified as a result of the 2019 rate case, to reflect that the LFCR-related cost recovery was kept in the LFCR, but was not. (*See* Tr. at 5087-5092.) Mr. Smith further testified that it looked like APS's calculations tried to follow the substance of the decision in the last rate case but that there was a discrepancy with the POA. (*See* Tr. at 5090.) Mr. Smith agreed that if the Commission has any concerns with the accuracy of the $58.5 million, the Commission could reject the proposal to transfer that amount into base rates and keep it in the LFCR, suggesting that might be "easier for everybody concerned." (*See* Tr. at 5090-5091.) Mr. Smith was reluctant to have the issue examined more closely by the Staff analyst in the LFCR filing docket, as he believed that the Staff analyst was already overworked. (*See* Tr. at 5091-5092.) At hearing, Mr. Smith stated that he was not sure Staff had a preferred recommendation. (*See* Tr. at 5092.)

complete amount would have been booked as accrued revenue, and the transfer would have been reflected on Schedule C-2 as a reduction to operating revenues as in prior APS and TEP rate cases. (APS Br. at 49-50; *see* Ex. AZLCG-32 at Sched. C-1, Sched. C-2 at 4.[348]) APS asserts that the ineligibility of part of the LFCR balance to be recorded as revenue under the alternative revenue program does not affect the accuracy or veracity of the $58.5 million TY balance; it just changes how the amount must be removed from the TY. (APS Br. at 50.)

APS argues that moving the $58.5 million into base rates will not result in over-recovery as asserted by AZLCG because the LFCR adjustor will be reduced by the same amount, making the transfer revenue neutral on customer bills. (APS Br. at 50; *see* Tr. at 2808, 2809, 4889; Ex. AZLCG-3 at 49; Ex. APS-29 at 7-8.) Further, APS asserts, it is necessary and appropriate for APS to continue to collect the $58.5 million in base rates because it reflects the TY level of lost fixed costs determined in conformance with prior decisions and the LFCR POA. (APS Br. at 50-51.)

AARP

AARP cites with approval RUCO's proposal to eliminate the LFCR. (*See* AARP Br. at 3-4.) AARP does not address the proposed $58.5 million transfer into base rates.

AZLCG

AZLCG argues that the Commission should reject APS's proposal to transfer $58.5 million in lost fixed costs into base rates and APS's calculation of its lost fixed costs because (1) APS's lost fixed costs calculation and the transfer into base rates will result in over-recovery of base rates, necessitating offsetting reductions in future LFCR calculations that are neither permitted by nor described in the LFCR POA; and (2) APS's calculation of its lost fixed costs violates the Commission-approved LFCR POA.[349] (AZLCG Br. at 75.) According to AZLCG, both ratemaking principles and the LFCR POA require the LFCR calculation to be reset following the effective date of new rates because all of the

[348] APS also cited to schedules from the 2016 rate case that are not part of the evidentiary record in this matter. APS asserts that because the LFCR was not transferred into base rates in the 2019 rate case, the pro forma adjustments made removed the $39.8 million in LFCR revenues and also removed an equal $39.8 million from expenses, for a zero dollar operating income impact. (APS Br. at 50; *see* Ex. RUCO-7 at 214-219; Tr. at 2808.)

[349] AZLCG's arguments are based on the LFCR POA as it existed in Ms. Hobbick's rebuttal testimony. (*See, e.g.,* AZLCG Br. at 81 n.503.)

utility's costs (including fixed costs) are considered in the rate case TY revenue requirement.[350] (AZLCG Br. at 75; *see* Ex. APS-30 at Att. JEH-06RB; Tr. at 4813-4814, 5073-5074.) Likewise, AZLCG states, the updated billing determinants presented by APS in the rate case capture all of the reduced ratepayer usage attributable to EE and DG investments both during and before the TY. (AZLCG Br. at 75; *see* Tr. at 5074; Ex. RUCO-7 at 215.) Because APS spreads its TY accrued costs over the TY billing determinants to ensure that all of APS's TY costs (including fixed costs) will be recovered through the rates established in the rate case, AZLCG asserts, the "rate case cures prior lost fixed costs." (AZLCG Br. at 76; *see* Tr. at 5067-5068, 5073, 2805, 3040, 3132, 3146; Ex. AZLCG-3 at 50.) It is for this reason, AZLCG states, that the LFCR POA states that lost EE and DG kWh must be calculated based on APS's last rate case. (AZLCG Br. at 76; *see* Ex. AZLCG-3 at 80-88.)

Because the LFCR recovers lost fixed costs revenue from the year before a LFCR filing, AZLCG states, APS during a TY will normally book both the actual revenues received through the LFCR and the deferred revenues (associated with TY sales) that APS will receive in the future through the LFCR mechanism. (AZLCG Br. at 76; *see* AZLCG-21; Ex. AZLCG-22.) AZLCG argues that the deferred revenues must be addressed in a rate case because they compensate for lost revenues incurred during the TY that will not recur once the new rates are set. (AZLCG Br. at 77.) Historically, AZLCG states, APS has removed the booked deferred revenues by removing them from TY revenues (i.e., transferring them to base rates) so that APS's revenue requirement would not be artificially depressed. (AZLCG Br. at 77; *see* Ex. AZLCG-30 at ex. A at 11.) AZLCG argues that because a rate case resets billing determinants, after a rate case, there are no more lost fixed costs from periods before or during the TY. (AZLCG Br. at 77.)

AZLCG approves of APS's having booked $27,149,479 in LFCR revenues during the TY and then removing the same amount from TY revenues, as AZLCG states APS and TEP have done in prior rate cases. (*See* AZLCG Br. at 77; Ex. AZLCG-33; Ex. APS-39 at Sched. C-2 at 14; Ex. AZLCG-31 at Sched. C-2 at 2; Ex. AZLCG-32 at Sched. C-2 at 4; Tr. at 5057-5063.) AZLCG disagrees with APS's then increasing expenses by $31,360,000 to reflect un-booked LFCR revenues, stating that this

[350] AZLCG states that all of the utility's costs are summarized in Schedule H-1. (AZLCG Br. at 75; *see* Ex. AZLCG-24 at 2; Tr. at 4812-4813.)

is "[w]here APS goes astray" because this type of adjustment has never been done before and is "questionable on its face." (AZLCG Br. at 77-78; *see* Ex. APS-39 at Sched. C2 at 14; Tr. at 5067-5068, 5076.) AZLCG acknowledges that the $31,360,000 plus the $27,149,479 collected through the LFCR approximately equal the $58,509,310 that APS calculated as the LFCR for the TY. (AZLCG Br. at 77-78; *see* Tr. at 5071-5075-5076.) AZLCG further acknowledges that the earnings test adopted in Decision No. 78317 made it impermissible for APS to book the LFCR as deferred revenues under GAAP until after the revenues are assured due to a determination that APS did not over-earn. (AZLCG Br. at 78; *see* Ex. RUCO-7 at 218-219; Tr. at 2863-2865.) AZLCG states: "Since that didn't happen in the [TY], those revenues do not impact the [TY] results like the deferred revenues booked in the [TY] do. Essentially, once APS stopped booking deferred revenues, the problem solves itself without further adjustment because the [TY] occurs before those other revenues were booked at all." (AZLCG Br. at 78.) AZLCG states that the problem with APS's approach is that it overstates APS's base revenue deficiency by $31,360,000.[351] (AZLCG Br. at 78-79; *see* Tr. at 2866.[352])

According to AZLCG, APS implicitly acknowledges the overstated revenue requirement "by proposing that once new rates go into effect those new rates will do double duty—they will pay the going forward costs and they will reduce the historic [TY] LFCR amounts"—because APS proposes to reduce the historic LFCR collections for the time period prior to the rate effective date once the new rates become effective.[353] (AZLCG Br. at 79-80; *see* Tr. at 2404.) AZLCG argues that APS's approach is unreasonable because it (1) artificially increases APS's base revenue requirement, (2) artificially decreases APS's future LFCR entitlement with no indication that the approach is appropriate under the LFCR POA, and (3) is not spelled out in the LFCR POA. (AZLCG Br. at 80.) AZLCG argues that while APS is unclear about whether reductions to the LFCR will continue in future years once new rates take effect, the artificial increase will continue each year until the next rate case, something that

[351] AZLCG provides an illustrative example to show how the expense approach results in a higher revenue requirement as compared to the historic approach and AZLCG's proposed approach. (*See* AZLCG Br. at 79.)

[352] Ms. Hobbick did not agree that APS's expenses were not actually $31,360,000 higher than their book expenses because of the operation of the LFCR and instead responded that "our lost revenues were lower, were inclusive of . . . and we had to . . . account for the additional dollars . . . on the expense side." (Tr. at 2866.)

[353] Ms. Hobbick acknowledged that the timing would be tricky because of APS's pending LFCR calculation filing for 2023 and the probable effective date for new rates in January 2024, but stated that APS would continue reducing the LFCR calculation by $58.5 million in its annual filings until such time as the LFCR calculation is performed using the billing determinants from this matter. (*See* Tr. at 2408-2409.)

AZLCG says the Commission recognized in Decision No. 78317 and that AZLCG states is not just and reasonable. (AZLCG Br. at 80; *see* Tr. at 2868-2869; Ex. AZLCG-3 at 50; Ex. RUCO-7 at 218.)

AZLCG asserts that the Commission should allow the transfer of the \$27.1 million of actual accrued deferred revenue but reject the transfer of the additional approximately \$31.4 million that APS has improperly categorized as expenses.[354] (AZLCG RBR. at 10.) AZLCG disputes APS's characterization of its proposal in this matter as consistent with prior cases and states that the Commission has never before allowed potential and uncertain future revenues to be included in base rates as APS proposes to do herein. (AZLCG RBr. at 10.) AZLCG argues that the Commission must reject APS's calculation of the TY LFCR because APS used sales reductions going back to the 2016 rate case rather than based on the billing determinants from the 2019 rate case, which AZLCG states violates the Commission-approved LFCR POA. (AZLCG Br. at 81.) AZLCG refers to the language of the LFCR POA included in Ms. Hobbick's rebuttal testimony, which states that DG savings and EE savings are determined using installations and savings occurring after "the effective date of APS's most recent general rate case," and argues that the "LFCR POA limits the amount of lost fixed cost revenue to the time period since the rate effective date of APS's most recent rate case not the most recent rate case where the LFCR was 'rolled-into or transferred into' base rates."[355] (AZLCG Br. at 81; Ex. APS-30 at Att. JEH-06RB at 2; Tr. at 4823-4824.) AZLCG points to Ms. Hobbick's testimony agreeing that the LFCR POA states that "cumulative verified" EE savings are to be calculated by comparing billing determinants from APS's last rate case TY with those in the LFCR evaluation year. (AZLCG Br. at 81; *see* Tr. at 2402, 2406, 2805.)

AZLCG argues that TEP's LFCR POA requires calculation of lost fixed costs associated with DG and EE between rate cases and requires that cumulative verified savings be reset to zero at the end of each general rate case, describing with approval the manner in which TEP calculates its LFCR

[354] AZLCG argues that APS's referring to the \$31.4 million as lost fixed costs experienced from December 1, 2021, through June 30, 2022, misstates the facts as established by the record because the amount represents neither a cost nor an expense but instead a potential and uncertain amount of lost revenues. (AZLCG RBr. at 11; *see* Tr. at 2863.) AZLCG asserts that the characterization is important because actual lost revenues are accounted for and fully resolved in the normal ratemaking process by using TY billing determinants to establish rates to collect the full TY revenue requirement. (AZLCG RBr. at 11-12.)

[355] APS's revised LFCR POA, which has an effective date after the end of the TY, does include language pertaining to the "effective date of APS's most recent general rate case in which cost recovery was transferred from the LFCR surcharge revenues to base revenues." (*See* Ex. APS-100.)

adjustments based on the lost fixed costs accrued since the effective date from TEP's most recent rate case, with no prior period EE losses included when they have been zeroed out upon conclusion of a general rate case per TEP's LFCR POA. (*See* AZLCG Br. at 81-83; Tr. at 4790-4792, 4796, 4800-4804, 4806; Ex. AZLCG-25 at 6; Ex. APS-84 at 2; Ex. AZLCG-27 at 1, 4; Ex. AZLCG-29 at 1, 5.) Despite the same type of language in APS's LFCR POA, AZLCG argues, APS calculated the EE and DG savings for its 2022 and 2023 LFCR filings (those that include the TY) and for the TY in this rate case using the information from the 2016 rate case, even after the rates from the 2019 rate case became effective. (AZLCG Br. at 83; *see* Ex. AZLCG-21 at 7; Ex. AZLCG-22 at 11; Ex. AZLCG-23 at 2, 4; Tr. at 4834, 4837, 5327.) AZLCG argues that APS's TY LFCR calculation for this matter inexplicably even used information from APS's 2011 rate case, although the rates from the 2011 rate case were not in effect during any portion of the TY. (AZLCG Br. at 83; *see* Tr. at 4836-4838, 5081-5082.) AZLCG argues that APS has violated the language of the LFCR POA, ignored the 2019 rate case in calculating lost fixed cost revenue, reached back to the 2016 rate case to inflate the value of its lost kWh sales, and yet also provided itself the benefit of the higher lost fixed cost revenue rate from the 2019 rate case. (AZLCG Br. at 83; *see* Tr. at 4834, 5087-5089; Ex. AZLCG-21 at 7; Ex. AZLCG-22 at 11.) According to AZLCG, APS's proposed LFCR adjustment herein is based on its unilateral amendment of its LFCR POA to reach back and add lost fixed costs in a manner inconsistent with the LFCR POA, which violates the contract between APS and its customers and the filed rate doctrine. (AZLCG Br. at 83-84; *see Sommer v. Mountain States Tel. & Tel. Co.*, 519 P.2d 874, 876-877 (Ariz. App. 1974)[356]; Decision No. 70460 (August 6, 2008) at 31; Tr. at 4840.)

AZLCG concludes that even if the Commission accepts APS's accounting approach, the Commission should require APS to recalculate the LFCR calculation for this matter following the LFCR POA and using lost EE and DG kWh from the end of the TY from the 2019 rate case, so that the "expenses" added are based on the corrected calculation. (AZLCG Br. at 84.) AZLCG states that the issue ultimately can be resolved in APS's pending LFCR filing but that the Commission should not

[356] AZLCG also cited *Szeto v. Ariz. Pub. Serv. Co.*, 252 Ariz. 378 (App. 2021), which had paragraphs 17-27 de-published by *Szeto v. Ariz. Pub. Serv. Co.*, 253 Ariz. 466 (2022). The language concerning a Commission-approved tariff governing the relationship between a public service corporation and its customers was not de-published.

allow over-collection of revenues through base rates by accepting an LFCR calculation that exceeds the level that would be calculated based on the plain language of the LFCR POA. (AZLCG Br. at 84.)

In its Responsive Brief, AZLCG adds that APS is not proposing merely to clarify the earnings test language but instead is proposing to defer for future recovery any LFCR amount in excess of the earnings test, permitting it "to build up a deferred LFCR balance and draw against that balance to shore up . . . financials." (AZLCG RBr. at 10.) AZLCG argues that a rate case establishes APS's total revenue requirement and that ratemaking should not guarantee recovery of any particular cost, as APS's proposal would do by allowing APS to defer for guaranteed future recovery purported lost fixed costs from a year in which APS exceeds its Commission-authorized ROE. (AZLCG RBr. at 11.) AZLCG urges the Commission to examine whether this would serve the public interest. (AZLCG RBr. at 11.)

Finally, AZLCG disagrees with APS's characterization of its accounting for lost fixed costs as "minor distinctions," stating that APS's calculations include lost fixed costs going back to the 2016 rate case, ignoring the plain language of the LFCR POA and more than doubling the time period for evaluating purported lost fixed costs, although APS is required to follow its Commission-approved POA to the letter. (AZLCG RBr. at 12; *see* APS Br. at 49; AZLCG Br. at 81; *Sommer v. Mountain States Tel. & Tel. Co.*, 519 P.2d 874, 877 (Ariz. App. 1974)[357].)

FEA

In its Responsive Brief, FEA supports AZLCG's recommendations and adjustments associated with the LFCR as detailed in AZLCG's Brief. (FEA RBr. at 1; *see* AZLCG Br. at 74-84.)

Kroger

In its Responsive Brief, Kroger strongly supports AZLCG's argument that APS's calculation of the costs tracked in the LFCR is incorrect and results in an over-recovery of costs that will grow each year. (Kroger RBr. at 3.) Kroger states that AZLCG is correct that APS's base revenue deficiency is overstated because APS calculated its proposed TY LFCR, reduced that amount by the amount of booked deferred revenues, and then artificially added expenses to its revenue requirement. (Kroger

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[357] AZLCG also cited *Szeto v. Ariz. Pub. Serv. Co.*, 252 Ariz. 378 (App. 2021), which had paragraphs 17-27 de-published by *Szeto v. Ariz. Pub. Serv. Co.*, 253 Ariz. 466 (2022). The language concerning a Commission-approved tariff governing the relationship between a public service corporation and its customers was not de-published.

RBr. at 3; *see* AZLCG Br. at 74-84.) Kroger argues that APS's proposal to transfer TY lost fixed costs into base rates will result in over-recovery of base rates and will necessitate offsetting reductions in future LFCR calculations, a flawed accounting approach that should be rejected as recommended by AZLCG. (Kroger RBr. at 3; *see* AZLCG Br. at 74-84.)

Ms. Nelson

Ms. Nelson states that the Commission should require APS to keep the LFCR adjustor.[358] (KN Br. at 4.)

RUCO

RUCO states that it is a major proponent of eliminating as many adjustor mechanisms as possible, in part because they increase the number of elements on an overly detailed electric bill that is not well understood by ratepayers. (RUCO Br. at 37; *see* Ex. RUCO-1 at 39.) In its Brief, RUCO endorses eliminating the LFCR.[359] (RUCO Br. at 37.) RUCO does not discuss the issue further in its Responsive Brief.

Staff

Staff discusses its disapproval of the original APS proposal to eliminate the LFCR and recover lost fixed cost revenues in the DSMAC and then acknowledges that APS discarded that proposal in its rebuttal testimony. (Staff Br. at 56-57; *see* Ex. APS-30 at 7.) Staff then states that it supports having the LFCR continued and also supports resetting the LFCR by transferring the amounts recovered in the LFCR during the TY into base rates. (Staff Br. at 57.) In its Responsive Brief, Staff adds that the LFCR POA should be updated to reflect the outcome of the decision in this matter and recommends that APS be required to file an updated LFCR POA that reflects the impact of the Commission's determinations affecting the LFCR in this matter. (Staff RBr. at 18.) Staff does not address AZLCG's concerns about the calculation of the LFCR or APS's proposal to change the recovery available after application of the earnings test.

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358 It is not clear whether Ms. Nelson is expressing a position on the transfer into base rates of the $58.5 million in LFCR revenues identified by APS.

359 This is inconsistent with Mr. Radigan's testimony at hearing, which did not call for elimination of the LFCR, though Mr. Radigan did express a desire for LFCR-related issues raised by AZLCG to be thoroughly investigated. (*See* Tr. at 4457-4458, 4838-4840.)

APS Response

In its Responsive Brief, APS asserts that Staff agrees the LFCR should remain in its current form and that both Staff and RUCO agree that the $58.5 million currently being collected in the LFCR should be transferred into base rates, although RUCO "inexplicably" also asserts that the LFCR be eliminated (a position in which AARP joins). (APS RBr. at 28; *see* Staff Br. at 57; RUCO Br. at 37; AARP Br. at 4.) APS argues that RUCO has provided no rationale for eliminating the LFCR other than complicated bills and that neither RUCO nor AARP has provided a plan to address recovery of future lost fixed costs caused by EE and DG if the LFCR is eliminated. (APS RBr. at 28; *see* RUCO Br. at 37; AARP Br. at 4.) APS argues that RUCO and AARP's positions should be disregarded because the LFCR is functioning as designed, supports key customer programs, and prevents build-up of unrecovered fixed costs between rate cases. (APS RBr. at 28; *see* Ex. S-21 at 40.)

APS asserts that AZLCG's position that only $27.1 million should be transferred into base rates from the LFCR is based on the following "several erroneous assertions" that are "false and inconsistent with both the LFCR POA and Decision No. 78317": (1) that Decision No. 78317's not transferring the LFCR into base rates should have eliminated or reduced the LFCR balance in existence at the time, (2) that APS has miscalculated or overstated its lost fixed costs in this matter, and (3) that APS has violated the LFCR POA. (APS RBr. at 28-29; *see* AZLCG Br. at 77.) APS argues that it specifically sought to keep the lost fixed cost recovery in the LFCR adjustor in the 2019 rate case rather than transferring the balance into base rates due to concerns that had arisen from the 2016 rate case and accomplished the non-transfer by removing the LFCR surcharge revenues from the TY and adjusting down TY expenses, thereby removing $39.8 million from the revenue deficiency in the 2019 rate case. (APS RBr. at 29; *see* Ex. RUCO-7 at 214-215.[360]) As a result, APS asserts, the 2019 rate case TY billing determinants recovered a lower revenue requirement through base rates, and the 2019 rate case TY's lost fixed costs remained in the LFCR adjustor, where the balance has continued to accumulate. (APS RBr. at 29.) Had the Commission intended to erase the balance in the LFCR adjustor or disallow collection of those

[360] APS also cited Late-Filed Exhibit 87 ("APS LFE 87") from the 2019 rate case, which was not an exhibit in this matter. Official notice is taken of APS LFE 87, which was filed in Docket No. E-01345A-19-0236 on April 7, 2021. APS LFE 87 shows that APS deducted $39.792 million of LFCR revenues from "Revenues from Surcharges" and from "Other Operating Expenses." (*See* APS LFE 87 at Sched. C-2 at 7.)

lost fixed costs, APS states, the Commission would have said so and reset the adjustor to zero either in Decision No. 78317 or the next LFCR proceeding, which it did not. (APS RBr. at 29.) Thus, APS argues, AZLCG is wrong that the 2019 rate case cured the potential for future lost fixed costs from preexisting EE and DG because that only happens if the lost fixed costs are reflected in the billing determinants and base revenue deficiency in the rate case, which they were not in the 2019 rate case. (APS RBr. at 30; *see* AZLCG Br. at 75-76.)

APS argues that allowing the transfer of \$58.5 million in lost fixed costs currently being collected in the LFCR will not result in over-earning as argued by AZLCG because it merely allows recovery of the authorized amount of lost fixed costs accrued from the time of the last transfer to base rates, on June 1, 2016, through the end of the TY in this matter. (APS RBr. at 30; *see* Ex. AZLCG-22 at Sched. 3, Sched. 4.) APS argues that AZLCG is incorrect that going back to the last transfer date violates the LFCR POA and results in over-recovery because no transfer occurred in the 2019 rate case, and the billing determinants were adjusted accordingly in the 2019 rate case. (APS RBr. at 30; *see* Ex. RUCO-7 at 218-219.) APS further notes that the LFCR POA was subsequently updated to include the new earnings test required by Decision No. 78317 and "other updates consistent with the non-transfer that occurred in Decision No. 78317." (APS RBr. at 30-31.[361]) APS reiterates and expounds on its explanation of the loss of the alternative revenue program accounting treatment for the LFCR revenues, which now must be booked as revenues when they are billed rather than before, and argues that the \$58.5 million is the actual amount of lost fixed costs that APS needs to recover regardless of how it is accounted for under GAAP or reflected in pro forma adjustments. (APS RBr. at 31.) APS further argues that transferring the \$58.5 million into base rates does not result in over-recovery of \$31.4 million because the \$31.4 million is a portion of the TY lost fixed costs, and "that amount will be removed from the adjustor and continue to be removed every year going forward."[362] (APS RBr. at

[361] APS cites a Notice of Compliance regarding the Revised LFCR POA filed in Docket No. E-01345A-19-0236 on October 3, 2023. This document was not part of the record in this matter, and official notice is taken of it. The Notice of Compliance approves, with an effective date of July 1, 2023, a Revised LFCR POA that was filed by APS on September 5, 2023. The Revised LFCR POA language is consistent with the language included in the LFCR POA included in Exhibit APS-100 herein, with the exception of the proposal in Exhibit APS-100 to allow for recovery of costs excluded as a result of the earnings test. We note that the LFCR POA as included in Ms. Hobbick's rebuttal testimony already included the new earnings test required by Decision No. 78317.

[362] The Commission understands "that amount" to be \$58.5 million, i.e., that APS proposes to reduce the lost fixed cost revenues calculation each year by \$58.5 million if the Commission approves the transfer of that amount into base rates

31.)

Resolution

The LFCR is a limited revenue decoupling mechanism that allows APS to collect approximately 50% of the lost fixed costs of providing service to customers (poles, wires, and other delivery infrastructure) that are not recovered between rate cases due to reduced customer usage caused by Commission-mandated EE and DG programs. (*See* Tr. at 2411, 2804, 5022; Ex. APS-100 at 41, 59.) The LFCR is calculated using EE savings based on reduced kWh hours and DG savings using metered data, and it does not take into account customer growth. (Tr. at 2804-2805; *see* Ex. APS-100 at 59-60.) When asked whether the LFCR would be rendered unnecessary due to the projected high rate of growth in customers and load to occur on APS's system, Ms. Hobbick responded that it would not because serving that additional load comes with additional costs, and the LFCR is intended to allow APS to meet its revenue target associated with the billing determinants set in the most recent rate case. (Tr. at 2805-2806.) When the LFCR was first approved, most of the EE and DG programs were residential in nature; currently, 40% of the funding associated with APS's EE and DG programs supports general service customers. (Tr. at 2806-2807.) Yet large general service customers are exempt from paying the LFCR surcharge.[363] (Tr. at 2810-2811.) This may be one of the reasons for AZLCG's opposition to transferring the entire $58.5 million into base rates, as any revenues included in base rates will be collected from all APS customers, including large general service customers, but it is clearly not the only reason.

Because APS proposed in its rate application to eliminate the LFCR, APS originally included a proposed copy of the LFCR POA that showed its cancellation. (*See* Ex. APS-36.) In its rebuttal testimony, APS provided a proposed LFCR POA that retained the vast majority of the language of the existing LFCR POA but included the proposed revised earnings test language as described above.[364]

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herein. The Commission also believes that APS only intends to remove the $58.5 million amount every year until the billing determinants from this rate case are used in calculating the LFCR.

[363] The rate schedules exempted are E-30, E-32L, E-32 TOU L, E-34, E-35, E-36XL, XHLF, and unmetered lighting schedules. (*See* Ex. APS-100 at 41.)

[364] With the exception of the proposed revised earnings test recovery language, this LFCR POA is consistent with the "conforming" LFCR POA filed by APS in Docket No. E-01345A-22-0042, the 2022 docket for approval of APS's LFCR mechanism reset, on July 3, 2023. Official notice is taken of this filing, which was not included as an exhibit in this matter. The July 3, 2023, LFCR POA added a Schedule 9 for Annual Earnings Test and a Schedule 10 for Capital Structure.

(*See* Ex. APS-30 at Att. JEH-07RB.) Subsequently, with no fanfare, in Exhibit APS-100, APS provided a different proposed version of the LFCR POA, which includes significant changes to language other than the revised earnings test language.[365] (*See* Ex. APS-100.) Most notably, the LFCR POA in Exhibit APS-100 added a Balancing Account provision, changed the definition of the current period, changed the dates to be used for the calculations of EE and DG savings, and changed the starting point for calculation of DG savings and EE savings to be "the effective date of APS's most recent general rate case in which cost recovery was transferred from the LFCR surcharge revenues to base revenues" instead of "the effective date of APS's most recent general rate case." (*See* Ex. APS-100 at 59-62; Ex. APS-30 at Att. JEH-06RB, JEH-07RB.)

AZLCG's arguments are based on the LFCR POA as it existed in Ms. Hobbick's rebuttal testimony, Exhibit APS-30 at Att. JEH-06RB (clean) and Att. JEH-07RB (redline) ("rebuttal LFCR POA"). Because the base language of the rebuttal LFCR POA was effective during the TY in this matter, that is appropriate.[366] AZLCG is correct that the rebuttal LFCR POA requires the starting period for calculating both DG and EE savings to begin with "the effective date of APS's most recent general rate case" and does not address the calculation of lost fixed costs beginning at a prior rate case effective date because the lost fixed costs revenues were not included in base rates in the most recent general rate case or, indeed, how APS is to handle the calculation of the lost fixed costs if there is a balance left in the LFCR mechanism after completion of a general rate case. Although the rebuttal LFCR POA includes the earnings test, it does not address how APS is to account for lost fixed cost

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[365] With the exception of the proposed revised earnings test recovery language, this revised LFCR POA language appears to be consistent with the "updated" LFCR POA filed by APS in Docket No. E-01345A-22-0042 on September 5, 2023, which was approved by Staff with an effective date of July 1, 2023, through a Notice of Compliance filed in the same docket on December 8, 2023. This approved revised LFCR POA is also consistent with the revised LFCR POA APS referenced in its Responsive Brief and of which official notice was taken above. Official notice is taken of both the September 5, 2023, LFCR POA filing and the December 8, 2023, Notice of Compliance filing in Docket No. E-01345A-22-0042. We note that the LFCR POA included in Exhibit APS-100 did not identify the language changes apart from the proposed revised earnings test recovery language.

[366] We note that APS's having a revision to the LFCR POA approved in two other dockets during the pendency of this matter is problematic, as APS never provided in this matter a redline showing the changes from the text of the LFCR POA as included in Ms. Hobbick's rebuttal testimony to the text of the LFCR POA as included in Exhibit APS-100. APS should have done that to make everyone aware of the significant differences between the two and the still pending status of the LFCR POA included in Exhibit APS-100 during the hearing in this matter (which is not noted on the cover page of Exhibit APS-100). Due to the sheer volume of the exhibits in this matter, and the relatively late submission of Exhibit APS-100 on September 10, 2023, as well as its not having been discussed with a witness, it is quite possible that parties have not even noticed the differences between the two.

revenues going forward (i.e., that they are ineligible for the alternative revenue program under GAAP). AZLCG is correct that APS's calculation of the lost fixed costs in this matter, and its accounting for how to transfer them into base rates, are not in conformance with the rebuttal LFCR POA, which was not revised in a manner consistent with Decision No. 78317's having adopted an earnings test and not having transferred the LFCR revenues into base rates. Because of this, we will not approve the transfer into base rates of the entire $58.5 million in this matter; instead, we will allow APS to transfer into base rates the booked $27,149,479 in LFCR revenues by removing this amount from "Revenues from Surcharges." We will also allow APS to keep the remaining $31,360,000 that reflects un-booked lost fixed cost revenues in the LFCR adjustor, to be dealt with either in its next general rate case or its next annual LFCR reset proceeding.

We will not approve APS's proposal to "clarify" the earnings test because, as AZLCG noted and we had already noticed, it is not a clarification—it is a fundamental modification of the consequences of APS having earnings that exceed the earnings test threshold. Decision No. 78317 clearly stated: "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." (Ex. RUCO-7 at 219.) That language was and remains clear and will be retained. The Commission is concerned because the LFCR POA does not take growth into account, and not allowing recovery of lost fixed costs when the earnings test threshold is exceeded is one way to ensure that the impacts of growth may impact the calculation of any LFCR surcharge.

Finally, because we believe the revised LFCR POA, as included in Exhibit APS-100, remains problematic, we will require APS, in consultation with Staff, AZLCG, and any other interested parties, to modify the LFCR POA to achieve at least the following: (1) modify the Balancing Account and all related language to clarify that APS will not be permitted to defer and/or collect any amounts related to a year in which the Earnings Test Threshold is lower than the Earnings Test Period's rate of return; (2) include as numbered pages within the POA each Schedule used for purposes of calculation; (3) explain, clearly and in detail (a) how each component of the lost fixed cost amount is to be calculated and using what starting point and billing determinants, (b) how each component of the calculation of future lost fixed cost amounts are impacted by whether the surcharge revenues were or were not transferred into base rates in the most recent general rate case, and (c) the accounting treatment in a general rate case to transfer lost fixed cost amounts into base rates when the prior general rate case did or did not transfer lost fixed cost amounts into base rates; and (4) identify for each line of each Schedule within the POA the source for the data included or to be included. We will require APS, within 90 days after the effective date of the decision in this matter, to file in this docket the proposed revised LFCR POA (both in clean and in redline form from the version included in Exhibit APS-100) and will require Staff to review the proposed revised LFCR POA and file a Staff Report and Proposed Order for Commission review and approval at an Open Meeting.

4. PSA

The PSA's purpose is to allow APS to recover fuel and purchased power costs and other production-related variable costs to the extent that they deviate from what is recovered through APS's most recently approved base fuel rate. (*See* Ex. S-21 at 12.) The PSA year generally begins on February 1.[367] (Ex. APS-30 at Att. JEH-11RB at 2.) APS is required to submit its annual PSA rate filing to the Commission by November 30 of each year. (*Id.*) The PSA has three components: (1) the forward component, (2) the historical component, and (3) the transition component. (*Id.* at 2-3.) The forward component is used to recover or refund the difference between the PSA costs forecasted for the upcoming calendar year and the PSA costs embedded in base rates and is calculated using forecasted kWh sales for the upcoming calendar year.[368] (*Id.* at 3.) The historical component is used to recover or refund the balances accumulated in the forward component tracking account and historical component tracking account during the immediately preceding PSA year and is calculated using projected January 31 tracking account balances and the forecasted kWh sales used to calculate the forward component. (*Id.* at 3.) The transition component is used if a mid-PSA-year change to the PSA rate is sought and provides for tracking of balances resulting from such a mid-PSA-year change. (*Id.* at 4) The PSA rate is the sum of the three components. (*Id.*)

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[367] The PSA POA states: "Except for circumstances when the Commission approves new base rates, a PSA Year begins on February 1 and ends on the ensuing January 31. In the event that new base rates become effective on a date other than February 1, the Commission may, at its discretion, adjust any or all of the PSA components to reflect the new base rates." (Ex. APS-30 at Att. JEH-11RB at 2.)

[368] Oddly, the PSA POA also describes the forward component as recovering or refunding "differences between expected PSA Year's PSA Costs and those embedded in base rates," with a footnote clarifying that a PSA Year is February 1 through January 31. (*Id.* at 2.) We note that there seems to be some internal inconsistency concerning what time period is to be reflected in the forecasts used to calculate the forward component.

In 2021 and 2022, the following amounts were included in the PSA to be recovered from/credited to ratepayers:[369]

Type of Cost or (Credit)	Included in PSA for 2021	Included in PSA for 2022
Fuel for Generation	$272.6 million	$439.1 million
Purchased Power (not including above-market costs of renewable purchased power agreements included in REAC)	$147.2 million	$207.0 million
Off-System Sales	($171.4 million)	($367.8 million)
Chemicals	$2.7 million	$12.4 million
Broker Fees (capped at amount in Base Fuel Rate)	$0.9 million	$0.9 million
Emission Allowances	$0	$0
Energy Storage Purchased Power Agreements	$0	$0
Total Costs:	$252.0 million	$291.6 million

The PSA surcharge was most recently modified in Decision No. 78877 (February 23, 2023),[370] in which the Commission increased the PSA rate from $0.007544/kWh to $0.019074/kWh, effective from March 1, 2023, and until further order of the Commission, to enable APS to recover its accrued PSA bank balance over a period of 24 months.[371] (Ex. S-21 at 13; Decision No. 78877 at 6.) The Decision also requires APS to "make a filing in the docket notifying the Commission" if the under-collected PSA bank balance approaches $500,000. (Decision No. 78877 at 6.)

We also note that the PSA POA requires APS to maintain and report monthly the balances in the forward component tracking account and the historical component tracking account. (Ex. APS-30 at Att. JEH-22RB at 3.)

<u>APS Proposal</u>

APS proposes to retain its current PSA POA with the following modifications:[372]

(1) An increase to the annual cap on PSA adjustor increases from $0.004 ("four mill") /kWh to $0.006 ("six mill")/kWh;

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[369] Ex. APS-53; Tr. at 1588-1590.

[370] Official notice is taken of Decision No. 78877, issued in Docket No. E-01345A-22-0297.

[371] APS reported in Docket No. E-01345A-22-0297 that its under-collected PSA balance had increased from $175 million on January 31, 2021, to $456 million on October 31, 2022. (Decision No. 78842 (January 23, 2023) at 2, n.2.) Official notice is taken of Decision No. 78842, issued in the same PSA reset docket.

[372] *See* Ex. APS-30 at Att. JEH-10RB, Att. JEH-11RB.

(2) Addition of a requirement for APS to notify Commission Staff when the uncollected PSA balance is greater than $150 million;

(3) Elimination of the requirement for APS to file third-party storage contracts and have them approved by the Commission in order to include them as Storage Product Costs in the PSA;

(4) Replacement of the alternate interest rate to be applied if the ROE is not used as the interest rate applied to an over-collection or under-collection;

(5) An increase to the base fuel rate as previously discussed and resolved in Section (VI)(F) herein; and

(6) Elimination of the language exempting from the PSA the flat amount of $1.25 million/month as a credit from the resale of capacity and energy displaced by AG-X ("off-system sales mitigation").

With the approval of the base fuel rate (item 5 above) in Section (VI)(F) herein, the Commission also approved APS's proposal to transfer into base rates $220.59 million in PSA costs and effectively approved elimination of the off-system sales mitigation provision (item 6 above). Thus, items 5 and 6 need not be further discussed here.[373]

APS argues that the PSA is functioning as intended and critically important and that the cost-sharing provision ("90/10 provision") suggested by some intervenors should be rejected because it would lead to significant financial instability for APS and would not improve APS's fuel and purchased power management. (APS Br. at 40.) APS notes that Staff's witness testified "the PSA is probably the most important adjustor mechanism . . . in effect for APS" and that the PSA appropriately balances customer and APS interests and further notes that the recent fuel and purchased power audit proceeding concluded that the PSA was working as intended and should be retained in its current form. (APS Br. at 41; *see* Ex. S-21 at 17; Tr. at 5019; Ex. S-35 at 7, 12.) Further, APS notes Mr. Smith's testimony that continuing the PSA helps to ensure relatively timely recovery of prudently incurred costs, which is key to APS maintaining its financial integrity and access to capital at reasonable rates. (APS Br. at 41; *see* Ex. S-21 at 17.) APS asserts that the PSA should be retained in its current form (i.e., without

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[373] We are cognizant that the off-system sales mitigation proposal is tied to APS's proposals for AG-X resource adequacy requirements, which will be discussed and resolved in Section (VI)(I)(4).

a 90/10 provision) because fuel and purchased power costs are determined by market forces and are largely outside APS's control, fuel and purchased power cost fluctuations can be unpredictable and volatile, APS does not earn any profit on fuel and purchased power costs through the PSA, and fuel and purchased power costs are substantial and material to APS's financial health. (APS Br. at 41; *see* Ex. APS-12 at 32; Ex. APS-6 at 17-19; Ex. S-21 at 17.)

APS touts its efforts in recent years to reduce costs and implement sophisticated hedging and off-system sales practices, which APS states have resulted in substantial savings passed to customers through the PSA. (APS Br. at 41.) APS asserts that the hedge program[374] alone in 2021 and 2022 produced savings of nearly $400 million that were included in calculating the PSA and that customers were saved another approximately $273 million[375] through off-system sales in 2021 and 2022. (APS Br. at 41-42; *see* Ex. APS-12 at 33-34; Tr. at 1496.)

APS further touts the features built into its PSA POA that it states are intended to help align APS's interests with customer interests, the most notable of which is the difference in carrying charges to be assessed for over-collections (ROE or short-term debt rate, whichever is greater) and under-collections (ROE or short-term debt rate, whichever is lower), which APS states serves as a powerful incentive for APS to minimize its fuel and purchased power costs. (APS Br. at 42; *see* Ex. S-21 at 16; Ex. APS-6 at 15.) APS asserts that APS is also strongly incentivized to reduce fuel and purchased power costs so that it can use its liquidity for capital investments, as opposed to having to seek additional debt capital that would increase its leverage and risk and thus result in higher costs to access capital. (APS Br. at 42; *see* Ex. APS-6 at 18.) Another feature that protects customers, APS claims, is the requirement for APS to be subjected to APS-funded fuel and purchased power audits that review the prudency of APS's decision-making, which must occur at least every three years and should be

[374] APS uses a three-year system hedge process designed primarily to manage fuel price volatility; APS hedges approximately 85% of its natural gas needs one year in advance. (Ex. APS-12 at 3, 32.) APS showed that it saved customers $80 million through the hedging program in 2021 and $316 million in 2022. (Ex. APS-12 at 33-34.) APS had the system hedge process evaluated by outside experts, who found that it was in line with industry best practices and effective in controlling price volatility but also recommended use of more dynamic hedging strategies that would include additional products, something that APS finds too speculative. (*See* Ex. APS-12 at 34.) APS has hired a consultant to work through how the additional hedging strategies could be implemented using historical probability analysis to minimize speculative market decisions. (Ex. APS-12 at 34-35.)

[375] This is significantly higher than the 2021 figure and significantly lower than the 2022 figure subsequently provided by APS in Exhibit APS-53 and shown in the table above. The reason for the disparity is unclear.

conducted in each rate case. (APS Br. at 43; *see* Ex. S-35 at 4; Tr. at 1494-1496.) APS points out that the most recently completed fuel and purchased power audit found that APS's PSA-related deferrals were reasonable and reflected costs that were prudently incurred and consistent with the categories of PSA-eligible costs. (APS Br. at 43; Ex. S-70 at 1-5, finding #10.)

APS urges the Commission to approve the six mill/kWh annual cap on PSA adjustor increases and the requirement for APS to notify the Commission anytime an uncollected PSA balance exceeds $150 million, stating that these provisions would improve APS's ability to manage PSA balances in the face of an increasingly volatile fuel and purchased power market. (APS Br. at 43-44; *see* Ex. APS-30 at 7; Ex. APS-6 at 17.) APS further asserts that increasing the annual cap would promote rate gradualism and contemporaneous recovery of fuel and purchased power costs while protecting customers from significant future PSA increases and that the notice requirement would provide greater transparency and an enhanced means of proactively addressing PSA increases. (APS Br. at 44; Ex. APS-6 at 16-17.)

APS strongly urges the Commission not to add a 90/10 provision to the PSA, stating that the 90/10 provision had "a brief and unsuccessful history in Arizona"[376] and was "wisely removed" from the PSA by the Commission in APS's 2011 rate case.[377] (APS Br. at 44; *see* Ex. RUCO-13 at ex. A at

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[376] APS cited Decision No. 67744 (April 7, 2005), in which the 90/10 provision was originally approved by the Commission. Official notice is taken of this decision, which adopted the PSA, with a 90/10 provision, as part of a settlement agreement. The Commission had previously, in a 1999 decision, required APS to request and the Commission to approve a PSA to recover the cost of providing power for standard offer/provider-of-last-resort customers and, in a 2003 decision, approved the concept of a purchased power adjustor that would include purchased power costs and not fuel costs. (Decision No. 67744 at 14.) In Decision No. 67744, the Commission expressly voiced its concerns about the PSA as proposed in the settlement agreement because of "real and significant" disadvantages from a customer standpoint and a regulatory standpoint. (*Id.* at 15.) The Commission disagreed with the parties that a 90/10 provision was a sufficient incentive for APS to hedge its natural gas costs effectively and characterized "[g]oing from a 100 percent at-risk position to 10 percent at-risk [as] almost . . . a 'free pass.'" (*Id.* at 16.) The Commission also did not believe that prudency reviews would provide as much incentive to APS to hedge costs on the front end as not having a PSA did. (*Id.* at 16.) Thus, the Commission modified the settlement agreement PSA by, *inter alia*, imposing a lifetime 4 mill/kWh increase cap, capping the balancing account at an aggregate amount of $100 million (thus causing PSA surcharge applications at that level), and limiting the amount of "annual net fuel and purchased power costs" to calculate the PSA to no more than $776,200,000. (*Id.* at 17, 40.)

[377] The Commission's removal of the 90/10 provision in APS's 2011 rate case was accomplished through approval of a settlement agreement, which adopted a lower base fuel rate, involved APS's withdrawal of a request to recover chemical costs through the PSA, eliminated the 90/10 provision, required APS to apply interest annually with different rates for over- and under-recoveries, and subjected APS to periodic fuel and power procurement audits funded by APS and performed by Staff-selected consultants. (Ex. RUCO-13 at 12.) Staff's position regarding the changes to the PSA was that the two new provisions (interest rates and audit requirement) would "provide incentives for APS to better manage its PSA balance." (Ex. RUCO-13 at 25.) The Decision did not find that the 90/10 provision was ineffective, just that Staff believed its elimination would benefit customers when fuel prices were lower, as they apparently were at that time (as evidenced by the lower base fuel rate). (*See* Ex. RUCO-13 at 25.)

¶ 7.3.) APS argues that there should not be a profit motive associated with the PSA and that the 90/10 provision was "a penalty provision" that either penalized APS by denying recovery of 10% of its prudently incurred fuel and purchased power costs or penalized customers by depriving them of 10% of the savings that would otherwise be credited through the PSA. (APS Br. at 44-45; *see* Ex. S-21 at 20-21; Tr. at 1497-1498; Ex. APS-6 at 17-18.) APS notes Mr. Joiner's testimony that a profit motive could create reliability risks if it leads to speculative hedging behavior[378] and, further, cautions that a 90/10 provision would harm APS's financial stability and financial metrics, a position with which Staff agrees. (APS Br. at 45; *see* Tr. at 1500-1503; Ex. APS-6 at 17-18; Ex. S-21 at 21-22.) APS argues that RUCO and AZLCG are wrong that a 90/10 provision would incentivize APS to make cheaper fuel and purchased power purchases because, as Staff's witness stated, the 90/10 provision's philosophical underpinning is that APS can control the fluctuations in fuel and purchased power costs, which APS cannot. (APS Br. at 45-46; *see* Ex. AZLCG-5 at 38-39; Ex. RUCO-4 at 5; Ex. S-21 at 19-20.) APS argues that its interests are already aligned with those of its customers and that adding a 90/10 provision thus would be unnecessary and inappropriate and would create penalty and profit incentives that would put APS and its customers at significant risk. (APS Br. at 46; *see* Ex. APS-6 at 18.) Because the record on the issue is complete, APS argues, there is no need to have a Phase 2 proceeding to determine whether the Commission should reinstate the 90/10 provision. (APS Br. at 46; *see* Ex. RUCO-4 at 6.)

<u>AARP</u>

AARP supports RUCO's testimony that the PSA has unnecessarily burdened APS's ratepayers with an \$800 million increase and that the Commission should conduct a Phase 2 proceeding in this docket to conduct a full analysis of the PSA, including a review of the PSA cap and of APS's hedging program to ensure that APS's interests are aligned with ratepayers' interests. (AARP Br. at 4; *see* Ex. RUCO-1 at 40-41.[379]) AARP argues that at a minimum, the PSA should be modified so that APS has

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[378] Mr. Joiner invoked Enron as an example of a risk/reward scenario gone wrong and stated that a 90/10 provision could promote the wrong behaviors by incentivizing traders to select less expensive and more risky resources instead of more expensive resources that are needed for reliability. (*See* Tr. at 1499-1503.)

[379] RUCO based this \$800 million figure on Schedule F-1 included with APS's rate application herein, which shows projected total company fuel and purchased power expenses for calendar year 2023 of \$1.638 billion and for calendar year 2024 of \$1.816 billion, as well as documents that were not made part of the evidentiary record herein. (*See* Ex. RUCO-1 at 40; Ex. APS-37 at Sched. F-1.) To obtain the \$800 million figure, Mr. Radigan characterized the 2023 figure as \$1.9 billion and compared it to a 2020 figure of \$1.1 billion. (*See* Ex. RUCO-1 at 40.) We note that APS LFE 87 from the 2019

"skin in the game" regarding fuel and purchased power costs (through a 90/10 provision) because PSA expenditures are not scrutinized to the same level as expenditures in rate cases. (AARP Br. at 4.)

AZLCG

AZLCG urges the Commission to reinstate the 90/10 provision because, AZLCG argues, APS has substantial control over PSA costs, APS's power cost decisions are "exceedingly difficult to evaluate in after-the-fact prudency reviews," and such cost-sharing mechanisms are common in the western U.S. (AZLCG Br. at 85.) AZLCG cites APS witness testimony agreeing that variable costs are "generally predictable, " that APS has significant control over numerous decisions that impact PSA costs (managing and maintaining generation resources, contracting for and managing power purchase agreements and fuel supply arrangements, selecting resources to procure, selecting the hedging policy to implement, and deciding whether to invest in DSM technologies), that APS employees that make bad decisions could increase costs, and that it is difficult to perform after-the-fact audits concerning all of the fuel and purchased power cost-related decisions that APS makes each year.[380] (AZLCG Br. at 86; *see* Tr. at 625-626, 1123-1128, 1155-1157, 1388.) In contrast, AZLCG cites APS testimony agreeing that ratepayers have no control over the decisions that result in power costs and can only reduce their exposure to those costs by reducing their usage. (AZLCG Br. at 86-87; *see* Tr. at 177, 222.)

Regarding the difficulty of performing after-the-fact audits of fuel and purchased power costs, AZLCG points to the processing timeline included in the PSA POA (November 30 to February 1), which provides little time for analysis; Mr. Joiner's acknowledgment that it is difficult to review the many decisions made in the context of when they were made; Mr. Higgins's testimony that APS's power-cost-related decisions are "so extensive that it is inadvisable for regulators to rely solely on after-the-fact prudence audits to ensure sound utility cost-management performance"; and the Commission's language in Decision No. 67744 that prudency reviews are difficult to conduct after the fact and do not incentivize APS to hedge costs to the same extent as not having a PSA did. (AZLCG Br. at 87-88; *see*

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rate case showed actual fuel and purchased power expenses for the test year in that matter (ending June 30, 2019) of $1.07 billion. (*See* APS LFE 87 at Sched. C-1 at 2.)

[380] In his testimony, Mr. Joiner also asserted that costs go up because of market forces and that costs can go up even with effective management, while likewise, costs can go down because of market forces even if someone is not making good decisions. (*See* Tr. at 1126-1128.)

Ex. APS-30 at Att. JEH-10RB; Tr. at 1124, 4372; Ex. AZLCG-3 at 53; Decision No. 67744 at 16.) AZLCG further cites Ms. Medine's testimony about the difficulty obtaining information needed to evaluate some of APS's decisions, such as for the 4CPP and Cholla liquidated damages costs, and some examination at hearing concerning whether a rate case is the appropriate forum for PSA prudency determinations. (AZLCG Br. at 88; *see* Tr. at 4676-4680, 5320.) Additionally, AZLCG argues that an after-the-fact prudency review does not protect ratepayers the same way that a 90/10 provision would because the Commission's definition of "prudently invested" presumes that all investments are prudently made[381] and allows the presumption to be set aside only upon the presentation of clear and convincing evidence of imprudence based on what was known or should have been known when the investments were made, and it is extremely difficult to determine what was known or should have been known when each decision was made. (AZLCG Br. at 88-89; *see* A.A.C. R14-2-103(A)(3)(l).)

AZLCG argues that a 90/10 provision would provide an incentive for APS to get the best possible deal with every transaction and would be consistent with how APS incentivizes its own employees to prudently manage costs through its Incentive Plan. (AZLCG Br. at 89; *see* Ex. AZLCG-3 at 56; Tr. at 595, 1128-1133.) Additionally, AZLCG points out that Montana, Idaho, and Wyoming all have sharing mechanisms in place for some or all of their regulated investor-owned electric utilities; that Oregon uses an earnings test, dead bands,[382] and sharing mechanisms for both of its regulated investor-owned electric utilities; and that the Colorado Legislature recently passed a law concerning Colorado PUC consideration of fuel cost-sharing mechanisms. (AZLCG Br. at 90; *see* Ex. AZLCG-3 at 56-57.[383]) AZLCG argues that because commodity markets have changed significantly since the 90/10 provision was eliminated more than 10 years ago, and the circumstances that led to its elimination no longer exist, it is "ripe for reconsideration." (AZLG Br. at 91.)

AZLCG attempts to dispel APS's argument that readopting a 90/10 provision would be "catastrophic" to APS's financials by asserting that if the 90/10 provision had been in place during the TY, APS would have recovered 98.2% of its fuel and purchased power costs from ratepayers and only

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[381] We note our finding in Section (VI)(B)(1) above that A.A.C. R14-2-103(A)(3)(l) does not create a presumption of prudency for O&M expenses, only for rate base items.

[382] Dead bands make the utility responsible for all power cost increases up to a certain amount and permit the utility to keep all of the power cost decreases up to a certain amount. (*See* Tr. at 3115-3116.)

[383] AZLCG additionally cited documents that are not part of the evidentiary record in this matter.

1.8% from shareholders,[384] because the 90/10 provision would apply only to the increased costs captured in the PSA, not the costs included in the base fuel rate. (AZLCG Br. at 91-92, n.572.)

IBEW Locals

The IBEW Locals support APS's request for an annual cap on increases of 6 mill/kWh and for notification to Commission Staff to be required if the under-recovered PSA balance exceeds $150 million. (IBEW Br. at 9.) The IBEW Locals assert that these adjustments are needed to minimize unrecovered balances, ensure APS can react to fuel and energy market volatility, and allow APS to pass through to ratepayers the actual expenses and savings associated with fuel and purchased power costs. (IBEW Br. at 9.) The IBEW Locals reject other parties' proposals for a 90/10 provision, arguing that APS is a market price-taker for fuel and purchased power, APS's fuel and purchased power costs are already subjected to scrutiny by Staff during fuel audits and by intervenors during rate cases, not having a 90/10 provision is the norm for fuel adjustors and expected by creditors, and imposing a 90/10 provision could negatively impact APS's credit metrics for purposes of power purchase agreements. (IBEW Br. at 9-10; *see* Ex. APS-6 at 14-15; Ex. S-21 at 14.) The IBEW Locals further argue that the 90/10 provision previously was found not to work for APS. (IBEW Br. at 10; *see* Ex. S-21 at 21.)

Ms. Nelson

Ms. Nelson states that the Commission should reconsider using the 90/10 provision "to ensure APS shareholders have a dog in the fight too" because ratepayers should not be the only ones responsible to pay. (KN Br. at 4.)

School Groups

The School Groups assert that the Commission should approve APS's proposals for a 6 mill/kWh annual increase cap and the requirement for APS to alert Staff when the PSA balance exceeds $150 million. (SG Br. at 10; *see* Ex. ASBA-2 at 12.)

Sierra Club

Sierra Club supports the AZLCG and RUCO recommendations to reinstate a 90/10 provision, arguing that APS's fuel and purchased power costs increased by $800 million between 2020 and 2023

[384] Using AZLCG's calculations, this would have been $20,229,000. (*See* AZLCG Br. at 91, n.572.)

and now constitute 40% of the total costs paid by ratepayers, largely due to APS's increased reliance on gas generation and the volatility of gas prices. (SC Br. at 42-43; *see* Ex. RUCO-1 at 40-41; Ex. RUCO-3 at 5.) Sierra Club argues that because APS bears no risk from fuel price volatility, it lacks sufficient incentives to keep fuel and purchased power costs low and needs to have its interests better aligned with those of ratepayers through a 90/10 provision. (SC Br. at 42-43; *see* Ex. AZLCG-3 at 52; Ex. RUCO-1 at 41.) Sierra Club disputes APS's position that it has no control over fuel cost increases, stating that APS has the ability to manage and mitigate fuel cost increases through its procurement policies and hedging program, resource dispatch practices, and use of external markets to obtain lowest cost energy. (SC Br. at 43; *see* Ex. APS-3 at 10; Tr. at 620-626; Ex. AZLCG-5 at 39.) Sierra Club asserts that if the Commission does not approve the 90/10 provision in this decision, the Commission should order further evaluation of a potential PSA cost-sharing mechanism in a Phase 2 of this case or in a new docket. (SC Br. at 43.)

In its Responsive Brief, Sierra Club reiterates the arguments from its Brief and cites AZLCG's calculation that APS would have recovered 98.2% of its fuel and purchased power costs from ratepayers had the 90/10 provision been in effect for the TY. (SC RBr. at 23; *see* AZLCG Br. at 91-92.) Sierra Club asserts that no evidence shows APS's credit rating or financial health would be harmed by requiring APS shareholders to bear the burden of such a small percentage of fuel and purchased power costs and cites RUCO and AZLCG's Briefs concerning the use of sharing mechanisms in other states. (SC RBr. at 23-24; *see* RUCO Br. at 19; AZLCG Br. at 90-91.)

<u>Vote Solar</u>

In its Responsive Brief, Vote Solar supports RUCO, AZLCG, and Sierra Club's recommendations for the 90/10 sharing mechanism to be reinstated. (VS RBr. at 2, 7-8.) Vote Solar asserts that without cost sharing, APS has no financial incentive to pursue lower cost or more stably priced fuel and purchased power for its customers, leaving ratepayers exposed to fuel price volatility and resulting in situations such as the 2023 PSA update that caused a $145 annual average residential bill increase. (VS RBr. at 8; *see* Decision No. 78877 at 6.)

<u>RUCO</u>

RUCO argues that the recent fuel adjustor under-collections for APS, TEP, and UNS Electric show that their fuel adjustors are not working as intended and are not in the best interest of residential customers, who have been subjected to pancaking of rate increases and rate shock. (RUCO Br. at 13; *see* Ex. RUCO-1 at 42.) RUCO argues that the main reasons for APS's fuel and purchased power cost increase of $800 million between 2020 and 2023 is APS's increased reliance on gas generation and its hedging program that ensures supply but keeps APS subject to market prices.[385] (RUCO Br. at 13-14; *see* Ex. RUCO-4 at 5.) RUCO criticizes APS and Staff's assertions that the PSA is working as intended and questions whether it is appropriate for APS to have a fuel adjustor if that is accurate because adjustors are intended to promote rate gradualism and reduce rate case frequency, and neither has been occurring with the PSA. (RUCO Br. at 14.) RUCO asserts that the PSA changes proposed by APS will not eliminate future under-collections and that the annual increase cap will only raise customer bills and allow APS to recover the under-collections faster. (RUCO Br. at 14.) RUCO argues that there are two ways to align APS's interests with ratepayer interests—review APS's hedging program and reintroduce a 90/10 provision—and that the Commission should review these together. (RUCO Br. at 14; *see* Ex. RUCO-1 at 41.) RUCO argues that APS's stated reasons for opposing the 90/10 provision[386] are all "red herrings" because no one is suggesting that the PSA be eliminated, only modified or further reviewed to address recurring under-collections. (RUCO Br. at 15.) RUCO acknowledges APS's assertion that the 90/10 provision would negatively impact APS's financial metrics and could have "unintended consequences," but asserts that the potential for unintended consequences should not preclude consideration of PSA modification and/or a review of the PSA because the current design of the PSA simply results in large bill increases for ratepayers. (RUCO Br. at 15.)

RUCO argues that APS's prior 90/10 provision did not result in APS's financial ruin and

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[385] During the hearing, Mr. Radigan testified that he was unaware that part of the reason for the size of the most recent PSA increase was due to a delay in collections ordered by the Commission during the COVID pandemic. (*See* Tr. at 4418.) While APS filed its annual PSA rate update on November 30, 2020, APS subsequently filed a letter voluntarily delaying implementation of the 4 mill/kWh PSA increase to April 2021 due to the COVID pandemic, and the Commission ultimately approved half of the PSA increase to take effect in April 2021 and the other half to take effect in November 2021. (*See* Ex. RUCO-7 at 74-75.) This increased the PSA under-collections that were addressed by the Commission in Decision No. 78877, in which the PSA rate was increased by 11.53 mill. (*See* Decision No. 78877 at 5, 6.)

[386] RUCO identifies these as the "Doomsday narrative"—that the PSA is viewed positively by credit rating agencies, that the absence of a PSA would significantly heighten APS's business risk, that the PSA results in improved credit metrics through discounts on the debt imputed to APS's PPAs by rating agencies, and that customers would incur additional financing costs without the PSA. (RUCO Br. at 15; *see* Ex. APS-6 at 14-15.)

recounts the history of the prior 90/10 provision, including the Commission's original concerns in 2005 that the 90/10 provision might not provide sufficient incentive for APS to hedge its gas costs effectively, its subsequent conclusion in 2007 that the 90/10 provision was working to ensure APS's diligence in fuel procurement and should be retained, and its approval in 2012 of a settlement agreement that eliminated the 90/10 provision but added the requirements for periodic audits and different interest rates on under-collections and over-collections. (RUCO Br. at 16-18; *see* Decision No. 67744 at 15-16; Decision No. 69663 (June 28, 2007)[387] at 106-107; Ex. RUCO-13 at 25.) RUCO argues that Staff's position on the 90/10 provision has evolved, with Staff now characterizing the 90/10 provision as resulting in either a "penalty" or "windfall" to APS based on market rates over which APS has no control because APS is a "price-taker." (RUCO Br. at 18; *see* Ex. S-21 at 20-21; Tr. at 5243.) RUCO argues that Staff's position that APS nonetheless is incentivized to minimize over-collections due to the different interest provisions is illogical if APS is merely a "price-taker" that has no control over what it pays. (RUCO Br. at 18-19; *see* Tr. at 5292.)

RUCO further argues that sharing mechanisms are effective in aligning the financial interests of ratepayers and shareholders and suggests that is why they are used in Hawaii, Idaho, Wyoming, Missouri, and Wisconsin.[388] (RUCO Br. at 19; *see* Ex. RUCO-20 at 22-23.) RUCO acknowledges that the APS under-collection of $800 million in 2022 was due to a short-term increase in natural gas prices but asserts that an efficient and successful hedging program is supposed to hedge against price volatility and high fuel prices and that because APS's hedging program failed to protect its customers adequately, APS may need a different type of hedging program. (RUCO Br. at 19; *see* Ex. RUCO-4 at 6; Ex. RUCO-1 at 42.)

RUCO recommends that the Commission direct Staff to hire an independent consultant with expertise in the area to review APS's hedging program and prepare for the Commission an in-depth report advising and educating on what the best hedging program for APS would be to protect ratepayers from short-term swings in market prices. (RUCO Br. at 19-20.) RUCO acknowledges that APS and

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[387] Official notice is taken of this decision, in which the Commission replaced the PSA's 4 mill/kWh lifetime cap with a 4 mill/kWh annual increase cap, eliminated the $100 million balancing account cap, and retained the 90/10 provision (with some new exclusions). (Decision No. 69663 at 106-107.)

[388] Wisconsin's cost-sharing occurs in the form of a 2% dead band. (*See* Ex. RUCO-20 at 23.)

Staff both believe APS's hedging practices are in line with industry standards and functioning as intended but refers to two confidential APS Hedge Plan Reports provided by APS[389] and states that the recommendations in these reports clearly support further Commission review. (RUCO Br. at 20; *see* Ex. RUCO-25; Ex. RUCO-26.) RUCO argues that the two Hedge Plan Reports and their recommendations were not vetted or resolved in the hearing for this matter, that additional review of the hedging program is needed to protect ratepayers, and that the Commission should consider holding this docket open for review of the in-depth Staff study, based upon which the Commission could then take action. (RUCO Br. at 20; *see* Ex. RUCO-4 at 6.)

Staff

Staff asserts that the PSA is probably the most important adjustor in effect for APS. (Staff Br. at 54.) Staff supports APS's proposal to discontinue Commission pre-approval of Storage Product Costs because these filings for approval have become frequent and routine and, Staff states, eliminating the prior approval does not mean that APS can be imprudent or unreasonable because the prudency of these contracts is reviewed in APS's rate cases. (Staff Br. at 55; *see* Ex. S-21 at 61.) Staff also supports the proposed 6 mill/kWh annual increase cap for the PSA, stating that it would result in a more reasonable balance and allow APS to better manage volatile market conditions while protecting customers by promoting rate gradualism. (Staff Br. at 55-56.)

In its Responsive Brief, Staff argues that the Commission should reject party proposals to reinstate the 90/10 provision because it "has not worked in the past and will not work any better now." (Staff RBr. at 18.) Staff argues that implementing a 90/10 provision assumes that APS would make cheaper fuel and purchased power purchases if it were sharing costs, which Staff argues is not true because fluctuations in the costs of fuel and purchased power are not under the control of utility management, and APS decisions regarding fuel and purchased power procurement cannot be incentivized by a 90/10 provision. (*See* Staff RBr. at 18-19; *see* APS Br. at 45-46; Ex. S-21 at 19-20.) Staff argues that the asymmetrical interest provision and the periodic fuel audits already balance the

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[389] Exhibit RUCO-26 includes copies of a September 2021 Hedge Plan Assessment Report and Findings conducted by Ernst & Young ("EY") and a February 2022 Hedge Plan Review conducted by Gelber & Associates. (*See* Ex. RUCO-26 (confidential); Ex. RUCO-25; Tr. at 4422.) At hearing, Mr. Radigan testified that he had not reviewed either the EY or the Gelber & Associates report. (Tr. at 4423.)

interests of APS and its customers. (Staff RBr. at 19.)

Staff argues that if the Commission considers changes to the PSA, it should focus on incentives targeted to items that have been deemed to be under the control and influence of management rather than the result of market-driven price fluctuations. (Staff RBr. at 19; *see* Tr. at 4946.) For example, Staff asserts, some sharing mechanisms are narrowly tailored to a particular category of costs. (Staff RBr. at 19.) Staff asserts that APS customers are actually better situated than customers in some jurisdictions because the PSA credits the net margins from short-term energy sales, while in some jurisdictions utilities are permitted to keep 20% to 30% of those net margins. (Staff RBr. at 19; *see* Tr. at 4946-4947.) Staff also notes Mr. Smith's testimony that very few states have cost-sharing mechanisms in place. (Staff RBr. at 19; *see* Tr. at 5366-5367.)

APS Response

In its Responsive Brief, APS disputes RUCO's argument that the main reason for the $800 million increase in fuel and purchased power costs between 2020 and 2023 was reliance on natural gas generation and APS's hedging program, stating that the increase in costs was mainly due to global fuel cost volatility and supply chain disruptions, both of which APS cannot control. (APS RBr. at 26; *see* RUCO Br. at 13-14; Tr. at 219; Ex. APS-12 at 32.) APS argues that the hedging program saved customers more than $340 million between 2020 and 2022[390] and that APS has passed $550 million in savings back to customers through the PSA over 2021 and 2022 when Western Energy Imbalance Market ("WEIM") participation is included. (APS RBr. at 26; Ex. APS-12 at 34; Ex. S-70 at 1-14; Tr. at 398.) APS reiterates that reinstating the 90/10 provision would penalize shareholders and customers. (APS RBr. at 26; *see* APS Br. at 44-46.)

APS asserts that AZLCG's argument about the difficulty of auditing and reviewing for prudency in the annual PSA reset processing period is premised on AZLCG's conflation of the annual reset process with the prudency review process, stating that APS's fuel and purchased power costs are subject to "rigorous prudency reviews" at any time, but no less frequently than every three years. (APS

[390] An APS data response shows that customers paid more under the hedging program in the years 2016 through 2020, at an average of $50.68 million per year, and that customers saved $83.4 million from the hedging program in 2021 and $315.6 million from the hedging program in 2022. (*See* Ex. RUCO-25 at 4-5.)

RBr. at 26-27; *see* Ex. APS-30 at Att. JEH-11RB; Ex. S-35 at 4.) APS argues that it would be impractical, maybe impossible, to have Staff conduct a prudency review with each annual PSA reset process, and that the "unnecessary delay" from such a review would prevent APS from passing costs or savings through the PSA to customers close to the time when those costs occur. (APS RBr. at 27.) APS reiterates that the PSA is working as intended and that this was Staff's determination in the most recent fuel audit. (APS RBr. at 27; *see* Ex. S-70 at 1-17.)

Finally, in response to AZLCG's claim that APS has "substantial control" over fuel and purchased power costs, APS cites Mr. Smith's testimony to the contrary and calls AZLCG "either naïve or disingenuous" for making the claim. (APS RBr. at 27; *see* Ex. S-21 at 20.)

Resolution

Concerning item 1 of APS's requested PSA POA modifications, the annual PSA increase cap, the Commission concludes that it is just and reasonable to adopt the proposed 6 mill/kWh cap. The 4 mill/kWh annual cap was adopted more than 15 years ago and is outdated in light of intervening economic conditions. The increase to the annual cap should mitigate to some extent the problem of under-collections within the PSA. We do not agree with RUCO that this is not an appropriate goal because even though under-collections are subject to a lower carrying cost than over-collections, they are still subject to a carrying cost that results in ratepayers paying more than the actual costs incurred.

Concerning item 2, the requirement to notify Staff when the PSA balance is greater than $150 million, we note that the PSA POA already requires APS to maintain and report monthly the balances in both the "Forward Component Tracking Account, which will record APS's over/under-recovery of its actual PSA Costs as compared to the Base PSA Costs recovered in revenue," and the "Historical Component Tracking Account, which will reflect monthly collections under the Historical Component." (*See* Ex. APS-30 at Att. JEH-11RB at 3.) It is unclear precisely the manner in which APS provides this report, although Mr. Cooper testified that APS provides transparent and detailed monthly reports to both the Commission and RUCO.[391] (Ex. APS-6 at 15.) Additionally, we note that Decision No. 78877 already requires APS to make a filing in Docket No. E-01345A-22-0297 if the

[391] These monthly reports do not appear to be made through compliance filings; it seems likely that they are simply submitted to Staff and RUCO and not filed in a docket.

under-collected PSA bank balance approaches $500,000. (*See* Decision No. 78877 at 6.) Of course, this does not address over-collections, which are also of concern to the Commission. Because the Commission desires for the public to be made aware when APS's PSA account balances are significantly higher or lower than what APS is collecting for fuel and purchased power costs through base rates, it is reasonable and appropriate for the Commission to require APS to make a filing in both the docket in which the then-current PSA rate was approved and in the docket for the most recently completed general rate case whenever the under-collected balance or over-collected balance of the PSA accounts exceeds $100 million. This filing requirement is intended to and shall replace the $500,000 filing requirement imposed by Decision No. 78877. The reason for adopting a $100 million reporting threshold, as opposed to the requested $150 million threshold, is that collecting or refunding a $100 million balance would create a noticeable change in residential customer bills, of approximately $7 for the average residential customer bill of 1,056 kWh, slightly higher than what would result from the 6 mill/kWh annual increase cap requested by APS and approved herein.[392] Further, because simply receiving a notification is not enough to address the problem that is causing the under-collection or over-collection, APS shall include in the notification a proposal for how the under-collection or over-collection should be addressed through the transition component of the PSA POA along with the calculations supporting the proposal. Staff shall, within 60 days after the filing of such a notification and proposal, review the notification and proposal, contact APS to obtain any supporting data necessary to scrutinize the calculations, and file in the docket in which the then-current PSA rate was approved, with a copy to the docket for the most recently completed general rate case, a Staff Report and Proposed Order analyzing the notification and proposal and recommending whether and in what manner the under-collection or over-collection should be addressed through the transition component of the PSA POA.

No party has contested item 3, the PSA POA revision to eliminate the requirement for APS to file third-party storage contracts and have them approved by the Commission in order to include them as Storage Product Costs in the PSA. This revision is supported by the evidentiary record herein and

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[392] $100 million divided by 14,968,021,000 kWh (the amount in TY sales) is approximately $0.0067/kWh. When this is multiplied by the average TY residential consumption of 1,056 kWh, the result is approximately $7.07.

will be adopted by the Commission.[393]

In item 4, the change to the alternate interest rate to apply when the ROE is not applied to the under-collected or over-collected PSA account balance, APS proposes to replace "APS's then existing short term borrowing rate" with "APS's deposit interest rate as established in Service Schedule 1." (Ex. APS-30 at Att. JEH-11RB at 6.) For any over-collection at the end of the PSA year, the interest is applied at a rate equal to the ROE or the alternate rate, whichever is greater; for any under-collection at the end of the PSA year, the interest is applied at a rate equal to the ROE or the alternate rate, whichever is less. (*See id.*) The rate identified in Service Schedule 1 is "the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website." (*See* Ex. APS-30 at Att. JEH-13RB at 5.) This revision in the PSA POA appeared for the first time in the PSA POA included in Ms. Hobbick's rebuttal testimony. (*See* Ex. APS-30 at Att. JEH-11 RB at 6; Ex. APS-36 at PSA POA (redline) at 5.) Ms. Hobbick did not mention the interest rate revision in her rebuttal testimony, and it is unclear whether the other parties hereto detected it. (*See* Ex. APS-30 at 7, 12-14; e.g., Tr. at 2622-2638.) This change also was not identified by APS in its Brief. Official notice is taken that on December 18, 2023, the one-year Treasury constant maturities rate was 4.95%. (*See* federalreserve.gov/releases/h15/ accessed on December 20, 2023.) Decision No. 78877 shows that the interest rate applied to the under-collected balance in January 2022 was only 0.10% and that the interest rate to be applied to the under-collected balance in January 2023 was to be 0.40%. (*See* Decision No. 78877 at 3.) This is more than 10 times lower than the interest rate proposed by APS herein, about which no testimony was provided.[394] While APS's then-existing short-term borrowing rate is more difficult for non-APS personnel to ascertain than is the one-year Treasury Constant Maturities rate, which is made publicly available and documented by the Federal Reserve, the Commission does not believe that it is in the public interest to raise the alternate rate most likely to be applied to under-collections by this magnitude without APS providing justification for doing so. The revision described in item 4 will be denied.

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[393] *See* Tr. at 5241-5243.

[394] In a data response, APS identified the 2023 customer deposit interest rate as 4.72%. (*See* Ex. S-18 at Att. RCS-3 at 122.) For the TY, APS's short-term debt cost rate was identified as 1.85%. (*See* Ex. APS-37 at Sched. D-1 at 2.)

Items 5 and 6 were approved (expressly and implicitly) above in Section (VI)(F) herein.

Whether or not to reinstitute a 90/10 provision for the PSA is a more difficult issue, in light of conflicting evidence concerning the extent to which APS is able to control the fuel and purchased power costs that it pays and concerning the probable impacts of a 90/10 provision. Opponents of the 90/10 provision essentially maintain that APS cannot control fuel and purchased power costs because APS is a market price-taker. On the other hand, proponents of the 90/10 provision argue that APS is able (or at least should be able) to exert a great deal of control over the fuel and purchased power costs it incurs, through its managerial decision-making concerning the resources it uses and its hedging program. We believe that the reality is somewhere in between these divergent opinions. APS obviously cannot control market prices for gas, which greatly contributed to the increased fuel and purchased power costs.[395] But those market prices were not the only reason for the size of the PSA under-collections recently experienced and resolved in Decision No. 78877. Although Mr. Radigan was unaware that the Commission's delay of PSA surcharge increases during the COVID pandemic exacerbated the under-collections, we have not forgotten the unintended pain caused by the Commission's providing ratepayers relief from the full 4 mill/kWh PSA increase during that difficult time. APS had no control over that particular outcome either.

But APS does have some control over the fuel and purchased power costs it pays. For example, APS has agreed to the price it pays for coal, including associated liquidated damages; APS decides its generation resource mix and the dispatch of those resources to meet load at any given point in time; and APS uses a hedging program to smooth out the worst of the spikes that could otherwise be experienced in gas prices. (*See* Tr. at 1418.) Mr. Joiner described the hedging program as insurance,[396] and we believe that is an apt description—you pay something for the protection every year, and in some years it saves you a great deal of money, like it did for ratepayers in 2021 and 2022, but in most years, it simply costs you some money. RUCO has taken the position that APS's hedging program is inadequate, but that appears to be based on extreme events that occurred to cause unprecedented spikes

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[395] Mr. Geisler cited the war in Ukraine, the Texas freeze event, and the extreme heat in summer 2020 as examples of events that caused the unusual spikes in gas prices. (*See* Tr. at 517-518.)

[396] *See* Tr. at 1191-1192, 1418.

in gas prices as well as the large under-collections that were caused not just by pricing but also by a prior Commission decision. RUCO asserts that the Commission should obtain detailed advice from experts in the field and thereafter make changes to APS's hedging program. The Commission notes that APS already has obtained detailed advice from experts in the field (EY and Gelber & Associates) and has asserted that it is in the process of determining, with yet another expert, the best way to implement Gelber & Associates' recommendations without causing speculative behavior that could put reliability at risk. The Commission believes that this is a responsible course of action and that APS should be permitted to complete this process and to make improvements to the hedging program, with an emphasis on saving customers as much as possible in fuel and purchased power costs while ensuring reliability. As Mr. Radigan acknowledged that he had not read the EY and Gelber & Associates reports on APS's hedging program, we do not believe that RUCO's position on this issue is fully informed and appropriate for adoption.

APS has credibly expressed concerns about the impacts on its credit rating and its ability to contract with counterparties if the Commission were to adopt a 90/10 provision in this matter. Mr. Geisler testified that a sharing mechanism would limit the amount of fuel and purchased power APS would be able to procure from the market, would be viewed as severely credit negative by credit agencies, would materially increase company risk, would likely increase APS's cost of capital, and would deteriorate APS's financial stability and ability to borrow capital needed to meet reliability and invest in the grid. (Tr. at 396, 538-539.) Mr. Joiner testified that APS's counterparties already require credit posting via a line of credit or a guarantee due to the large trade volumes in APS's power purchase agreements and term deals and opined that because APS would be seen as responsible for 10% of its purchased power costs if a 90/10 provision were imposed, and is already under a negative watch, the credit posting requirements would be increased, becoming more costly for APS and its customers. (Tr. at 1498-1499.) Mr. Cooper testified that a 90/10 provision would effectively disallow 10% of APS's fuel and purchased power costs even though they were prudently incurred and would detrimentally impact APS's credit quality and financial stability because the PSA is the adjustor mechanism upon which credit rating agencies focus the most. (Tr. at 623, 707-708, 743.) While the 90/10 provision proponents have disputed that APS's credit rating, financial stability, and contracting ability would be detrimentally impacted if a 90/10 provision were adopted, they have not established that this testimony from Mr. Geisler, Mr. Joiner, and Mr. Cooper is not credible.

APS has also credibly expressed that the 90/10 provision would not change APS's fuel and purchased power procurement practices or economic dispatch practices. Mr. Geisler testified that APS already is incentivized to keep fuel and purchased power costs as low as possible because of the regular fuel and purchased power audits done by the Commission, the fact that the cost of capital to pay for purchased power is higher than what APS charges customers in interest under the PSA, and the fact that APS makes no profit from the PSA. (Tr. at 539.) Mr. Joiner testified that APS would not do anything differently if there were a 90/10 provision and that he and the trade floor take great pride in their efforts to provide value to customers by purchasing lower cost energy and selling excess energy through off-system sales, but also stated that a 90/10 provision could be viewed by traders as promoting more speculative behavior that Mr. Joiner would not support because it could jeopardize reliability. (Tr. at 1111-1112, 1466, 1499-1503.) Mr. Joiner also testified that in his experience, if a utility starts making money through a cost-sharing mechanism, the cost-sharing mechanism is eliminated by regulators so that the savings can all be passed on to customers.[397] (Tr. at 1397-1398.) Additionally, Mr. Cooper testified that APS has an incentive to ensure its fuel and purchased power costs are low because APS needs to use so much of its liquidity, which is finite, to fund fuel and purchased power, which is a source of extreme frustration. (Tr. at 675-676.) While the 90/10 provision proponents have disputed that APS's decision-making and practices would not change if a 90/10 provision were adopted, they have not established that this testimony from Mr. Geisler, Mr. Joiner, and Mr. Cooper is not credible.

AZLCG's concerns about the difficulty of performing after-the-fact prudency reviews of APS's fuel and purchased power costs are valid but are not a reason to reestablish a 90/10 provision in the PSA. We cannot see how a 90/10 provision would enhance the Commission's or intervening parties' ability to perform after-the-fact prudency reviews, which are inherently difficult and time consuming but also necessary. Additionally, as stated previously, we do not agree that the definition of "prudently

[397] This appears to be what happened with the 90/10 provision previously included in APS's PSA, although it was eliminated through a settlement agreement.

invested" from A.A.C. R14-2-103(A)(3)(l), which is used only in the definition of "Original cost rate base," controls prudency determinations related to O&M expenses such as fuel and purchased power costs. As we did in Section (VI)(E) above in relation to Cholla and 4CPP liquidated damages, the Commission again directs APS, in future Fuel and Purchased Power Audits, and in future rate cases, to provide Staff and Staff's consultants with all available documentation supporting APS's contemporaneous decision-making concerning APS's fuel and purchased power costs. It is not in APS's best interests, or the public interest, for APS to hold back the information that explains and supports its choices and demonstrates its efforts to mitigate costs passed through to ratepayers.

The preponderance of the evidence herein does not support reestablishing a 90/10 provision in APS's PSA. Thus, we will require APS to file, after the effective date of this decision, a revised PSA POA that includes the revisions approved herein and that provides consistency in the time periods used for calculating the forward component, meaning that the forecasted costs and the forecasted kWh consumption shall be for the same 12-month period.

5. SRB

APS Proposal

APS requests Commission approval of a new SRB mechanism that would allow APS to recover, between rate cases, approved capital carrying costs for specific new APS-owned generation resources procured through an ASRFP process and with a minimum rate base investment of $50 million.[398] (Ex. APS-3 at 10; *see* Tr. at 185, 339; Ex. APS-30 at Att. JEH-09RB.) APS proposes an earnings test for the SRB so that it could not be used to earn more than APS's most recently authorized ROE. (Tr. at 194-195.) APS modeled the SRB after the SRB proposed by TEP in the 2022 TEP rate case, which was denied by the Commission, but added features intended to address the problems noted in the TEP decision. (Tr. at 532-535.)

In its final proposed form, attached hereto as Exhibit A, the SRB POA:

- Provides for recovery of approved Qualifying Resource Capital Carrying Costs[399] not already

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[398] In its application, APS proposed modifications to the REAC to recover certain capital carrying costs between rate cases for renewable generation assets but subsequently abandoned that proposal in favor of the SRB. (Tr. at 462.)

[399] In Section 1, the SRB POA imprecisely refers to "Capital Carrying Costs for Qualifying Resources," although that is not the defined term in the POA.

recovered in base rates or through a separate recovery mechanism;

- Defines Qualifying Resource Capital Carrying Costs to include:
  - A return at APS's Adjusted Weighted Average Cost of Capital,[400] which is the WACC approved in the most recent general rate case discounted by 1.00%;
  - Depreciation expense calculated using the rates approved in APS's most recent general rate case;
  - Income taxes and property taxes;
  - Deferred taxes and Tax Credit Benefits[401] associated with Qualifying Resources; and
  - Associated O&M expenses;
- Requires a Qualifying Resource:
  - To be owned by APS;
  - To have an investment cost of at least $50 million;
  - To be classified in one or more of the following FERC accounts:
    - Steam Production (310 through 316),
    - Nuclear Production (320 through 325),
    - Hydraulic Production (330 through 336),
    - Other Production (340 through 346), or
    - Energy Storage (348, 351, or 363);
  - Not to be a coal-fired steam generator;
  - To be in service at the time of SRB recovery;
  - To be consistent with APS's IRP Action Plan; and
  - To be acquired through an All-Source RFP process that complies with A.A.C. R14-2-705 and R14-2-706 and uses an Independent Monitor;
- Limits APS to one SRB Application each year and a total of five Applications between general

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[400] APS omits "Average" in the definition of the term in Section 2, although it appears in the definition of "Qualifying Resource Capital Carrying Costs."

[401] APS omits "Benefit" in the definition of Qualifying Resource Capital Carrying Costs, although that is included in the subsequently defined term.

rate cases;[402]

- Limits the year-over-year annual SRB adjustor increase to 3% of APS's jurisdictional base rate revenue requirement as determined in APS's most recent rate case;
- Subjects any SRB increase to an Earnings Test that allows recovery of costs not to exceed the Earnings Test Threshold, which is the ROE authorized in APS's most recent rate case, "with an updated capital structure and cost of debt adjusted to reflect authorized recovery of the FVI approved in the most recent rate case," but defers any amount above the Earnings Test Threshold in a Balancing Account for recovery in a future year;
- Requires any over-collection in the Balancing Account to be credited interest at a rate equal to APS's authorized ROE or APS's deposit interest rate established in Service Schedule 1, whichever is greater, and to be refunded to customers over the following 12 months;
- Requires any under-collection in the Balancing Account to be charged interest at a rate equal to APS's authorized ROE or APS's deposit interest rate established in Service Schedule 1, whichever is less, and to be recovered from customers over the following 12 months;[403]
- Requires Balancing Account amounts to be included in the SRB adjustor rate in a future year, subject to the Earnings Test;
- Requires APS to engage in an SRB stakeholder process, tied to its RPAC process, that:
    - Includes quarterly public stakeholder meetings and the sharing of SRB project information,
    - Requires APS to hold a stakeholder comment period and provide written responses to stakeholder comments, and
    - Requires APS to make good-faith efforts to include stakeholder feedback in developing its SRB Applications;
- Requires the following process once APS has completed development of a Qualifying Resource and placed the Qualifying Resource into service (i.e., once it is used and useful in providing

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[402] Language included in Section 9 of the SRB POA is somewhat different than this language from Section 1; the different language is described below.

[403] The language concerning recovery over 12 months is included in the definition of "Applicable Interest" but seems potentially inconsistent with application of the Earnings Test and the 3% cap.

service):

- APS must file with the Commission, in a new docket[404] and in the docket used for APS's most recently concluded rate case, a Notice of Intent to File an Application for Approval of Schedule SRB-1 ("SRB Notice") that includes SRB Tables I, II, and III[405] from the SRB POA;
- APS must post a link to the SRB Notice in a prominent location on the main page of its website (as a means to notify its customers)[406];
- APS must hold at least one open house and one technical conference for each Qualifying Resource;
- Intervention and discovery must be made available after the filing of the SRB Notice;
- At least 60 days after filing the SRB Notice, APS must file an Application for Approval of Schedule SRB-1 ("SRB Application"), which must include SRB Tables 1, II, and III as well as supporting schedules for the following:
  - Calculation of the SRB Adjustor Rate,
  - Calculation of the revenue requirement for the Qualifying Resources and the determination of jurisdictional FVRB,
  - Identification of the Qualifying Resource(s) for which SRB recovery is requested, with associated in-service dates and total company and jurisdictional costs;
  - Calculation of the Balancing Account balance over a 12-month period;[407]
  - Calculation of the Earnings Test Threshold; and
  - Identification of Bill Impacts by customer class, with some subclasses broken out and seasonal bill impacts identified;
- APS must hold at least one stakeholder review meeting after the SRB Application is

[404] The new docket is to be used for the first Notice and Application and any subsequent Notices and Applications until conclusion of APS's next rate case.

[405] SRB Table I is ASRFP public information. SRB Table II is a schedule of planned Qualifying Resource projects. SRB Table III is a schedule of completed Qualifying Resource projects.

[406] APS must also post a link to the SRB Application once that has been filed.

[407] Presumably this is intended to be for the 12-month period that concluded immediately before the Application is filed, although the schedule does not make that clear.

filed;

  - Staff must make its best efforts to review and process the SRB Application promptly, with the goal of completing its review and filing a Staff Report within 60 days after the SRB Application is filed, and must make a site evaluation as part of its review;
  - Discovery may continue after the SRB Application is filed "if necessary";
  - Prudency for a Qualifying Resource may be determined by the Commission in the SRB Application proceeding or may be deferred until APS's next general rate case; and
  - The SRB Application must be considered and approved by the Commission for Schedule SRB-1 to become effective;
- Requires APS, every 12 months after the initial SRB Application is approved by the Commission, to file an Application to Reset Schedule SRB-1 ("Reset Application"), which:
  - Must include calculations for the Earnings Test; calculations for the 3% revenue cap; and updated SRB Tables 1, II, and III; and
  - May include a request to recover through the Schedule SRB-1 adjustor for additional Qualifying Resources;
- If a Reset Application includes a request to recover through the Schedule SRB-1 adjustor rate for additional Qualifying Resources, requires APS to file a new SRB Notice;
- Restricts APS to filing one Reset Application that includes a request to recover through the Schedule SRB-1 adjustor for additional Qualifying Resources each year;[408]
- Restricts APS to a total of five Reset Applications that include a request to recover through the Schedule SRB-1 adjustor for additional Qualifying Resources before filing its next rate case application;[409]
- Requires each Qualifying Resource for which recovery is being obtained through Schedule SRB-1 to be moved into rate base in APS's next rate case, where it will be subject to a return

[408] This suggests that APS could file additional Reset Applications in a year if they did not include additional Qualifying Resources, although the Commission does not believe that is APS's intention or that APS would have any reason to desire to do that.

[409] This suggests that there could be a total of six SRB adjustments between the initial rate case in which the SRB mechanism is approved and APS's next rate case: one SRB Application and five Reset Applications. The Commission does not believe that is APS's intention. As the immediately prior footnote observes, it also suggests that there could be multiple Reset Applications in a year.

at the same WACC applied to all other rate base items; and

- Requires that Schedule SRB-1 be reset upon issuance of the Commission's decision in APS's next rate case.

APS asserts that the SRB is necessary for APS to procure the substantial new generation resources needed for APS reliably to serve anticipated customer load growth (60% in energy usage and 40% in peak demand by 2031) and to transition cost-effectively to a balanced, more diverse resource fleet. (APS Br. at 35, 36; *see* Ex. APS-4 at 3.) According to APS, it will need to procure approximately 3,500 MW of new resources beyond what it currently has under contract during a time when it will also lose approximately 1,350 MW of dispatchable thermal generation. (APS Br. at 35; *see* Tr. at 1108-1109; Ex. APS-76 at 2; Ex. APS-12 at 2.) APS argues that the SRB will put APS-owned resources on similar footing with purchased power resources, helping to ensure that projects selected for procurement from ASRFPs are the most affordable for customers irrespective of APS's need to access capital for project ownership. (APS Br. at 35; *see* Tr. at 229-230.) APS notes Mr. Geisler's testimony that without the SRB, APS may be forced to select purchased power resources over more cost-effective APS-owned resources because of difficulties accessing capital.[410] (APS Br. at 35-36; *see* Tr. at 197.) APS also asserts that overreliance on purchased power resources leads to reliability risks and notes that 65% of the purchased power resource projects APS has procured through ASRFPs since 2020 were delayed or cancelled due to challenges experienced by third-party developers. (APS Br. at 36; *see* Tr. at 197-197, 252, 393.) APS asserts that with its owned projects, it will have a much higher degree of certainty and control that resources will be delivered when needed to serve customers reliably. (APS Br. at 36; *see* Tr. at 196-197.)

APS argues that the SRB provides important customer benefits by supporting reliable service, providing prompt tax credits between rate cases, providing a discounted WACC and no return on the

[410] Mr. Geisler testified that APS will need to borrow capital to afford investing in new generation and in the absence of the SRB, due to APS's significantly reduced credit rating and being on negative watch with credit rating agencies, APS may not be able to obtain the credit necessary to be able to afford competitively priced projects that would be owned by APS and may be forced to select more expensive third-party owned projects because the costs of third-party-owned projects can be more timely recovered through the PSA. (Tr. at 192-193, 197, 230.) APS obtains debt in its own right, not through PNW. (Tr. at 697.)

FVI,[411] reducing the frequency of rate cases, supporting rate gradualism, and enabling APS to attract debt and equity capital on more favorable terms. (APS Br. at 36-37; *see* Ex. APS-4 at 6-8.) APS also touts the "extensive customer protections" built into the SRB POA, including the requirement for a generation resource to be procured through an ASRFP that involves a Commission-approved Independent Monitor, the 3% annual increase limit, the earnings test, the limit of five resets between rate cases, the $50 million minimum investment threshold, the robust stakeholder process, and the fact that the generation resource must be used and useful and in service before it can be included in the SRB. (APS Br. at 37; *see* Ex. APS-11 at 15-16; Tr. at 4964-4969.) Additionally, APS asserts that the SRB stakeholder process, which will include the RPAC, additional stakeholder meetings, a notice of intent before a request to include a project in the SRB, open houses and technical conferences, discovery, and other processes, will ensure transparency and provide both stakeholders and the Commission the opportunity to participate and obtain information. (*See* APS Br. at 37-38.)

According to APS, capital tracking mechanisms have been used in Arizona to support rate recovery between rate cases for renewable energy resources, environmental improvements to generation plants, and replacement of aging infrastructure, and this type of mechanism is also commonly used across the U.S. for capital investments including traditional and renewable generation and transmission and/or delivery infrastructure. (APS Br. at 38-39; *see* Ex. APS-4 at 4-6; Ex. APS-2 at Att. TNG-01DR;[412] Ex. APS-61.) APS also claims that each of the holding companies included in Dr. Morin's peer group used for cost of capital analyses has a generation investment tracker that recovers either renewables or a blend of renewable and traditional generation sources.[413] (APS Br. at 39; *see* Ex. APS-102.)

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[411] The accuracy of this is clouded by the Earnings Test Threshold definition, which includes "updated capital structure and cost of debt adjusted to reflect authorized recovery of the Fair Value Increment (FVI) approved in the most recent rate case" and the inclusion in Schedule E of the SRB POA of FVI-related language and a calculation of "WACC adjusted for FVI" "in order to achieve the approved FVI increment" on OCRB.

[412] Exhibit APS-61 shows that of 305 separately listed electric and gas utilities (or jurisdictional utility divisions) throughout the U.S., there were a total of 21 adjustor mechanisms that covered traditional generation costs. Exhibit APS-61 also states that 13% of adjustor clauses across the U.S. include traditional generation costs. The means for calculating this figure were not provided.

[413] This does not appear to be accurate. Exhibit APS-102 appears to show that 7 of the 24 holding companies included in Dr. Morin's proxy group do not have generation investment capital trackers, as indicated by "N" thereon. (*See* Ex. APS-102; Ex. APS-33 at Att. RAM-02DR.) Of the 38 generation investment capital trackers identified in Exhibit APS-102, 19 appear to allow for traditional generation investments.

APS asserts that the SRB conforms to constitutional requirements and does not constitute single-issue ratemaking because it is permissible for the Commission to use a fair value determination from a previous rate case, add on the value of infrastructure improvements made between rate cases, and determine fair value and set a rate between general rate cases. (APS Br. at 39-40; *see Residential Util. Consumer Office v. Arizona Corp. Comm'n*, 240 Ariz. 108, 112 (2016) ("*SIB Opinion*").) APS states that the SRB complies with the requirements established in the *SIB Opinion* upholding the Commission-approved System Improvements Benefits adjustor mechanism ("SIB") and satisfies the Arizona Constitution. (APS Br. at 40.)

AZLCG

AZLCG argues that the Commission should reject the SRB because it is unlawful single-issue ratemaking that does not provide the Commission an opportunity to complete a constitutionally sufficient determination of FVRB, the APS SRB proposal should be treated the same as the rejected "almost identical" TEP SRB proposal, and the SRB fails to protect and benefit ratepayers sufficiently and thus is not in the public interest. (AZLCG Br. at 56.) Based on *Scates v. Arizona Corp. Comm'n*, 118 Ariz. 531 (Ariz. Ct. App. 1978 ("*Scates*") and the *SIB Opinion*, AZLCG argues that single-issue adjustments to utility rates are unlawful unless the utility presents information that allows the Commission to complete a constitutionally sufficient finding of current fair value, which the SRB would not because while the SRB POA includes a "purported updated determination of Jurisdictional [FVRB]," the calculation does not recognize changes in plant, accumulated depreciation, contributions in aid of construction ("CIAC"), advances in aid of construction ("AIAC"), and accumulated deferred income taxes ("ADIT"), as were included for the SIB's updated fair value determination. (AZLCG Br. at 58; *see* Tr. at 2846-2848, 5034-5035.) Rather, AZLCG asserts, the SRB calculation of FVRB would simply involve adding the SRB investment cost to the FVRB established by the Commission in this decision. (AZLCG Br. at 58-59; Ex. APS-97 at 6-7; Tr. at 5033.) AZLCG argues that this "gives short shrift" to the constitutional requirement for the Commission to determine FVRB, citing Mr. Smith's testimony that the SRB FVRB calculation would be "just kind of piecemealing . . . for selected items" and the Commission's conclusion in the 2022 TEP rate case that TEP's proposed SRB was not constitutional.[414] (AZLCG Br. at 59; *see* Tr. at 5033-5034; Ex. APS-84 at 113-114.) In its Responsive Brief, AZLCG reiterates that the SRB's design is unconstitutional because unlike the SIB, the SRB does not recognize the other changes described in the *SIB Opinion* (changes in plant, accumulated depreciation, CIAC, AIAC, and ADIT). (AZLCG RBr. at 9.)

AZLCG argues that the Commission's reasons for rejecting the TEP SRB are equally compelling and applicable here, specifically citing the following characteristics that the APS SRB proposal shares with the rejected TEP SRB:

- The SRB being single-issue ratemaking because it would adjust rates in response to a single cost item considered in isolation, without considering offsets to rate base or other aspects of APS's cost to serve that could move rates in a different direction;[415]
- The SRB not being tailored to address immediate safety and reliability issues, and the lack of any evidence that APS would be unable to provide safe and reliable service without the SRB;[416]
- The SRB being designed to address regulatory lag, which is an insufficient reason to forgo the traditional ratemaking methodology, because regulatory lag works both ways, and APS is always interested in maintaining and if possible improving its earnings;[417]
- The SRB not including a requirement for a rate case application filing, which means there is no established rate case interval to ensure that the costs included in the SRB and charged to ratepayers are prudent;[418]
- The timing of the SRB proposal providing parties insufficient time to examine it fully and fairly, because APS did not request the SRB until its rebuttal testimony, which left parties two weeks to review and issue discovery on it before filing surrebuttal testimony, and insufficient time to fully vet issues related to the SRB, such as what would happen if costs collected in the SRB were later determined in a rate case to have been imprudent;[419] and
- The SRB not accounting for decreases in net plant investment due to accumulated depreciation

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[414] We note that this is implied in the 2022 TEP rate case decision but not expressly stated. (*See* Ex. APS-84 at 114.)
[415] AZLCG Br. at 60; *see* Ex. APS-84 at 113; Ex. AZLCG-1 at 44; Ex. AZLCG-5 at 30; Tr. at 188, 2608.
[416] AZLCG Br. at 60; *see* Ex. APS-84 at 113; Tr. at 393.
[417] AZLCG Br. at 61; *see* Ex. APS-84 at 113; Tr. at 182, 1953.
[418] AZLCG Br. at 61; *see* Ex. APS-84 at 113; Ex. APS-97.
[419] AZLCG Br. at 61-62; *see* Tr. at 185-187, 525, 532, 2425-2426, 2781-2782, 2592, 5327.

on existing plant.[420]

AZLCG argues that the ratepayer "protections" and "benefits" offered in the SRB proposal are insufficient to overcome the Commission's rationale for rejecting the TEP SRB and, further, that these provisions must be viewed against the alternative of rejecting the entire SRB, not approval of an SRB without these features. (AZLCG Br. at 63.) AZLCG argues that the 3% annual cap is a ratepayer risk rather than a ratepayer protection because it would allow APS to recover approximately $360 million in additional costs by the third year of the SRB's implementation (i.e., approximately 95.3% of APS's requested revenue deficiency in this matter) without filing a rate case application. (AZLCG Br. at 64; *see* Ex. APS-30 at Att. JEH-02RB; Ex. APS-4 at 2; Ex. APS-97 at 6; Tr. at 188, 2347, 2386-2387, 2421-2423, 2426-2427; 2820, 4973.) AZLCG points out that the SRB increases would be on top of any other adjustor increases that might be approved between rate cases and, further, that the SRB Balancing Account would result in any costs exceeding the 3% cap simply being deferred with carrying costs for future recovery through the SRB. (AZLCG Br. at 64; *see* Tr. at 189-190, 2421-2422.)

Additionally, AZLCG argues, the earnings test does not limit APS's recovery of costs because APS also proposes for the costs exceeding the earnings test to be deferred with carrying costs for future recovery through the SRB or rolled into base rates. (AZLCG Br. at 64-65; *see* Ex. APS-97 at 6; Tr. at 2422-2423, 2426-2427, 2820.) Thus, AZLCG asserts, the SRB is a deferred accounting mechanism that would allow APS to recover the full value of all SRB projects regardless of APS's over-earning, making the earnings test a "company-oriented provision" as opposed to a ratepayer protective measure. (AZLCG Br. at 65; *see* Tr. at 2427, 2590, 4974.) AZLCG further observes that because the earnings test would be based on figures from APS's FERC Form 1, rather than data established in this rate case, the Commission and parties will not have the opportunity to evaluate and impact the additional costs from investments made and expenses incurred between rate cases. (AZLCG Br. at 65; *see* Tr. at 2428-2429.)

The limit on SRB applications between rate cases also offers only "illusory protection," AZLCG argues, because the SRB does not require APS to come in for a rate case at all, and five SRB

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[420] AZLCG Br. at 62-63; *see* Ex. APS-84 at 113; Ex. AZLCG-5 at 30-31; Tr. at 3031. AZLCG also asserts that the SRB would not recognize incremental revenues. (AZLCG Br. at 63; *see* Ex. AZLCG-5 at 30-31; Tr. at 3031.

applications would allow APS to recover $600 million annually without recognition of any cost reductions between rate cases or any determination of the prudency of the SRB-recovered costs. (AZLCG Br. at 65-66; *see* Ex. APS-97; Ex. APS-30 at Att. JEH-02RB; Ex. AZLCG-5 at 29-30; Tr. at 2348, 2386-2387, 2421-2422, 2781-2782.)

AZLCG further argues that the potential for prudency evaluations to be made in SRB proceedings does not sufficiently protect ratepayers because APS proposes to require Staff to complete its review within 90 days,[421] prudency reviews take time, and APS would prefer to have prudency determinations deferred until rate cases, which AZLCG appears to conclude means that prudency reviews would be deferred to rate cases and all costs would be included in the SRB without a prudency analysis. (AZLCG Br. at 66; *see* Ex. APS-97 at 7, 27; Tr. at 2424-2425, 2780, 4380, 5031.) AZLCG argues that deferring the prudency review would confuse the issue, leading to administrative inefficiency or even implicit approval of costs. (AZLCG Br. at 66; *see* Tr. at 2784.)

AZLCG also argues that the purported benefits to ratepayers from the SRB (promotion of lowest cost resource selection, flow-through of tax credits, WACC discount, rate gradualism, and rate case delay) also do not warrant its approval. (AZLCG Br. at 66-67; *see* Tr. at 190-191, 199, 312, 382, 2347-2348.) AZLCG states that APS's argument that its owned projects could better compete with third-party developers in an ASRFP if there were an SRB is a red herring, because APS committed to procuring the most economic resources through its ASRFP process even if the SRB is not adopted, and APS has provided only speculation and not evidence to establish that it will not be able to bid competitively in its ASRFPs at some point in the future if the SRB is not approved. (AZLCG Br. at 67; *see* Tr. at 190-191, 193, 196-197, 591-592, 2347, 3666-3668.[422]) AZLCG points out that while Mr. Geisler testified that APS would not be able to afford the capital investments needed to meet growing demand without the SRB, Mr. Cooper testified that APS would have access to capital to meet growing demand, just at a borrowing rate higher than desired. (*See* AZLCG Br. at 67, n.420; Tr. at 191, 591-592.) AZLCG further argues that if the SRB were critical, APS would have included the SRB proposal

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[421] In the final SRB POA proposed, this is actually 60 days.

[422] AZLCG also cited *Arizona Corp. Comm'n v. Citizens Utils. Co.*, 120 Ariz. 184, 190 (App. 1978) for the proposition that speculation is not substantial evidence that supports a Commission decision.

in its initial application, not its rebuttal testimony.[423] (*See* AZLCG Br. at 67, n.420.) If APS is unable to access credit on favorable enough terms to bid into ASRFPs, AZLCG asserts, APS can file a rate case application. (AZLCG Br. at 67; *see* Tr. at 198, 300.)

AZLCG further argues that tax credits are not cost savings to ratepayers, even if they are flowed through the SRB, because APS has acknowledged that the SRB will never be a negative number, and third-party developers are eligible to receive the same tax credits as APS and can pass tax credit savings through in their bids.[424] (AZLCG Br. at 68; *see* Tr. at 191, 199, 201, 472.) AZLCG also argues that calling the 1% WACC discount a customer benefit is misleading and inaccurate because the full WACC will be applied once the carrying costs on SRB assets are rolled into base rates. (AZLCG Br. at 68; *see* Tr. at 191, 325, 2348, 2604, 4383.) AZLCG criticizes APS for likening the WACC discount to an efficiency credit both because APS admitted that the SRB does not include an efficiency credit and because the efficiency credit in the approved SIB mechanisms is 5%, which APS agreed would be a significant reduction to SRB costs not included in their SRB POA proposal. (AZLCG Br. at 68; *see* Tr. at 342, 2600-2602, 4383; Ex. RUCO-8 at 20.) AZLCG also criticizes APS for stating that the SRB would provide rate gradualism, stating that APS is misapplying the principle because rate gradualism is a consideration in cost of service and revenue allocation, not a rationale for allowing rate increases between rate cases to cause lower rate increase requests in the next rate case application. (AZLCG Br. at 68-69; *see* Tr. at 190, 312, 3393; *Freeport Minerals Corp. v. Arizona Corp. Comm'n*, 244 Ariz. 409, 414-415 (App. 2018).) AZLCG further expresses skepticism that the SRB would cause APS to delay future rate cases because APS declined to commit to a "stay-out" provision and would not specify the extent to which the SRB would delay a subsequent rate case, and other parties have debated whether the SRB would delay rate case applications. (AZLCG Br. at 69; *see* Ex. APS-4 at 8; Ex. S-24 at 64; Tr. at 327, 382-383, 2612-2613, 4380, 4966, 5237.)

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[423] We note that APS's application proposed an expansion of its REAC to allow recovery of capital carrying costs for new APS-owned non-carbon emitting resources, including energy storage and excluding nuclear energy resources. (*See* Ex. APS-36 at REAC POA (redline).) With the level of storage investments APS intends to make, this would have included significant capital investment for which recovery would have been requested through the REAC. APS proposed to invest $230 million in renewable and energy storage systems in 2022, $210 million in 2023, and $450 million in 2024, and Mr. Cooper opined that $450 million is the annual level of investment likely necessary to serve customers. (*See* Ex. APS-5 at 17.)

[424] We note that while third-party developers can choose to do this, they can also choose not to, making this an inapt comparison when APS has committed to passing through the tax credits.

Additionally, AZLCG asserts, the investments proposed to be included in the SRB are not appropriately dealt with through an adjustor mechanism because they are all within APS's control, and adjustor mechanisms are generally reserved for expenses that are outside the utility's control or required by law or rule. (AZLCG Br. at 67-68; *see* Ex. RUCO-18 at 2; Ex. AZLCG-5 at 30; Ex. AZLCG-1 at 44; Tr. at 771.) AZLCG points out that APS's own evidence shows the rarity of capital tracking mechanisms. (AZLCG Br. at 69-70; *see* Ex. APS-2 at Att. TNG-01DR at 2; Ex. APS-61 at 99-100; Tr. at 328-329, 451-452, 2434, 2436.) The Commission should deny approval of the SRB, AZLCG asserts, because adjustment mechanisms shift the risk associated with recovery of costs from shareholders to customers. (AZLCG Br. at 70; *see* Ex. RUCO-18 at 1.)

Finally, AZLCG argues that the SRB would inequitably allocate production costs because it would allocate costs on a 100% energy basis, which is contrary to the treatment of production demand costs in base rates proposed by APS and historically approved by the Commission, both of which involve allocation based on both energy and capacity. (AZLCG Br. at 70-71; *see* Tr. at 1610-1611, 1614, 2376-2380.) AZLCG states that Ms. Hobbick agreed APS has not provided testimony or other evidence to support a different allocation of the production demand costs included in the SRB[425]and that there was merit to the idea of allocating SRB costs in the same way as base rate production demand costs. (AZLCG Br. at 71; *see* Tr. at 2379-2382.) AZLCG criticizes the SRB for being designed to collect costs from all APS customers, including AG-X customers, which would result in AG-X customers who receive their entire generation service (energy and capacity) from third-party generation service providers ("GSPs") (rather than APS) (i.e., those AG-X customers who self-supply resource adequacy ("RA")) paying generation investment costs through the SRB and subsidizing SRB investments until the next rate case in which the costs are removed from the SRB. (AZLCG Br. at 71; *see* Tr. at 2370-2379.) AZLCG notes Ms. Hobbick's agreement that customers who are using the generation resources included in the SRB would pay less due to assessing the SRB surcharge on AG-X customers who self-supply RA. (AZLCG Br. at 71-72; *see* Tr. at 2373.) AZLCG argues that by

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[425] Specifically, Ms. Hobbick agreed that APS had presented no cost allocation justification or class cost of service study to support a 100% energy-weighted allocation of fixed production costs, stating that APS does not typically do a class-level cost of service study for adjustment mechanisms. (*See* Tr. at 2379-2380.)

proposing to eliminate energy and capacity costs for AG-X customers who self-supply RA, APS has admitted that it is not just and reasonable to charge these AG-X customers for generation investments. (AZLCG Br. at 72.) AZLCG further contests Ms. Hobbick's testimony that AG-X customers who self-supply RA would benefit from the SRB because they might leave the AG-X program and need resources to provide them service, stating that it is inconsistent with APS's proposal to require a three-year notice for such AG-X customers to return to standard APS service so that APS has time to procure adequate resources to serve them. (AZLCG Br. at 72; *see* Ex. APS-11 at 36-37; Tr. at 2371-2372.) AZLCG argues that if the Commission approves the SRB (which it should not), the Commission should (1) require that SRB costs be allocated using the same production demand allocation methodology approved by the Commission for non-SRB costs, and (2) exempt from the SRB AG-X customers who self-supply RA under the AG-X proposal made by APS herein.[426] (AZLCG Br. at 72.)

<u>IBEW Locals</u>

The IBEW Locals support APS's proposed SRB because it will allow APS to make the significant investments in generation needed because APS has been and will continue to face record peak loads. (IBEW Br. at 10.) The IBEW Locals state that ratepayers will have to pay for the generation resources at some point and that APS's suggestion to have ratepayers pay gradually through SRB charges rather than through sharp rate increases will be better for ratepayers. (IBEW Br. at 10-11.) The IBEW Locals add that the SRB will allow APS to pass tax savings associated with projects through to ratepayers promptly and may lengthen the time between rate cases. (IBEW Br. at 11.) The IBEW Locals assert that the SRB will protect ratepayers due to the 3% annual cap, the earnings test, the limit on number of SRB resets between rate cases, and a balancing account with asymmetrical interest provisions. (IBEW Br. at 11; *see* Ex. APS-4 at 3-7.)

<u>Ms. Nelson</u>

Ms. Nelson asserts that the Commission should reject the SRB proposal because it would allow annual 3% increases and would not require APS to come in for a rate case within a specific interval,[427]

[426] The AG-X proposal is discussed in Section (VI)(I)(4).

[427] Ms. Nelson argued that the SRB could result in a 30% rate increase over 10 years, but that is inconsistent with the proposed SRB POA, which would limit the number of SRB proceedings between rate cases. (*See* KN Br. at 2; Ex. APS-97 at 5; APS Br. at Att. C at 1.)

meaning that the Commission and stakeholders would not be able to exercise oversight or review prudency until APS files a rate application. (KN Br. at 2.)

Sierra Club

Sierra Club agrees that APS needs access to capital to transition to clean energy and that APS would benefit from more timely cost recovery, but advocates for the SRB to be denied because it is too broad, does not allow sufficient review of APS's investments, and does not ensure transparency and meaningful stakeholder input. (SC Br. at 40.) Sierra Club asserts that the SRB would allow recovery for APS-owned gas generation and would allow recovery of investments without the thorough review of costs and revenues that occur in a rate case. (SC Br. at 40.) Sierra Club criticizes the SRB POA for not defining the process for stakeholder meetings, not identifying the stakeholders who must be included, and not identifying the information APS must provide to stakeholders. (SC Br. at 41; *see* Ex. APS-30 at Att. JEH-09RB at 4, 5.) Sierra Club also asserts that the SRB POA does not provide for a hearing or allow stakeholders to file testimony, engage in discovery,[428] or cross-examine witnesses. (SC Br. at 41; *see* Tr. at 2548-2549.) Additionally, Sierra Club asserts that the prudency of the capital investments included in the SRB would not be determined until a rate case,[429] which could be years after the time the investments are made and cost recovery begins. (SC Br. at 41; *see* Tr. at 2550.) Sierra Club notes that a number of parties have expressed concerns about the SRB being insufficiently developed and lacking adequate customer protections and states that Sierra Club likewise cannot support the SRB as proposed. (SC Br. at 41; *see, e.g.,* Ex. S-24 at 68-69; Ex. AZLCG-5 at 29.) Sierra Club urges the Commission to reject the proposed SRB and direct APS to develop a new adjustor proposal that is limited to zero-emission resources and that includes well-defined and robust procedures for stakeholder participation, including the opportunity to conduct discovery, present testimony, and have a hearing if necessary. (SC Br. at 41-42.)

In its Responsive Brief, Sierra Club argues that the SRB would limit the Commission's oversight of capital spending and leave customers vulnerable to imprudent investments. (SC RBr. at

[428] We note that the opportunity for discovery was added in APS's SRB POA included as Exhibit APS-97.

[429] We note that the opportunity for prudency determinations to be made in an SRB proceeding was added in APS's SRB POA included as Exhibit APS-97.

1, 21.) Sierra Club notes that APS filed a revised version of the SRB POA on September 10, 2023, and proposes additional changes in the SRB POA included in its Brief, but states that although the changes represent a slight improvement, the SRB is still overbroad, does not ensure adequate oversight of APS's expenditures, and does not adequately protect customers. (SC RBr. at 21; *see* Ex. APS-97; APS Br. at Att. C.) Sierra Club criticizes the revised SRB POA for not including a hearing or testimony and asserts that stakeholder meetings and a comment period are not an adequate substitute in light of the breadth of the SRB, the $50 million investment threshold, and the lack of a prudency review until a rate case. (SC RBr. at 21-22; *see* APS Br. at Att. C at 6-8.) Sierra Club acknowledges that the SRB POA would not allow recovery of coal-fired resources but notes that gas-fired generation resources would still be permissible SRB investments. (SC RBr. at 22.) Sierra Club also argues that APS's SRB is "very similar" to TEP's SRB that the Commission rejected due to concerns that apply equally hereto. (SC RBr. at 22-23.) Sierra Club maintains that the Commission should reject the SRB and direct APS to develop a new adjustor proposal for a future rate case. (SC RBr. at 23.)

<u>SWEEP & WRA</u>

SWEEP and WRA assert that the SRB POA does not sufficiently protect ratepayers because it would not involve the full review of revenues and costs as performed in a rate case and increases the risk of APS over-recovering its costs. (SWEEP/WRA Br. at 18; *see* Tr. at 3435.) SWEEP and WRA assert that if the SRB had been in effect "without application limits or restrictions on qualifying resources," APS would have been able to collect 42% of its PTYP costs from this proceeding,[430] outside of a rate case. (SWEEP/WRA Br. at 18-19.) SWEEP and WRA also oppose the SRB "because it would allow recovery of costs for assets not yet in service."[431] (SWEEP/WRA Br. at 19.) Ratepayers would pay more rather than less under the SRB, SWEEP and WRA argue, because of the interest accrued on balances in the SRB Balancing Account at APS's ROE rate.[432] (SWEEP/WRA Br. at 19; *see* Ex. SWEEP-2 at 6.)

[430] SWEEP and WRA state that they calculated this figure by adding the PTYP costs in Exhibit APS-10 Attachments JT-01RJ through JT-06RJ and then subtracting all costs above the $50 million minimum threshold. The value of this calculation is unclear.

[431] This is inaccurate. (*See* Ex. APS-97; APS Br. at Att. C.)

[432] While the SRB POA would allow for interest to accrue on any amount included in the Balancing Account, the ROE would be applied to an under-collection only if the ROE is lower than the alternate interest rate, which APS has proposed to be "APS's deposit interest rate as established in Service Schedule 1." (*See* APS Br. at Att. C at 2.)

In its separate Responsive Brief, SWEEP agrees that a reduction in the frequency of rate cases, which APS claims would be a benefit of the SRB, would be desirable, but states that the SRB's reliance on an earnings test is not an appropriate substitute for rate cases and that the earnings test must adequately protect customers and recover only authorized revenue. (SWEEP RBr. at 7.) SWEEP states that the earnings test proposed by APS is insufficient and flawed and recommends that the Commission deny APS's SRB proposal. (SWEEP RBr. at 7.)

In its separate Responsive Brief, WRA reiterates the arguments from the SWEEP/WRA Brief and adds that the SRB would constitute single-issue ratemaking, which the Commission discourages, and would have no "guardrails" and run the risk that APS-owned resources would be favored in ASRFP bid reviews. (WRA RBr. at 4-5.) WRA asserts that the current IRP stakeholder process ends before the ASRFP review of bids and that there is no process in place through which stakeholders are provided additional information concerning how bids conform to the IRP analysis or why variations from IRP assumptions are warranted. (WRA RBr. at 5; *see* Ex. SWEEP-1 at 17.) WRA argues that because the SRB would allow APS to begin recovering on its owned resources without any Commission rate review of revenues and costs or a full prudency determination, the "Commission should not give APS an incentive to favor its resources over others." (WRA RBr. at 5.) WRA characterizes the SRB as a "blank check"; states that it would allow APS to select any type of resource and begin cost recovery immediately, with no stakeholder input and no prior Commission review or approval; and states that it would also compromise the IRP process.[433] (WRA RBr. at 5.)

<u>RUCO</u>

RUCO argues that the SRB should be rejected because, like the SIB, it is not an interim rate or an adjustor; it would not reduce the number of APS's adjustor mechanisms or be limited to cleaner non-carbon based energy sources like the originally proposed expanded REAC; and it is very similar to TEP's SRB, which was rejected by the Commission. (RUCO Br. at 3-5; *see SIB Opinion* at 113; Ex. APS-3 at 8, 10-11; Ex. APS-84 at 113-114, ex. D at 1-6; Ex. APS-30 at Att. JEH-09RB at 1-6.) RUCO acknowledges that APS revised the SRB POA to address issues raised in this matter, and agrees

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[433] Several of these assertions are inaccurate, as the SRB POA prohibits coal-fired resources, does not allow cost recovery until after Commission review and approval, and does require stakeholder meetings. (*See* APS Br. at Att. C at 2.)

that the final proposed SRB is like a SIB in some ways, but argues that in "the ways that count for the ratepayer, it is not 'like the SIB.'" (RUCO Br. at 6; *see* Ex. APS-97.) RUCO argues that the SRB is problematic because its scope is not narrow like that of the SIB, and its does not require a rate case filing to allow true up (as the SIB generally does), instead only limiting the number of surcharge requests between rate cases. (RUCO Br. at 6-7.) RUCO cites Mr. Smith's testimony that Staff envisioned an SRB-type mechanism designed to support transition away from fossil-fueled generation and toward renewables, that the SIB is not the best model for an APS SRB, and that an in-depth process involving stakeholders should be used to work out the parameters and details of what would be included in the SRB and how it would function. (RUCO Br. at 7; *see* Ex. S-24 at 63, 68-69.) RUCO adds that APS's failure to include the SRB in its application suggests that such a broad mechanism was "an afterthought to align with TEP's request" rather than an urgency for APS. (RUCO Br. at 7.)

Additionally, RUCO argues that the concerns raised with the TEP SRB proposal have not been resolved in APS's SRB POA because the types of investments to be included in the SRB are not clearly identified; APS has not persuasively shown that traditional ratemaking should be forgone in favor of "single-issue, extraordinary ratemaking"; and the SRB's ratepayer-protection features are inadequate. (RUCO Br. at 7-8.) RUCO expresses doubt that approval of the SRB would result in less frequent APS rate cases, based on APS's current suite of adjustors and the fact that the application in this matter was filed less than a year after the decision in the last rate case. (RUCO Br. at 8.) RUCO criticizes the SRB's inclusion of a discounted WACC (to be applied only while an investment is being recovered through the SRB) rather than an efficiency credit such as the one in the SIB.[434] (RUCO Br. at 8-9; *see* Ex. RUCO-8 at 20.) RUCO adds that the SRB has not been vetted by stakeholders through this matter and that it is the type of "rushed" and unvetted stakeholder process the Commission discouraged in the TEP decision. (RUCO Br. at 9; *see* Ex. APS-84 at 114.) RUCO also asserts that the SRB is single-issue ratemaking, as was the TEP-proposed SRB, which the Commission must consider when determining whether it is fair to ratepayers and in the public interest. (RUCO Br. at 9; Ex. APS-84 at

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[434] RUCO also asserts that UNS Electric has proposed an efficiency credit for its requested SRB, although this is not part of the record in this matter. Staff's witness was unable definitely to confirm that the UNS Electric SRB proposal included an efficiency credit but did state that Staff believes an efficiency credit would be an improvement in any SRB proposal that Staff would want an SRB to include. (*See* Tr. at 5363.)

113.)

RUCO argues that the SRB is not limited to specific operating costs, as the Arizona Court of Appeals has stated that adjustors are, and appears to question whether the SRB's provision of updated measurements would satisfy the Commission's constitutional fair value requirement. (RUCO Br. at 10; *see Scates* at 534-535; *SIB Opinion* at 114.) RUCO argues that the SRB will significantly impact customer bills each year, without flowing through to ratepayers any actual cost savings experienced since the last rate case, and that this mismatch is why the SRB represents piecemeal or single-issue ratemaking and why it would cause ratepayers to pay more than their actual cost of service over time. (RUCO Br. at 10.) RUCO cites the *Scates* decision's warning that piecemeal ratemaking is "fraught with potential abuse." (RUCO Br. at 11; *see Scates* at 534.)

RUCO also argues that the timing of prudency determinations for plant included in the SRB is problematic whether prudency is determined in the SRB proceeding or in a subsequent rate case because there is no rate case filing requirement in the SRB; every prudency determination will involve substantial investments; and "[a] procedure where the prudency determination is not made at the same time as the recovery of the investment or shortly thereafter is destined to fail" because determining imprudence years after an approved SRB request would cause APS significant financial harm and thus be "impossible" for the Commission to make, effectively eliminating the purpose of a prudency determination. (RUCO Br. at 12.) RUCO argues that determining prudency in the SRB proceeding would be "better, but highly inefficient and extremely costly . . . and [a] deter[rent] . . . for stakeholders" to participate due to the "daunting" nature of the undertaking. (RUCO Br. at 12.) RUCO opines that having five SRB proceedings between rate cases followed by a rate case would be far more "time consuming, expensive[,] and onerous than participating in one rate case." (RUCO Br. at 12.) RUCO further argues that "the potential for unintended consequences is alarming" and points to the PSA and its "massive under[-]collection problem" to support that the SRB must be thoroughly vetted and carefully considered, as the Commission stated in the TEP decision. (RUCO Br. at 13.) RUCO also questions who would decide in which proceeding prudency would be determined (APS or the Commission), whether Staff and stakeholders would have any say on the issue, and whether it is even possible for prudency to be resolved under the current parameters of the SRB POA. (RUCO Br. at 13.)

RUCO urges the Commission to reject the SRB. (RUCO Br. at 13.)

Staff

Staff expresses skepticism that the SRB will reduce rate case frequency, although APS has stated that is one of the reasons for the SRB. (Staff Br. at 60-61.) Staff notes that the projected capacity resources that would qualify for SRB inclusion, with expected costs and in-service dates, are included in a highly confidential portion of Mr. Smith's testimony.[435] (Staff Br. at 61; *see* Ex. S-24 at 67; Ex. S-23 at Att. RCS-14 at 11-13.) Staff acknowledges the Commission's rejection of the proposed SRB in the 2022 TEP rate case and notes that the Commission indicated it would consider a modified version that addresses the concerns raised and contains important customer safeguards. (Staff Br. at 61; *see* Ex. APS-84 at 112-114.) Staff states that it envisions an SRB mechanism that functions as a transition mechanism as APS moves from fossil fuel generation to renewables and supports the concept of an SRB but recommends that an in-depth stakeholder process be used to establish the specifics of what the SRB would include and how the SRB would work. (Staff Br. at 61-62; *see* Ex. S-24 at 68-69.) Staff recommends that the Commission direct further exploration of the SRB using such a process and that the SRB "provide for Commission involvement at an earlier stage of the process." (Staff Br. at 62.)

In its Responsive Brief, Staff sets forth at length the concerns expressed by the Commission concerning the TEP-proposed SRB that was rejected in the 2022 TEP rate case. (Staff RBr. at 19-20; *see* Ex. APS-84 at 113-114.) Staff states that with the proposed SRB POA included with its Brief, APS has made a number of refinements and reiterates that Staff supports the SRB as a transitional mechanism to clean energy, with additional modifications. (Staff RBr. at 21.) Staff asserts that the SRB process should involve the Commission earlier because the proposed SRB POA involves the Commission only after the projects are chosen, completed, and in service, as opposed to the SIB, which involves the Commission at the beginning of the process by having the Commission approve in a rate case the specific projects to be recovered through the SIB. (Staff RBr. at 22.) Staff asserts that it is

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[435] Mr. Smith stated that the SRB revenue requirements shown were based on APS's requested 10.25% ROE. (*See* Ex. S-24 at 67.) Although the numbers are highly confidential, we note that APS does not project reaching or exceeding the SRB cap in the years shown.

important for the Commission to see the scope of projects reviewed, the reasons behind APS's selection of a preferred project over others, and the estimated costs of projects. (Staff RBr. at 22.) Staff argues that information on all of the likely projects to be proposed for recovery through the SRB between rate cases should be supplied to the Commission at the earliest possible time and that Staff "supports the SRB only if the Commission is involved at a much earlier stage of the process[,] . . . consistent with the SIB process." (Staff RBr. at 22.)

Staff agrees with APS that the SRB conforms to constitutional requirements and is not single-issue ratemaking, stating that the *SIB Opinion* makes it clear that a full rate case is not necessary to determine fair value provided that the fair value determination from a previous rate case (not too long ago) is used along with the value of infrastructure improvements made between rate cases to determine fair value and aid the Commission in setting rates. (Staff RBr. at 23; *see SIB Opinion*.)

Further, Staff asserts, the final prudency determination concerning any SRB-included projects should be made in a rate case. (Staff RBr. at 23.) Staff asserts that the prudency determination is part of the Commission's ratemaking rules and that establishing prudency outside of a rate case could impact the Commission's ability to fully review the issue. (Staff RBr. at 23.)

<u>APS Response</u>

In its Responsive Brief, APS argues that it needs to procure substantial amounts of generation in the coming years to meet load growth and replace coal-fired generation, and the SRB is necessary for APS to meet future load and ensure continued reliable service. (APS RBr. at 19.) APS notes that the SRB is limited to new APS-owned generation or storage resources and does not allow recovery for other capital investments such as distribution, transmission, or information technology, or for coal-fired assets. (APS RBr. at 19-20.) APS points out that projects to be included in the SRB must meet identified generation needs and be procured through an ASRFP subject to a "robust stakeholder process" and an independent monitor, and argues that this will ensure that the resources are the best low-cost generation or storage resources to meet customer needs reliably. (APS RBr. at 19-20.) APS asserts that it will hold quarterly stakeholder meetings to discuss development of SRB-qualifying projects and keep stakeholders informed, that it will solicit stakeholder comments and make good-faith efforts to consider and address stakeholder feedback, and will conduct an open house and technical conference before filing an SRB application to allow Staff and stakeholders to view the project and get additional information. (APS RBr. at 20.) APS argues that the SRB has a "fulsome application process," allows for discovery, and provides "ample time" for the Commission and stakeholders to analyze APS's request and provide feedback and recommendations to the Commission before a decision. (APS RBr. at 20-21.) APS also points out that contrary to the assertions of SWEEP and WRA, a project must be used and useful and in service before APS seeks cost recovery for it through the SRB. (APS RBr. at 21.) Further, APS points out, the resource must be determined prudent, either in the SRB proceeding or a subsequent rate case, and because the Commission has the authority to address the issue should an SRB-included project subsequently be determined imprudent in a rate case, such as by ordering a refund and disallowing any costs proven to be imprudent, the issue need not be resolved in the SRB POA. (APS RBr. at 21.)

APS touts the earnings test, which would require the Commission to review and consider updated financial information and changes in APS's financial condition since the most recent rate case, specifically including rate base (including plant in service and applicable depreciation), deferred and other taxes, regulatory assets and liabilities, operating expenses, operating income, and applicable income tax for the most recent calendar year as reported in the FERC Form 1. (APS RBr. at 21.) APS asserts that the financial data would be adjusted for Commission-ordered pro forma adjustments related to surcharges and items removed in the most recent rate case. (APS RBr. at 21.) Further, APS asserts, the earnings test expressly considers changes to APS's capital structure and will include consideration of the FVI approved in the most recent rate case.[436] (APS RBr. at 21.) The rate of return for the calendar year, determined using all of this data, will then be compared to APS's threshold rate of return (the rate of return approved in the most recent rate case) to ensure that SRB recovery would not result in over-earning. (APS RBr. at 21-22.) APS argues that the SRB process may actually provide ratepayers more protection than a rate case because it involves scrutinizing only one or two resources at a time rather than the multitude of projects that are considered in a rate case. (APS RBr. at 22.) APS

[436] It is not clear what it means to "consider the FVI." The WACC approved in a recent rate case is calculated based on OCRB rather than FVRB, meaning that it does not "consider the FVI." Considering the FVI, which occurs only in a case in which RCND has been proposed, generally means calculating the FVROR to apply to the FVRB. Yet APS has consistently referred to the WACC in the context of the SRB, not the FVROR.

also argues that the SRB will benefit customers because it will create more gradual rate increases, spread over time, as opposed to a rate case. (APS RBr. at 22.; *see* Ex. APS-3 at 8; Ex. APS-31 at 5.) In response to arguments concerning the benefits of an efficiency credit versus the WACC discount, APS demonstrates that for a hypothetical $500 million plant project included in the SRB, the reduced WACC would save customers $2 million more annually than would a 5% efficiency credit.[437] (APS RBr. at 22-23.)

Further, APS argues, the SRB is not single-issue ratemaking and is not unconstitutional because the SRB represents a recognized method of setting a rate between rate cases and complies with the constitutional requirement for the Commission to determine fair value when setting rates, a determination that the *SIB Opinion* clearly allows to occur outside of a rate case. (APS RBr. at 23-24; *see SIB Opinion* at 112.) APS asserts that the scenario in *Scates* is distinguishable from the proposed SRB because the Commission in *Scates* had made no determination of fair value and had given no consideration to the impact the rate increase would have on the utility's rate of return. (APS RBr. at 24-25; *see Scates* at 537.) APS points out that the SRB requires a finding of fair value and includes an earnings test to ensure that the SRB will not result in APS exceeding its ROE. (APS RBr. at 24-25.)

Finally, in response to AZLCG's concerns about the applicability of the SRB surcharge to all general service customers, including those AG-X customers that self-supply RA, APS asserts that the AG-X program currently allows AG-X customers to move from AG-X to standard service freely, which makes the program cyclical and problematic for non-participating customers. (APS RBr. at 25.) APS asserts that when AG-X customers move back to standard service, they take advantage of resources funded by non-AG-X customers, making it appropriate for AG-X customers to contribute to the SRB. (APS RBr. at 25.) APS adds, however, that it would consider exempting from the SRB surcharge AG-X customers who self-supply RA if in the future the AG-X program is revised to allow customers to self-supply RA and require provision of at least three years' notice before leaving AG-X and returning to standard service. (APS RBr. at 25.)

. . .

[437] APS shows that the discounted WACC would produce annual capital carrying costs of $42 million, as opposed to $44 million with the 5% efficiency credit. (*See* APS RBr. at 23.)

Resolution

No party has disputed that APS needs to make very significant, perhaps unprecedented, capital investments in generation resources to meet the increased load and demand anticipated due to the high levels of growth in customer energy and capacity needs between now and 2030. While Mr. Geisler painted a picture of an APS that potentially could not afford to make the capital investments needed for APS-owned projects at all without the SRB (or a similar capital investment recovery mechanism), Mr. Cooper clarified that APS could make the capital investments but would pay undesirable financing costs to do so. Undesirable financing costs ultimately mean higher rates to be paid by customers in subsequent rate cases, an outcome that the Commission would like to minimize to the extent possible. The Commission would also like to avoid lumpy rate increases that are likely to result from APS making very significant capital investments in generation resources and recovering on those investments only through traditional rate cases. While the concept of an SRB may not be supported by "gradualism," in the traditional sense of the word (as described by AZLCG), an SRB would result in more gradual increases as opposed to the rate shock that could result from a rate case that newly recognizes vast increases in plant in service made since the previous rate case. The Commission also desires to remove any impediment that APS may have to selecting the lowest cost reliable generation resource (or storage) project to meet customer needs safely and reliably, such as APS claims to exist because it is able to recover on power purchase agreements in a more expedited fashion than it can on its owned resources. Additionally, the Commission is cognizant of the delays and cancellations of third-party provider projects selected through APS's recent ASRFPs and joins in APS's concern that this type of scenario could continue. Finally, despite suggestions to the contrary, the Commission believes it unlikely that a third-party provider (who also has a profit motive) will pass tax credit benefits from a project through to ratepayers in its pricing to the same extent that APS would if it were required to do so under the SRB POA.[438]

Based on the *SIB Opinion*, the Commission is confident that the SRB POA conforms to the constitutional requirement for the Commission to determine fair value and establish rates in

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[438] We note Mr. Joiner's testimony that the Inflation Reduction Act has not created a net meaningful impact in the cost of resources from third-party developers. (*See* Tr. at 1363-1364.)

consideration of that fair value. The *SIB Opinion* very clearly establishes that the fair value determination can be made in a proceeding that follows a rate case, based on the FVRB established in the rate case and additional updated information. That is precisely what the SRB POA would do.

Staff recommends that the Commission be inserted into the SRB process earlier than it is under the proposed SRB POA, without specifying how or the point at which this could or should occur but with language suggesting that it would be during the consideration of ASRFP bids. Currently, APS considers ASRFP bids after the RPAC has provided input on the ASRFP and with the involvement of the Commission-approved Independent Monitor. (*See* Ex. APS-11 at 15-16.) The Commission is concerned that Commission involvement during APS's ASRFP bid evaluation process could insert the Commission into resource management decisions in a way that threatens impermissible managerial interference. The Commission believes that Staff should be involved in APS's RPAC[439] but that it is not the Commission's role to determine the resources that APS should select from the bids received through an ASRFP. The Commission's role is to determine the prudency of the capital investments selected by APS after they are made and pursuant to the Commission's ratemaking rule. Although Staff cites the SIB as the impetus for its idea that the Commission should have earlier involvement in the SRB process, the SIB involved different types of investments than the SRB, specifically the replacement of crumbling infrastructure that had already been identified by a water/wastewater utility in a rate case. The Commission's determining that a utility is correct in its assessment that certain portions of its infrastructure need replacement is very different from the Commission's directing a utility to obtain specific resources in response to an ASRFP. The former is essentially determining the propriety of a proposed capital project and its method of financing, and the latter is managing the utility and an inappropriate role for the Commission.

After considering all of the evidence and arguments presented herein, the Commission finds that it is just and reasonable to approve an SRB for APS in this matter, albeit with significant modifications from the SRB POA attached hereto as Exhibit A. With the approval of an SRB, the Commission is providing APS a benefit beyond traditional ratemaking. In light of this, the Commission

[439] The RPAC includes stakeholders representing consumer advocacy groups, public interest groups, environmental advocates, and industry. (Ex. APS-11 at 15.)

will temper that benefit somewhat from APS's SRB proposal to ensure that ratepayers are adequately protected. APS shall modify the SRB POA to conform to the following:

- A coal-fired steam generator may be an SRB Qualifying Resource;
- APS shall not be permitted to defer for future recovery in a subsequent SRB proceeding any amount that exceeds the 3% year-over-year cap on the SRB surcharge increase;
- If APS exceeds the Earnings Test Threshold, APS shall not be permitted to defer for future recovery in a subsequent SRB proceeding any amount that exceeds the Earnings Test Threshold and shall not be permitted to increase the SRB surcharge to be applied for the following year;
- If APS under-collects through the SRB surcharge, APS shall not be permitted to collect any such under-collection in a subsequent SRB proceeding;
- To the extent that AIAC and/or CIAC has been provided to APS for any Qualifying Resource proposed for recovery through the SRB, the entire AIAC and/or CIAC amount shall be deducted from the costs included in calculating the SRB surcharge;
- APS shall be limited to an initial SRB Application and five Reset Applications, with no more than one filed in each 12-month period, before its next rate case application is filed;
- The prudency of projects proposed for inclusion in the SRB shall be determined by the Commission during an SRB proceeding, not during a rate case, and shall be based upon the definition of "prudently invested" included in A.A.C. R14-2-103(A)(3)(l);
- The possibility of a hearing to determine the prudency of an investment proposed for inclusion in the SRB shall be provided in an SRB proceeding upon party (APS, Staff, or Intervenor) request;
- The deadline for a Motion to Intervene shall be 60 days after APS files an SRB Notice;
- In addition to notifying its customers through posting a link to the SRB Notice on its website, APS shall, with its regularly scheduled billing immediately following the date when the SRB Notice is filed, mail or email to its customers,[440] as a billing insert or a separate communication, an explanation of the SRB Notice that includes at least (1) how to find the SRB Notice and the

[440] The delivery method used by APS shall be consistent with the manner in which each customer receives their monthly bill.

subsequent SRB Application/Reset Application on the APS website, (2) standard Commission-required information about intervention and instructions to file a Motion to Intervene, (3) the deadline for a Motion to Intervene, and (4) a phone number to contact a representative of APS;

- Staff's deadline for completing its review and filing a Staff Report[441] and/or a Request for Hearing ("Staff Report/Request for Hearing") shall be 90 days after the SRB Application/Reset Application is filed;
- An Intervenor's deadline for filing an Objection to SRB Application/Reset Application and/or a Request for Hearing ("Intervenor Objection/Request for Hearing") shall be 75 days after the SRB Application/Reset Application is filed;
- Each party may file a Response to a Staff Report/Request for Hearing or Intervenor Objection/Request for Hearing within 14 days after it is filed, and APS may include in its Response a Request for Hearing;
- If a Request for Hearing is filed:
    - The Hearing Division shall issue a Procedural Order scheduling the hearing to occur within 60 days after the Request for Hearing is filed, unless the parties agree to a later date or a later date is necessary due to Commission scheduling constraints;
    - The hearing shall be scheduled for one day only, unless good cause exists for additional scheduled hearing days;
    - The scope of the hearing shall be limited to determining the prudency of the capital investments APS proposes in the SRB Application/Reset Application, and the standard to be used shall be the definition of "prudently invested" included in A.A.C. R14-2-103(A)(3)(l); and
    - The Hearing Division shall issue a Recommended Opinion and Order for the Commission's final determination of prudency and approval or disapproval of the SRB Application/Reset Application;

[441] If Staff is not filing a Request for Hearing along with its Staff Report, Staff's Staff Report shall be accompanied by Staff's Proposed Order for Commission determination of prudency for each Qualifying Resource included in the SRB Application/Reset Application and Commission approval or denial of the SRB Application/Reset Application.

- When each Qualifying Resource for which Capital Carrying Costs are being recovered through the SRB is moved into rate base in a subsequent general rate case, the plant balance for the Qualifying Resource shall reflect all accumulated depreciation since the actual in-service date;
- An AG-X customer who self-supplies RA, as described and resolved in Section (VI)(I)(4) herein, shall be exempt from the SRB surcharge for the duration of the time the customer maintains its status as an AG-X customer who self-supplies RA; and
- APS shall ensure that the modified SRB POA consistently uses the terms that are defined rather than variations on those terms, and shall ensure that the language of the SRB POA and the language used on Tables I, II, and III and the Schedules accompanying the SRB POA is consistent with the directives described above.

Additionally, to ensure that Staff is well informed of APS's generation resource procurement plans and the information behind them at an early stage, and thus positioned to review an SRB Application and Reset Applications more efficiently, we will require Staff to participate actively in APS's RPAC.

H. Cost of Service Study ("COSS") Issues

1. Allocation of Production Demand Costs

a. Allocation Method

In Decision No. 78317, the Commission determined that the Staff-proposed Average and Peak – 4 Coincident Peak ("A&P-4CP") allocation method for production costs more appropriately reflected the actual contributions each customer class makes to system peak demand and should be used instead of the APS-proposed Average and Excess – Non-Coincident Peak ("A&E-NCP") allocation method because APS's A&E-NCP method[442] disproportionally allocated production costs to customers with lower load profiles, overstated costs for Church customers and School customers, and likely overstated costs for residential customers (to the extent their class NCPs do not occur during the CP). (Ex. RUCO-7 at 234.) The Commission expressly stated: "APS's production needs are largely driven by its

[442] APS's A&E-NCP method used two measures of demand: (1) Average Demand, derived from a class's average hourly demand each hour of the year; and (2) Excess Demand, derived from the amount of a class's NCP demand that exceeded the class's Average Demand. (Ex. RUCO-7 at 226.) The costs were allocated to each class based on its proportionate share of the sum of NCP Excess Demands. (*Id.*) For the residential class, the total residential costs were reallocated to subclasses based on the subclasses' contributions to the system coincident peak over the 4CP. (*Id.*)

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." (Ex. RUCO-7 at 234-235.) Additionally, the Commission directed APS, in its next rate case, to 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. (Ex. RUCO-7 at 235, 433.)

The Commission also ordered APS in the COSS for its next rate case to perform specific analyses related to the "extra costs" that APS claimed to incur to provide service to DG customers (beyond the costs of providing their delivered power and energy). (Ex. RUCO-7 at 433-434.) The issue of cost allocation specifically to DG customers is discussed in Section (VI)(H)(3).

APS Proposal

Pursuant to the direction provided in Decision No. 78317, APS in this matter performed three A&P-based COSSs: (1) a COSS based on site-load for residential customers, (2) a COSS that combined residential solar and non-solar customers, and (3) a COSS based on delivered load.[443] (APS Br. at 55.) Additionally, consistent with its own preferences, APS performed a COSS using an A&E-4CP allocation method for production demand costs. (APS Br. at 55.) APS recommends that the Commission adopt the A&E-4CP method in this case and for use in future rate cases. (APS Br. at 55; *see* Ex. APS-24 at 18.)

APS asserts that production-related assets generally are designed and built to enable APS to meet its system peak load. (APS Br. at 56.) According to Mr. Moe, the A&P method and A&E method each calculate two components, with the first component being each class's share of annual energy (aka average demand) and the second component being each class's share of peak demand. (Ex. RUCO-24 at 15.) The measure of each class's share of peak demand is different for the two methods, however, because the A&P method measures the entire peak demand (i.e., including the average portion), and the A&E method measures only the amount by which the peak demand exceeds the average demand (i.e., the excess peak demand). (Ex. RUCO-24 at 16-17.) Mr. Moe and Mr. Higgins

[443] In its Brief, APS referred to this as a study based on distribution load.

both characterized the A&P's inclusion of the average demand within the entire peak demand as "double-counting" of the energy component. (APS Br. at 56; *see* Ex. APS-24 at 16017; Ex. AZLCG-3 at 8.) Mr. Moe also testified that Staff's A&P method uses a weighted average calculation to combine the energy and peak components that places even more emphasis on the energy component. (Ex. RUCO-24 at 17.) APS argues that the A&P method improperly assumes that a large portion of power plant capacity costs are driven by customers' energy usage at all times in all seasons and that this does not align with actual peak load demand in APS's service territory. (APS Br. at 56; *see* Ex. APS-24 at 16.)

APS argues that the A&E-4CP is a better method to allocate production demand costs, asserting that it is the method APS is required to use in FERC rate cases to ensure that the right proportion of cost is being allocated to each jurisdiction. (APS Br. at 57; *see* Ex. APS-24 at 12.) APS also asserts that the A&E-4CP method is supported by FEA, AZLCG, Walmart, and the School Groups.[444] (APS Br. at 57; *see* Ex. APS-25 at 7; Ex. AZLCG-3 at 8; Ex. Walmart-1 at 10; Tr. at 3553.) APS states that the average demand (average hourly demand for each hour of the year for each class) reflects the base level of demand that drives the costs for baseload power plants, while the excess demand (the amount of 4CP demand that exceeds the average demand for each class) reflects the cost driver for peaking power plants. (APS Br. at 57; *see* Ex. APS-24 at 16-18.) Mr. Moe testified that many utilities use the 4CP method or a similar method focused only on peak demand (without an average/energy component) to allocate production demand costs and that if they instead use an allocator that combines both peak demand and energy, the A&E method is preferred by most jurisdictions. (*See* Ex. APS-24 at 18.)

APS argues that it has demonstrated the A&E-4CP method is preferable over the A&P method because it more accurately reflects the cost to serve customers in APS's service area, it is conceptually valid, it is widely accepted in the industry, and both high-load-factor and low-load-factor parties recognize that it fairly allocates costs to all customers (including schools and houses of worship). (APS Br. at 57-58; *see* Ex. APS-24 at 15-18; Ex. AZLCG-3 at 8; Tr. at 3553.) APS requests that the

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[444] The School Groups' Brief provides at best tepid support for the A&E-4CP method, stating "that its impact on other customer classes might be disruptive" and suggesting a "middle ground" that would use the A&P-4CP method with less weighting of the average component. (*See* SG Br. at 8.)

Commission adopt the A&E-4CP method for use in future rate cases. (APS Br. at 58.)

AZLCG

AZLCG argues that APS has historically used the A&E-NCP method to allocate production demand costs, that the Commission recently approved TEP's use of the A&E-NCP method with Staff's support,[445] and that Staff has consistently supported use of the A&E method in electric rate cases over the past 15 years with the exception of the last APS rate case, in which Staff advocated for and the Commission required APS to use the A&P method. (AZLCG Br. at 35-36; *see* Ex. AZLCG-3 at 18-20; Ex. RUCO-7 at 234; Ex. APS-25 at 7.) AZLCG asserts that the Commission approved the A&P method in the last rate case because of concerns that the A&E-NCP method did not recognize CP as the primary driver of production demand costs[446] and disproportionately allocated production demand costs to low-load-factor customers. (AZLCG Br. at 36; *see* Ex. RUCO-7 at 234.) AZLCG asserts that it, APS, FEA, Walmart, and the School Groups[447] support APS's use of an A&E-4CP method for production demand cost allocation. (AZLCG Br. at 36; *see* Ex. APS-25 at 2; Ex. FEA-2 at 11-12; Ex. AZLCG-3 at 8; Ex. Walmart-1 at 10; Tr. at 1586, 3389, 3405, 3564.) AZLCG argues that the A&E-4CP method is superior to the A&P method because by emphasizing annual energy usage rather than system peak usage, the A&P method does not adequately consider the classes responsible for APS's costs in meeting summer peak demand. (AZLCG Br. at 36; *see* Ex. APS-25 at 7, 17-18; Ex. FEA-2 at 10; Ex. AZLCG-3 at 8-11; Ex. AZLCG-14 at 1-2; Ex. Walmart-1 at 8-10; Tr. at 1586, 1600, 1707-1709, 3389, 3564, 4546-4547, 4736.[448])

AZLCG argues that the A&P method's "double energy weighting problem" is well known and has caused other PUCs to reject it. (AZLCG Br. at 37; *see* Ex. AZLCG-3 at 12-13.[449]) AZLCG notes

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[445] Decision No. 79065 reveals that the production demand cost allocation method used by TEP was not disputed by Freeport, FEA, or any other party and thus was discussed in the decision only in passing and never with the method named. (*See* Ex. APS-84 at 60-64.) Thus, any Commission approval of the method was made only implicitly.

[446] AZLCG fails to note the Commission's determinations in Decision No. 78317 that the A&P-4CP method "more appropriately reflects the actual contributions each class of customers makes to system peak demand" and that "customers with high load factors consume a significant amount of energy during system peak hours and contribute significantly to peak demand." (Ex. RUCO-7 at 234-235.)

[447] As noted previously, the School Groups do not strongly support a change to the A&E-4CP method. (*See* SG Br. at 8.)

[448] It should be noted that although RUCO's witness agreed that class cost of service analyses should consider and weigh each class's contribution to summer peak and that APS's generation investments are focused on ensuring adequate resources to meet summer peaks, RUCO's witness did not provide any testimony concerning the appropriate allocation method for APS's production demand costs, and RUCO did not take a position on the issue. (*See* Tr. at 4734-4736.)

[449] AZLCG quotes an Iowa PUC order from 2011 and a Missouri PUC order from 2010. (*See* Ex. AZLCG-3 at 12-13.)

Walmart's testimony that Staff's A&P method allocates production demand costs 74.64% on an energy basis and 25.36% on a peak demand basis. (AZLCG Br. at 37; *see* Ex. Walmart-1 at 10.) In contrast, AZLCG asserts, the A&E-4CP method allocates costs based on average energy use and excess demand, meaning that the incremental amount of production plant required to meet peak summer loads is properly allocated to the classes who create the need for the additional capacity. (AZLCG Br. at 37; *see* Ex. AZLCG-3 at 17; Tr. at 1600-1601.)

AZLCG further criticizes the A&P method for its reliance on judgment, stating that "the 'average' component of the A&P methodology can be any number based on the subjective judgment of experts and the Commission."[450] (AZLCG Br. at 37; *see* Tr. at 1613, 1732-1733.) AZLCG notes that in the A&P-4CP method approved in the last rate case, Dr. Dismukes used the system load factor to weight the average component, with the result being that production capacity costs were allocated 48% to 49% on an energy basis, which AZLCG argues is "far in excess" of what would be reasonable. (AZLCG Br. at 37-38; *see* Ex. Walmart-1 at 9; Ex. AZLCG-3 at 11; Tr. at 1610-1611.) AZLCG asserts that jurisdictions using the A&P method and the NARUC Manual reflect use of a lower weighting for the average component. (AZLCG Br. at 38; *see* Ex. AZLCG-3 at 12-13; Ex. AZLCG-12 at 1-2; Tr. at 1613, 1707, 1734.)

Additionally, AZLCG argues, because the A&E-4CP method evaluates customer class contributions to system peak demand, which often do not match school demand patterns, it addresses the Commission's concerns regarding the allocation of production demand costs to schools. (AZLCG Br. at 38; *see* Ex. APS-25 at 8; Tr. at 1605-1606.) AZLCG notes that the A&E-4CP method allocates fewer costs to schools than does the A&P-4CP method used by APS and that the School Groups believe the A&E-4CP method is fair. (AZLCG Br. at 38; *see* Ex. AZLCG-5 at 32; Ex. AZLCG-3 at ex. KCH-16, ex. KCH-17; Tr. at 1604-1605, 3553-3554.)

Further, AZLCG argues that although APS witness testimony in the last rate case opposed the A&E method used with CP because it collapses into a 1CP allocator and does not reflect both demand

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[450] This statement is misleading. It is the weighting of the average component in the A&P method, as opposed to the average component itself, that is subject to the application of judgment. Mr. Moe testified that in the A&P method, the weighting of the average component can be adjusted; that Dr. Dismukes's weighting of the average component was the system load factor, approximately 48%-49%; and that, in Mr. Moe's experience, the weighting usually is a 25% load factor. (*See* Tr. at 1611-1613.)

and energy information,[451] that issue does not exist in this matter because both APS and AZLCG have designed their A&E-4CP methods to keep the excess demand component from producing a negative result, meaning that all customer classes would be allocated a share of capacity costs based on average usage and then based on excess demand. (AZLCG Br. at 39; *see* Ex. AZLCG-3 at 22; Tr. at 1613-1614, 1715, 1719, 1766-1767.) AZLCG argues that although APS has proposed approval of the A&E-4CP allocation method only for future use, the Commission should instead approve the comprehensive A&E-4CP COSS that Mr. Higgins completed in this case,[452] with which AZLCG asserts APS has not taken issue. (AZLCG Br. at 39; *see* Tr. at 1609-1610, 3557.) AZLCG also asserts that the Commission should order that APS use the A&E-4CP allocation methodology for production demand costs in this matter, even if the Commission decides to approve an across-the-board rate increase without reference to an approved COSS, because approving a COSS will guide future filings, provide an understanding of the level of subsidization in rates, and provide useful guidelines in designing rates. (AZLCG Br. at 40, n.230; *see* Tr. at 1595, 1753-1754.)

In its Responsive Brief, AZLCG disagrees with Staff's assertion that the Commission rejected use of the A&E-4CP method in the last rate case, stating that Decision No. 78317 speaks for itself and that the Commission is best positioned to interpret its own order. (AZLCG RBr. at 15-16.) AZLCG further states that the Commission determined in the last rate case that both the A&E and A&P methods are reasonable alternatives for allocation of peak demand costs but selected the A&P method. (AZLCG RBr. at 16.) AZLCG also criticizes Staff for inconsistency—emphasizing energy loads as an important contributing factor to production plant costs and then also stating that APS's generation needs are driven by summer system peaks. (AZLCG RBr. at 16.) AZLCG maintains that the energy focus of the A&P method does not align with the primary cost driver of APS's production capacity costs. (AZLCG RBr. at 16.) AZLCG also criticizes Staff's concerns about the issues with the A&E-1CP calculation, stating that both APS and AZLCG designed their A&E-4CP calculations so that the excess

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[451] AZLCG clarifies that with a "pure A&E-4CP allocator," if negative excess demand is allowed, a customer class that does not contribute to 4CP would be allocated a reduced or no share of capacity costs. (AZLCG Br. at 39; *see* Tr. at 1714-1715, 1767.) Mr. Moe testified that the NARUC Manual allows for the excess demand component to go negative in the A&E-4CP method. (Tr. at 1715.)

[452] Mr. Higgins's COSS results are summarized in Exhibits KCH-17-F and KCH-19-F, which are attachments to AZLCG's Brief. AZLCG states that the actual COSS is in AZLCG's workpapers. The Commission does not have access to parties' workpapers unless they are admitted as exhibits, which the AZLCG COSS was not.

component cannot produce a negative result and each customer class will be allocated a share of capacity costs based on both average usage and excess capacity. (AZLCG RBr. at 17; *see* Ex. AZLCG-3 at 22; Tr. at 1613-1614, 1715, 1766-1767.)

FEA

FEA argues that the A&P method approved in the last rate case is not a reasonable or accurate production cost allocation method and that the Commission should reverse its prior decision and approve continued use of the A&E method for production cost allocation, as also advocated by AZLCG and Walmart. (FEA Br. at 11; *see* Ex. AZLCG-1; Ex. Walmart-1.) FEA cites with approval Mr. Moe's double-counting criticism and asserts that the double counting results in over-allocation of fixed production and transmission capacity costs to high-load-factor customers, to the benefit of low-load-factor customers. (FEA Br. at 11-12; *see* Ex. APS-24 at 16-17.) FEA argues that the A&P method overemphasizes energy benefits and underemphasizes capacity benefits, while the A&E method separates the amount of system capacity needed to serve average demand and the amount needed to serve demands in excess of average demand, thereby reasonably and accurately allocating production costs to customer classes. (FEA Br. at 12; *see* Ex. APS-24 at 16-17.) FEA cites Mr. Gorman's testimony explaining how the A&E and A&P both use "two buckets" to calculate allocations, one that contains the capacity needed to serve average demand, and one that contains the capacity needed to serve peak demand, and criticizes the A&P method because its two buckets together exceed total system capacity due to inclusion of the capacity to serve average demand within the second bucket containing capacity needed to serve peak demand. (FEA Br. at 12-13; *see* Ex. FEA-2 at 10-11.) Thus, FEA argues, the A&P method double counts the capacity needed to serve average energy demands. (FEA Br. at 13; *see* Ex. FEA-2 at 11.)

FEA asserts that a CP method would be the most accurate allocation method, because it would accurately assign across rate classes the capacity that is needed to serve all rate classes' demands every hour of the year, including peak hour. (FEA Br. at 13; *see* Ex. FEA-2 at 11-12.) FEA recommends, however, that APS's COSS using the A&E-4CP method be approved by the Commission. (FEA Br. at 13.)

In its Responsive Brief, FEA argues that Staff provided no evidentiary support for its position that the arguments of APS, FEA, AZLCG, and Walmart supporting the A&E method conflate the concepts of energy and demand and the role each plays in utility system planning and no evidence supporting its claim of mathematical issues that could arise when a CP measure is used with the A&E method. (FEA RBr. at 2, 3; Staff Br. at 40.) FEA argues that it is Staff that conflates the issues because the remedy for Staff's expressed concern with the calculation of the A&E method centers around the use of a CP or NCP demand component and does not support use of the A&P method over the A&E method. (FEA RBr. at 3.) FEA also argues that Staff did not rebut the double-counting argument. (FEA RBr. at 2; *see* Staff Br. at 36-42.) FEA reiterates that the A&E-4CP method is more accurate and balanced than the A&P-4CP method. (FEA RBr. at 3.)

School Groups

The School Groups acknowledge their advocacy in the last rate case against the A&E-NCP production cost allocation method used by APS therein. (SG Br. at 4-5; *see* Ex. ASBA-1 at 10-11.) The School Groups assert that Mr. Sarver analyzed both the A&E-4CP method and the A&P method to determine which was most appropriate for APS's system, along with two other options. (SG Br. at 6.) Mr. Sarver concluded that the A&E-4CP method is the "functional equivalent" of a 4CP method because it makes the average component "virtually irrelevant" in determining a class's allocation, meaning that the allocation is entirely proportional to the "excess" component used. (SG Br. at 6-7; *see* Ex. ASBA-2 at 4-5.) Mr. Sarver also concluded that the A&P-4CP method resulted in nearly equal weighting of the average component (49%) and the peak component (51%), meaning that a class's energy use had nearly the same weight in cost allocation as did the class's 4CP. (SG Br. at 7; Ex. ASBA-2 at 5-6.)

The School Groups argue that because the system peak is the crucial design criteria for production capacity, the 4CP should have significant weight in production cost allocation, and that while average demand does not influence how much production capacity must be obtained, it may affect the type of production needed (long duration versus short duration assets), meaning that the average demand should also have some positive weight in production demand cost allocation. (SG Br. at 7; *see* Ex. ASBA-2 at 7.) The School Groups assert that they prefer the A&E-4CP method "but recognize that its impact on other customer classes might be disruptive." (SG Br. at 8.) Thus, the

School Groups suggest, as a "middle ground," that the A&P method be modified to attribute less weight to the average component, specifically suggesting a weighting of 20% average component and 80% peak component. (SG Br. at 8.) The School Groups assert that this weighting would result in production allocation between the general service (38%) and residential (60%) classes similar to what was seen with the historical A&E-NCP method, but that the use of the 4CP with the peak component results in equitable distribution of production costs among the subclasses. (SG Br. at 8.) The School Groups also assert that this weighting would prevent a sudden, sizable shift in cost allocation.[453] (SG Br. at 8; *see* Ex. ASBA-2 at 8-9.)

Walmart

Walmart states that it supports APS's proposal to allocate production capacity costs using the A&E-4CP[454] allocator. (Walmart Br. at 1; *see* Ex. Walmart-1 at 4.) Walmart states that it agrees with APS, FEA, and AZLCG that the A&P method is not an accurate methodology and the A&E method should instead be used, particularly because the A&P-4CP method does not focus on peak production as the driver for production capacity costs. (Walmart Br. at 2.) Walmart urges the Commission to reconsider using the A&P-4CP and instead to examine using the 4CP or A&E-4CP method for production capacity cost allocation. (Walmart Br. at 3.)

Staff

Staff recommends that the Commission maintain the requirement for APS to use the A&P-4CP method adopted in Decision No. 78317, asserting that it results in a fair and reasonable allocation of APS's relative costs to serve its customers. (Staff Br. at 34.) Staff notes the criticism of the A&P-4CP method from APS, AZLCG, FEA, and Walmart. (Staff Br. at 35-37; *see* Ex. S-13 at 11.) Staff acknowledges that judgment is used to determine the appropriate weighting of each of the two components used in the A&P (average and peak) and that the weighting the Commission approved in the last rate case was based on APS's system load factor—with the average component weighted by

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[453] The School Groups state, consistent with Mr. Sarver's testimony, that the 20/80 weighting would prevent a sizable shift in production cost from the residential class to the general service class. The Commission is not sure that is what Mr. Sarver and the School Groups actually meant, as the general service class would not seem to be in jeopardy of such a cost shift if average demand is weighted less. (*See* Ex. ASBA-2 at 9.)

[454] Walmart used "A&E-NCP" on the first page of its brief, which we believe to have been a typographical error, as Mr. Chriss advocated for use of the A&E-4CP or the 4CP method. (*See* Ex. Walmart-1 at 4.)

the overall system load factor and the peak component weighted by one minus the system load factor. (Staff Br. at 36; *see* Ex. S-12 at 12.) Staff acknowledges other parties' claims that the Commission erred in approving the A&P-4CP in Decision 78317, that the A&P-4CP results in double-counting of the average component, and that the use of the system load factor to determine weighting is inconsistent with the NARUC Manual. (*See* Staff Br. at 36-37; *see* Ex. S-12 at 12-13; Ex. S-13 at 2; Ex. APS-24 at 18; Ex. AZLCG-1 at 8-11, 13; Ex. FEA-1 at 10-12; Ex. Walmart-1 at 10.)

Staff argues that the A&P-4CP method approved in Decision No. 78317 is consistent with other state PUCs that recognize energy loads are an important contributor to production plant costs. (Staff Br. at 38; *see* Ex. S-12 at 13.) Staff cites a Michigan PUC order from 2015 concluding that utilities design their generation systems to meet electric load requirements at all times, using a variety of resources to provide sufficient capacity and low-cost energy to customers, not to meet electric load requirements for only a few hours of the year. (Staff Br. at 38; *see* Ex. S-12 at 13.[455]) Staff asserts that the most basic method to determine whether a generating unit is designed to serve average load or peak load is to look at its capacity factor,[456] because a high capacity factor shows that a unit operates a great deal during the year and serves as baseload generation (i.e., serving both energy and demand),[457] and a low capacity factor (15% or less) shows that a unit is generally held in reserve and only cycled on to

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[455] Dr. Dismukes provided the following Michigan PUC quote concerning DTE Electric Company:

> The Commission agrees with . . . Staff, the Attorney General, Energy Michigan, and [Environmental and Consumer Advocates] that DTE Electric's production system was not designed and built solely for the purpose of providing capacity for four hours a year. Indeed, if that were the case, DTE Electric's generation asset portfolio would be very different and would certainly include far fewer of the large base load units that comprise much of the company's current fleet. Instead of building a system to simply meet demand, the company developed its production plant to both deliver energy and provide capacity at the lowest overall cost to all customers who use the system. Thus, DTE Electric's generating system includes a mix of base load plants that were significant investments, but that provide abundant, reliable, and low-cost energy to all customers, and peaking plants, with low fixed production costs and typically higher fuel costs than the base load units. These peaking plants are the units that are used to meet peak demand in the summer months.

Ex. S-12 at 13-14 (quoting Michigan PUC Case No. 17689 Opinion and Order (June 15, 2015) at 21-22).

[456] Capacity factor indicates usage over a period of time compared to maximum potential output. (Ex. S-12 at 14.)

[457] As "empirical support" for use of the A&P-4CP method, Dr. Dismukes examined the 2022 capacity factors of APS's generating units and determined the allocation of energy and demand costs based on the outcome of this analysis, concluding that 58.8% of plant in service would be allocated based on energy and the other 41.2% based on demand. (Ex. S-12 at ex. DED-2.) Dr. Dismukes used a 15% capacity factor threshold to differentiate between energy and demand usage. (*Id.*) Of the 34 separate generating units listed, 13 had allocations based on energy, with 4 of those having capacity factors between 15.34% and 31.15% and the remaining 9 having capacity factors between 50.18% and 90.47%. (*See id.*) The remaining 21 generating units had allocations based 100% on demand. (*See id.*)

meet peak demand. (*See* Staff Br. at 38; Ex. S-12 at 14.)

Staff refers to the double-counting argument as a "myth" typically propagated by large/industrial customer groups. (Staff Br. at 39; *see* Ex. S-12 at 15.) Staff also disagrees with claims about the superiority of the A&E method, arguing that these claims conflate the concepts of energy and demand and the role each plays in utility system planning and, further, effectively presume that utilities initially design their systems to meet baseload needs and only later add resources dedicated to meeting the needs of customers who have peaking requirements. (Staff Br. at 39; *see* Ex. S-12 at 14-15.) Staff argues that this is incorrect because demand and energy are separate utility planning parameters, and system planners develop resources to meet all of the utility's load requirements, not those of a specific class or customer. (Staff Br. at 39; *see* Ex. S-12 at 15.) Staff argues that it is incorrect to presume that peak energy usage can be divided into a portion representing the average annual system requirement and a second portion representing the load requirement exceeding the average annual system requirement because this does not reflect the reality that a utility must plan for energy and capacity system requirements independently, not as a single combined system parameter. (Staff Br. at 39; *see* Ex. S-12 at 16.) Staff further notes that the A&E method can use any measure of peak demand, but that unless the NCP is used, the results negate the demand-and-energy nature of the A&E. (Staff Br. at 40; *see* Ex. S-12 at 17-18.) Staff further argues that the Commission has already rejected the use of the A&E-4CP method to allocate production costs.[458] (Staff Br. at 40; *see* Ex. S-13 at 3.)

Staff argues that APS proposes to use an A&E-NCP production cost allocation method for some customer classes[459] while using an A&E-4CP for those customer classes with low load factors and asserts that the use of NCP for peak demand is inappropriate with production plant assets because an NCP demand measure assumes a low level of load diversity. (Staff Br. at 41; *see* Ex. S-12 at 19.)

Staff recommends that the Commission approve use of the A&P-4CP method in this rate case for the same reasons articulated in Decision No. 78317 because nothing provided by APS "changes or adds new light that should lead to a change in . . . methodology." (Staff Br. at 42; *see* Ex. S-12 at 20.)

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[458] This is an overstatement. Although both Staff and APS mentioned the potential to use an A&E cost allocation method with a CP measure of demand in the last rate case, each specifically discussed the A&E-1CP method and advocated against its use. (*See* Ex. S-13 at 3; Ex. RUCO-7 at 232-234.)

[459] This is inconsistent with our understanding of APS's position in this matter, which did not advocate for use of the A&E-NCP.

In its Responsive Brief, Staff states that it is not persuaded that the Commission should require APS to replace the A&P-4CP method with the A&E-4CP method for production demand cost allocation. (Staff RBr. at 25.) Staff reiterates the arguments made in its Brief and comes to the same conclusions as in its Brief. (Staff RBr. at 25-29.)

APS Response

In its Responsive Brief, APS notes that only Staff supports continued use of the A&P-4CP method while APS, FEA, AZLCG, Walmart, and the School Groups[460] support use of the A&E-4CP method. (APS RBr. at 38; *see* APS Br. at 57; FEA Br. at 11; AZLCG Br. at 34; Walmart Br. at 1; SG Br. at 8.) APS argues that the record in this matter shows the A&E method to be a more reasoned and accepted method that was routinely accepted by the Commission until APS's last rate case. (APS RBr. at 39; *see* Ex. APS-24 at 12.) APS reiterates the "'double counting' flaw" and asserts that it is the reason the A&P method is rarely adopted in other jurisdictions. (APS RBr. at 39; *see* Ex. APS-24 at 18.) APS reiterates that both high-load-factor and low-load-factor customers are supporting the A&E-4CP herein.[461] (APS RBr. at 39; *see* Tr. at 3553.) APS also argues that the A&E-4CP method more accurately reflects the costs to serve APS's customers due to the characteristics of APS's load profile and weather. (APS RBr. at 39; *see* APS Br. at 57-58; Ex. APS-24 at 15-18.) APS urges the Commission to adopt the A&E-4CP method for use in future rate cases. (APS RBr. at 39.)

Resolution

With the exception of Staff, the parties to this matter appear to have focused on one portion of the Commission's conclusions in Decision No. 78317 concerning allocation of production demand costs, to the exclusion of another portion. This suggests that the Commission's language may not have been sufficiently clear. In Decision No. 78317, the Commission stated that "APS is a summer-peaking utility, and a large portion of its production costs are attributable to peak demand" and further stated "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." This second statement appears

[460] As noted previously, the School Groups' support for adoption of the A&E-4CP method in this matter is not strong; they actually propose a "middle ground" alternative that would use the A&P-4CP with different weighting. (*See* SG Br. at 8.)
[461] See immediately previous footnote.

to have been disregarded by the parties to this matter other than Staff. To be clear, what the Commission meant was that it does not view "peak demand" as only the "excess demand" that is included in the second bucket under the A&E method. Rather, peak demand includes both the average demand and the excess demand, i.e., it is consistent with the second bucket under the A&P method. The Commission is cognizant that this is an unpopular view in this matter but believes that it is supported by Staff's evidence provided herein.

Dr. Dismukes's analysis of capacity factors for APS's generating units shows that in 2022 APS generating units representing 4,087 MW of the total 6,972 MW in nameplate capacity, or approximately 58.6%, were used to support baseload, as indicated by their capacity factors ranging from 15.34% to 90.47%. (*See* Ex. S-12 at ex. DED-2.) If a much more conservative 50% capacity factor threshold (compared to the 15% capacity factor threshold used by Dr. Dismukes) is used to denote a baseload generating unit, the baseload generating units represent 3,829 MW of the total 6,972 MW in nameplate capacity, or approximately 54.92%. (*See* Ex. S-12 at ex. DED-2.) These generating units that are operated to serve baseload demand are also operated to serve peak demand. Although the baseload demand (i.e., average demand) is not included in the second bucket under the A&E method, in reality, the average/baseload demand does not magically vanish during times of peak demand. It is still very much present. Thus, while high-load-factor customers' usage is not "peaky," it absolutely contributes greatly to peak demand costs, and that contribution must be represented in the allocation of production demand costs to ensure that all customer classes are paying their fair share. The Commission continues to believe that the A&P method, which includes the average demand portion of the peak demand in the second bucket, provides a fairer allocation of production demand costs than does the A&E method.

The Commission is cognizant that the A&P method tends to be disfavored by high-load-factor customers and favored by low-load-factor customers and notes that this pattern appears to exist in this matter as well.[462] The Commission's conclusion herein is not inconsistent with APS's testimony that high summer peak demand continues to be a primary driver of APS's production capacity costs; it is

[462] The School Groups' advocacy concerning use of the A&E method is equivocal rather than the full-throated endorsement that the high-load-factor customer parties provide for the A&E method.

consistent with the reality that high summer peak demand is comprised of both average demand and "excess demand." The Commission's conclusion is also consistent with Mr. Moe's acknowledgment that both the A&P-4CP method and the A&E-4CP method are reasonable methods for allocation of production demand costs. (*See* Tr. at 1615.) The Commission notes Dr. Dismukes's testimony that addition of the XHLF customers anticipated to be served by APS's system would make the A&P-4CP method even more appropriate to use for production cost allocation in future rate cases than it is in this rate case. (*See* Tr. at 4563-4564.) We also note Mr. Geisler's testimony that even if those XHLF customers were not anticipated, APS expects a record level of growth over the next 10 years caused by increased usage from residential, small business, and medium-sized business customers and the general societal shift toward electrification, which is meaningfully increasing usage and changing usage patterns. (Tr. at 408.) Additionally, we note that both Mr. Joiner and Mr. Moe testified that late evening and overnight hours are more and more driving the need for additional capacity, as opposed to the 4CP. (*See* Tr. at 1745-1746.)

The A&P-4CP method used by APS in this matter allocated 48.8% of production costs for average demand and 51.2% of production costs for peak demand, resulting in 41.79% of production costs allocated to general service customers and 57.12% to residential customers (as compared to 35.52% to general service customers and 63.64% to residential customers under the A&E-4CP method). (*See* Ex. APS-25 at Att. JRM-03RB.) The Commission finds that these allocations of production demand costs obtained using the A&P-4CP method are just and reasonable and directs APS to continue using the A&P-4CP method for its next rate case.

b. Costs Allocated to AG-X Customers

APS Proposal

APS criticizes as flawed AZLCG's argument that AG-X customers should be allocated very little in production demand costs because AG-X customers rely on very little APS generation to back up their GSP-provided supplies. (APS Br. at 58; *see* Ex. AZLCG-3 at 26, 28-29.) APS states that this argument ignores the fact that APS is the provider of last resort for AG-X customers and must provide backup power (RA) to cover the full load of AG-X participants. (APS Br. at 58; *see* Ex. APS-11 at 29-30.) APS points to Mr. Joiner's testimony that AG-X customers are primarily served with market energy contracts that are not required to be tied to a specific generation resource or resource portfolio, meaning that the market-based resources can be curtailed at any time, including during critical peak hours when resources are scarce and replacement power very expensive. (APS Br. at 58; *see* Ex. APS-11 at 31-33.) APS further points to Mr. Joiner's testimony that such curtailments are occurring more frequently in the western U.S. region. (APS Br. at 58; *see* Ex. APS-11 at 32; Tr. at 1504-1505.) APS argues that the failure of AG-X deliveries is already problematic, noting that in the summers of 2020, 2021, and 2022, there were instances when up to 76% of all AG-X energy supplies failed to deliver. (APS Br. at 59; *see* Ex. APS-11 at 33-34.) APS compares AZLCG's argument that AG-X customers should be allocated less than 1% of production demand costs because AG-X contracts were curtailed less than 1% of the time during the TY to an argument that a homeowner should only be required to pay 1% of their home hazard insurance premium if the water pipe burst at their home only lasted 1% of the total hours in the year. (APS Br. at 59; *see* Ex. APS-2 at 9.) APS further characterizes AZLCG's argument as irrelevant and a conflation of capacity and energy costs. (APS Br. at 59.) APS states that in the COSS it treated AG-X supply contracts in a manner consistent with the industry standard and allocated generation capacity costs to the AG-X class in the same manner as it did for all other customers,[463] to account for the APS generation resources that ensure RA and continuous reliable service for AG-X customers. (APS Br. at 59; *see* Ex. APS-25 at 9.) APS argues that AZLCG's production cost allocation arguments should be rejected because APS must maintain generation capacity to account for the full load of all of its customers, even AG-X customers. (APS Br. at 59.)

<u>AZLCG</u>

AZLCG argues that APS's proposal to allocate production demand costs to AG-X customers as if they were full-service customers is unjust and unreasonable and should be rejected. (AZLCG Br. at 40; *see* Ex. AZLCG-3 at 26; Tr. at 1616-1617.) AZLCG argues that because AG-X customers commit to third-party energy supplies and market risk on a long-term basis, APS does not need to procure additional generating capacity to serve AG-X load. (AZLCG Br. at 40; *see* Ex. AZLCG-3 at

[463] In the COSS, Mr. Moe allocated to the AG-X customer class costs that were based on the metered loads delivered to the customers, regardless of whether the loads were generated from APS generation resources or came from the AG-X customers' GSPs. (Tr. at 1616-1617.) Mr. Moe testified that this allocation of production costs was used because APS provides AG-X customers the same RA as it provides to all of its other customers. (Tr. at 1617.)

27.) AZLCG asserts that APS has, for at least the last five years, used generation from the AG-X program to meet APS's total-system RA requirements,[464] and that APS has also relied on AG-X GSP-provided generation in its IRPs to defer capacity investments.[465] (AZLCG Br. at 40-41; *see* Ex. AZLCG-3 at 27-28; Tr. at 1284-1285.) AZLCG argues that without the AG-X resource, APS would have been close to or below its RA requirements. (AZLCG Br. at 41; *see* Tr. at 1285.) Additionally, AZLCG asserts that in the TY, AG-X customers required only 2,456 MWh of APS generation due to GSP curtailments, meaning that the GSPs provided 99.8% of AG-X customers' energy in the TY. (AZLCG Br. at 41; *see* Ex. AZLCG-3 at 29.) Thus, AZLCG argues, treating AG-X customers like full-service customers for the purpose of allocating generation costs makes no sense and is not reflective of the limited way the AG-X customers use the system. (AZLCG Br. at 41; *see* Ex. AZLCG-3 at 27-28.)

AZLCG argues that AG-X customers should be allocated production costs based on their actual use of APS's system, as other customers are. (AZLCG Br. at 41.) AZLCG argues that Dr. Dismukes agreed cost allocation should be based on actual usage rather than imputed usage;[466] that APS has conceded it uses actual usage data in its COSS to allocate costs to full-service customers; and that Mr. Moe agreed APS would not use each class's theoretical maximum load to allocate costs in a COSS.[467] (AZLCG Br. at 41-42; *see* Tr. at 1627-1630, 4549.) AZLCG asserts that the Commission should adopt AZLCG's proposed COSS that uses the A&E-4CP method and allocates costs to AG-X customers

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[464] Mr. Joiner further testified that APS would not be able to count AG-X deals going forward unless APS's AG-X program RA proposals herein are approved. (Tr. at 1285.)

[465] AG-X is included as an existing resource in the 2023 IRP, but it is included within a category ("Market/Call Options/Hedges/AG-X") that starts at 887 MW in 2023, drops to 374 MW in 2024, and then is between 106 and 142 MW from 2025 through 2038. (*See* 2023 IRP at Att. F.9(B)(1).) It is unclear whether or to what extent the category includes AG-X MW, particularly in years 2025 onward. (*See id.*) In comparison, Exhibit NRG-7 shows that APS counted AG-X MW in its existing purchased power resources in its Monthly Loads & Resources for years 2018 through 2022, with the values ranging from 99 to 160 MW depending on the year and month. (*See* Ex. NRG-7.)

[466] Dr. Dismukes was responding specifically to a question concerning how to analyze the costs for a low-load-factor customer class in a COSS, whether to use actual loads or imputed loads based on how much energy the customer class could use if they used energy all the time. (*See* Tr. at 4549.) Dr. Dismukes stated that actual loads are usually used because allocations are usually made using known and measurable TY usage information. (*See id.*)

[467] Mr. Moe testified that an argument could be made for using a class's theoretical maximum load to allocate fixed production costs among and between classes but that he was not recommending that and was recommending use of the A&E-4CP. (*See* Tr. at 1629-1630.)

based on actual usage[468] because charging AG-X customers the same production costs as full-service customers is contrary to the evidence in this matter. (AZLCG Br. at 42.) AZLCG argues that APS's COSS imputes to AG-X customers energy and peak demand that was delivered by GSPs, not by APS, and that regardless of the production cost allocation method approved, there is no cost basis to include in the average component more than 0.2% of metered AG-X usage or to include in the demand component more than the actual metered peak demands delivered by APS for AG-X customers. (AZLCG Br. at 42.[469])

In its Responsive Brief, AZLCG characterizes as misleading APS's argument that AG-X customers receive backup power for their full loads. (AZLCG RBr. at 7; *see* APS Br. at 58.) AZLCG argues that APS's resource planning develops resources to meet each class's contribution to system peak demands during periods of high coincident demand, not to meet all customers' full hypothetical usage, arguing that this is essentially what APS asserts it does for AG-X although using full hypothetical load is not a sound or accepted basis for allocating costs. (AZLCG RBr. at 7; *see* Tr. at 1414, 4549.)

AZLCG also denies that its proposal conflates energy and capacity, stating that APS itself confused the concepts when asserting that there were instances where up to 76% of AG-X energy supplies failed to deliver. (AZLCG RBr. at 8; *see* APS Br. at 59.) AZLCG states: "It is irrefutable that capacity and energy are different concepts, and APS cannot ignore that both need to be considered for allocation purposes." (AZLCG RBr. at 8.) AZLCG argues that AG-X customers should not be allocated costs as though they receive no service from GSPs, because from an energy perspective, AG-X customers received only 0.2% of total AG-X energy from APS, and from a capacity perspective, AG-X customers had only 1 MW of GSP curtailment during any of the 4CP hours. (AZLCG RBr. at 8; *see* Ex. AZLCG-3 at 29, 31-32.) AZLCG argues that regardless of the production cost allocation method used, AG-X customers overpay their cost of service by $12 million annually. (AZLCG RBr.

[468] The results of this COSS are included in exhibit KCH-18-F (page 2) to the Brief. (*See* AZLCG Br. at 42.) This COSS results in a base revenue decrease of $12.039 million, or 15.88%, for the AG-X class. (*See* AZLCG Br. at ex. KCH-18-4 at 2.)

[469] AZLCG provided as exhibit KCH-18-F (page 1) to its Brief the results of a COSS using the A&E method for the Commission to use if it "decides that AG-X customers should be allocated production demand costs as if they did not receive generation service from a GSP." (AZLCG Br. at 42, n.247.) This COSS results in a base revenue increase of $12.929 million, or 17.05%, for the AG-X class. (*See* AZLCG Br. at ex. KCH-18-4 at 1.)

at 8; *see* Ex. AZLCG-3 at 29-30.)

AZLCG reiterates that allocating costs to AG-X customers as though they consumed energy at maximum load with no service from GSPs is contrary to fact and results in AG-X customers being treated differently than every other customer class, for whom costs are allocated based on actual TY usage, particularly during peak periods.[470] (AZLCG RBr. at 8.)

NRG

In its Responsive Brief, NRG criticizes APS for mischaracterizing AZLCG's position by stating that AZLCG objects to the allocation of production demand costs to customers participating in the AG-X program. (NRG RBr. at 12.) NRG asserts that Mr. Higgins does not object to the allocation of production demand costs to AG-X customers, only to the allocation of those costs in the same manner as they are allocated to full service rate classes. (NRG RBr. at 12; *see* Ex. AZLCG-3 at 26.) NRG asserts that it is important to call out the misrepresentation because it establishes a "strawman position that no party holds to create a favorable impression of APS's proposal." (NRG RBr. at 12.)

APS Response

In its Responsive Brief, APS asserts that AZLCG's argument that AG-X customers should not be treated as full-service customers for allocation of generation costs because GSPs provided 99.8% of their energy supply during the TY, and thus should only be allocated costs based on their actual usage of APS generation, is flawed because it ignores that APS is the provider of last resort and required to provide RA for AG-X customers' full loads. (APS RBr. at 39-40.) APS argues that because AG-X customers take service within APS's balancing area and depend on APS's generation capacity when GSPs fail to deliver, they use and benefit from the same mix of resources as all APS customers, and failure to allocate production costs to them based on their full loads would shift costs to non-AG-X customers. (APS RBr. at 55-56; *see* Tr. at 1503-1504.)

Resolution

Mr. Moe testified that APS's allocation of production costs to AG-X customers was based on the AG-X program as it exists now, under which APS provides to AG-X customers RA sufficient to

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[470] This is inaccurate if the site load COSS is accepted for residential DG customers, because it also bases cost allocation on imputed usage of the system rather than actual usage of the system.

cover their full loads regardless of whether the AG-X customers rely on that RA or not. (*See* Tr. at 1631.) Mr. Moe acknowledged the proposals in this matter to change the AG-X RA-related requirements, including by providing AG-X customers the option to obtain RA from their GSPs rather than from APS. (Tr. at 1631.) Mr. Moe stated that if the RA proposals are approved, and AG-X customers are able to obtain RA from GSPs, APS will be able to adjust the cost allocation model going forward to reflect that someone else is providing RA, based on the contracts that will provide APS that assurance. (Tr. at 1631.) Mr. Moe stated that the production demand cost being allocated to AG-X customers currently is for RA and does not reflect a cost shift from non-AG-X customers to AG-X customers, although there would be such a cost shift once GSPs are actually providing RA to AG-X customers. (*See* Tr. at 1632.)

Mr. Joiner testified that on August 18, 2020, nearly 60% of AG-X schedules were curtailed and that similar events occurred in 2021 and 2022, with up to 74% of AG-X schedules curtailed. (Ex. APS-11 at 33.) Mr. Joiner stated that the curtailments are becoming more frequent and of longer duration and that they pose a reliability risk to non-AG-X customers because the curtailments occur when the system needs the power most and it is the most difficult and expensive to backfill. (Tr. at 1504-1505.) Mr. Joiner testified that if the AG-X RA-related program changes are not made, the curtailments in GSP deliveries that occur when the deliveries are needed most will expose APS customers to reliability risks and will result in all customers paying the costs to serve the curtailed AG-X customers because APS, as the provider of last report, is obligated to serve. (Tr. at 1113.)

The evidence of record establishes that AG-X customers currently are receiving RA[471] from APS and that during the TY they relied on that RA at critical times when curtailments occurred. It is true that curtailments are relatively infrequent and that the amount of energy needed to be provided to AG-X customers by APS as the provider of last resort was a minute portion of the total energy used by AG-X customers during the TY. But that does not mean it would be fair to allocate only a minute portion of production costs to AG-X customers. Currently, APS's generation resources stand by at all

[471] The North American Reliability Corporation ("NERC") defines RA as "the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including line losses)." (Ex. APS-12 at 39.) Mr. Joiner testified that in practical terms, RA is the critical component that ensures resources can be depended on for reliable operations even during emergencies and can often be referred to as capacity. (*Id.*) Energy, on the other hand, is the "fungible commodity produced" by resources and "an economic tool to serve customer needs." (*Id.* at 39-40.)

times to provide capacity to AG-X customers when needed, and AG-X customers use APS's generation resources at critical times. Until AG-X customers are successfully obtaining RA from GSPs rather than APS, it is just and reasonable to allocate to AG-X customers production costs that reflect their reliance on APS for RA to cover their entire loads.

2. Allocation of Distribution Costs

APS Proposal

APS states that secondary distribution equipment[472] serving individual homes or small groups of homes is sized specifically for the location being served and cannot be used to serve power needs in another neighborhood. (APS Br. at 59-60; *see* Ex. APS-24 at 42; Ex. APS-25 at 11-12.) For the COSS, APS allocates secondary distribution costs using the Sum of Individual Max ("SIM") allocator, which adds the individual peak demands for each customer each month for each class. (APS Br. at 60; *see* Ex. APS-24 at 13.) APS asserts that the SIM allocator has been used by APS and accepted by the Commission for years. (APS Br. at 60; *see* Ex. APS-24 at 13.)

According to APS, Staff's argument that secondary distribution costs should be allocated based entirely on class NCP rather than the SIM allocator is contrary to standard theory and practice for COSSs in the industry and invalid because of how secondary distribution equipment is sized and the inability to use secondary distribution equipment to serve different areas. (APS Br. at 60; *see* Ex. APS-25 at 2, 11.) APS argues that the SIM allocator best reflects the cost driver for secondary distribution equipment. (APS Br. at 60; *see* Ex. APS-25 at 11-12.)

Staff

According to Staff, because APS agrees with Staff that the minimum system method ("MSM") and zero-intercept method ("ZIM") have theoretical and practical flaws and can be expensive and time consuming to perform, APS used an alternative method known as the minimum-load method ("MLM") to estimate the customer component of primary distribution costs. (Staff Br. at 42; *see* Ex. S-13 at 7; Ex. APS-25 at 10-14.) Staff argues that the MLM "is a novel and non-standard analysis that does not appear to estimate the supposed customer component of primary distribution costs." (Staff Br. at 43;

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[472] This includes customer transformers, service drops to customer homes, and other point-of-delivery equipment. (APS Br. at 59; *see* Ex. APS-24 at 42; Ex. APS-25 at 11.)

see Ex. S-13 at 7.) Additionally, Staff argues that even attempting to estimate a customer-related portion of primary distribution costs is deeply flawed and has even been called "clearly indefensible" in academic literature.[473] (Staff Br. at 43; *see* Ex. S-13 at 7; Ex. S-58.) Staff recommends that the Commission "revisit" its decision to have specific FERC account distribution assets classified as both demand-related and customer-related. (Staff Br. at 43.)

Additionally, Staff recommends that the Commission adopt a 100% class NCP cost allocation method for non-customer-related secondary voltage distribution plant costs. (Staff Br. at 34; Staff RBr. at 25; *see* Ex. S-12 at 2.) Staff argues that APS's SIM allocation method is inconsistent with APS's findings regarding load diversity and that Staff's NCP method is based on Dr. Dismukes's analysis of what would constitute a fair and reasonable approximation of the relative cost of service. (Staff Br. at 35; Staff RBr. at 26; *see* Ex. S-12 at 3.) Staff acknowledges that the Commission rejected allocation of secondary distribution costs based on the NCP method in the last rate case but continues to recommend herein that secondary distribution costs be allocated based on NCP demands rather than using the SIM allocator. (Staff Br. at 43; *see* Ex. S-13 at 8.) Staff agrees that secondary distribution systems are designed to meet local area loads but argues that diversity exists even in small, localized areas and that a distribution transformer serving customers with diverse load patterns with peak demand at different times can be sized smaller than a transformer serving customers with homogeneous load patterns and demands. (Staff Br. at 443; Staff RBr. at 29; *see* Ex. S-13 at 8.) Staff argues that APS's SIM allocator assumes no diversity in load patterns and is not supported by evidence provided by APS in prior proceedings.[474] (Staff Br. at 43-44; Staff RBr. at 29-30; *see* Ex. S-13 at 8.)

APS Response

In its Responsive Brief, APS agrees with Staff's assessment of its position on the MSM and ZIM but argues that the MLM is based on sound analysis and estimates the customer component by

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[473] In *Principles of Public Utility Rates*, Professor Bonbright et al. acknowledge that the vast majority of utilities use some form of minimum system to classify distribution costs, which is in line with FERC accounts, but opine that the "hypothetical cost of a minimum-sized distribution system" is properly excluded from both customer costs and demand-related costs and "should be recognized as a strictly unallocable portion of total costs." (*See* Ex. S-58 at excerpt page 492.) This does not support Staff's position that the distribution costs should be allocated based on demand.

[474] Dr. Dismukes described a 2016 APS analysis of the load profiles of its residential customers, which found and named five separate generalized load profiles (including weekday evening peakers, weekday night owls, weekday daytimers, and two others) and found that the largest cohort was weekday evening peakers but that approximately 58% of residential customers did not fall into that category. (Ex. S-12 at 27.)

comparing the minimum load that the existing distribution system actually serves with the average load served and using the difference between the two as the demand component. (APS RBr. at 40-41; *see* Ex. APS-25 at 11.) APS asserts that the MLM is straightforward and transparent, does not involve the speculative assumptions implicit in the MSM and ZIM, and is easier and less costly to conduct than the MSM or ZIM. (APS Br. at 41; *see* Ex. APS-25 at 11.)

Regarding secondary distribution costs, APS argues that Staff's position goes against industry standard theory and practice because secondary distribution equipment is sized to meet the demands of a few homes. (APS RBr. at 41.) APS reiterates that NCP class information is an inappropriate allocator because excess capacity on secondary distribution equipment cannot be used to serve another customer and that the best reflection of the cost driver is the SIM, not the NCP method. (APS RBr. at 41.)

Resolution

In Decision No. 78317, the Commission found persuasive FEA's position that APS should allocate the distribution costs in FERC accounts 360, 361, and 364 through 368 as both demand-related and customer-related because the NARUC Manual identified them as appropriately allocated as demand-related and customer-related, and logically there is a minimum distribution system that must exist to serve customers irrespective of the customers' consumption. (Ex. RUCO-7 at 241; *see* Tr. at 1719-1720.) APS included this change in its COSS. (Ex. APS-24 at 14; Tr. at 1719-1724.) Mr. Moe acknowledged that Professor Bonbright roundly criticized attempting to classify minimum distribution system costs as customer-related, but stated that these minimum system studies are done across the county and from a theoretical perspective make sense although they are challenging in practice. (Tr. at 1728-1731; Ex. S-58.) In *Principles of Public Utility Rates*, Professor Bonbright acknowledges that the vast majority of utilities use a minimum system to classify costs, while asserting that these costs should be treated as "strictly unallocable." (*See* Ex. S-58.) In an embedded COSS, such as that performed by APS, all costs are included somewhere; the question is where. (*See* Ex. APS-24 at 10.) Regardless of Professor Bonbright's criticism, and Staff's continued criticism, the Commission continues to believe that it is just and reasonable to allocate the distribution costs in FERC accounts 360, 361, and 364 through 368 as both demand-related and customer-related. The Commission approves APS's use of the MLM and APS's allocation of these costs.

In Decision No. 78317, the Commission did not find persuasive Staff's position that APS needed to change its secondary distribution cost allocation method from a SIM method to a 100% class NCP method, instead concluding that because secondary distribution equipment is location specific and sized based on the kW power demands of the location for which it is installed, its sizing is not impacted by load diversity, and use of individual customer peaks is more reflective of the secondary distribution equipment needed to serve the individual customers than would be the class NCPs. (Ex. RUCO-7 at 241.) The Commission continues to believe that this is true. Regardless of the load diversity that may exist in the small, localized area that secondary distribution equipment is designed to serve, APS is not going to switch out the secondary distribution equipment with smaller sized distribution equipment. Even if APS were inclined to do so, it would be illogical to do so based on specific individual customer load patterns, which literally could change overnight. The Commission approves APS's use of the SIM method and APS's allocation of these costs.

3. Allocation of Costs for Rooftop Solar Customers

In Decision No. 78317, the Commission determined that APS's COSS allocated to DG solar customers costs that appeared to be in excess of the costs actually incurred to serve those customers. (Ex. RUCO-7 at 254.) Additionally, the Commission stated that while it was not convinced that APS did not provide additional services to DG solar customers that are not provided to non-solar customers, APS had not yet made sufficient efforts to quantify the costs and needed to quantify the costs so that the issue could be examined more thoroughly and resolved in APS's next rate case (i.e., this matter). (Ex. RUCO-7 at 255.) Thus, the Commission ordered APS to 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; [and]
- File the analysis and each COSS required above with the Commission as part of its application.[475]

APS Proposal

In this matter, APS prepared two COSSs to address the DG-customer-related directives in the last rate case ("solar COSSs")—(1) a solar COSS prepared based on site load, which APS referred to as a "top down" approach; and (2) a solar COSS prepared based on delivered load, which APS referred to as a "bottom up" approach. (APS Br. at 60; *see* Ex. APS-24 at 19.) In its last two rate cases, APS used the site load/top down approach for its solar COSS. (APS Br. at 60-61.) With the top down approach, APS calculated the cost of service for the site load (the total consumption by a given residence) and then provided cost credits for DG self-supply, resulting in the net impact on utility costs from a solar customer and the appropriate cost responsibility to recover through rates. (APS Br. at 61; *see* Ex. APS-24 at 20.) With the bottom-up approach, APS calculated the cost of service based on delivered load (the load supplied by APS as measured by the meter) and then added utility costs APS states were incurred on behalf of the solar customer, resulting in what APS states is the net value (or cost) of the solar export power. (APS Br. at 61; *see* Ex. APS-24 at 20.) APS points to Mr. Moe's testimony that the top-down/site load approach is more accurate because the unadjusted delivered load approach tends to understate the costs APS incurs to serve solar customers. (APS Br. at 61; Ex. APS-24 at 21.) APS asserts that DG customers are partial requirements customers and that both the portion of their load served by APS and the portion of their load served by DG require support and costs from APS because the DG customer is connected to the grid at all times and relies on APS for backup power to serve the home when the DG is insufficient. (APS Br. at 61; *see* Ex. APS-24 at 24.) According to Mr. Moe, a bottom-up/delivered load approach ignores the costs incurred by APS for the self-supply portion, although the DG customer relies on APS for reliable service. (APS Br. at 61-62; Ex. APS-24

[475] Ex. RUCO-7 at 433-434.

at 21.)

APS argues that AriSEIA/SEIA's position—that APS's solar COSSs should be disregarded because APS's inability to identify and quantify specially designated assets or services specifically tied to DG customer backup power or grid support demonstrates that those extra costs do not exist[476]—should itself be disregarded because it is not "directly compelled by the plain language" of Decision No. 78317 and would render the COSS exercise moot. (APS Br. at 62; *see* Ex. AriSEIA-3 at 4; Tr. at 3905-3907; Ex. RUCO-7 at 433-434; Ex. APS-25 at 14-15.) APS argues that the additional costs to serve DG customers fall into discrete, well-understood categories and include costs for backup production capacity, costs for the reserve margin, costs for generation services that DG cannot provide (ramping, integration, and in-rush current supply), primary grid costs relied upon because the DG customer is connected to the grid, primary grid costs used by the DG customer to export power to the grid, and secondary grid costs that are sized to serve connected load and are not reduced when a customer adds DG. (APS Br. at 62-63; *see* Ex. APS-24 at 23-24.) APS points to Mr. Moe's testimony that these costs are not unique to APS, are accepted in the industry, and exist even though they are difficult to isolate and specifically quantify. (APS Br. at 63; *see* Ex. APS-25 at 16; Tr. at 1795.) APS also argues that following the approach advocated by AriSEIA/SEIA would be incongruous with the method to perform a COSS and would produce "absurd" results. (APS Br. at 63; *see* Ex. APS-25 at 14-15, 17.) APS argues that the top down/site load approach is the appropriate and correct approach for a solar COSS in the context of a rate case and should be adopted by the Commission for use in future rate case proceedings. (APS Br. at 63; *see* Ex. APS-25 at 16.)

<u>AriSEIA/SEIA</u>

AriSEIA/SEIA state that APS "concocted" its site load COSS construct in the last rate case by calculating the pre-solar load for DG customers and using that as a site load to allocate costs to DG

[476] Mr. Lucas testified:

> The Commission should find that APS did not do as the Commission ordered and failed to identify, quantify, and justify any extra costs that are incurred specifically to provide service to DG customers beyond the costs of providing their delivered power and energy. It should also direct the Company to use only delivered load data for solar customers in its COSS in future rate cases.

Ex. AriSEIA-3 at 4.

customers, although that is not what APS provided to those DG customers. (AriSEIA Br.[477] at 22.) AriSEIA/SEIA state that under the site load method, APS assumes no load is served by DG and then offsets some costs with a "solar credit." (AriSEIA Br. at 22, n.74.[478]) AriSEIA/SEIA argue that the site load construct "is an extreme outlier" for COSSs, as APS is the only entity AriSEIA/SEIA have seen use it, and APS could not identify any other utility in the U.S. that uses it. (AriSEIA Br. at 22; *see* Ex. AriSEIA-1 at ex. KL-28.) AriSEIA/SEIA argue that this is because there is no justification for using site load rather than delivered load for the COSS. (AriSEIA Br. at 23.)

AriSEIA/SEIA note that this issue was debated extensively in the last rate case, assert that APS was unable to identify the cost for any additional grid services that it claimed DG customers caused beyond what was reflected in their actual APS-delivered power, and note that AriSEIA/SEIA urged the Commission in the last rate case to order APS to abandon the site load concept and revert to a COSS based on delivered load. (AriSEIA Br. at 23.[479]) AriSEIA/SEIA note the solar-COSS-related requirements imposed on APS by Decision No. 78317 and argue that the Commission's directive 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)" meant that "APS should identify additional new assets, new operating costs, or new services that are specifically incurred by providing services to DG customers . . . [and that] must be incremental to those needed to provide delivered power and energy." (AriSEIA Br. at 23-24; *see* Ex. RUCO-7 at 357-358, 255-256.) AriSEIA/SEIA argue that this directive eliminated APS's argument that solar customers are not paying their fair share for the existing system when they generate much of their own power because the "Commission has already determined that the allocation of costs of the existing system (which is already covered by the cost of providing DG customers their delivered power and energy) is not the issue" by asking APS to identify the extra costs not identified in the delivered COSS.[480] (AriSEIA/SEIA Br. at 24; *see* Ex. AriSEIA-1 at 96.) AriSEIA/SEIA argue that APS failed to follow

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[477] For brevity, the joint AriSEIA/SEIA Brief and Responsive Brief are cited herein as AriSEIA Br. and AriSEIA RBr.

[478] AriSEIA/SEIA also cite a portion of Mr. Lucas's testimony from the last rate case, which is not part of the evidentiary record in this matter.

[479] AriSEIA/SEIA also cite a portion of Mr. Lucas's testimony from the last rate case, which is not part of the evidentiary record in this matter.

[480] This is an overstatement. The Commission did not find in Decision No. 78317 that either the site load or delivered load COSS method was appropriate for DG customers. That is why the Commission required APS to file both in this rate case.

the Commission's order because it did not focus on new, incremental assets, operating costs, or services and instead reverted to cost allocation arguments the Commission previously dismissed. (AriSEIA/SEIA Br. at 24-25; *see* Ex. AriSEIA-1 at 98.) AriSEIA/SEIA argues that APS's claim that DG customers impose additional costs and do not pay for them, forcing non-DG customers to pay for them, is inaccurate because solar customers pay the same rate for their delivered power as non-DG customers pay. (AriSEIA/SEIA Br. at 25; *see* Ex. AriSEIA-1 at 103.)

AriSEIA/SEIA further argue that when DG customers are able to lower their delivered energy consumption after installing DG, this does not force other customers to make up for any costs, because DG customers lower the CP and NCP and thus are less costly to serve, meaning that the revenue recovery from their delivered energy is in line with that of non-DG customers. (AriSEIA Br. at 25; *see* Ex. AriSEIA-1 at 95, 103-104.[481]) AriSEIA/SEIA argue that APS conflates revenue recovery with cost of service.[482] (AriSEIA Br. at 25; *see* Ex. AriSEIA-1 at 102, 104.) AriSEIA/SEIA argue that only by analyzing what its system would have looked like in the TY without residential DG and how much more it would have spent on generating capacity, fuel costs, and market purchases to backfill the residential DG resource,[483] and comparing that with the actual TY costs, could APS determine if costs are higher or lower with DG customers and whether the reduction in revenue collection from DG customers outweighs the avoided costs. (AriSEIA Br. at 25.) AriSEIA/SEIA argue that APS has failed to make this analysis and has also failed to identify or justify any costs explicitly related to assets, expenses, or services required to provide DG customers service beyond those to serve their delivered load. (AriSEIA Br. at 25-26.)

Further, AriSEIA/SEIA argue, APS has attempted to add nearly 50% of costs beyond the delivered COSS based on the asserted extra costs to serve DG customers, although it is obvious, AriSEIA/SEIA state, that a customer's self-supplying some portion of its generation does not increase APS's assets, operational expenses, or services beyond what they need to provide delivered energy and

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[481] AriSEIA/SEIA also cite a portion of Mr. Lucas's testimony from the last rate case, which is not part of the evidentiary record in this matter.

[482] A COSS assesses both costs and cost recovery for customer classes. (*See* Ex. APS-25 at 25-26.) A COSS that did not show the current TY level of cost recovery would have little to no value as guidance for revenue allocation.

[483] AriSEIA/SEIA assert that the maximum single hour generation of residential solar in the TY was 1,077 MW. (AriSEIA Br. at 25.) AriSEIA/SEIA cite for this figure an APS workpaper that is not part of the record in this matter.

power.[484] (AriSEIA Br. at 26; *see* Ex. AriSEIA-1 at 106-107.) AriSEIA/SEIA assert that APS did nothing to identify, analyze, or justify additional costs and instead "rearranged existing costs for existing assets and threw revenue deficiencies into the mix." (AriSEIA Br. at 26.) AriSEIA/SEIA add that APS acknowledged at hearing that solar customers do not cause APS to incur extra costs to serve them. (AriSEIA Br. at 26; *see* Tr. at 457, 1736-1737.[485])

AriSEIA/SEIA argue that the Commission should recognize APS's solar COSSs as a failure to follow the directive from Decision No. 78317, order APS to provide an unaltered delivered COSS[486] in the next rate case, and recognize such approach as accurately reflecting the cost to serve solar customers. (AriSEIA Br. at 26.)

AriSEIA/SEIA further argue that although they acknowledge DG customers are partial requirements customers and that the Commission has previously found they should be separated into a distinct class in the COSS, the findings from the last rate case and this matter merit the Commission's reconsideration of that position. (AriSEIA Br. at 26; *see* Ex. AriSEIA-1 at 103; Decision No. 75859 (January 3, 2017)[487].) AriSEIA/SEIA argue that testimony demonstrates there is diversity of load among the residential class already, and with the addition of new technologies (such as battery storage and electric vehicles), new load profiles will emerge. (AriSEIA/SEIA Br. at 26-27.) AriSEIA/SEIA state that creating a different COSS class for each new technology or combination of technologies will be burdensome. (AriSEIA Br. at 27.) Further, AriSEIA/SEIA argue, APS has now failed in two rate cases to identify extra costs incurred (beyond those required to provide delivered energy and power) to serve DG customers. (AriSEIA Br. at 27.) AriSEIA/SEIA urge the Commission to direct APS to treat

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[484] Mr. Lucas testified that the total delivered COSS for the four solar subclasses was $255 million, and APS added approximately $123.3 million in extra costs asserted to be incurred due to DG customers. (*See* Ex. AriSEIA-1 at 106-107.)

[485] Mr. Geisler clearly stated that there are no extra costs to serve DG customers, that the issue is that the amount of revenue recovered due to their reduced consumption does not cover their cost of service. (*See* Tr. at 457.) Mr. Moe did not necessarily agree with that statement. (*See* Tr. at 1736-1737.)

[486] AriSEIA/SEIA assert that because APS included adjustments in the delivered COSS related to "extra costs," AriSEIA/SEIA were unable to validate the underlying methodology used. (AriSEIA Br. at 26, n.89.)

[487] Official notice is taken of Decision No. 75859, issued in Docket No. E-00000J-14-0023, the docket for the Commission's investigation of the value and cost of DG. In addition to finding that rooftop solar DG customers are partial requirements customers who export power to the grid and are a separate class of customers, the decision found that the record did not support approval of a specific COSS methodology and that utilities would be directed to submit COSSs in rate cases based on models with spreadsheets containing links between inputs and outputs made available to all parties, with all inputs, assumptions, and calculations clearly described and explained; and that allow for the ability to change inputs and assumptions used in the calculation. (Decision No. 75859 at 174.)

DG customers like other residential customers, who already have load variations among them. (AriSEIA Br. at 27.) AriSEIA/SEIA assert that the Commission took a step in that direction when it ordered APS to produce a COSS combining DG and non-DG customers but that the document APS provided for the combined COSS in this matter was based on the site load COSS and contained hardcoding that bypassed much of the COSS model's functionality. (AriSEIA Br. at 27; *see* Ex. AriSEIA-1 at 98.) AriSEIA/SEIA urge the Commission to direct APS in its next rate case to provide a fully functional combined COSS that incorporates DG customer load based on delivered load allocators combined with other non-DG customers on similar rates and with the "solar credit" adjustment stricken. (AriSEIA Br. at 27.) AriSEIA/SEIA argue that this is not inconsistent with DG customers' status as partial requirements customers. (AriSEIA Br. at 27.)

In their Responsive Brief, AriSEIA/SEIA characterize APS's argument about the acceptability of APS's COSS as "the Commission should adopt it, because any other recommendation would produce a result [APS does] not like." (AriSEIA RBr. at 9.) AriSEIA/SEIA refute that Mr. Lucas stated he was interpreting Decision No. 78317 other than according to its plain language and assert that he merely acknowledged the Decision did not include the words "new equipment." (AriSEIA RBr. at 9-10; *see* Tr. at 3905-3907.) AriSEIA/SEIA argue that Mr. Lucas refuted each of the additional costs APS attributes to DG customers and that APS "simply has not been able to identify any additional or extra costs attributable" to them, though APS "may very well want them to be there." (AriSEIA RBr. at 10.) AriSEIA/SEIA maintain that the Commission should adopt the recommendations from their Brief. (AriSEIA RBr. at 15.)

<u>Vote Solar</u>

Vote Solar argues that both of APS's COSSs rely on flawed and unjustified analysis and discriminate against DG customers by assigning them costs that are not incurred by APS and that are not associated with any services APS provides. (VS Br. at 2, 9, 17.) Vote Solar argues that the Commission should decline to approve either COSS and should not make any rate-related determinations based on them. (VS Br. at 2, 9-10, 17.) Vote Solar argues that APS fails to demonstrate that the electricity services residential DG customers use are any different from those used by non-DG residential customers and relies on "arbitrary estimates to quantify purported extra costs." (VS Br. at

9-10.) Vote Solar argues that DG customers use less energy overall and reduce their energy consumption during system peak, contributing to lower system costs for all customers, thus making it "nonsensical" to conclude that they cause APS to incur additional costs not caused by other residential customers. (VS Br. at 10.)

Vote Solar argues that the site load COSS is "largely identical" to the COSS APS presented in its last rate case, which the Commission did not accept. (VS Br. at 10; *see* Ex. RUCO-7 at 255.) Further, Vote Solar argues, customers have the right to reduce energy consumption, through whatever measures, and it is inappropriate to allocate costs to a customer class based on energy usage that was not supplied to the customer by the utility. (VS Br. at 10.) Vote Solar states that APS tries to "correct this flaw" by crediting DG customers with the value of the benefits they receive from self-supply, but that this approach is needlessly complex and does not change the fact that costs are assigned for "hypothetical energy deliveries" not used by the customers. (VS Br. at 10.)

Vote Solar argues that in the delivered load COSS, APS first allocates costs to DG customers based on their actual delivered load and then attempts to quantify additional costs that the utility purportedly incurs because of DG customers' self-supply of a portion of their energy needs. (VS Br. at 11.) Vote Solar argues that to accept this construct, one must accept that DG customers receive additional services from APS that are fundamentally different from the services provided to non-DG customers, although these "extra" services (such as "backup power" and "additional general services") are indistinguishable from services provided to all customers. (VS Br. at 11.) For example, Vote Solar states, DG customers may have increased energy deliveries in the evening hours or when clouds go by, but the same is also true for non-DG residential customers, because customers' energy usage profiles are variable, and a great deal of variation exists within each defined customer class. (VS Br. at 11.) Vote Solar argues that one can single out many sub-groups of customers within a class based on demographic factors or technology adoption and identify differences in their usage patterns, but APS designs and dispatches its system to serve the aggregated expected load of all customers, not that of any single customer or customer sub-group. (VS Br. at 11-12; *see* Tr. at 1669-1670.) Vote Solar points to Mr. Moe's testimony that unanticipated increases and decreases in load are normal for residential customers and that APS does not encounter difficulties in serving customers when their loads are unexpectedly higher or lower than normal. (VS Br. at 12; *see* Tr. at 1668-1669.) Vote Solar argues that APS did not present any evidence to show that DG customer load is more variable than residential class load and that no APS witness identified a specific piece of equipment or system upgrade needed to serve DG customers. (VS Br. at 12; *see* Tr. at 1672-1675.) Further, Vote Solar asserts, APS cannot distinguish between a customer load increase caused by turning on an appliance versus declining DG output.[488] (VS Br. at 12; *see* Tr. at 1666-1667.)

Vote Solar argues that the four "additional generation services" identified by APS as provided to DG customers (which include following customer load, ramping up and down to meet load, and in-rush current)[489] are "intrinsic to the provision of electricity service for all customers and not uniquely required to serve solar customers." (VS Br. at 12; *see* Ex. APS-24 at 38.) Vote Solar points to Mr. Moe's testimony that these "additional generation services" are included within the generation service that DG customers receive from APS (and pay for) when they are not self-supplying and are not incurred separately on DG customers' behalf. (VS Br. at 12; *see* Ex. APS-24 at 38; Ex. VS-2 at 23.) Additionally, Vote Solar argues, the fourth "additional generation service," integration, is neither unique to DG customers nor a direct cost incurred by APS but instead an estimate of the economic impact associated with adjusting dispatch of the system in response to the actual output of a specific generation resource. (VS Br. at 13.) Vote Solar asserts that integration costs can be quantified for utility-scale resources, and that these costs are relevant in planning decisions, but that the integration of all resources on a system is an inherent part of providing electric service and not a distinguishable cost APS incurs on behalf of specific customers or resources. (VS Br. at 13.)

Vote Solar argues that DG customers on average are less expensive to serve than other residential customers because they use less energy throughout the year, use less energy during the CP hour of 5 to 6 p.m. in the summer months, and have peak usage that occurs later in the evening and over fewer hours at a time when other residential customer usage is declining. (VS Br. at 13; *see* Ex. VS-3 at 12-13.) Vote Solar argues that because DG customers' energy usage peaks after the CP hour,

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[488] Mr. Moe stated that APS would see a difference if a customer was exporting energy because the exports would decrease. (*See* Tr. at 1667.)

[489] The fourth identified "additional generation service" is integration of the solar generator with the utility's generation portfolio. (*See* VS Br. at 12; Ex. APS-24 at 38.)

there is no justification for imposing additional costs on DG customers, and it is discriminatory to apply to DG customers cost allocation metrics that are different from those used for other customer classes. (VS Br. at 14.) Vote Solar argues that costs should be allocated to DG customers based on delivered load, which captures usage of the system during the CP hour, because APS has asserted that "production demand costs are driven by the need to serve high critical system peak load hours," and APS witnesses testified in other contexts[490] that customers' reduced usage during the CP hour provides benefits to the grid and contributes to cost savings for all customers by reducing the cost of infrastructure needed to serve system peak demand. (VS Br. at 14; *see* Ex. APS-25 at 8; Tr. at 254-255, 409.) Vote Solar argues that a reduction in energy usage during the system peak hour is no different, regardless of whether it is caused by DG or another measure, that there is excess capacity on the system at hours other than the system CP because generation infrastructure is built to serve system CP, and that it is "nonsensical" to believe that DG customers who reduce system peak load are driving the need for new energy infrastructure or causing APS to incur additional costs not caused by non-DG residential customers. (VS Br. at 14-15.)

Further, Vote Solar argues, APS's quantification of "extra costs" is arbitrary and not supported by the evidence, based on allocation of costs to DG customers for the kWh they self-supplied and an estimate of the "firmness"[491] of DG that is not supported by the evidence, rather than based on the cost of any equipment or system upgrades actually used by APS to serve DG customers. (VS Br. at 15; *see* Tr. at 1672-1675.) Vote Solar argues that Mr. Moe's determination of firmness value for DG solar (based on his assessment of its availability, its dependability, and DG customers' obligation to operate solar generators) was based on estimates rather than formula driven. (VS Br. at 15-16; *see* Ex. APS-24 at 25, 28-36; Tr. at 1662-1664.) Vote Solar argues that cost allocation must be based on actual data and evidence to be just and reasonable and that it is not fair or equitable to rely on the APS COSS's "ballpark estimates and unproven assertions" to make decisions about customer responsibility for cost

[490] Specifically, Mr. Geisler spoke to the benefits from customer usage reductions obtained through the smart thermostat DR program, Cool Rewards, and through XHLF customers using on-site generation or other measures to reduce demand during peak hours. (*See* Tr. at 254-255, 409.)

[491] Mr. Moe stated that other terms used for firmness-related concepts are RA, capacity value, reliability, and effective load carrying capability. (*See* Ex. APS-24 at 25.) Mr. Moe stated that the core issue is the amount of solar generation capacity APS can dependably rely on to serve the customer's load during critical peak hours. (*See id.*)

of service. (VS Br. at 16.)

Finally, Vote Solar argues that by creating the RCP applicable to residential DG customers, the Commission has already made a policy decision on how to value exported solar energy and has drawn "a clear line" between energy that is exported and energy that is used for self-supply. (VS Br. at 16; *see* Decision No. 75859 at 177.) Vote Solar argues that because of the Commission's policy decision on the pricing of exported energy, it is not evaluated using standard cost-of-service principles and is irrelevant to a determination of the cost of serving a DG customer's load. (VS Br. at 13.) Vote Solar argues that the RCP is intended to represent both the costs and benefits to the grid from exported energy and that there is no causal relationship between the value of an exported kWh and the type of customer who exported it or their cost of service. (VS Br. at 16.) Thus, Vote Solar argues, the COSS applicable to DG customers should not consider the costs and benefits associated with exported energy, so that cost-of-service issues are not confused with the approach the Commission approved for the RCP. (VS Br. at 16-17.)

In its Responsive Brief, Vote Solar reiterates that the Commission must not approve either of APS's COSSs because they include unjustified costs and arbitrary quantification of costs and discriminate against customers with DG. (VS RBr. at 2.)

APS Response

In response to AriSEIA/SEIA and Vote Solar's arguments that both of APS's solar COSSs should be rejected, APS argues that the importance of recognizing a solar COSS intensifies as rooftop solar installations grow because the DG class is substantial and growing, has unique energy usage and on-site generation, and has important ramifications for cost recovery. (APS RBr. at 42; *see* VS Br. at 9-10; AriSEIA Br. at 6; Ex. APS-24 at 19.) APS argues that both of its COSSs used sound reasoning and that the arguments of Vote Solar and AriSEIA/SEIA should be disregarded. (APS RBr. at 42.) APS argues that the fundamental problem with Vote Solar and AriSEIA/SEIA's arguments about the site load COSS is that there are additional costs beyond the delivered load associated with serving DG customers because both DG customers' delivered load and self-supplied load "require support and costs from the utility because the customer is connected to the grid at all times and relies on the utility for backup power." (APS RBr. at 42-43; *see* Ex. APS-24 at 21, 23-24.) APS argues that a COSS based solely on delivered load ignores the costs associated with the self-supplied load. (APS RBr. at 43; *see* Ex. APS-24 at 21.)

In response to AriSEIA/SEIA's argument that the site load approach is an "extreme outlier" in the COSS world, APS argues that it is "based on sound COSS principles" and that its novelty does not mean that it is unreasonable or unworthy of adoption. (APS RBr. at 43.) Moreover, APS notes that the Commission has classified residential DG customers as partial requirements customers and determined that the question of whether they are paying their fair share is best determined in a solar COSS in a rate case. (APS RBr. at 43; *see* Ex. APS-24 at 19.) APS further argues that AriSEIA/SEIA provided no constructive feedback on either of APS's solar COSS approaches in this matter. (APS RBr. at 43.) APS argues that Vote Solar and AriSEIA/SEIA's arguments concerning the delivered load COSS also should be rejected, for the reasons discussed in APS's Brief. (APS RBr. at 43; *see* APS Br. at 62-63.)

APS further argues that APS is not discriminating against DG customers because they have a different peak profile but instead is fairly allocating costs across their customer class, which is appropriately separate from the non-DG residential customer class because DG customers are partial requirements customers with on-site generation who use the grid to export energy and require backup support that has costs that are not captured through an unadjusted delivered load COSS. (APS RBr. at 43-44.)

Concerning Vote Solar's argument that the delivered load COSS estimated firmness value should be rejected, APS argues that estimates are an intrinsic part of developing a COSS and that the firmness value is based on data and evidence. (APS RBr. at 44.) APS asserts that Mr. Moe examined empirical data for the dependability factor and the availability factor and, after examining all three factors in light of the TY data and concepts, determined that DG's firmness is significantly reduced over the critical summer peak hours and that a 40% firmness value was reasonable, meaning that APS must supply backup production capacity for 60% of the self-supply to ensure reliable service. (APS RBr. at 44-45; *see* Ex. APS-24 at 25-26, 28-29. 35-37.)

APS also disagrees with Vote Solar's assertion that export power should be excluded from the solar COSS to avoid confusing cost-of-service issues with the Commission-approved RCP analysis and approach. (APS RBr. at 45.) APS points to Mr. Moe's testimony that the cost of export power represents a direct cost obligation to the other customer classes, while the benefits of solar exports (such as reduced fuel costs) are a direct cost savings to other classes, and that the net value of export power is an important part of identifying any deficiencies for the DG class and their impact on other customer classes. (APS RBr. at 45; *see* Ex. APS-25 at 25-26.)

APS also argues that AriSEIA/SEIA's request for the Commission to require APS to produce a fully functional COSS combining DG customers with non-DG customers on similar rates and incorporating DG customer load based on delivered load should be summarily rejected because DG customers are partial requirements customers who have their own unique load profile and require additional costs to serve. (APS RBr. at 45-46; *see* Ex. APS-24 at 18-19, 23-24; Tr. at 3788-3790; Ex. VS-3 at 12, 14.) APS argues that it is important for the Commission to receive DG-customer-specific data because combining DG customers with non-DG customers would hide data on DG adoption and hinder the Commission's ability to determine whether there are any cost shifts or benefits associated with DG customers. (APS RBr. at 46.) APS further argues that AriSEIA/SEIA's request is inconsistent with Decision No. 75859, which found that the issue of whether DG customers were paying their fair share is best answered in a solar COSS in a rate case. (APS RBr. at 46; *see* Ex. APS-24 at 19; Decision No. 75859 at 146.)

<u>Resolution</u>

APS currently has approximately 165,000 residential customers with solar DG, which is more than 15% of its residential customers, and at peak production, the solar DG produces in the GW range. (Tr. at 1340, 1690.) The Commission has previously established that rooftop solar customers are partial requirements customers because APS provides them power when their systems are not providing sufficiently to meet the customers' loads. APS maintains that those power costs are not reflected in the rooftop solar customers' billed usage or in a COSS that allocates based on delivered load rather than site load. (Tr. at 1682-1685, 1737-1738.) The record shows that in summer months, residential DG produces from approximately 6 a.m. to approximately 7 p.m., with a large drop off in generation beginning at approximately 3 p.m. and almost a complete drop off by 6 p.m. (*See* Ex. APS-24 at 28-29; Ex. VS-3 at 12, 14, 17, ex. KB-1.) The record also shows that in summer months, residential DG customers have very different median load patterns as compared to non-DG residential customers, primarily relying on self-supply from approximately 9 a.m. to approximately 3 p.m., relying on APS for at least some power at all other times, and having peak usage after the residential non-DG customers in approximately the hours of 6 p.m. to 8 p.m. (*See* Ex. VS-3 at 12, 14.) The evidence also shows that for some summer dates in 2022, the DG customers' median load peak was higher than the median load peak for the non-DG residential customers. (*See* Ex. VS-1 at 12, 14.) Additionally, the record shows that on the TY peak load day for residential customers, residential DG reduced the residential class peak by approximately 360 MW and contributed approximately 150 MW during the system CP hour of 5 p.m. to 6 p.m. (*See* Ex. VS-3 at 17.) Because of the large number of residential DG customers, the impacts of their DG systems collectively, and their very different load patterns, the Commission continues to believe that it is appropriate to treat them as a separate class in a COSS.

The more difficult question is how costs should be allocated to them in that COSS—whether according to their delivered load, their site load, or some other measure. In the last rate case, the same debate occurred about the services APS provides to residential DG customers, with APS asserting that the COSS needed to capture the cost of grid services for export and backup services (such as in-rush current) and AriSEIA/SEIA criticizing APS for not quantifying the grid services costs, which were characterized as "additional costs needed to serve DG solar customers." (*See* Ex. RUCO-7 at 242, 244.) When the Commission adopted the requirements related to APS's solar COSSs in Decision No. 78317, the Commission envisioned APS specifically analyzing and identifying the services that it provides to DG customers (along with any equipment used to provide those services), comparing that to the services provided to non-DG customers (along with any equipment used to provide those services), and determining once and for all what additional efforts and/or equipment APS must use to ensure reliable service to DG customers that it does not also use to ensure reliable service to non-DG customers. Contrary to AriSEIA/SEIA's understanding, the Commission did not expect APS to identify new assets, new operating costs, or new services; it did expect APS to identify and quantify the cost of the incremental services and incremental equipment usage already occurring. In retrospect, perhaps this was naïve. The evidence of record in this matter now makes it clear that APS does not truly provide additional services and does not use additional equipment to serve DG customers.[492] What APS does provide DG customers, however, is RA. In the same way that APS steps in to serve AG-X customers when their GSPs fail to deliver, APS provides DG solar customers capacity and energy when they need it, but on a larger scale and generally on a much more predictable and consistent basis, although any individual DG system may have diminished production or may cease production at any time due to a multitude of conditions. APS's generation resources stand by at all times to provide capacity to residential DG customers when needed, and residential DG customers use APS's generation resources on a daily basis. Because of this, as it is just and reasonable to allocate production costs to AG-X customers based on their site load, it is also just and reasonable to allocate costs of service to DG customers based on their site load, with credits made based on the difference between the site load and delivered load using the credit factors for each cost type as described in Mr. Moe's testimony. (*See* Ex. APS-24 at 22, Att. JRM-05DR.) Allocating costs to DG customers based only on their delivered load does not provide the full picture of the capacity and other resources that APS must have at the ready to provide reliability for DG customers when needed.[493]

But this should not be the end of the inquiry. The Commission finds merit in Vote Solar's idea that APS should analyze what its system would have looked like in the TY without residential DG and how much more it would have spent on generating capacity, fuel costs, and market purchases to backfill the residential DG resource and then compare that with actual TY costs. The Commission will direct APS to prepare this analysis for its next rate case, provide it with its rate application with sufficient detail for parties to scrutinize the stated differences, and use it to inform the credits that APS applies to the residential DG class in its site load-based COSS. The Commission desires detailed data to support the credits provided to DG customers in the site load COSS.

4. Allocation of Revenues

In Decision No. 78317, the Commission determined that it was not able to adopt any of the

[492] Mr. Moe was not able at hearing to identify with confidence any specific additional costs from equipment, upgrades, additions, or services that APS incurred as a direct result of customers installing rooftop solar, although he believed that there are such costs. (Tr. at 1672-1675.) Additionally, Mr. Geisler very candidly stated that there are no extra costs; there are just costs that are not covered by only the revenue generated through delivered load. (*See* Tr. at 457.)

[493] Additionally, the Commission agrees with some of the arguments made by AriSEIA/SEIA and Vote Solar regarding the inexact and speculative nature of some of the adjustments made to the delivered load COSS.

COSSs proposed in that rate case in their entireties and that the record had not established that a unity rate of return was an appropriate objective in that case. (Ex. RUCO-7 at 264.) The Commission further determined based on a comparison of the COSS results obtained by APS and Staff, that certain subclasses were likely not fully covering their costs of service (R-XS, R-Basic, R-Basic L, Legacy Solar (Energy), Legacy Solar (Demand), Church, E-32 L, AG-X, and R-2 and R-3 combined) and that the remaining classes were likely either fully covering their costs of service (TOU E (at least non-solar) and E-32 TOU L) or over-recovering their costs of service (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). (Ex. RUCO-7 at 264.) Because the Commission did not have a COSS upon which it could rely for guidance in reasonably allocating the revenue requirement change to improve subsidization to an appropriate extent, the Commission adopted an even revenue allocation as proposed by APS. (Ex. RUCO-7 at 264.) The Commission determined that this would ensure gradualism and consistency in APS's rates and was appropriate in light of the extreme changes made in Decision No. 76295, from which customers were still recovering. (Ex. RUCO-7 at 264.)

APS Proposal

In this matter, APS again proposes an approximately even distribution for revenue allocation, which it states would result in an average base rate increase of 11.1% for residential and general service customers. (APS Br. at 63, Att. B at Sched. A-1.) Specifically, APS proposes the following base revenue increases, net increases following adjustor impacts, and day 1 net increases by class:[494]

Class	Base Rate % Increase	% Increase Net of Adjustors	Day 1 Net % Increase
Residential	20.36%	16.61%	11.14%
General Service	20.54%	17.91%	11.14%
Irrigation/Water Pumping	25.20%	19.07%	11.14%
Outdoor Lighting	15.21%	14.23%	10.16%
Dusk to Dawn	15.22%	14.79%	13.29%
Overall Retail Sales	20.44%	17.19%	11.14%

While the proposed base rate revenue increases for the residential subclasses are all within the range

[494] *See* APS Br. at Att. B at Sched. H-1.

of 20.35% to 20.39%, APS proposes slightly wider variations within the general service subclasses, with most of the subclasses proposed to have base rate revenue increases between 21.24% and 21.31%, but the following subclasses proposed to receive lower or higher increases:[495]

E-30	E-32M	E-32L	E-34	Schools L
21.19%	21.07%	19.83%	18.71%	21.41%

APS asserts that its revenue allocation proposal is intended to support gradualism, avoid disparate impacts among rate classes, and minimize the increase to the residential class that would result if the COSS was followed to establish the revenue allocation. (APS Br. at 63-64; *see* Ex. APS-30 at 6; Decision No. 68487 (February 23, 2006) at 38.[496]) APS also cites *Freeport Minerals Corp. v. Arizona Corp. Comm'n*, 244 Ariz. 409, 412 (App. 2018) ("*Freeport*")[497] to support the idea that although the COSS historically has been used as a guideline to allocate revenues, regulators usually also consider other factors (economic, social, historical) that may affect customers and often adopt rates deviating from strict cost of service.

APS notes that RUCO supports its proposed revenue allocation and that Walmart does not oppose it but proposes a removal of class subsidies if APS is granted less than its full proposed revenue increase. (APS Br. at 64; *see* Ex. RUCO-3 at 8; Ex. Walmart-1 at 4.) APS argues that the revenue allocations proposed by Staff, FEA, and AZLCG would result in higher increases for the residential class than APS's proposal, with Staff proposing that no class receive a rate increase greater than 1.15 times the system average increase, FEA proposing that the residential class increase be no greater than 1.5 times the system average increase, and AZLCG proposing that no class increase be greater than 1.33 times the system average increase. (APS Br. at 64-65; *see* Ex. S-12 at 34; Ex. AZLCG-3 at 36; Ex. FEA-2 at 7; Tr. at 3390, 3395, 4544.) APS opposes imposing increases that would result in a wide

[495] *See* APS Br. at Att. B at Sched. H-2. The E-32M, E-32L, and E-34 subclasses include AG-X customers. (*See id.*) The E-32TOU L subclass also includes AG-X customers, but it is proposed to receive an increase of 21.31%. (*See id.*)

[496] Official notice is taken of this decision, issued in Docket No. G-01551A-04-0876, a Southwest Gas Corporation rate case. In the decision, the Commission stated that movement closer to cost-based rates is a laudable goal but must be balanced with consideration of gradualism, fairness, and encouragement of conservation. (Decision No. 68487 at 38.)

[497] The court concluded that rate shock is a well-founded concern that permits the Commission to invoke gradualism to deviate from strict cost of service when establishing a just and reasonable revenue allocation, that gradualism can be sufficient justification for eliminating subsidies incrementally, and that Freeport had not established clearly and convincingly that the Commission's revenue allocation decision was arbitrary, unlawful, or unsupported by substantial evidence. (*See Freeport*, 244 Ariz. at 414-415, 417.)

range of customer impacts and argues that its approach is consistent with gradualism, and intended to avoid rate shock, particularly for residential customers, which is a valid concern that permits deviation from strict cost of service when determining a just and reasonable revenue allocation. (APS Br. at 65; *see* Tr. at 2445-2446; *Freeport* at 412.) APS argues that its revenue allocation is reasonable and should be approved. (APS Br. at 65.)

AARP

AARP urges the Commission not to order any cost shifts from other customer classes onto the residential class. (AARP Br. at 5.)

AZLCG

AZLCG argues that the Arizona Constitution and Arizona law require the Commission to move rates toward cost of service to reduce or eliminate subsidies. (AZLCG Br. at 50.) AZLCG argues that Arizona Constitution Article 15, § 3 requires the Commission to prescribe just and reasonable classifications and just and reasonable rates and charges; that cost of service is highly relevant to establishing just and reasonable rates; and that Arizona Constitution Article 15, § 12 and A.R.S. § 40-334, respectively, prohibit the Commission from allowing discrimination in charges between customers who receive a like and contemporaneous service and unreasonable differences in rates or charges between places or classes of service. (AZLCG Br. at 50; *see* Ariz. Const. Art. 15, §§ 3, 12; *Sun City Home Owners Ass'n v. Ariz. Corp. Comm'n*, 252 Ariz. 1 (2021) ("*SCHOA*"); A.R.S. § 40-334.) AZLCG argues that "wholly ignoring cost of service" is unlawful. (AZLCG Br. at 51.[498]) AZLCG cites *Freeport*, in which the Court of Appeals affirmed a Commission revenue allocation that did not eliminate subsidies but moved toward parity, because the Commission's decision was made in the interests of gradualism and avoiding rate shock, and *SCHOA* for the principal that a rate structure through which one class subsidizes another may reflect impermissible discrimination. (AZLCG Br. at 51-52; *see Freeport* at 413, 414, 417; *see SCHOA* at 6-7.)

AZLCG argues that APS's proposed revenue allocation would involve no movement toward parity and that when the Commission approved such a revenue allocation in APS's last rate case, it was

[498] AZLCG cites a Maricopa County Superior Court case invalidating City of Tucson water rates, which is inapposite because it involved municipal rates rather than public service corporation rates.

because the Commission determined it did not have a COSS upon which it could rely as guidance to allocate the revenue requirement to mitigate subsidization. (AZLCG Br. at 52; *see* Ex. APS-32 at 2; Ex. S-12 at 32; Ex. RUCO-7 at 264.) In this matter, AZLCG contends, the Commission has both a COSS created using the A&P method and a COSS created using the A&E method. (AZLCG Br. at 52.) AZLCG notes that APS has acknowledged its revenue allocation does not move toward cost of service; asserts that Staff, FEA, and AZLCG witnesses all agree that this is true; asserts that APS's revenue allocation would move some classes further away from cost of service; and argues that APS's proposed revenue allocation thus is unconstitutional and unlawful. (AZLCG Br. at 52; *see* Ex. FEA-2 at 5; Tr. at 2447-2448, 3411, 3414, 3530, 4550.)

Further, AZLCG argues, there are policy reasons to move rates toward cost of service, including basic fairness and the desire to avoid the "perverse incentives" created by inaccurate price signals and instead promote economically justified beneficial use. (AZLCG Br. at 52-53; *see* Ex. SWEEP-2 at 12; Tr. at 1594-1597,[499] 2447-2449, 3393-3394,[500] 4549-4550, 4736-4737.[501]) AZLCG argues that the only way the Commission could approve what APS proposes is to ignore the COSS, which the Arizona Constitution and state law prohibit the Commission from doing. (AZLCG Br. at 53; *see* Ex. S-12 at 32.)

AZLCG argues that Staff, FEA, AZLCG, and the School Groups all agree the Commission should use a COSS to set rates. (AZLCG Br. at 54; *see* Ex. S-12 at 34; Ex. AZLCG-3 at 36-37; Ex. FEA-2 at 7; Tr. at 3389-3390, 3559-3560.) AZLCG recounts the parties' proposals for caps on any class rate increase in relation to the system average (FEA at 1.5 times, Staff at 1.15 times, and AZLCG at 1.33 times), notes that the level of any increase will be dependent on the revenue requirement approved by the Commission, and asserts that its mid-point revenue allocation cap recommendation

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[499] Mr. Moe did not agree that the existence of large subsidies creates concerns about fairness, instead stating that the rates and charges are determined by the Commission to be just and reasonable and that he bowed to that determination. (Tr. at 1595.) Mr. Moe also stated that there may be a reason for a subsidy and that it may be accepted as okay. (Tr. at 1595.)

[500] Mr. Gorman agreed that the goal of gradualism is to move incrementally toward full recovery of the allocated cost of service, but also stated: "Rate affordability is a critical important factor these days and it applies to all customer[s], not any specific rate class. And it should be considered in assessing the overall revenue requirement of the utility." (Tr. at 3392-3394.)

[501] Mr. Radigan agreed that it is reasonable to move rates closer to cost of service, that doing so means better price signals are sent to customers, that it is important to send reasonable price signals to ensure efficient use of energy, and that sending accurate price signals helps APS efficiently meet the challenges of load growth, but also stated that all of these concerns have to be balanced against ratepayer impacts. (Tr. at 4736-4737.)

would be a marked and reasonable step toward cost of service and that Ms. Hobbick agreed it would mitigate some of the impact customers would experience and reduce concerns about rate shock. (AZLCG Br. at 54; *see* Ex. S-12 at 34; Ex. FEA-2 at 7; Ex. AZLCG-3 at 36-37; Tr. at 2445-2446, 3390, 3395-3396, 4565.) AZLCG asserts that its proposed revenue allocation, using APS's original proposed revenue requirement, is shown on page 2 of Exhibit KCH-19-F,[502] attached to its Brief, and recommends that the class revenue requirements shown be scaled down in proportion to any reduction in the overall revenue requirement ultimately approved by the Commission. (AZLCG Br. at 55.)

FEA

FEA argues that APS's proposed revenue allocation is fairly uniform and does not reasonably move all rate classes closer to cost of service. (FEA Br. at 8-9; *see* Ex. APS-29 at 3.) FEA cites Mr. Gorman's testimony showing that based on APS's application revenue requirement, the residential class would need a 37.3% revenue increase to reach cost of service, while the general service class would need only a 6.1% revenue increase. (FEA Br. at 9; *see* Ex. FEA-2 at 5.) FEA notes that Mr. Gorman's testimony also showed that the increase based on an A&E production demand cost allocator would be even higher for the residential class, at 40.1%, while the general service class would need only a 2.0% increase.[503] (FEA Br. at 9; *see* Ex. FEA-2 at 5.)

FEA argues that APS's proposed revenue allocation does not increase the residential class revenue requirements sufficiently to make a meaningful and gradual movement toward cost of service and that this would force other classes' rates to stay above cost of service. (FEA Br. at 9.) FEA argues that to move the residential class to cost of service, the residential class revenue requirement needs to be set at 1.63 times the system average increase of 22.9%.[504] (FEA Br. at 9.) FEA recommends, however, that the residential class instead be required to shoulder a revenue requirement increase set at 1.5 times the system average increase, which FEA shows as an increase of 34.3%. (FEA Br. at 10; *see* Ex. FEA-2 at 7.) FEA argues that moving rates toward cost of service is fair and reasonable to all

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[502] Exhibit KCH-19-F, page 2, shows that the cap of 1.33 times the system average equaled 30.93% and that the bundled floor of 0.64 times the system average equaled 14.28%. (*See* AZLCG Br. at ex. A at Ex. KCH-19-F at 2.)

[503] Mr. Gorman also showed that using the A&P method, the residential class would need a rate increase of 22.8%, and the general service class would need a rate increase of 23.0%. (FEA Br. at 9; *see* Ex. FEA-2 at 5.) The total revenue requirement numbers are similar under each scenario but not the same; it is unclear why. (*See* FEA Br. at 9; Ex. FEA-2 at 5.)

[504] This is based on APS's originally proposed application revenue requirement. (*See* Ex. APS-29 at 3.)

customers because it ensures that all customers are paying the cost of providing service, it encourages conservation, and it provides more efficient load characteristics that offer APS an opportunity to improve the efficiency and economics of infrastructure investments needed to serve load. (FEA Br. at 10; *see* Ex. FEA-2 at 6.)

FEA argues that although APS identified the reasons behind APS's choice not to move customer classes closer to cost of service,[505] APS failed to provide any evidence showing how the proposed revenue spread considers any of these factors. (FEA Br. at 10-11; *see* Ex. FEA-3 at 7.) FEA states that it agrees with APS that gradualism and stability are important and that gradual movement to cost of service is fair and reasonable to all classes and argues that APS's revenue allocation proposal does not achieve this because it does nothing to address the subsidies that other rate classes are paying to cover the residential class. (FEA Br. at 11.) FEA recommends that the residential class receive an increase of approximately 1.5 times the system average increase and that the general service class receive an increase of approximately 0.42 times the system average increase, asserting that this would result in a fair and reasonable gradual movement toward parity. (FEA Br. at 11.)

Walmart

If the Commission awards a revenue requirement increase lower than that proposed by APS, Walmart recommends that the Commission take steps to address subsidies by distributing the decrease in two steps: (1) apply half of the overall decrease amount to rate classes with an indexed rate of return ("IRR")[506] greater than 1.0, based on the proportional contribution of each class to the overall current revenue requirement as shown in the COSS; and (2) apply the remaining half of the overall decrease amount to all classes on an equal percentage basis, provided that this does not move any class to an IRR greater than 1.0. (Walmart Br. at 2.)

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[505] These factors included residential customers recently experiencing an atypical PSA increase and the implementation of the court resolution surcharge, the shorter TOU window approved in the last rate case, and the changes to on-peak and off-peak ratios and customer charges in the last rate case. (FEA Br. at 10; *see* Ex. APS-30 at 6.)

[506] The IRR is an indexed measure of the relationship of a class's rate of return to the overall system rate of return. (Ex. Walmart-1 at 13.) An IRR of 1.0 shows parity, that a class is paying rates that reflect the costs to serve the class. (*Id.*) An IRR greater than 1.0 shows that a class is subsidizing another class or classes. (*Id.*) An IRR lower than 1.0 shows that a class is being subsidized by another class or classes. (*Id.*) The IRR is calculated by dividing the rate of return for an individual class by the rate of return for the company as a whole. (Ex. RUCO-3 at 7.) We note that APS calculated the IRR for each class and subclass using the rate of return for the total company, not just the jurisdictional rate of return. (*See* Ex. APS-24 at Att. JRM-02DR.)

Walmart argues that the E-32M and E-32L classes are paying significantly more than their class cost of service and subsidizing other classes but asserts that if the Commission approves APS's requested revenue requirement, Walmart does not oppose APS's proposed revenue allocation. (Walmart Br. at 3.) However, if the Commission approves a lower revenue requirement, Walmart argues, the Commission should use its proposed two-step revenue allocation. (Walmart Br. at 3.) Walmart argues that the Commission should ensure all rate classes are no longer paying significantly more than their cost of service by moving rates for each class closer to cost of service. (Walmart Br. at 3-4.)

RUCO

RUCO supports APS's proposed revenue allocation, under which each class receives the same day one percentage increase.[507] (RUCO Br. at 34; *see* Ex. RUCO-3 at 2.) RUCO states that APS's COSS shows the residential class is paying a lower rate of return than the overall system average for all classes, which RUCO states could be explained in part by the majority of solar installations being on residential homes. (RUCO Br. at 34.) RUCO states that APS believes solar customers are not contributing enough to meet their cost of service, but that there are a large number of residential customers with solar installations who are not currently studied separately as a group.[508] (RUCO Br. at 34.) RUCO states that residential solar customers' paying less than the cost to serve them would lower the rate of return for the residential class as a whole. (RUCO Br. at 34.) RUCO asserts that the accuracy of the solar COSS needs to be examined and that the solar customers should be studied separately from the non-solar residential customers. (RUCO Br. at 34.) "Given these concerns and the need for additional cost-of-service analysis," RUCO recommends adoption of APS's proposed revenue allocation and that future COSSs separately study solar customers and customers served under frozen rates by service class and major retail rate function. (RUCO Br. at 34-35.)

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[507] In its Brief, RUCO refers to the net day one increase as 13.62%, which is consistent with APS's application. (*See* RUCO Br. at 34; Ex. APS-37 at Sched. H-1.) The proposed net day one increase was reduced on rebuttal and again on rejoinder and is now approximately 11.2%, with some variation among classes and subclasses. (*See* Ex. APS-32 at 2; Ex. APS-30 at Att. JEH-02RB; APS Br. at Att. B at Sched. H-1.)

[508] We note that the COSS adopted in this matter studied residential solar customer costs and returns separately, although it did group customers on legacy solar rate schedules into two classes based on whether their rate schedules did or did not include demand, rather than including each legacy solar rate schedule as its own COSS class.

Staff

Staff opposes APS's proposed revenue allocation, asserting that APS's proposal disregards COSS results and that the increases should be more proportional to class costs of service. (Staff Br. at 48; *see* Ex. APS-30 at 4-6; Ex. S-12 at 32-34.) Staff states that its proposal promotes the interest of better aligning rates with costs of service while mitigating rate shock by capping any class's increase at 1.15 times the overall average rate increase. (Staff Br. at 48; *see* Ex. S-12 at 34.) Staff states that APS's proposal focuses on impacts to residential customers while Staff's proposal promotes just and reasonable rates for all classes and mitigates subsidization between classes. (Staff Br. at 48; *see* Ex. APS-29 at 3; Ex. APS-30 at 5-6; Ex. APS-32 at 2; Tr. at 2443-2445; Ex. S-12 at 34.) Staff recommends adoption of a revenue allocation based on the results of Dr. Dismukes's proposed COSS.[509] (Staff Br. at 48; *see* Ex. S-12 at 3.) Staff asserts that this would result in a maximum base revenue increase for any customer class of 26.3%.[510] (Staff Br. at 48; *see* Ex. S-12 at 3.) Staff acknowledges that regulators diverge from setting rates at full cost of service for policy reasons such as limiting rate shock or for equity but asserts that establishing rates based on cost of service limits subsidies and promotes appropriate customer rationing. (Staff Br. at 48-49; *see* Ex. S-13 at 10.)

Staff notes the positions of other parties on revenue allocation and that APS has stated it does not propose moving toward cost of service due to concerns about rate gradualism and stability for residential customers, who experienced non-typical bill impacts in 2023 due to the PSA increase in March and the court resolution surcharge in July. (Staff Br. at 49; *see* Ex. S-13 at 9.) Staff states, however, that the Staff proposal tempers rate increases for some classes as compared to APS's initial proposal. (Staff Br. at 49; *see* Ex. S-12 at 3.)

In its Responsive Brief, Staff opposes Walmart's recommended revenue allocation, arguing that it seeks to benefit certain customer classes disproportionately at the expense of others and would reduce the rate gradualism that would otherwise occur under APS's proposed revenue allocation. (Staff RBr. at 30.) Staff also defends its proposed revenue allocation from APS's criticism, stating that it is widely

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[509] Dr. Dismukes's COSS used a 100% class NCP cost allocation method for non-customer-related secondary-voltage distribution plant costs, which resulted in the residential class's rate of return increasing to 0.58% and the general service class's rate of return decreasing to 5.62%. (*See* Ex. S-12 at 29-30; ex. DED-3.)

[510] This figure is based on APS's originally requested revenue requirement.

accepted that reasonable rates should be informed by cost of service and that APS's proposal ignores cost causation. (Staff RBr. at 30.) Staff states that although it appreciates APS's concern regarding "potential pancaking of rate increases" due to changes in adjustor mechanisms and the impact of this matter, Staff continues to recommend the revenue allocation method based on Dr. Dismukes's COSS. (Staff RBr. at 31.)

APS Response

In its Responsive Brief, APS observes it is unsurprising that AZLCG and FEA, the large customer intervenors, are pressing for more revenue to be allocated to the residential class and thus less to be allocated to them. (APS RBr. at 35.) APS argues that its more even distribution avoids disparate impacts among rate classes and observes the principle of gradualism, which the Commission has long recognized should be used to avoid large, one-time increases to any customer class. (APS RBr. at 35-36; *see* Decision No. 68487 at 38.) APS argues that although Staff, FEA, and AZLCG recommend higher levels of revenue allocation to residential customers, neither Staff nor FEA calculated bill impacts based on their proposals. (APS RBr. at 36; *see* Tr. at 3395, 4563.) In its Responsive Brief, APS provides both a table and a more detailed Attachment A showing the difference in the day one net impacts based on the Staff, AZLCG, and FEA proposals, all of which show marked increases for the residential class and smaller increases or even a slight decrease (FEA) for the general service class. (*See* APS RBr. at 36-37, att. A.[511])

APS argues that *Freeport* supports APS's proposal to avoid a disparate impact to the residential class (as opposed to AZLCG's proposal) because the Commission in the underlying decision had rejected a revenue allocation that would have increased bills to the residential class by approximately 25%, and the Court of Appeals agreed that the Commission had the discretion to deviate from a strict cost-of-service rate design and consider other factors such as rate shock. (APS RBr. at 37-38; *see* *Freeport* at 412-415.) APS argues that to establish a reasonable revenue allocation, one must carefully balance the opposing interests of the different customer classes. (APS RBr. at 38.) APS asserts that

[511] It is unfortunate that APS chose not to provide this information until its Responsive Brief, as it could easily have been included in an exhibit and thus vetted by the other parties, or even provided in its Brief. As it stands, Attachment A is not a part of the evidentiary record in this matter.

the proposals of Staff, FEA, and AZLCG would all result in unnecessarily high bill impacts for residential customers. (APS RBr. at 38.) APS states that its proposed revenue allocation considers the bill impacts to residential customers in light of the recent PSA and court resolution surcharge increases and the changes to rate design made in the last rate case, appropriately balances the interests of the customer classes, and is in the public interest. (APS RBr. at 38.) APS requests that the Commission adopt the APS-proposed revenue allocation. (APS RBr. at 38.)

Resolution

In this matter, the Commission approves APS's site load COSS that maintains solar customers in a separate class, although it does not approve APS's use of total company returns to calculate IRRs, which the Commission believes should be calculated on the basis of jurisdictional returns.[512] (*See* Ex. APS-24 at Att. JRM-02DR.) The COSS shows the following level of TY recovery of cost of service for the following residential subclasses on a percentage basis and results in the follow IRRs based on jurisdictional returns:[513]

Legacy Solar (Energy)	Legacy Solar (Demand)	R-Basic (0-600 kW)	R-Basic (601-999 kW)	R-Basic (1000+ kW)	TOU-E	TOU-E w/Solar	R-3 (Demand)	R-3 w/Solar
37.73%	68.04%	70.44%	75.08%	95.25%	81.63%	50.38%	78.86%	56.22%
-2.35	0.03	-0.04	0.47	2.68	1.12	-3.10	0.65	-2.31

The COSS shows the following level of TY recovery of cost of service for the following general service and classified service subclasses on a percentage basis and results in the following IRRs based on jurisdictional returns:[514]

E-20 Church	E-30, E-32 XS (0-20 kW)	E-32TOU XS (0-20 kW)	E-32 S (21-100 kW)	E-32TOU S (21-100 kW)	E-32 M (101-400 kW)	E-32TOU M (101-400 kW)	GS-Schools M, L (TOU)
75.64%	104.59%	**122.56%**	102.99%	**117.97%**	100.89%	85.46%	84.19%
-0.07	3.92	6.84	3.72	6.12	3.45	0.95	0.56

E-32 L (401+ kW)	E-32TOU L (401+ kW)	E-34	E-35 (TOU)	AG-X	E-221 (NonAG)	Street Lighting	Dusk to Dawn
92.91%	98.04%	62.61%	78.82%	78.05%	94.01%	102.81%	100.99%
2.38	3.26	-3.26	-0.80	-0.30	1.96	3.70	3.50

[512] Dr. Dismukes calculated IRR based on jurisdictional returns. (*See* Ex. S-12 at ex. DED-1, ex. DED-3.)
[513] Ex. APS-24 at Att. JRM-02DR at 2; *see* Ex. APS-36 at 1.
[514] Ex. APS-24 at Att. JRM-02DR at 1, 3-4; *see* Ex. APS-36 at 1.

Thus, the COSS shows that the following rate subclasses are producing less than 70% of their cost of service, as designated by shading in the tables above: Legacy Solar (Energy), Legacy Solar (Demand), TOU-E with Solar, R-3 with Solar, and E-34. Likewise, the COSS shows that the following rate subclasses are producing more than 105% of their cost of service, as designated by bold text in the tables above: E-32 TOU XS and E-32 TOU S. These shaded and bolded results indicate levels of subsidization that should be improved through the revenue allocation adopted herein. The Commission is cognizant of the pain caused to residential ratepayers by the recent PSA surcharge increase that began on March 1, 2023, and will stay on customer bills until February 1, 2025, and of the court resolution surcharge that began on July 1, 2023, and will stay on customer bills in a reduced form until the end of APS's next general rate case. The Commission is aware of the many residential customers who provided public comment, a number of them in anguish about their inability to afford any rate increase. In recognition of the financial impacts that increasing rates to cover cost of service would have on these customers, the Commission will approve a gradual approach that is essentially a modified version of Staff's proposal; is designed to avoid rate shock; and is focused on ameliorating the worst of the subsidization in APS's current rate design. The Commission finds that the following revenue allocation is just and reasonable and in the public interest:

- The shaded subclasses shall receive revenue allocation at the level of approximately 1.15 times[515] the system average increase.
- The bolded subclasses shall receive revenue allocation at the level of 0.85 times the system average increase.
- The remaining subclasses shall receive revenue allocation at the level of the system average increase.

Although the Commission did not adopt Staff's COSS, the Commission notes that Staff's COSS also supports this outcome. In his alternative COSS, created using a 100% class NCP cost allocation methodology to allocate non-customer-related secondary-voltage distribution plant costs, Dr.

[515] This is to ensure that APS is not required to over-allocate revenue, due to the higher number of subclasses that will receive a higher increase as opposed to the number of subclasses that will receive a lower increase.

Dismukes found the following jurisdictional IRRs for the residential, general service, and classified service subclasses:[516]

Legacy Solar (Energy)	Legacy Solar (Demand)	R-Basic (0-600 kW)	R-Basic (601-999 kW)	R-Basic (1000+ kW)	TOU-E	TOU-E w/Solar	R-3 (Demand)	R-3 w/Solar
-2.34	0.00	0.03	0.48	2.67	1.12	-3.13	0.62	-2.31

E-20 Church	E-30, E-32 XS (0-20 kW)	E-32TOU XS (0-20 kW)	E-32 S (21-100 kW)	E-32TOU S (21-100 kW)	E-32 M (101-400 kW)	E-32TOU M (101-400 kW)	GS-Schools M, L (TOU)
-0.10	3.91	**6.80**	3.66	**6.07**	3.39	0.94	0.53

E-32 L (401+ kW)	E-32TOU L (401+ kW)	E-34	E-35 (TOU)	AG-X	Irrigation/ Water Pumping (E-211)	Street Lighting	Dusk to Dawn
2.35	3.23	-3.26	-0.80	-0.26	1.99	3.54	3.44

These IRRs also demonstrate that customers on the shaded rate plans are receiving the greatest subsidies from other classes/subclasses and that customers on the bolded rate plans are providing the greatest subsidies to other classes/subclasses. The Commission believes that in the circumstances of this matter, the public interest warrants a move toward rate parity, while taking into account the impacts this will have on the various rate classes/subclasses and the need for gradualism. The Commission notes that even with an increased revenue allocation, the results of the Commission's other determinations herein mean that customers on the shaded plans will still experience base rate increases at a level lower than the base rate revenue increase proposed by APS in its application and noticed to all customers, which was 22.9% overall.[517]

It should also be noted that each of the COSSs presented by the AZLCG, which were not adopted herein, supported a significantly higher base revenue increase for the residential class as a whole: 37.10% in the AZLCG-"corrected" APS site load COSS, 43.18% in the AZLCG A&E-4CP COSS "Adjusted for AG-X Curtailments," 42.29% in the AZLCG A&E 4CP COSS with "AG-X

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[516] Ex. S-12 at ex. DED-3.

[517] Official notice is taken of the notice filing made by APS in this matter on February 16, 2023, which included the language of the prescribed notice as provided directly to customers by mail or email, by publication in newspapers, and by posting on the APS main webpage. The notice also included the following language in all capitals and generally in bold: '**THE FINAL RATES APPROVED BY THE COMMISSION MAY BE HIGHER, LOWER, OR DIFFERENT THAN THE RATES PROPOSED BY COMPANY OR BY OTHER PARTIES.**'

Allocated Full-Service Fixed Generation Costs," and 38.26% in the AZLCG A&P-4CP COSS "Adjusted for AG-X Curtailments." (*See* Ex. AZLCG-3 at ex. KCH-16 at 2, ex. KCH-17, ex. KCH-18.) Likewise, the FEA provided evidence that based on APS's site load COSS, the residential class would need a 37.3% revenue increase to reach cost of service, while the general service class would need only a 6.1% revenue increase, and that if the FEA's preferred production cost allocation method were used, the residential class would need an even higher increase of 40.1%, while the general service class would need only a 2.0% increase. (*See* Ex. FEA-2 at 5.) Given the evidence, a higher-than-average system base rate increase for the residential class as a whole or for any subclass of the residential class should not come as a shock.

The Commission is aware that to achieve this movement toward rate parity, APS will need either (1) to include an additional charge applicable only to DG solar customers who take service under TOU-E and R-3; or (2) to separate the TOU-E tariff and the R-3 tariff into two separate tariffs each, with one applicable to customers who have DG solar and the other to customers who do not. The Commission believes it would be preferable to include an additional charge applicable only to DG solar customers on each tariff, to minimize customer confusion concerning which tariff applies to their situation.

While rooftop solar advocates may argue that this revenue allocation unlawfully discriminates against rooftop solar customers, the Commission observes that there is a sizable disparity between the extent to which rooftop solar customers on TOU-E and R-3 cover their costs of service as compared to non-rooftop solar customers on TOU-E and R-3. It would not be just and reasonable for the Commission to ignore this disparity and increase the revenue allocation for all customers on TOU-E and R-3 to make up for the difference, as this would only perpetuate the subsidization of rooftop solar customers by non-rooftop solar customers.

Additionally, and importantly, the Commission has previously determined that rooftop solar customers are partial requirements customers and thus a separate class for purposes of the COSS, and their on-site generation and exports of energy result in rooftop solar customers using APS's system in a manner that non-rooftop solar customers do not. The exporting of energy to APS's system alone results in rooftop solar customers on TOU-E and R-3 not receiving "the same service under like circumstances" or "substantially the same or similar service" as non-rooftop solar customers on TOU-E and R-3. Non-solar customers do not export energy to the grid.

But there are additional features of the service provided to rooftop solar customers that must be recognized, as discussed in reference to the COSS cost allocation issue. Most notably, APS's generation resources must stand by at all times to provide RA to rooftop solar customers when needed, and rooftop solar customers have a very different load pattern than non-rooftop-solar customers and in the summer months create their own median load peak that is later than and on occasion higher than the non-rooftop-solar customers' median load peak.

For all of these reasons, it is just and reasonable, under Article 15, § 3 of the Arizona Constitution, for the Commission to prescribe that the rooftop solar customers on TOU-E and R-3 should be classified separately for the purpose of establishing just and reasonable rates and charges to be collected by APS. Further, because of these differences, this separate classification and the assessment of an additional charge upon rooftop solar customers on TOU-E and R-3 does not result in discrimination in charges, service, or facilities made between persons or places for rendering a like and contemporaneous service under Arizona Constitution Article 15, § 12. Rooftop solar customers on TOU-E and R-3 are not receiving "the same service under like circumstances" or "substantially the same or similar service" as non-rooftop solar customers on TOU-E and R-3, and it is just and reasonable and in the public interest for the Commission to authorize APS to charge them an additional fee to ensure that more of their costs of service are covered without causing additional subsidization by non-rooftop solar customers. Likewise, assessing an additional fee on the rooftop solar customers on TOU-E and R-3 does not subject any person to any prejudice or disadvantage or establish or maintain any unreasonable difference as to rates, charges, service, facilities or in any other respect between classes of service under A.R.S. § 40-334.

I. Specific Tariff Related Issues

1. Basic Service Charges

<u>APS Proposal</u>

APS proposes to increase the basic service charge ("BSC") for the residential class consistent with the class average so that it will recover a larger portion of fixed costs, such as for meter reading, customer service, and billing, none of which have reduced costs when a customer consumes less energy. (APS Br. at 84; *see* Ex. APS-30 at 15-16; Ex. APS-32 at 6-7.) APS asserts that its proposal would result in residential customers paying approximately 70% to 80% of their corresponding costs of service. (APS Br. at 84; *see* Tr. at 2762; Ex. APS-30 at 16.) APS asserts that RUCO supports its proposed BSC increase because it is relatively small, close to the overall class average increase, and reflective of cost-causation principles. (APS Br. at 84; *see* Ex. RUCO-3 a 13; Tr. at 4415.) APS notes that Staff and SWEEP and WRA opposed the proposed BSC increase as counterproductive for incentivizing customers to reduce consumption (such as through EE or changes in usage). (APS Br. at 84; *see* Ex. S-12 at 47; Ex. SWEEP-2 at 10.) APS argues that their positions ignore the fixed costs underlying these charges that must be recovered. (APS Br. at 84-85; *see* Ex. APS-30 at 15-16.) APS argues that customers who adopt EE measures do not reduce their use of these services, so they should not receive a discount for those services. (APS Br. at 85; *see* Ex. APS-32 at 6-7.) APS also addresses Staff's argument that increasing BSCs shifts rate burden to low-use customers, whom Staff's witness claims are associated with lower income households, stating that APS's analysis of limited-income discount program (Rate Rider E-3) participants shows that they use nearly the same amount of energy as those who are not on the limited-income discount program, with participants on Rate Rider E-3 using an average of 1,011 kWh/month compared to the overall residential class average consumption of 1,056 kWh/month. (APS Br. at 85; *see* Ex. S-12 at 49; Ex. APS-32 at 7.) APS notes that customers participating in Rate Rider E-3 receive a significant discount on their bills, which includes to the BSC. (APS Br. at 85; *see* Ex. APS-32 at 7.) APS further notes Dr. Dismukes's testimony that if the Commission were to increase the BSC, it should be limited to the overall average increase to the residential class, which is consistent with APS's proposal. (APS Br. at 85; *see* Tr. at 4518.) APS further disputes Dr. Dismukes's claim that APS's proposed BSC is higher than the regional average, showing that APS and TEP charge similar amounts and that other Arizona electric utilities charge considerably more.[518] (APS Br. at 85-86; *see* Ex. S-12 at 46-47; Ex. APS-32 at 7-8.) APS argues that

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[518] For example, APS shows its proposed non-TOU residential BSC as $14.70, compared to the current BSC of $12, and compared to TEP's BSC of $13 and UNS Electric's BSC of $15. (*See* APS Br. at 86; Ex. APS-32 at 8.) APS also shows SRP and electric cooperative non-TOU BSCs ranging from $20 to $31. (*See* APS Br. at 86; Ex. APS-32 at 8.)

the current BSCs are recovering much less than their corresponding costs, that the proposed BSCs still will not achieve full recovery,[519] and that the Commission should approve the proposed BSC increase as appropriate, necessary, and supported by the evidence. (APS Br. at 87; *see* Ex. APS-30 at 16.)

<u>AARP</u>

AARP opposes any increase to the BSC, which is what APS's customers must pay each month even if they use no electricity. (AARP Br. at 5.) AARP would prefer that the BSC remain low so that customers have as much control as possible over their monthly bills and urges the Commission instead to apply increases to usage-based charges. (AARP Br. at 5.) AARP asserts that if the residential BSC is increased at all, it should not be increased by a higher percentage than the ultimate overall system revenue increase approved by the Commission—for example, if the Commission raises APS's revenue requirement by 8%, the BSC should go up by no more than 8%. (AARP Br. at 5.)

<u>RUCO</u>

RUCO supports APS's residential BSC proposal. (*See* RUCO Br. at 35; Ex. RUCO-3 at exec. summ.) Mr. Radigan testified that RUCO endorsed APS's proposed rate design because it generally results in the BSC receiving a slightly higher charge than the overall average, which is appropriate because a large portion of the proposed rate increase is due to additions to the backbone electric system, which increases the basic cost of service. (*See* Ex. RUCO-3 at 13.)

<u>Staff</u>

Staff acknowledges the current level of cost recovery obtained through APS's residential BSCs, as well as the cost recovery level that would result from APS's proposal, but does not agree with APS's proposed increase in residential or commercial BSCs. (Staff Br. at 50.) Staff asserts that the BSCs would increase by approximately 25% and that APS's current BSCs are similar to those of other investor-owned utilities in the region. (Staff Br. at 50-51; *see* Tr. at 4517; Ex. S-12 at ex. DED-8.) Staff argues that increasing the BSC as proposed would detrimentally impact the public policy goal of promoting EE and would negatively impact limited-income customers by undercutting affordability as

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[519] Ms. Hobbick's testimony shows that the current R-Basic Tier 1 customers pay BSCs that achieve only 53% cost recovery and that their proposed BSC would increase cost recovery to 64%, while the BSCs for R-Basic Tier 1 and 2 customers, TOU-E customers, and R-3 customers achieve cost recovery in the range of 63% to 66% and with the proposed BSCs would achieve cost recovery of 77% to 81%. (*See* Ex. APS-30 at 16.)

well as other rate equity initiatives APS has proposed in this matter. (Staff Br. at 51; *see* Ex. S-13 at 11.) Staff argues that increasing the BSC would shift the rate burden within the residential class to lower-use customers, whom Staff argues research has revealed are consistently associated with lower income households. (Staff Br. at 51; *see* Ex. S-13 at ex. DED-15.[520]) Staff argues that if the proposed BSC is approved, it will have a disproportionately adverse impact on lower income households. (Staff Br. at 51; *see* Ex. S-13 at 12.) Staff asserts that because APS may recover portions of any revenue loss caused by EE through the LFCR, APS would not be financially harmed if the BSC was not increased, while residential customers would be harmed if the increased BSC were approved. (Staff Br. at 51.) If the Commission determines that an increase to the BSC should be approved, Staff recommends that the Commission approve an increase that is no larger than the allowed system average, which would be approximately $1.70/month.[521] (Staff Br. at 52; *see* Tr. at 4518.)

In its Responsive Brief, Staff recounts APS's criticism of Staff's position and argues that they are not persuasive because "it is axiomatic that a consumer has less control over the payment of a fixed charge than a variable charge" and, thus, if a greater portion of a bill is fixed, the consumer has less control over the total bill amount through behavioral changes, which is what EE programs rely on, and will be less likely to change behavior. (Staff RBr. at 23-24.) Staff notes that APS is able to collect portions of lost revenue through the LFCR and argues that this means APS would not be financially harmed if the BSC was not increased. (Staff RBr. at 24.) Staff also argues that APS's own data shows that low-income households use approximately 4.5% less energy than the residential class on average, which Staff asserts means that low-income household bills are disproportionately driven by the BSC and would be disproportionately impacted by an increase to the BSC. (Staff RBr. at 24.) Staff argues that if the BSC is increased, it would detrimentally impact promotion of EE, would negatively impact limited income customers, and would shift the rate burden within the class to lower use customers. (Staff RBr. at 24-25.) Staff maintains its recommendation that any increase to the BSC be no larger than the system average increase. (Staff RBr. at 25, 31; *see* Tr. at 4518.)

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[520] The 2020 EIA data provided by Dr. Dismukes for the most part shows that average site energy consumption trends upwards with household income. (*See* Ex. S-13 at ex. DED-15 at 2.) The outlier was that the usage for the lowest income household exceeded the usage for each of the next two income levels. (*See id.*)

[521] This dollar amount is based on Mr. Smith's recommended revenue increase. (*See* Tr. at 4518.)

APS Response

In its Responsive Brief, APS acknowledges the arguments of AARP and Staff and asserts that they ignore the underlying fixed costs the BSC is intended to collect, which are not reduced with the consumption of less energy, through EE or other means. (APS RBr. at 63-64; *see* Ex. APS-30 at 15-16; Ex. APS-32 at 6-7.) APS reiterates that lower income householders do not use significantly less energy, based on usage data for the E-3 program, and that these customers receive substantial discounts on their entire bills, including the BSC. (APS RBr. at 64; *see* Ex. APS-32 at 7.) APS argues that it does not seek to shift costs by increasing the BSC and that its proposal instead will reduce cost shifts because current residential BSCs are recovering significantly less than their corresponding costs and still will not achieve full recovery. (APS RBr. at 64; *see* Ex. APS-30 at 16.) APS further argues that AARP and Staff's request that any increase in the BSC be no larger than the system average increase is consistent with APS's proposal and reiterates that even with the proposed increase, APS's BSCs would be less than those charged by other utilities. (APS RBr. at 64-65; *see* APS Br. at 85-86.)

Resolution

APS proposes to increase residential and general service BSCs consistent with the system average increase, which is proposed at 20.36% for the residential class and 20.54% for the general service class. (APS Br. at Att. B at Sched. H-1, Sched. H-2.) The residential class rate schedules currently have the following daily BSCs, which result in the monthly charges shown in regular text based on a 30-day month and would result in the monthly charges shown in italics with the proposed 20.36% increase:[522]

Legacy Solar E-12 (Energy)	Legacy Solar ET-1, ET-2 (Energy)	Legacy Solar ECT-1R, ECT-2 (Demand)	R-Basic (0-600 kW)	R-Basic (601-999 kW)	R-Basic (1000+ kW)	TOU-E	R-EV	Legacy R-2 (Demand)	R-3 (Demand)	R-Tech
$0.320	$0.622	$0.622	$0.316	$0.400	$0.400	$0.400	$0.400	$0.409	$0.400	$0.473
$9.60	$18.66	$18.66	$9.48	$12.00	$12.00	$12.00	$12.00	$12.27	$12.00	$14.19
$11.55	*$22.46*	*$22.46*	*$11.41*	*$14.44*	*$14.44*	*$14.44*	*$14.44*	*$14.77*	*$14.44*	*$17.08*

With the exception of the proposed BSC for the E-12 rate schedule, the Commission finds that a proposed increase to each BSC consistent with the ultimately approved system average increase

[522] *See* Ex. APS-36.

(which will be less than 20.36%) is just and reasonable to ensure that APS is able to recover a larger portion of its fixed customer-related costs of service through the BSC. The Commission agrees with APS that these fixed costs do not vary based on consumption and thus should be collected primarily through the BSC rather than through variable rates based on consumption. The Commission also notes that the R-Basic Tier 1 BSC is now and will remain set at a level lower than that of the other residential rate schedules, specifically to address affordability for households with the lowest consumption that have selected service through the fixed energy charge plan. The Commission further notes that even with APS's proposed level of increase, which exceeds the ultimate increase that will be approved herein, the BSCs for all but the Legacy Solar ET and ECT rates and R-Tech would fall within the range of residential BSCs recently approved for TEP, which were set at $12 and $15. (*See* Ex. APS-84 at 74.)

In Section (VI)(H)(4), the Commission determined that the residential rate schedules shaded in the table above are being overly subsidized by other customers and should receive a revenue allocation that is higher than the system average. The Commission did not define particular rate design elements to carry out the increase. In light of the very low BSC for the E-12 rate plan, however, the Commission directs APS to ensure that the increase is achieved in large part by increasing the BSC to $12 per month ($0.40 per day). The Commission would prefer to raise the BSC for E-12 higher, to be consistent with the BSC for TOU-E and a number of the other residential rate plans, but does not desire to cause rate shock for customers on E-12 and does not desire to surprise customers by approving a BSC significantly higher than that originally proposed by APS.

2. E-32 M and E-32 L

<u>APS Proposal</u>

APS has not proposed a revamping of the rate design for E-32 M or E-32 L and argues that Kroger's arguments to modify these rate schedules should be rejected because they would cause disproportionate impacts. (APS Br. at 79.) APS asserts that Kroger desires to reduce energy-related charges while increasing demand charges, in a revenue neutral manner. (APS Br. at 79; *see* Ex. Kroger-1 at 6-7; Tr. at 3528.) APS notes that Kroger's witness admitted Kroger would benefit economically from the proposal because of the high load factors of its stores in APS's territory, while lower load factor customers would experience bill increases. (APS Br. at 79; *see* Tr. at 3531-3533.) APS argues that Kroger's proposal should be rejected because proper rate design is premised on balancing cost allocations with customer impacts, and reducing overall energy costs for higher load factor customers at the expense of lower load factor customers would increase disparate impacts within the general service class and would not maintain rate stability. (APS Br. at 79; *see* Ex. APS-30 at 18-19.)

Kroger

Kroger argues that the generation component of the E-32 M and E-32 L summer and winter proposed energy charges is set at a level significantly above cost of service, as shown in APS's COSS, and should be addressed in this matter by maintaining the current level of the generation component of the bundled energy charges and not increasing the unbundled generation energy charges. (Kroger Br. at 1.) Kroger asserts that the revenues not collected in the energy charges could be collected through the demand charges instead, resulting in a revenue neutral rate design change that will not impact APS's revenue requirement or any other rate classes. (Kroger Br. at 1.)

Kroger takes issue with APS's proposal to increase all of the rate elements in E-32 M, noting that APS's proposal is to increase summer, winter, and delivery energy charges by approximately 26%, more than the overall average increase proposed for E-32 M of 23.6%.[523] Kroger states that this is problematic first because the COSS provides no basis to include any kWh component in the delivery charge, as 100% of the 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; *see* Ex. APS-24 at 13.) Nonetheless, Kroger argues, APS's proposed E-32 M rate includes $51 million of distribution delivery charges to be collected on an energy basis.[524] (Kroger Br. at 3.) Kroger asserts that APS does not dispute that its proposed E-32 M rate design does not comport with its COSS. (Kroger Br. at 3; *see* Ex. APS-30 at 18-19.) Although Kroger argues that the delivery charge should be eliminated in E-32 M, as it has been for E-32 L, Kroger recommends, in recognition of intra-class bill impacts and in the interest of rate stability, that the proposed unbundled delivery charge be maintained at its present

[523] These percentages are based on the originally proposed rates included in APS's rate application. (*See* Ex. APS-36.)

[524] Kroger states that it calculated the $51 million using total E-32 M kWh and the proposed unbundled delivery charge of $0.01549. (Kroger Br. at 3.) Schedule H-2 shows that E-32 M (AG-X and non-AG-X combined) consumed 3,386,643 MWh in the TY. (*See* APS Br. at Att. B at Sched. H-2.) When this is converted to kWh and then multiplied by the proposed unbundled delivery charge, the result is $52,459,100. (*See* APS Br. at Att. B at Sched. H-2.)

level. (Kroger Br. at 3; *see* Ex. APS-30 at 19.) Kroger argues that the revenues that would have been collected through energy charges should instead be collected through an increase in demand charges. (Kroger Br. at 3-4.)

Kroger's second concern with the E-32 M rate is related to the generation component of the energy charges. (Kroger Br. at 4.) Kroger argues that E-32 M is what is known as an "hours' use type of rate," meaning that the tier 1 energy block is designed to recover fixed demand-related costs in the first 200 hours of kWh usage per kW demand, meaning that tier 1 recovers both demand-related and energy-related costs, and tier 2 should recover only energy-related costs. (Kroger Br. at 4; *see* Ex. Kroger-1 at 10-11.) Kroger argues that the tier 2 charges include costs exceeding the actual energy-related costs identified by APS in its COSS and through a data response. (Kroger Br. at 4; *see* Ex. Kroger-1 at 11.) Kroger argues that the unit cost of production energy, which is the basis for the unbundled generation energy charges, indicates that the cost is \$0.0393/kWh, as compared to APS's proposed unbundled tier 2 generation energy charges for summer and winter of \$0.05875 and \$0.03955, respectively. (Kroger Br. at 4-5; *see* Ex. APS-36.) Kroger asserts that the weighted unbundled tier 2 generation energy rate is \$0.05046, meaning that the proposed E-32 M tier 2 generation charge is 28.4% higher than the cost of service and that the proposed tier 2 energy rates are \$0.01116 too high. (Kroger Br. at 5.) Kroger argues that these generation charges clearly include demand-related costs unrelated to energy usage and that their inclusion sends an incorrect and economically inefficient price signal to customers. (Kroger Br. at 5.) Kroger further argues that APS's own response to a data request, espousing that the alignment of charges with cost drivers results in fair and efficient rates, supports Kroger's position and not APS's position on this issue. (Kroger Br. at 5; *see* Ex. Kroger-1 at 12-13.) Rather than recommending that the tier 2 generation charge be set at cost, Kroger recommends that APS not be allowed to increase the unbundled generation component and that recovery of the costs that otherwise would have been recovered by the proposed increase to it instead be recovered through demand charges. (Kroger Br. at 5-6.)

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Kroger proposes the following E-32 M bundled energy charges:

Bundled Rate	Present Rate	Kroger Proposed Rate	Kroger Proposed Increase %
Summer tier 1 kWh	$0.10065	$0.12347	22.7%
Winter tier 1 kWh	$0.08532	$0.10408	22.0%
Summer tier 2 kWh	$0.06210	$0.06282	1.2%
Winter tier 2 kWh	$0.04678	$0.04750	1.5%
Standby Delivery	$0.01230	$0.01230	0.0%

Kroger asserts that adoption of its recommendations on both the E-32 M delivery charges and the E-32 M unbundled generation charges would result in a shift of approximately $27.4 million to E-32 M demand charges. (Kroger Br. at 6; *see* Ex. Kroger-1 at 14.) Kroger further asserts that the changes would impact only E-32 M customers and would be revenue neutral for APS. (Kroger Br. at 7.)

Kroger argues that the E-32 L rate design also recovers significant demand-related costs through energy charges,[525] specifically through the unbundled generation summer and winter rates per kWh. (Kroger Br. at 7-8.) Kroger states that the unit cost of production energy for E-32 L is $0.0384/kWh and that APS's proposed weighted summer/winter average unbundled E-32 L generation charge is $0.05275/kWh, meaning that $0.01435/kWh is the amount of fixed costs APS proposes to recover through E-32 L energy charges. (Kroger Br. at 8-9.) Kroger recommends that the E-32 L unbundled summer and winter generation charges not be increased, which would result in a shift of approximately $32.2 million in revenue from energy charges to demand charges. (Kroger Br. at 9.) Kroger notes that if the Commission adopts Kroger's proposal, the E-32 L generation rate will still exceed the unit cost of production energy, because that rate currently has a weighted average of $0.04169/kWh. (Kroger Br. at 9.) Kroger proposes the following E-32 L bundled energy charges:

Bundled Rate	Present Rate	Kroger Proposed Rate	Kroger Proposed Increase %
Summer kWh	$0.05258	$0.05330	1.4%
Winter kWh	$0.03542	$0.03614	2.0%

Kroger asserts that these recommended changes for the E-32 L bundled energy charges would impact only E-32 L customers and would be revenue neutral for APS. (Kroger Br. at 10.)

[525] On page 7 of its Brief, Kroger states that APS's proposed E-32 L rate design "would recover significant energy-related costs through demand charges." We understand this to be a typo and the opposite of what Kroger intended.

In its Responsive Brief, Kroger argues that APS has not addressed the substance of Kroger's proposed rate design for E-32 M and E-32 L, criticizing APS for only stating that Kroger would benefit from the proposal. (Kroger RBr. at 1-2.) Kroger states that this is not a substantive response, that every party in a rate case advocates for positions that are to the party's benefit, and that the Commission should reject APS's argument as irrelevant and unresponsive. (Kroger RBr. at 2.) Kroger argues that APS has not questioned the accuracy of Kroger's analysis or that Kroger's proposal would reduce subsidies paid by higher load factor customers and that Kroger's proposal should be adopted because it will keep from making the problems with the E-32 M and E-32 L rate designs worse. (Kroger RBr. at 2.)

APS Response

In its Responsive Brief, APS states that Kroger requests to have energy-related charges under E-32 M and E-32 L reduced while demand charges are increased,[526] which will cause disparate impacts to lower load factor customers. (APS RBr. at 62.) APS argues that Kroger's proposal would result in "reduced energy costs for higher load factor customers like Kroger" while "mask[ing] the variability of bill impacts for lower load factor customers." (APS RBr. at 62.) APS points out that Kroger consumes more than 113 million kWh annually on APS rates, that Kroger's facilities are generally high load factor customers, and that Kroger does not dispute that its proposal would result in higher bills for lower load factor customers. (APS RBr. at 62-63; *see* Tr. at 3524, 3531-3533.) APS points out that the Commission previously has recognized that rate designs serve the public interest when they address affordability, fairness, and rate stability. (APS RBr. at 63.[527]) APS argues that Kroger's proposal is designed to reduce its energy costs at the expense of lower load factor customers and would not maintain rate stability, while APS's proposal establishes the correct balance between energy and

[526] It is accurate that Kroger proposes for demand charges to be increased in E-32 M and E-32 L, but it is not accurate that Kroger proposes for energy charges to be decreased; rather, Kroger advocates for E-32 M tier 2 energy charges to be increased very minimally, for E-32 M standby delivery charges not to be increased at all, and for E-32 L energy charges to be increased very minimally. (*See* Kroger Br. at 7, 10.)

[527] APS cited page 74 of Decision No. 68858, with an issuance date of December 17, 2020. This is incorrect. The Commission takes official notice of Decision No. 68858 (July 28, 2006), which includes the language referenced by APS at page 39: "The rate design approved herein addresses the goals of conservation, efficient water use, affordability, fairness, simplicity, and rate stability, and is in the public interest."

demand while maintaining rate stability and minimizing disparate impacts to customers. (APS RBr. at 63; *see* Ex. APS-30 at 19.)

Resolution

APS has not rebutted the substance of Kroger's analysis, focusing instead on policy reasons for not changing the E-32 M and E-32 L rate designs. Thus, we conclude that Kroger's analysis is accurate. The question is what to do about it. APS is correct that the Commission values affordability, fairness, and rate stability. APS's proposal appears to be influenced primarily by concerns of affordability for lower load factor E-32 M and E-32 L customers as well as rate stability for these same customers. The fairness issue is less clearly served by APS's proposal, in light of the analysis conducted by Kroger. It is unfortunate that Kroger did not provide an analysis of the bill impacts that would result from its proposals, based on its proposed increases to demand charges. Had it done so, the Commission would be in a better position to determine whether its proposals would result in rate shock if adopted in full. Without that information, the Commission does not believe that it would be just and reasonable to adopt Kroger's position. However, the Commission desires to ameliorate the situation identified by Kroger and not disputed by APS, so that the E-32 M and E-32 L rate schedules will become more consistent with cost of service. To that end, the Commission finds that it is just and reasonable and in the public interest to make the following increases to the E-32 M bundled energy charges:

Bundled Rate	Present Rate	Kroger Proposed Rate	Kroger Proposed Increase %	Commission Approved Increase
Summer tier 1 kWh	$0.10065	$0.12347	22.7%	System Average %
Winter tier 1 kWh	$0.08532	$0.10408	22.0%	System Average %
Summer tier 2 kWh	$0.06210	$0.06282	1.2%	Half of System Average %
Winter tier 2 kWh	$0.04678	$0.04750	1.5%	Half of System Average %
Standby Delivery	$0.01230	$0.01230	0.0%	One-Quarter of System Average %

Additionally, the Commission finds that it is just and reasonable and in the public interest to make the following increases to the E-32 L bundled energy charges:

Bundled Rate	Present Rate	Kroger Proposed Rate	Kroger Proposed Increase %	Commission Approved Increase
Summer kWh	$0.05258	$0.05330	1.4%	Half of System Average %
Winter kWh	$0.03542	$0.03614	2.0%	Half of System Average %

APS shall make up the remainder of the system average increase percentage for each of these rate schedules through evenly distributed increases to demand charges. With these modifications, the E-32 M and E-32 L rate schedules will gradually move closer toward cost of service without producing rate shock.

3. E-32 L SP

In Decision No. 78317, the Commission directed APS to revise the E-32 L SP rate schedule by:

- Eliminating the 20% peak demand reduction requirement for eligibility;
- Setting a year-round three-hour on-peak period of 4 p.m. to 7 p.m. weekdays;
- Creating a differential between on-peak and remaining-hour demand rates consistent with the differential imposed between on-peak and off-peak hours in APS's other demand rate plans;
- Imposing demand charges only during on-peak and remaining hours;
- Allowing sufficient time for storage systems to charge fully before the on-peak period; and
- Setting the BSC at the same level as the BSC for E-32 L.[528]

Additionally, the Commission ordered APS to engage in a collaborative process with AriSEIA/SEIA and other interested stakeholders (including Staff) concerning the effectiveness of the E-32 L SP plan and any issues that may arise; allowed APS to file an application in the 2019 rate case docket within 12 months after Decision No. 78317 for consideration of further modifications to the E-32 L SP tariff, based on the evidentiary record in the 2019 rate case; and held open the evidentiary record from the 2019 rate case docket for 12 months for that purpose. (Ex. RUCO-7 at 441.) The Commission further

[528] Ex. RUCO-7 at 376-377.

ordered APS each month, as a compliance item in the 2019 rate case docket, to file an update providing customer participation in E-32 L SP and describing any meetings or collaboration with stakeholders. (*Id.*)

In response, APS held seven stakeholder workshops over a period of nine months and filed regular updates with the Commission on the substance of the meetings. (Ex. APS-30 at 20; Ex. APS-32 at 12-14.) In November 2022, in a different docket, APS filed an application ("E-32 L SP application") proposing extensive changes to E-32 L SP, which still had no customers taking service under it. (Decision No. 78966 (May 9, 2023) at 1-2.[529]) The E-32 L SP application proposed the following changes, which were designed to be revenue neutral:

- The seasonal structure for demand charges was changed from Summer On-Peak and Summer Remaining Peak to Summer and Winter On-Peak and Off-Peak, with lower demand charges per kW;
- The energy charges were increased, with the exception of the Winter Off-Peak charge, which was slightly decreased; and
- The on-peak period was changed from a year-round weekday on-peak period of 4 p.m. to 7 p.m. to a year-round every day on-peak period of 4:00 p.m. to 9:00 p.m.[530]

Consistent with Staff's recommendation, the Commission approved the E-32 L SP application in Decision No. 78966. (Decision No. 78966 at 3-4.)

<u>APS Proposal</u>

APS does not propose to revise the recently approved E-32 L SP tariff in this matter, other than by revising the specific charges therein.[531] (*See* Ex. APS-100 at 17-22.) APS argues that AriSEIA/SEIA's proposal to modify the E-32 L SP tariff is premature and would effectively undermine stakeholder processes, especially the one ordered by Decision No. 78317. (APS Br. at 81.) APS argues that AriSEIA/SEIA is the only participant in the stakeholder process who has argued against the

[529] Official notice is taken of this decision, issued in Docket No. E-01345A-22-0281 ("E-32 L SP docket"), specific to APS's application for approval of revisions to E-32 L SP.
[530] *See* Decision No. 78966 at 2-3.
[531] Interestingly, APS does not specify the revisions to the specific charges desired, instead including "X.XXX" for each. (*See* Ex. APS-100 at 18-20.) The Commission understands this to mean that APS is proposing that each of these charges be increased by the system average percentage increase.

revision approved in Decision No. 78966 and that AriSEIA/SEIA's argument that the prior on-peak period should be restored is unsupported by data showing that APS's peak is moving later into the day as well as the lack of participation in the tariff with the prior on-peak period. (APS Br. at 81; *see* Ex. AriSEIA-1 at 60-68; Ex. AriSEIA-3 at 22-28; Ex. APS-32 at 12-13.[532])

APS argues that Mr. Lucas acknowledged that AriSEIA/SEIA's proposal would cause higher energy rates for customers and, additionally, argues that his criticisms of the changes made to the tariff ignore costs and lack merit. (APS Br. at 82; *see* Tr. at 3974-3975.) APS points out that Mr. Lucas argues for weekends to be excluded from on-peak rates, which APS states is inconsistent with Ms. Hobbick's and Mr. Joiner's testimony showing that there is only a small difference between average weekend and weekday loads and would result in APS's not receiving valuable information about weekend loads that should be considered when determining how to encourage peak load reduction and use of energy storage. (APS Br. at 82; *see* Ex. APS-32 at 12-13; Ex. APS-12 at 38-39; Ex. APS-14 at 3.) APS argues that Mr. Lucas's argument for the shorter on-peak period is also not supported, as it ignores that APS's load drops only 10% between 8 p.m. and 9 p.m., that solar production drops substantially after 4 p.m., that the net-peak periods of demand are shifting later into evening and overnight hours, and that the period of 7 p.m. to 9 p.m. is a period of resource scarcity and increased wholesale electricity prices.[533] (APS Br. at 82; *see* Ex. APS-30 at 20-21; Ex. APS-32 at 12; Ex. APS-12 at 6-8, 36-37.) APS also states that APS's analysis is not based on weather normalized data, contrary to AriSEIA/SEIA's assertions, because APS must ensure generation capacity to meet all weather conditions, not just for average system load.[534] (APS Br. at 82; *see* Ex. APS-32 at 14; Ex. APS-12 at 6-8, 36-37.)

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[532] APS also cited AriSEIA/SEIA comments filed in the E-32 L SP docket, which are not part of the evidentiary record in this case.

[533] Mr. Joiner testified that the top five hours of customer demand during the TY were 3 p.m. to 8 p.m. and that the five-hour net-load peak was 4 p.m. to 9 p.m. (Ex. APS-12 at 7.) APS anticipates that the net peak will continue to shift later into the evening with greater use of energy storage and renewables in the generation portfolio. (*Id.*) Mr. Joiner also showed that the highest priced hour in the TY, based on Western EIM pricing, was 7 p.m. to 8. p.m.; the second highest priced hour was 6 p.m. to 7 p.m.; and the third highest priced hour was 8 p.m. to 9 p.m., which was very slightly higher than the 5 p.m. to 6 p.m. hour. (*See* Ex. APS-12 at 36.) Mr. Joiner further showed that the weekend evening pricing follows a similar pattern to that of weekday evening pricing. (*See* Ex. APS-12 at 37-38.)

[534] Ms. Hobbick testified that APS does not weather normalize customer usage data when designing rates and planning for resources to serve peak hours. (Ex. APS-32 at 14.)

AriSEIA/SEIA

AriSEIA/SEIA argue that they largely support the revisions made to the E-32 L SP tariff in Decision No. 78966 but remain concerned about APS's expansion of the on-peak period to include weekends and the hours of 7 p.m. to 9 p.m. (AriSEIA Br. at 17.) AriSEIA/SEIA claim that weekend loads and prices are meaningfully lower than weekday loads and prices and, thus, that the weekend hours should not be included in the on-peak period. (AriSEIA Br. at 17.) AriSEIA/SEIA further argue that all of the other active E-32 TOU and residential TOU tariffs use a weekday only on-peak period and that the Commission should order APS to conform the E-32 L SP tariff to this pattern because APS's arguments "fall flat" and should be rejected unless APS plans to adopt weekday on-peak hours for all of its tariffs. (AriSEIA Br. at 17-18.) Additionally, AriSEIA/SEIA argue that APS's own data do not support the expansion of the E-32 L SP on-peak hours to include the period from 7 p.m. to 9 p.m. because the on-peak period of 4 p.m. to 7 p.m. captures well the system peak load. (AriSEIA Br. at 18.) AriSEIA/SEIA recommend that the Commission direct APS to change the E-32 L SP tariff back to having a weekday-only on-peak period of 4 p.m. to 7 p.m.[535] (AriSEIA Br. at 18.) AriSEIA/SEIA further recommend that the Commission order APS to modify the E-32 L SP rates by retaining the proposed demand charge levels and recalculating the on-peak and off-peak volumetric rates to target a 3:2:1 ratio of summer peak, winter peak, and off peak, respectively. (AriSEIA Br. at 18.) Further, AriSEIA/SEIA argue that the Commission should require APS to file an updated E-32 L SP tariff clearly stating that "monthly peak site load" means measured on-peak delivered demand, because there is no reason to introduce the controversy of "site load" versus "delivered load" into the E-32 L SP tariff. Additionally, AriSEIA/SEIA argue that the Commission should require APS to create an E-32 SP tariff for all E-32 customer sizes, because it is arbitrary to limit the eligibility for the pilot based on minimum demand, and a 50 kW reduction from a medium-sized customer has the same value as a 50 kW reduction from a large-sized customer. (AriSEIA Br. at 18.) AriSEIA/SEIA argue that APS can maintain its aggregate enrollment limit for the pilot while allowing customers with lower levels of peak demand to participate. (AriSEIA Br. at 18.)

[535] AriSEIA/SEIA characterize their position as maintaining the on-peak period for which they advocate, although the on-peak period was modified by Decision No. 78966.

Vote Solar

In its Responsive Brief, Vote Solar supports AriSEIA/SEIA's recommended revisions to the E-32 L SP tariff. (VS RBr. at 2, 8.) Vote Solar asserts that the E-32 L SP tariff is substantially improved from the prior version but does not include the on-peak period required by Decision No. 78317, which was weekdays from 4 p.m. to 7 p.m. (VS RBr. at 9.) Vote Solar notes that no other active E-32 or residential TOU tariff includes an on-peak period including weekends or extending to 9 p.m. (VS RBr. at 9.) Vote Solar argues that the on-peak period of 4 p.m. to 7 p.m. captures system coincident peak, which is a key driver of system costs. (VS RBr. at 9; *see* Ex. VS-3 at 17.) Further, Vote Solar argues, a shorter on-peak period is appropriate for a pilot rate because it will improve potential customers' confidence that they will be able to dispatch their storage through the entire on-peak period. (VS RBr. at 9.) Additionally, Vote Solar notes that it supports AriSEIA/SEIA's recommended revisions, including clarification of the ambiguous term "monthly peak site load" as meaning measured on-peak delivered demand. (VS RBr. at 9.)

APS Response

APS did not address the issue further in its Responsive Brief.

Resolution

AriSEIA/SEIA and Vote Solar do not accept the Commission's determination in Decision No. 78966 that it was in the public interest to expand the E-32 L SP on-peak period to include weekends and to include the hours from 7 p.m. to 9 p.m. The evidence of record in this matter establishes that although the TY system CP was 5 p.m. to 6 p.m., net peak load was from 4 p.m. to 9 p.m. and is expected to continue moving later into the evening; and that the hours from 7 p.m. to 9 p.m. were some of the highest priced hours during the TY. AriSEIA/SEIA and Vote Solar's arguments for changing the on-peak period back to weekdays are supported by the facts.

AriSEIA/SEIA and Vote Solar's arguments about the need to clarify the meaning of "monthly peak site load" in the E-32 L SP tariff, to mean measured on-peak delivered demand, has merit and was not addressed by APS in its Brief or Responsive Brief. This issue was addressed by Ms. Hobbick in her rebuttal testimony, however, in which she stated APS "is supportive of modifying the language for clarity and proposes to use similar language found in many of APS's TOU rate schedules defining the monthly peak load criteria as the average kW supplied during the 15-minute period of maximum use during on-peak hours for each respective billing period. (*See* Ex. APS-30 at 21.) We agree with AriSEIA/SEIA and Vote Solar that the term "monthly peak site load" should be defined and with APS that the type of definition described would be just and reasonable. Thus, we will direct APS to make this revision in the conforming E-32 L SP tariff to be filed consistent with this Decision.

While we note that APS has not responded to AriSEIA/SEIA's proposal for additional E-32 storage pilot tariffs to be approved for customers with smaller demands, and agree that 50 kW in reduced demand has the same value regardless of from what size customer it comes, two things give us pause in requiring this expansion—first, E-32 L SP is a pilot for which data have not yet been gathered, meaning that the tariff and its rate design really have not yet been tested, and, second, the stakeholder process apparently did not result in a recommendation for the pilot to be expanded to other customer sizes. Because of the nature of E-32 L SP as an untested pilot, the Commission believes that it is just and reasonable not to require expansion at this time. If the pilot proves successful, the issue should be raised and addressed in APS's next rate case.

4. AG-X

In Decision No. 78317, the Commission declined to approve expansion of AG-X, as requested by various intervenors; identified RA as a major issue that needed to be addressed; and directed APS to engage in a collaborative process with AG-X stakeholders (including at least GSPs, AG-X customers,[536] prospective AG-X customers, RUCO, and Staff) to analyze and identify solutions to at least a number of specifically identified issues with AG-X, which, *inter alia*, touched on cost shifts to non-AG-X customers, RA, transmission capacity resource constraints, participation by other customer sizes, and the cap on the program. (*See* Ex. RUCO-7 at 285-286.) The Commission held the 2019 rate case docket open for 12 months to allow APS to submit a proposal for a modified AG-X or another buy-through program to be considered in light of the record from that case and required APS to file monthly updates. (*See id.* at 286-287.) Additionally, the Commission directed APS to make several uncontested changes to the AG-X tariff and, because one of these modifications was to allow AG-X

[536] AG-X customers include hospitals, universities, grocery stores, and retail stores. (*See* Ex. S-12 at 52.)

customers load growth of up to 10% at existing locations taking AG-X service for deliveries at the Palo Verde hub, ordered that the $15 million PSA mitigation be increased proportionately to any increases in AG-X beyond its 200 MW cap. (*See id.* at 287.)

APS held 11 stakeholder workshops that were attended by stakeholders including Staff, RUCO, Freeport, NRG, Calpine, and Walmart. (APS Br. at 66.[537]) APS reached consensus with stakeholders on revising scheduling protocols to allow for intraday scheduling to reduce imbalance settlements and increase AG-X customer operational flexibility and implemented this change through the AG-X Program Guidelines before APS filed its rate application in this matter. (*See* APS Br. at 67; Ex. APS-11 at 37; Ex. APS-30 at 30-31.[538])

APS Proposal

APS's proposed revised AG-X POA, attached hereto as Exhibit B, includes APS's proposal to change the AG-X program by:[539]

- Reducing the aggregated peak load requirement a customer must have from 10 MW to 5 MW;[540]
- Allowing a customer on E-32 M, E-32 TOU M, E-32 S, or E-32 TOU S to participate;[541]
- Eliminating obsolete language regarding initial reservation of 100 MW (of the 200 MW program) to customers with specific characteristics and regarding evaluation of the AG-X program in APS's next rate case;
- Adding a number of definitions related to RA and the Western Resource Adequacy Program ("WRAP") operated and administered by the Northwest Power Pool dba Western Power Pool;
- Imposing a new requirement for a GSP to provide RA[542] for its customer's load either by:

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[537] APS cited filings made in the 2019 rate case docket, which are not part of the record in this matter.
[538] APS cited a filing made in the 2019 rate case docket, which is not part of the record in this matter.
[539] *See* Amended Ex. APS-98.
[540] APS states that it reached consensus with stakeholders on allowing customers on E-32 M and E-32 S to participate in AG-X by reducing the aggregated peak load requirement and modifying program eligibility, a proposal that is made in this matter. (APS Br. at 67.) To support this, APS cited a filing made in the 2019 rate case docket, which is not part of the record in this matter.
[541] Currently AG-X allows E-32 M and E-32 TOU M accounts to participate as part of an aggregated group if the accounts are located on the same premises and served under the same name. (Amended Ex. APS-98 at 9.)
[542] According to Mr. Joiner, APS considers the following characteristics to demonstrate a resource or capacity purchase can be used for reliability planning: (1) it is not already being used for RA by another entity; (2) if a resource, it is owned by

   - Purchasing RA from APS, or
   - Demonstrating RA seasonally;
- Requiring an AG-X customer to meet RA during the first year after the effective date of the AG-X program changes by:
   - Purchasing RA from APS and paying a transition reserve capacity charge of $6.453/kW, or
   - Receiving RA from the GSP in compliance with the WRAP Tariff (which allows for eligible DR provided through the GSP) and paying no reserve capacity charge (the "self-supply" option);
- Requiring an AG-X customer to meet RA after the first year by:
   - Purchasing RA from APS and paying a reserve capacity charge equal to the unbundled generation demand charge of E-34,[543] or
   - Receiving RA from the GSP in compliance with the WRAP Tariff (which allows for eligible DR provided through the GSP) and paying no reserve capacity charge (the "self-supply" option);
- Reducing the AG-X administrative management fee from $0.00171/kWh to $0.00164/kWh to better reflect the cost to manage the program;
- Providing that failure of a GSP who is providing RA to meet the timing of the WRAP Forward Showing Program will result in the GSP's termination from AG-X;[544] and
- Requiring an AG-X customer who obtains RA from its GSP to provide notice to APS three-years before leaving the AG-X program and returning to standard service, to ensure APS has enough time to procure replacement resources cost effectively, although APS may agree to a shorter timeframe provided it does not shift cost or risk to non-AG-X customers.[545]

APS, contracted by APS, or otherwise available to be called upon by APS for system reliability; and (3) it includes "high priority or firm transmission" to ensure it will be delivered to serve APS load, including assurances of access to the APS balancing authority. (Ex. APS-11 at 31-32.)

[543] This charge is currently $9.724/kW and is proposed to be increased. (*See* Ex. APS-36.)

[544] Amended Ex. APS-98 shows stricken language about failure to meet the timing of Forward Showing, but that language is included in error, as it is not part of the currently approved AG-X tariff. (*See* Amended Ex. APS-98 at 14; Ex. APS-36.)

[545] Ex. APS-1 at 8-9; APS-11 at 32; Amended Ex. APS-98 at 14. It should be noted that the redline version of Amended Exhibit APS-98 on page 15 in the section concerning returning to standard generation service includes new text that should be shown with red underlining and is not.

As noted previously in relation to the PSA, APS also proposes to eliminate the $15 million PSA off-systems sales mitigation if its RA-related AG-X modifications are approved, as these modifications are expected to address the current AG-X program cost shift to non-AG-X customers. (*See* Ex. APS-29 at 23.) APS notes that the revised RA definition and references to DR as included in WRAP were originally proposed by NRG and agreed to by APS in this matter and that the revision to allow for an AG-X customer to return to standard service earlier than three years after notice was originally proposed by Calpine and NRG and agreed to by APS in this matter. (APS Br. at 68; *see* Ex. NRG-1 at 23-24; Ex. APS-12 at 41; Ex. CSN-2 at 3-4; Ex. APS-32 at 17; Ex. APS-14 at 18; Tr. at 1140-1146.)

APS argues that its proposed RA framework, which is designed to comply with the RA requirements of the WRAP Tariff, should be approved because it addresses the reliability risks currently posed by the AG-X program. (APS Br. at 68.) APS explains that WRAP is a compliance program designed in response to western region resource challenges from load growth and plant retirements, to address reliability planning regionally by assessing and addressing RA, and requires participants to collaborate, make their resource needs and supplies visible to all participants, and share pooled resources. (APS Br. at 68; *see* Ex. APS-12 at 44-45.) The WRAP Tariff[546] was approved by FERC in spring 2023, and APS and 21 other utilities have committed to participating in the WRAP program. (APS Br. at 68-69; *see* Ex. APS-12 at 45.) APS is currently a non-binding member of WRAP and will become a binding member in 2026. (APS Br. at 69; *see* Ex. APS-12 at 44; Tr. at 1166-1167.) APS asserts that to meet RA requirements, generation supplies must be delivered through firm or high priority transmission pathways, must come from identifiable resources, must not be needed for RA by another entity, and must not be recallable even in an emergency. (APS Br. at 69; *see* Ex. APS-12 at 40.) According to APS, RA is a critical component of reliability and essential to ensuring delivery of electricity during grid-stressed conditions, and the AG-X program's current lack of RA requirements puts all APS customers at risk because AG-X energy can be recalled when the grid is stressed, such as occurred with AG-X resources the evening before Mr. Joiner's testimony and has occurred in summer 2020, 2021, and 2022. (APS Br. at 69-70; *see* Ex. APS-11 at 33-36; Ex. APS-29 at 24; Ex. APS-12 at

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[546] The WRAP tariff was admitted as Exhibit APS-85.

40; Tr. at 1290, 1316.) APS asserts that the "firm" market energy under AG-X contracts can be recalled during the most high-risk times (system emergencies); that APS expects these occurrences to increase in frequency due to the scarcity of capacity resources in the western region; and that APS must provide capacity to back up undelivered AG-X deliveries to ensure grid reliability. (APS Br. at 70; *see* Ex. APS-12 at 39-41; Ex. APS-11 at 32-33; Tr. at 1504-1506.) APS asserts that its RA proposal would align the AG-X program with APS's existing planning practices as well as WRAP requirements and industry standards, would maintain equal requirements between resources, and would mitigate potential penalties for failure to meet WRAP RA requirements.[547] (APS Br. at 69-70; *see* Ex. APS-12 at 44-46.) APS argues that its RA proposal for AG-X will ensure that AG-X customers equally share the cost of reliable capacity and that the cost is not unfairly shifted to non-AG-X customers. (APS Br. at 70; *see* Ex. APS-12 at 42.)

APS argues that NRG's recommendation for RA requirements to be limited to planning margins until APS becomes a binding member of WRAP should be rejected because it is premised on APS's relying on AG-X energy supplies as RA for its load and resource planning, something that APS acknowledges it has been doing but states is a vestige of different, non-volatile western market conditions when capacity resources were available. (APS Br. at 70-71; *see* Ex. NRG-1 at 9; Tr. at 1505-1506.) APS argues that AG-X customers should not be exempt from meeting full RA requirements pending APS's becoming a binding member of WRAP and that APS's new RA framework should take effect one year after the new rates become effective so that all of APS's resources (including those used to serve AG-X) are reliable, because relying on AG-X customer purchases for RA poses reliability risks for all customers. (APS Br. at 71; *see* Ex. APS-30 at 29; Tr. at 1505-1506.)

APS argues that intervenors' proposals to replace the APS-proposed reserve capacity charge for AG-X customers that obtain APS-supplied RA should be rejected because the proposed charges are too low and would shift generation costs to other customer classes. (APS Br. at 71; *see* Ex. APS-30 at 27.) APS currently charges AG-X customers a reserve capacity charge of $5.248/kW to cover their

[547] APS, as the WRAP member, would be the entity subject to the WRAP penalties once it is a binding member. (*See* Tr. at 1279.)

necessary backup costs and states that AZLCG's proposed reserve capacity charge set at $1.864/kW would cover only a small portion of the capacity needed to meet RA needs and would benefit AG-X customers at the expense of non-AG-X customers. (APS Br. at 71-72; *see* Ex. AZLCG-3 at 33; Ex. APS-30 at 28.) APS also criticizes as "simply wrong" AZLCG's argument that GSPs provide RA by serving 99% of AG-X customers' energy needs in a year, asserting that energy and capacity are different and that the wholesale energy contracts used to supply AG-X customers have no capacity value, only provide energy, and do not qualify as RA under WRAP. (APS Br. at 72; *see* Ex. AZLCG-3 at 29; Ex. APS-14 at 14; Ex. APS-30 at 28; Tr. at 1290.)

APS argues that NRG's proposed reserve capacity charge also must be rejected because it would not produce sufficient revenue to cover the costs necessary to ensure RA for AG-X customer load; would thus shift AG-X RA costs to non-AG-X customers; and is based on the capacity cost of a hypothetical power plant, whereas APS's capacity rates are based on actual costs for APS's resources. (APS Br. at 72; *see* Ex. APS-30 at 27, 29; Ex. APS-12 at 45-46.) APS notes that NRG, as a GSP, has the option to offer such a rate for NRG-supplied RA provided to its AG-X customers. (APS Br. at 73; *see* Ex. APS-30 at 28.)

APS also argues that the AG-X aggregated peak load requirement should not be set lower than the 5 MW proposed by APS because the AG-X program involves financial and programmatic risks for AG-X participants, who no longer benefit from APS's hedging program and must be able to negotiate their own contracts with GSPs and to protect their own interests. (APS Br. at 73; *see* Ex. APS-14 at 21-22.) APS asserts that AG-X was designed for larger commercial customers with experience in energy management and that smaller general service customers with loads as low as 1 MW[548] are less likely to have professional energy managers to complete the sophisticated transactions necessary for AG-X and may not have the financial strength to navigate significant market volatility. (APS Br. at 73-74; *see* Ex. APS-14 at 22; Tr. at 1215-1217.) Additionally, APS expresses concern that allowing customers with loads as low as 1 MW would increase AG-X program administrative costs. (APS Br. at 74; *see* Ex. APS-30 at 30; Ex. APS 14 at 22.)

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[548] An average big box store or grocery store has a load of 1 MW. (*See* Tr. at 207, 1215.)

Additionally, APS argues, the Commission should not expand the AG-X program beyond its current 200 MW cap or lift the 10% growth cap on AG-X customer loads. (APS Br. at 74; *see* Ex. AZLCG-3 at 30-36; Ex. S-12 at 55; Ex. CSN-1 at 1-2; Ex. CSN-3 at 2; Ex. NRG-1 at 1-3.) There is no compelling reason to support expanding the program, APS asserts, because AG-X has been undersubscribed for more than a year, and participation continues to decline.[549] (APS Br. at 74; *see* Ex. APS-14 at 21; Tr. at 1241-1242.) According to APS, this undersubscription shows that the AG-X program relies on APS to serve as the provider of last resort. (APS Br. at 74; *see* Ex. APS-14 at 21.) APS expresses concern about customers transitioning on and off of the AG-X program because when a customer goes onto AG-X, the customer no longer pays the PSA, leaving other customers to pay all of the PSA costs even though the AG-X customer also benefitted from APS's resources and hedging program before switching to AG-X. (APS Br. at 74; *see* Tr. at 1233-1236.) Additionally, APS expresses concern about AG-X expansion complicating the proper allocation of costs, causing stranded costs for non-AG-X customers, and causing constraints for transmission reservation and scheduling. (APS Br. at 74; *see* Ex. APS-12 at 46; Ex. APS-30 at 30.) APS recommends that the effectiveness of its RA proposals be monitored, so it can be determined whether additional modifications to AG-X are necessary, and that the AG-X program be assessed in the future.[550] (APS Br. at 75; *see* Tr. at 1241; Ex. APS-11 at 36.) APS argues that the AG-X program is cyclical and has lower participation when market conditions are volatile; that the modifications proposed by APS herein should be evaluated thoroughly before any expansion is considered by the Commission; and that the intervenors have not disputed that expansion of AG-X would likely shift costs to other APS customers. (APS Br. at 75; *see* Ex. APS-12 at 46; Ex. APS-11 at 36; Tr. at 1241.)

<u>AZLCG</u>

AZLCG agrees with APS's proposal to charge no reserve capacity charge to those AG-X customers who self-supply RA but argues that APS's proposed reserve capacity charge for APS-provided RA is unjust, unreasonable, and not in the public interest for three reasons. (AZLCG Br. at

[549] Mr. Joiner opined that AG-X participation has been dwindling because market prices are not getting cheaper, and customers are analyzing costs and benefits and concluding that it is in their best interest to go back to APS standard service. (*See* Tr. at 1242-1243.)

[550] Mr. Joiner testified that he would like to see how the AG-X programs works for at least two years after APS becomes a binding member of WRAP in 2026. (*See* Tr. at 1241.)

43; *see* Ex. APS-29 at 24; Ex. AZLCG-3 at 31; Ex. APS-32 at Att. JEH-02RJ at 4; Amended Ex. APS-98 at 4; Tr. at 1618, 2451, 2457.) First, AZLCG argues, the proposed AG-X reserve capacity charge is not cost-based because in the TY, GSPs provided 99.8% of AG-X customers' energy, and only 1 MW was curtailed during any of the 4CP hours, meaning that AG-X customers provided nearly all of their own generation and should not be charged the same generation demand charge as customers who provided none. (AZLCG Br. at 43; *see* Ex. AZLCG-3 at 29, 31-32; Ex. AZLCG-5 at 36; Tr. at 4003, 4038.) AZLCG argues that the self-supply option does not remedy the problem because all of APS's rates must be just, reasonable, and cost-based, including the APS-supplied RA reserve capacity charge. (AZLCG Br. at 43-44; *see* Tr. at 4027, 4031, 4043.)

Second, AZLCG argues, the AG-X class will experience rate shock from the reserve capacity charge because the first year's transition reserve capacity charge[551] represents a 9.6% increase over current rates, and the subsequent years' reserve capacity charge would be approximately a 58% increase over current rates and a 48% increase over the transition rate. (AZLCG Br. at 44; *see* Ex. APS-36; Ex. AZLCG-20; Tr. at 2455-2462.)

Third, AZLCG argues, APS failed to include the proposed reserve capacity charge in its proof of revenue, instead only using the first year's transition reserve capacity charge, which means that AG-X customers would pay more than their cost of service, and APS would over-recover its revenue requirement. (AZLCG Br. at 45.) According to AZLCG, Ms. Hobbick agreed that this could result in APS's recovering more than its costs from AG-X customers,[552] but qualified this by stating that APS does not know to what extent AG-X customers will select APS-supplied RA versus self-supplied RA and thus assumed a 50/50 split. (AZLCG Br. at 45; *see* Tr. at 2471-2475.) AZLCG argues that APS did not use the 50/50 assumption in its proof of revenue but instead simply used the first year's transition reserve capacity charge without explanation. (AZLCG Br. at 45; Tr. at 2477-2478.) AZLCG

[551] AZLCG refers to a transitional reserve capacity charge of $6.3370/kW, but the AG-X POA provided with Ms. Hobbick's rejoinder testimony and the final amended AG-X POA provided as Amended Exhibit APS-98 propose a transitional reserve capacity charge of $6.453/kW. (*See* AZLCG Br. at 44; Ex. APS-32 at Att. JEH-02RJ; Amended Ex. APS-98.)

[552] Ms. Hobbick also testified that if every AG-X customer chooses to self-supply RA through its GSP, APS will have a revenue deficiency. (Tr. at 2473.)

argues that APS's approach "violates a basic principle of ratemaking where utilities do not and should not consider the elasticity of demand in setting rates." (AZLCG Br. at 45; *see* Tr. at 2473-2477.[553])

AZLCG recommends that the reserve capacity charge for APS-supplied RA be set at 15% of the E-34 generation demand charge, to account for the 15% reserve margin that APS is required to maintain, which would correspond to a reserve capacity charge of approximately $1.864/kW-month. (AZLCG Br. at 45; *see* Ex. AZLCG-3 at 33.) AZLCG notes that NRG proposes a similar charge, which is also intended to be a charge for reserve capacity rather than a full-service demand charge as proposed by APS. (AZLCG Br. at 45-46; *see* Ex. AZLCG-5 at 37; Tr. at 4041.)

Additionally, AZLCG argues, the Commission should provide certainty that the AG-X program will not be terminated because an AG-X customer that chooses to self-supply RA will need to enter into a long-term contract for power supply resources exceeding the customer's actual loads, and termination of the AG-X program without sufficient notice would leave the AG-X customer obligated to pay both APS and the former GSP for capacity until the expiration of the long-term contract (i.e., with stranded costs). (AZLCG Br. at 46, 47; *see* Ex. AZLCG-3 at 31; Tr. at 1134.) AZLCG also argues that more competitively priced RA bids would be available if there were program certainty, pointing out that Mr. Joiner agreed the number of contract offers increases when long-term contracts are solicited. (AZLCG Br. at 46; *see* Tr. at 1135.) AZLCG notes that APS's capacity resources are intended to be in service for decades and that APS's RA proposal, which requires three years' notice to APS before an AG-X customer with self-supplied RA leaves AG-X, also reflects a long-term planning nature. (AZLCG Br. at 46-47; *see* Ex. APS-11 at 36-37; Tr. at 1135.) AZLCG also notes Mr. Joiner's testimony that it would not be unreasonable for the Commission to require three years' notice to an AG-X customer that self-supplies RA before termination of the AG-X program and that this would support the viability and success of the self-supply option. (AZLCG Br. at 47; *see* Tr. at

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[553] Ms. Hobbick did not agree with AZLCG's proposition that PUCs and utilities typically do not consider the elasticity of demand when setting rates, stating that in some jurisdictions, particularly those with forward-looking test years, assumptions are made concerning how customers will respond to price signals. (*See* Tr. at 2473-2474.) Ms. Hobbick maintained that the AG-X billing determinants were not adjusted based on any assumptions because TY billing determinants were applied to the transition reserve capacity charge, which produces a result comparable to a 50/50 assumption. (*See* Tr. at 2474-2475.)

1137-1138.) AZLCG urges the Commission to require three years' notice to AG-X customers before the AG-X program may be terminated. (AZLCG Br. at 47.)

AZLCG also argues that AG-X customers should be permitted to increase their loads at existing service locations by more than the current 10% cap because increasing AG-X load can free up energy and capacity to serve APS's anticipated growth and thereby reduce costs by deferring additional resources. (AZLCG Br. at 47-48; *see* Tr. at 209, 217, 1287-1288.) AZLCG points out that there is currently open capacity in the AG-X program and that APS recently switched to flow gate methodology for transmission reservations, which is more efficient and should allow APS to accommodate a higher volume of AG-X transactions, and argues that an AG-X customer who can use a less encumbered transmission path should be able to increase their load and support economic growth. (AZLCG Br. at 48; *see* Ex. AZLCG-3 at 34-35.)

AZLCG also supports Staff and Calpine's recommendations to expand the AG-X program to 400 MW and urges the Commission to approve such expansion. (AZLCG Br. at 48; *see* Ex. S-12 at 55; Ex. CSN-1 at 3.)

Further, AZLCG argues, it is not yet clear how AG-X customers can use DR to meet RA requirements, something Mr. Joiner acknowledged, because APS's language to allow for DR leaves some questions unanswered. (AZLCG Br. at 48-49; *see* Ex. APS-12 at 41; Tr. at 1143-1144; Amended Ex. APS-98 at 3-4.) For example, AZLCG states, it is not clear whether APS intends to call on AG-X DR only when a GSP curtails deliveries or would also call on AG-X customers to curtail load when APS faces a reliability event caused by something else. (AZLCG Br. at 49.) Additionally, AZLCG asserts, the proposed AG-X POA requires AG-X customers to receive DR from GSPs, although Ms. Hobbick agreed that AG-X customers may be able to implement DR themselves,[554] and NRG witness Dr. Kaufman testified that a successful DR program would likely need to be implemented by APS.[555] (AZLCG Br. at 49; *see* Amended Ex. APS-98 at 3-4; Tr. at 2481, 4035-4036.) According to AZLCG,

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[554] Ms. Hobbick agreed that an AG-X customer that implements its own DR mechanism would not be acquiring that from its GSP and that it would be fair to modify the POA to make it so that an AG-X customer could avoid the generation capacity charge if it self-supplies RA either by purchasing RA from its GSP or implementing DR mechanisms. (*See* Tr. at 2481.)

[555] Dr. Kaufman opined that to be WRAP compliant, a DR program would likely need to be managed by APS rather than a GSP. (*See* Tr. at 4035-4036.)

Mr. Joiner agreed that AG-X customers cannot use DR to meet RA requirements until the details are explored and defined and, additionally, indicated that APS is willing to work with AG-X customers to flesh out those details. (AZLCG Br. at 49; *see* Tr. at 1144-1146.) AZLCG urges the Commission to approve APS's revised AG-X POA language related to DR; to require APS to engage with interested stakeholders to define further the use of DR to meet RA requirements in the AG-X program; and to require APS, within six months after the Commission's decision, to make a compliance filing in this docket that includes the AG-X POA revisions for DR. (AZLCG Br. at 49-50.)

In its Responsive Brief, AZLCG maintains that AG-X customers should be required to pay a reserve capacity charge based on 15% of the E-34 generation demand charge, which AZLCG states is substantially higher than the actual cost to serve AG-X customers and should alleviate any doubt that AG-X customers are being subsidized by non-AG-X customers. (AZLCG RBr. at 8-9.)

Calpine

Calpine, which operates as a GSP for the AG-X program, recommends the following treatment of APS's proposals for AG-X:[556]

- The AG-X program's aggregated peak load threshold should be 1 MW rather than the APS-proposed 5 MW, as it would better allow for participation by medium-sized customers, consistent with the Commission's directive in Decision No. 77043 (January 16, 2019), the Commission's Policy Statement Regarding AG-Y Alternative Generation/Buy-Through Program ("AG-Y Policy");[557]
- APS's proposed notice requirements for return to APS's standard service, which are different for AG-X customers that self-supply RA and those that obtain APS-supplied RA, should be approved;

[556] Calpine Br. at 1-2.

[557] Decision No. 77043 was admitted herein as Exhibit CS-3. In the AG-Y Policy, the Commission directed APS "to 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 3.) APS proposed an alternative AG-Y program in the 2019 rate case, but it was not a buy-through program and was rejected by the Commission. (Ex. RUCO-7 at 284-285.)

- The AG-X POA[558] should provide the notice requirements for AG-X customers that change their RA provider, with AG-X customers moving from APS-supplied RA to self-supplied RA required to provide APS notice six months before the WRAP Forward Showing deadline, and AG-X customers moving from self-supplied RA to APS-supplied RA required to provide APS three years' notice, though this may be shortened at APS's discretion if there will be no shift of cost or risk to non-AG-X customers;[559]
- The AG-X program should be expanded from 200 MW to 400 MW or, in the alternative, if the Commission shares APS's concerns with a 200-MW expansion, should be expanded by 50 MW per year when enrollment reaches the existing enrollment cap, for a total potential expansion to 400 MW; and
- APS should be required to provide the AG-X Program Guidelines, which are to include important elements of the RA requirements not set forth in detail in the POA, to the Commission for approval before the one-year transition period for existing AG-X customers to select APS-supplied or self-supplied RA begins.

Calpine provides a revised version of Amended APS Exhibit 98, reflecting Calpine's proposed revisions to the POA, as Attachment 1 to its Brief. Although Calpine does not specifically mention it in its Brief, Calpine's proposed AG-X POA changes the consequences for the failure of a GSP providing RA to meet the Forward Showing Program timing—replacing the mandatory termination from the AG-X program with the assessment of penalties.[560] (*See* Calpine Br. at Att. 1 at 6.)

Calpine argues that the aggregated peak threshold should be 1 MW rather than the APS-proposed 5 MW because it would be more consistent with the AG-Y Policy, as APS's tariffs make clear that a 5-MW customer is a large-sized customer (401 kW or more), not a medium-size customer (101 kW to 400 kW), and APS's AG-Y proposal from the 2019 rate case included medium-sized customers without any aggregation threshold. (Calpine Br. at 6-7; *see* Ex. APS-36; Ex. CS-4 at 1; Tr. at 2490-2492.) Additionally, Calpine argues, APS has not demonstrated that the 5-MW threshold will

[558] Calpine uses the term "Rate Rider," which is accurate for AG-X. For the sake of simplicity, this decision uses "POA" as a generic term for the Commission-approved document that sets out the rules for a specific rate plan or rate rider.
[559] Calpine notes that APS agreed with these notice requirements but did not include them in the AG-X POA.
[560] Calpine should have expressly stated this proposal in its Brief. Its failure to do so makes it less likely that the other parties, including APS, noticed the proposed revision and is problematic.

meaningfully expand eligibility because it does not know and has provided no evidence of how many customers served by E-32 S and E-32 M would be able to aggregate to meet the 5-MW threshold and acknowledged that a 1-MW threshold would likely allow more medium-sized customers to participate. (Calpine Br. at 7; *see* Ex. CS-1 at 8; Tr. at 2493-2494.) Calpine argues that other utilities with similar programs use a 1-MW threshold. (Calpine Br. at 8; *see* Ex. CSN-2 at 2.) Calpine also argues that APS's concern about medium-sized customers lacking sophistication or access to professional energy managers should be disregarded because the AG-Y Policy directed the inclusion of such customers, GSPs provide guidance to help customers understand the options and risks inherent with participation in AG-X, customers with 1 MW of load (especially if part of large national companies) could have in-house energy managers, and customers without in-house energy managers could engage consultants. (Calpine Br. at 8; Ex. APS-14 at 22; Tr. at 3328-3330, 3340-3341.) Further, Calpine argues, APS's concern about administrative costs should be rejected because APS has provided no evidence demonstrating that administrative costs would be significantly increased with a 1-MW threshold and has actually proposed to lower both the aggregation threshold and the administrative charge in this matter, which would be contradictory if a lower threshold results in higher administrative costs. (Calpine Br. at 8-9; *see* Ex. APS-30 at 30; Ex. CSN-2 at 2; Ex. APS-29 at 22; Tr. at 2487.) Nonetheless, Calpine states, it would be willing to support a higher administrative charge if APS demonstrated and quantified increased administrative costs resulting from a 1-MW threshold, as APS agreed that any increased cost could be recovered through a higher administrative charge than it proposed. (Calpine Br. at 9; *see* Tr. at 2488-2489.) Calpine suggests that the Commission direct APS to use the 1-MW threshold and make a compliance filing demonstrating APS's proposed increased administrative charge, which the Commission could approve after interested parties are provided an opportunity to support or oppose any increase to the administrative charge.

Calpine supports as reasonable and requests Commission approval of APS's proposed AG-X POA language (as included in Amended Exhibit APS-98) concerning an AG-X customer's return to APS standard service, which is different for AG-X customers receiving APS-provided RA and those with self-supplied RA, because the notice period may be shortened in APS's discretion if doing so does not shift cost or risk to other customers. (Calpine Br. at 9-10.)

Calpine argues that the Commission should require the notice provision for changing RA providers to be included in the AG-X POA so that prospective AG-X customers are aware that it exists and APS is not able to change the notice provision unilaterally with no Commission oversight. (Calpine Br. at 10-11.) Calpine asserts that all parties now agree to the notice periods that should govern an AG-X customer's changing its RA provider, with the only disagreement being whether the notice provisions should be included in the AG-X POA. (Calpine Br. at 10; *see* Ex. APS-14 at 19; Tr. at 1230-1232, 3313.) Calpine states that APS acknowledged the omission of the notice provision from the POA and suggested it was done to create flexibility so that APS could change the notice period without amending the AG-X POA or seeking Commission approval.[561] (Calpine Br. at 11; *see* Tr. at 2494-2500.)

Additionally, Calpine argues that the AG-X program should be expanded to 400 MW or, in the alternative, expanded by 50 MW per year beginning when AG-X customer enrollment reaches the 200 MW cap, because, as Staff witness Dr. Dismukes testified and Calpine and NRG also noted, the AG-X program historically has been popular; expanding AG-X to smaller customer sizes could result in increased program participation; the Commission would not be able to expand the program until APS's next rate case even if the program becomes fully subscribed and again has interest exceeding its cap after the conclusion of this rate case; and failure to expand the program could undermine the Commission's desire to expand the program to smaller customers. (Calpine Br. at 11-12; *see* Ex. S-12 at 52, 54; Ex. CSN-1 at 13-16; Ex. CSN-2 at 6-10.) Calpine urges the Commission to expand AG-X in this matter because once the issues from the last rate case are resolved, it is logical to ensure that customers are not shut out from participating in AG-X as they were at the time of the last rate case. (Calpine Br. at 12.) Calpine states that its alternative proposal, for incremental expansion, is intended to balance competing interests. (Calpine Br. at 12.) Calpine notes that Mr. Joiner expressed a willingness to consider expansion of AG-X if the program cap were reached and acknowledged that the program cap can only be expanded in a rate case. (Calpine Br. at 12-13; *see* Tr. at 1241-1243.)

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[561] Ms. Hobbick confirmed that APS desires to keep those notice provisions in the Program Guidelines, which historically have not been approved by the Commission and have not been posted on APS's website but instead provided to customers and GSPs upon request. (*See* Tr. at 2496-2500.)

Calpine argues that the enrollment of a few customers could quickly fill the existing 75 MW of available capacity to reach the cap again and that the paced expansion would allow APS to gain experience with the new RA provisions while still allowing the program potentially to expand before the next rate case if it again becomes fully enrolled. (Calpine Br. at 13; *see* Tr. at 3314, 3327, 3338-3339.)

Calpine argues that contrary to APS's assertions, there is not a transmission constraint at the Palo Verde hub that should preclude expanding AG-X and notes that there have been no curtailments of transmission from the Palo Verde hub to APS's loads.[562] (Calpine Br. at 13-14; *see* Ex. CSN-3 at 2-12; Ex. CSN-4 at 2-7; Ex. CS-2; Tr. at 1246, 3345-3348.) Calpine argues that based on historical usage data and reasonable expectations, an expanded 400-MW AG-X program with all deliveries made to the Palo Verde hub would not materially impact APS's ability to use the Palo Verde hub for non-AG-X customers because shifting load from APS-supplied energy to GSP-supplied energy does not impact the available transmission capacity to serve load within APS's balancing authority; it merely changes the entity delivering the power to the boundary of APS's system. (Calpine Br. at 14; *see* Ex. CSN-3 at 5-6; Tr. at 3345-3346, 3354-3356.[563]) Additionally, Calpine argues, for the period from now to 2031, APS has reserved more network transmission from the Palo Verde hub to APS loads (including AG-X customers) than it has historically used, by 792 MW to more than 2,000 MW, meaning that it has a substantial amount of network transmission to accommodate future load growth in its service territory. (Calpine Br. at 14; *see* Ex. CSN-3 at 8-9; Tr. at 3346-3347.) Calpine further notes that APS

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[562] Mr. Joiner agreed that there has never been a curtailment of transmission from the Palo Verde hub to APS loads for any energy that is resource specific and that has firm transmission delivery. (Tr. at 1246.) But Mr. Joiner expressed concern about real-time or short-term market opportunities for import or export that would be reduced by having the AG-X program expanded and using more transmission at the Palo Verde hub. (Tr. at 1245-1246.) Mr. Joiner further testified that APS's need for transmission is expected to grow substantially, making it important for its customers that its available transmission is preserved. (Tr. at 1246.) Mr. Joiner agreed that if there is a constraint on the transmission path from the Palo Verde hub to APS's loads that APS would be obligated to upgrade the transmission system before a problem develops to ensure that all APS balancing authority loads can be reliably served but stated that the process to build additional transmission can take 10 years. (Tr. at 1247.) Mr. Joiner acknowledged that APS is already working on a new 500-kV transmission line from the Jojoba substation to Rudd, which should increase capacity from the Palo Verde hub, but stated that he is also concerned about flows to the Palo Verde hub from California and northwestern sites. (*See* Tr. at 1247.)

[563] Mr. Goddard acknowledged that there could be a hypothetical situation where market opportunities for cheaper energy beyond what is necessary to serve APS's native load were available for APS to buy but would have to be deferred because of the AG-X load used at the Palo Verde hub, but stated that would be well beyond what has historically been delivered at the Palo Verde hub and would represent a "business constraint" rather than a transmission constraint. (*See* Tr. at 3354-3356.)

is planning for a new 500 kV transmission line from the Jojoba Substation to the Rudd Substation to be online by 2028, which will increase APS's ability to bring generation resources from the Palo Verde hub to the Phoenix metro area to meet future growth. (Calpine Br. at 14; *see* Tr. at 3346.) Calpine also notes that APS's recent change in how it calculates transmission availability, from the rated path method to the flow gate method, should result in more transmission being calculated as available for use. (Calpine Br. at 14;[564] Ex. CSN-4 at 5-7; Ex. CS-1; Tr. at 3358-3360.) Calpine asserts that APS is agreeable to having AG-X deliveries up to the current 200 MW cap continue at the Palo Verde hub but is not agreeable to having the Palo Verde hub used for incremental deliveries if the program cap is expanded.[565] (Calpine Br. at 15; *see* Tr. at 1252-1253.) Because the Palo Verde hub is the most liquid point of delivery for the AG-X program to use, Calpine argues, the Commission should require that the Palo Verde hub be the point of delivery for any expansion unless a specific customer and GSP agree to an alternative delivery point. (Calpine Br. at 14-15; *see* Tr. at 3360-3361

Finally, Calpine argues that the Commission should require that the AG-X Program Guidelines be approved by the Commission before the one-year transition period for selection of RA providers begins. (Calpine Br. at 15.) Calpine agrees with the one-year transition period for AG-X customers to evaluate their options and make an RA selection but argues that some of the key elements of the RA framework have not yet been resolved because the AG-X POA relies heavily on revisions to the AG-X Program Guidelines that have not yet been made. (Calpine Br. at 15.) Calpine acknowledges that the Commission has not previously approved the AG-X Program Guidelines but states that Commission review and approval is necessary now because APS proposes to include important elements of the RA requirements in the Program Guidelines rather than in the POA, and APS has not yet shared the necessary amendments with interested parties. (Calpine Br. at 15-16; *see* Tr. at 3338.) Calpine points out that the AG-X POA simply refers to the AG-X Program Guidelines for important details, including how APS will implement the self-supply RA option—such as the deadlines and

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[564] Calpine mistakenly referred to APS's former methodology as the contract path method. (*See* Calpine Br. at 14; Tr. at 3359.) Mr. Goddard testified that switching from the rated path method to the flow gate method was "a step in the right direction to get more accurate and reliable transmission reservations." (Tr. at 3359-3360.)

[565] Mr. Joiner testified that having increased AG-X deliveries beyond 200 MW would degrade the import capability at the Palo Verde hub, which means increased costs to non-AG-X customers and could also lead to reliability concerns. (*See* Tr. at 1253.)

requirements for a GSP's RA showing, whether and how a GSP will be allowed to cure a deficient RA showing, and the type of RA deficiency that would warrant termination of the GSP from AG-X as opposed to the assessment of penalties as exist in WRAP.[566] (Calpine Br. at 16; *see* Tr. at 2501-2506.) Calpine argues that without these details, it is not possible for GSPs and AG-X customers intelligently to select the form of RA that best suits them. (Calpine Br. at 16; *see* Tr. at 2505-2506.) Further, Calpine argues, if the Commission does not retain the authority to resolve disputes regarding how these issues should be handled, it would be granting APS the sole discretion to do so in the manner it chooses, even over the objection of stakeholders. (Calpine Br. at 16.)

In its Responsive Brief, Calpine takes issue with APS's representation that the stakeholders reached agreement on the 5-MW aggregation threshold, asserting that neither it nor NRG agreed with APS's proposed threshold, as was indicated in Mr. Bass's testimony. (Calpine RBr. at 3-4; *see* Ex. CSN-1 at 8-9; Tr. at 3338.) Calpine also notes that to support its assertion about agreement, APS's Brief cites a letter filed in the 2019 rate case docket that is not an exhibit in this matter and argues that the Commission should disregard the letter (and presumably APS's assertion that there was stakeholder agreement) because the letter is not evidence of record.[567] (Calpine Br. at 4-5.)

<u>NRG</u>

NRG states that its subsidiary, Direct Energy Business, is a GSP under AG-X. (NRG Br. at 1.) NRG joins in and adopts every position Calpine expressed in its Brief related to AG-X program issues other than RA. (NRG Br. at 1.) Related to RA, NRG requests for the Commission to do the following:[568]

- Require GSPs providing service under AG-X to be WRAP compliant only when APS itself becomes a binding member of WRAP;

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[566] We note that Calpine's proposed revised AG-X POA would resolve this by only allowing for penalties, although Calpine did not mention that in its Brief. (*See* Calpine Br. at Att. 1.) The language included by Calpine is consistent with language included in the definition of "Resource Adequacy" in the proposed AG-X POA, which, unlike the section on "Default of the Third-Party Generation Provider," does not refer to termination for a failure to meet the timing of the Forward Showing Program and instead states: "Generation Service Providers must provide Forward Showing to APS three weeks prior to APS's obligation to submit its Forward Showing. Failure to submit a timely Forward Showing Program or meet the program guidelines for the Operations Program may result in penalty charges which will be charged to the offending Generation Service Provider as applicable."

[567] The Commission does not consider the cited letter to be evidence of record and has not relied on it in any way in reaching its determinations in this matter.

[568] NRG Br. at 2.

- Reject APS's proposed reserve capacity charge and instead set the charge at \$1.75/kW-month;
- Authorize a third RA option that allows a GSP to provide RA for demand while APS provides RA for the reserve planning margin; and
- Require APS to develop an AG-X DR program that satisfies RA requirements.

NRG argues that until APS is a binding member of WRAP, AG-X customers' RA requirements should be limited to the planning reserve margin for the AG-X load, and AG-X contracts (WSPP Schedule C contracts) should be treated as RA compliant. (NRG Br. at 15.) NRG argues that the Commission should not approve APS's proposal to require GSPs to serve only fully WRAP compliant products to AG-X customers after the decision in this matter because APS itself is not yet a binding member of WRAP and is not yet WRAP compliant itself. (NRG Br. at 15.) NRG argues that it would be reasonable and prudent to rely on GSP-provided resources because they have been more reliable than APS's own resources. (NRG Br. at 15.) NRG further argues that until APS is a binding member of WRAP, the only RA cost APS incurs for an AG-X customer is the cost of planning reserves and, thus, that is the only cost AG-X customers should be required to pay. (NRG Br. at 15-16.) NRG claims that the impact of requiring WRAP compliance for AG-X resources will be increased costs for AG-X customers that are unnecessary and that will unreasonably discourage AG-X program participation. (NRG Br. at 16.)

NRG points out APS's acknowledgment in a data response that APS's WRAP compliance showing for the months of February 2023 and February 2024 did not demonstrate WRAP compliance and claims that Exhibit NRG-7 also shows that APS has not been WRAP compliant in one or two months of every year since 2018.[569] (NRG Br. at 16; *see* Ex. NRG-14; Ex. NRG-7.) Further, NRG asserts, Mr. Joiner testified that APS's seasonal purchase agreements for 2,000 MW of additional capacity were not all WRAP compliant[570] and that APS relied on real-time energy purchases that were not WRAP compliant to maintain its 15% reserve margin during the summer 2023 heatwave. (NRG Br. at 16-17; *see* Ex. APS-14 at 5; Tr. at 1330, 1333-1334.) In light of APS's own current

[569] WRAP did not exist yet for most of these years, as the WRAP Tariff is dated January 1, 2023, and was only approved by FERC in spring 2023. (*See* Ex. APS-12 at 45.) APS points this out in Exhibit NRG-14. Nonetheless, we understand the point NRG is making.

[570] Mr. Joiner's testimony cited by NRG does not specifically address whether the 2,000 MW seasonal contracts are WRAP compliant. (*See* Tr. at 1330, 1333-1334.)

noncompliance with WRAP, NRG argues, it is unreasonable for the Commission to require GSPs to provide only WRAP compliant energy, and the Commission should reject APS's proposal to do so. (NRG Br. at 17.)

Because APS will not be a binding member of WRAP until 2026,[571] and Mr. Joiner testified that APS needs that time to get ready and ensure it is fully compliant, NRG argues that it is unreasonable for APS to expect AG-X customers and GSPs immediately to transition to full WRAP compliance. (NRG Br. at 17; *see* Tr. at 1278, 1548.) NRG adds that even after becoming a binding WRAP member, APS will not be subject to full WRAP compliance requirements for another three years, which is when the penalties for failure to meet compliance step up completely, meaning that APS will not be a full WRAP member subject to full WRAP requirements until 2029. (NRG Br. at 17; *see* Tr. at 1279.) Thus, NRG argues, it would be unreasonable to require full WRAP compliance from AG-X customers and GSPs when APS will not be subject to full compliance requirements until 2029. (NRG Br. at 17.)

NRG argues that it would be unreasonable to allow APS to change its treatment of AG-X resources before it is a binding member of WRAP because APS has consistently relied on AG-X resources to meet its RA requirements, and the AG-X resources have been "exceptionally reliable." (NRG Br. at 18.) NRG points to Mr. Joiner's acknowledgment that APS historically has counted AG-X resources toward its RA compliance;[572] APS's needing to use AG-X resources not to be RA deficient in several months shown in Exhibit NRG-7; AG-X resources' having availability exceeding 99.5% in 2020 to 2022, which was higher than the reliability of APS's thermal generating facilities in those years; and Mr. Joiner's agreement that some of APS's market purchases have had a higher curtailment rate than AG-X supplies have.[573] (NRG Br. at 18-19; *see* Tr. at 1284-1285, 1345; Ex. NRG-7;[574] Ex.

[571] Mr. Joiner clarified that as of the hearing, there were no binding members of WRAP, so there was not yet anyone with whom APS could do business even if it were a binding member. (*See* Tr. at 1548.) Mr. Joiner stated that the non-binding members had been submitting data and going through mock WRAP auctions and "gear]ing up and mak[ing] sure that [they] are fully compliant, and hav[ing] . . . discussions with special programs like AG-X to make sure that there's no penalty to AG-X participants or non-AG-X participants." (Tr. at 1548.)

[572] Mr. Joiner also testified that APS will not be able to continue counting AG-X resources toward its RA compliance if APS's RA proposal is not approved by the Commission. (*See* Tr. at 1284-1285.)

[573] Mr. Joiner clarified that these market purchases were made in real time for economic purposes, not for RA, that they were low-cost purchases that represented economic opportunities to benefit customers. (*See* Tr. at 1345-1346.)

[574] Exhibit NRG-7 includes Monthly Loads & Resources charts for select quarters of 2018 through 2022.

NRG-1 at 12-13.) NRG further argues that the WSPP Schedule C contracts used in the AG-X program provide an advantage over APS's thermal fleet because the WSPP Schedule C contracts provide for liquidated damages in the event of curtailment, and APS doesn't receive liquidated damages when its own fleet is unavailable. (NRG Br. at 19; *see* Ex. NRG-1 at 13.) NRG argues that liquidated damages enhance the reliability of AG-X resources by allowing APS to pursue market energy purchases with no financial risk, even if the market purchases are made at extreme prices. (NRG Br. at 19; *see* Ex. NRG-1 at 13.) This is another reason, NRG argues, to allow the AG-X program to rely on WSPP Schedule C contracts until APS becomes a binding member of WRAP. (NRG Br. at 19.)

Additionally, NRG argues, because APS currently counts AG-X resources toward its RA requirements (treating them as capacity), the only cost APS incurs to serve AG-X customers with RA is the cost of the planning reserve, and that is the only cost that AG-X customers should be required to pay for RA until APS is a binding member of WRAP. (NRG Br. at 20; *see* Ex. NRG-1 at 9-11.) NRG argues that APS's proposed reserve capacity charge is "really a planning charge" and should be reduced because AG-X customers are not full requirements customers and should not be charged as though they are. (NRG Br. at 21.) According to NRG, the reserve capacity charge assessed to AG-X customers should be $1.75/kW-month. (NRG Br. at 21.) NRG argues that APS clearly distinguishes between its planning for RA (what WRAP would call the Forward Showing) and its real time operations and that APS's proposed reserve capacity charge for AG-X is related to this planning component and not to real time system operation. (NRG Br. at 21.) NRG points to Mr. Joiner's testimony that real time is separate from RA constructs and that APS makes energy sales in the real time market using resources it relies on for RA.[575] (NRG Br. at 21; *see* Tr. at 1309-1310, 1314.) NRG states that the distinction between planning and real time operations is consistent with WRAP, which differentiates between the Forward Showing (i.e., planning) and the operating program (i.e., delivery of energy). (NRG Br. at 21; *see* Ex. NRG-1 at Att. LK-4.) NRG recounts Dr. Kaufman's testimony that demand planning and serving demand are two different functions and that an AG-X customer who selects APS-supplied RA is only

[575] Specifically, Mr. Joiner stated that in a hypothetical scenario where an AG-X customer that is supplied RA by APS is receiving full service of its needs from the GSP, APS could, on a non-firm (i.e., recallable) basis, sell energy from a resource relied upon to supply the RA because the non-firm nature of the sale would mean that the RA resource remains available to serve the AG-X customer at any point. (*See* Tr. at 1313-1314.)

receiving the demand planning from APS, while the GSP provides the actual service, meaning that any resources APS secures for planning purposes for the AG-X customer are "freed up in actual operations to provide other services," and AG-X customers do not impose the same level of costs on APS as full requirement customers do. (NRG Br. at 22-23; *see* Tr. at 1312-1313, 4003; Ex. NRG-1 at 18.) NRG further notes that AG-X customers do not receive the benefits from the economic use of the "freed up" resources. (NRG Br. at 22; *see* Tr. at 2519.) Thus, NRG argues, the AG-X RA charges should reflect only the planning component of generation demand charges or, in WRAP terms, the cost of the Forward Showing. (NRG Br. at 23.) NRG argues that the E-34 demand generation charge proposed to serve as the reserve capacity charge for APS-supplied RA represents the cost of both planning for demand and serving demand in actual operations, making it inappropriate for AG-X customers. (NRG Br. at 23; *see* Ex. NRG-1 at 17-18.) NRG argues that because WRAP does not require additional showings after the Forward Showing is completed, a WRAP member has only energy obligations following the Forward Showing and can source that energy from any resource. (NRG Br. at 24; *see* Ex. NRG-1 at Att. LK-4.) Thus, NRG asserts, APS does not set aside a resource for an AG-X customer when it supplies that customer's RA and can use the resource to meet other energy and capacity needs, something that APS cannot do with a full requirements customer. (NRG Br. at 24.) NRG argues that the reserve capacity charge must reflect the net benefits non-AG-X customers can receive (and AG-X customers cannot receive) from APS's ability to use the AG-X resource to provide service to other customers, thereby reducing net power costs, and to make market sales. (NRG Br. at 24-25; *see* Tr. at 2519.) NRG asserts that to calculate the appropriate reserve capacity charge, Dr. Kaufman used cost estimates from EIA's Annual Energy Outlook for 2022 and APS's 2020 IRP price assumptions for a hypothetical 1,083 MW combined cycle combustion turbine ("CCCT"). (NRG Br. at 25; *see* Ex. NRG-1 at 19-20.) Dr. Kaufman calculated a levelized fixed cost for the CCCT of \$9.22/kW-month, which he offset with net revenues of \$7.70/kW-month, reaching a cost to serve demand for planning but not for operations of \$1.52/kW-month, which Dr. Kaufman stated is the true cost of APS providing RA to AG-X customers for 100% of their loads. (NRG Br. at 25; *see* Ex. NRG-1 at 20.) Because APS is required to have a 15% planning margin, NRG asserts, this means that the appropriate reserve capacity charge for APS to supply RA for AG-X load is \$1.75/kW-month. (NRG Br. at 25.)

Further, NRG argues, the Commission should authorize a third RA option that allows a GSP to provide RA for demand while APS provides RA for the 15% planning reserve margin. (NRG Br. at 26.) NRG argues that this hybrid option could "help overcome obstacles" that will make it difficult or impossible for an AG-X customer to self-supply RA. (NRG Br. at 26.) NRG states that a GSP providing an AG-X customer RA (self-supplied RA) would need to acquire two different products—one to serve the AG-X customer's load, and one to serve the 15% reserve margin. (NRG Br. at 26; *see* Ex. NRG-1 at 4.) NRG asserts that the reserve margin product is problematic because APS has stated that it must be a call option product, something that Dr. Kaufman testified is "not readily available and that . . . would be operationally and technically impractical to implement." (NRG Br. at 26; *see* Ex. NRG-1 at 4-5.[576]) NRG states that its hybrid option removes this problem by permitting APS and the GSP to focus on products readily available in the market, with the GSP providing RA through firm energy products delivered to APS to serve 100% of the AG-X customer's load and APS providing a capacity product like the products APS already acquires to serve the 15% reserve margin for all of its customers. (NRG Br. at 26; *see* Ex. NRG-1 at 5.) NRG calculates the appropriate cost for this hybrid option to be 13%[577] of NRG's proposed reserve capacity charge, or \$0.23/kW-month. (NRG Br. at 27; *see* Ex. NRG-1 at 5.)

Finally, NRG urges the Commission to order APS to develop a DR program specific to AG-X customers, with the intent being for AG-X customers to be able to use the DR program to demonstrate compliance with RA requirements. (NRG Br. at 27.) NRG asserts that a DR program conforming to these criteria and that aligns with WRAP requirements would be in the public interest and should be adopted:[578]

- The program would offer a fixed monthly payment equal to the APS-supplied RA reserve capacity charge multiplied by the WRAP-qualifying capacity contribution for the DR program;
- A load curtailment would only be called if an AG-X customer's energy is not expected to be delivered by a GSP;

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[576] Dr. Kaufman stated that "APS intends to require that GSP [sic] be prepared to actually deliver energy in excess of the its [sic] AG-X customer's actual load in the operational timeframe through the use of a call option contract, or otherwise." (Ex. NRG-1 at 4.)

[577] The 13% is obtained by dividing the 15% reserve margin by the 15% reserve margin plus 100%. (*See* Ex. NRG-1 at 5.)

[578] NRG Br. at 27; *see* Ex. NRG-1 at 23-24.

- A load curtailment would be optional if market energy is available to APS; and
- If load is curtailed, the AG-X participant would receive an incentive payment equal to the hourly liquidated damages rate paid by the GSP multiplied by the volume of energy curtailed.

Dr. Kaufman testified that the DR program should be developed in collaboration with stakeholders and filed concurrently with the AG-X Program Guidelines. (Ex. NRG-1 at 24.)

In its Responsive Brief, NRG accuses APS of "cherry-pick[ing] instances where AG-X resources have not been available" to make AG-X resources appear less reliable and argues that the evidence is clear that AG-X resources are more reliable than APS's own resources, citing the information provided in NRG's Brief. (NRG RBr. at 13.) NRG further argues that a finding that AG-X resources are not as reliable as APS's own resources would have no effect on the validity of Dr. Kaufman's recommendations anyway, and would only call into question the prudency of APS's own planning, because Dr. Kaufman's calculations of the cost of APS-provided RA did not take into account AG-X energy reliability. (NRG RBr. at 13.)

Additionally, NRG argues that APS's argument that the reserve capacity charge must cover the full cost of capacity ignores and fails to address that planning for and providing RA are two different things with two different costs. (NRG RBr. at 14.) NRG also takes issue with APS's criticism of Dr. Kaufman's proposed reserve capacity charge because it is based on a hypothetical plant rather than existing APS resources, asserting that Dr. Kaufman directed the Commission to Mr. Higgins's embedded cost approach if the Commission prefers to set rates using embedded costs rather than avoided/marginal costs. (NRG RBr. at 15; *see* Tr. at 4042.) NRG further criticizes APS for omitting discussion of the real-time value of resources used to provide RA, something that is directly addressed in Dr. Kaufman's method and indirectly addressed in Mr. Higgins's method. (NRG RBr. at 15.)

NRG argues that APS's providing AG-X customers the option to self-supply RA does not mean that APS can charge rates for APS-supplied RA that are not just and reasonable. (NRG RBr. at 15.) NRG characterizes APS's argument to this effect "irrelevant" to the issue of whether the APS-proposed reserve capacity charge is just and reasonable, stating that no amount of alternative options gives APS the right to offer unjustified rates and charges to its customers. (NRG RBr. at 15.)

Finally, NRG states that Staff's "generic support" for APS's AG-X proposal must be weighed against the admission at hearing by Staff's witness that he had not analyzed NRG's proposal for the reserve capacity charge and had not compared the merits of APS's proposed charge versus NRG's proposed charge. (NRG Br. at 15-16; *see* Tr. at 4555-4556.) NRG argues that for this reason, the Commission should disregard Staff's support for APS's proposal as to the reserve capacity charge. (NRG RBr. at 16.)

Staff

Staff states that the AG-X program has seen decreasing participation levels, in the form of both more customers voluntarily terminating enrollment in AG-X and customers who were interested in joining AG-X withdrawing their planned participation.[579] (Staff Br. at 44; *see* Ex. S-12 at 49; Ex. APS-29 at 21-22.) Staff recounts that three customers had left AG-X over the past two years, that one additional customer had announced plans to leave the program in 2023, and that 75 MW of the total 200 MW cap were available for future participants. (Staff Br. at 44; *see* Ex. S-12 at 49-50.) Staff states that APS's proposed revisions to AG-X are, according to APS, intended to generate additional interest and participation in the program. (Staff Br. at 44; *see* Ex. S-12 at 50; Ex. APS-29 at 22.) Staff recounts the prior popularity of the AG-X program and opines that a recent rise in wholesale energy prices could be having an impact on the opportunity cost of "buying through" from the market. (Staff Br. at 45; *see* Ex. S-12 at 52, Att. ex. DED-11.)

Staff asserts that APS, as the regional balancing authority, currently provides capacity (i.e., RA) for AG-X customers and partially recovers these capacity costs from AG-X customers through a reserve capacity charge. (Staff Br. at 46; *see* Ex. S-12 at 51; Ex. APS-29 at 23.) Staff briefly describes APS's proposed changes to the AG-X program, including the RA options and their accompanying reserve capacity charges, the notice requirements, and the reduction of the aggregated peak load requirement and recommends that the Commission approve APS's proposed modifications to AG-X. (Staff Br. at 46; *see* Ex. S-12 at 60.)

[579] Staff notes that only one out of five customers on the AG-X waiting list contacted APS to express an interest in joining AG-X. (Staff Br. at 44; *see* Ex. S-12 at 50; Ex. APS-29 at 22.)

Additionally, Staff recommends that the Commission increase the existing cap on total enrollment in AG-X from 200 MW to 400 MW. (Staff Br. at 46; *see* Ex. S-12 at 60.) Staff disagrees with APS's rationale for not expanding the AG-X program and states that keeping the current enrollment cap could undermine the Commission's prior directive for the AG-X program to be expanded to smaller customers. (Staff Br. at 47; *see* Ex. S-12 at 54.)

Staff also states that if AG-X is revised so that it no longer requires the $1.25 million/month off-system sales mitigation, Staff agrees with APS's proposal to eliminate that provision from the PSA POA. (Staff Br. at 47-48; *see* Ex. S-24 at 62.)

APS Response

APS states that, consistent with good utility standards, APS has implemented practices to ensure the reliability of its resources and purchases to include characteristics of RA because generation resources in the west are now constrained, and APS and many other utilities are participating in regional grid reliability improvements and conforming their practices to new regional guidelines that require load-serving entities to demonstrate that they are providing RA with a reserve margin for the loads they serve. (APS RBr. at 46-47; *see* Ex. APS-11 at 12-13; Ex. APS-12 at 40-41, 44-45; Tr. at 1107.) APS reiterates that its proposed modifications to AG-X are designed to address the reliability and cost-shift risks currently resulting from AG-X customers' being served by GSP resources that lack RA characteristics. (APS RBr. at 47.) APS states that the Commission should reject intervenors' alternative RA proposals because they are insufficient and would likely perpetuate the existing problems with AG-X and that the Commission likewise should reject party proposals to expand the size and scope of the AG-X program. (APS RBr. at 47.)

APS argues that Calpine's suggestion that GSPs can provide guidance to medium-sized customers who participate in AG-X is tacit acknowledgment that Calpine's proposal for a minimum aggregation limit of 1 MW would result in the participation in AG-X of smaller, more financially vulnerable commercial customers who may or may not be able to obtain a third-party consultant to provide guidance. (APS RBr. at 47-48; *see* Ex. APS-14 at 21-22; Tr. at 2828.) APS asserts that Calpine has provided no solution to that problem and, further, that Calpine has not provided enough information to verify the appropriateness of the other state program with a 1 MW limit that Calpine cites. (APS

RBr. at 48; *see* Ex. CSN-2 at 2.) APS maintains that its own 5 MW limit was the direct result of stakeholder discussions during the collaborative process and that it will allow broader participation by smaller customers. (APS RBr. at 48; *see* Ex. APS-11 at 30-31; Ex. APS-14 at 21-22.) APS also argues that despite the AG-Y Policy, Decision No. 78317 made it clear that AG-X's RA and other program flaws needed to be addressed before AG-X could be expanded. (APS RBr. at 49; *see* Ex. RUCO-7 at 284-285.) APS argues that it would be inappropriate and inconsistent with Decision No. 78317 to consider the customer eligibility expansion proposed by Calpine before the proposed RA improvements are implemented and determined to be effective. (APS RBr. at 49.) APS argues that without any evidence to establish that smaller size customers desire to join AG-X and without regard for the administrative and financial burden to those customers and the increased complexity and costs of the program for APS, Calpine is effectively proposing to restart AG-X for a different type of customer with different resources and needs, although AG-X was specifically designed for large customers. (APS RBr. at 49; *see* Ex. APS-14 at 21-22; Ex. APS-30 at 30.)

APS argues that the proposals for expansion of the AG-X program cap from 200 MW to 400 MW are "a solution in search of a problem" because the parties have not presented any evidence of additional customers requesting to participate in AG-X, the evidence of record concerning future energy market conditions does not support the idea that more customers will come forward, and APS has thus far been unsuccessful in signing up customers from the AG-X wait list. (APS RBr. at 50; *see* Ex. APS-12 at 12; Ex. CSN-2 at 6-9; Ex. APS-29 at 22.) Concerning the proposal to allow existing AG-X customers to expand their loads beyond 10% of their original allotment, APS points to Ms. Hobbick's testimony that current AG-X customers are already permitted to do that if they submit a request for expansion, provided that there are no customers on the wait list and the overall program is no greater than the 200 MW cap.[580] (APS RBr. at 50; *see* Ex. APS-32 at 16; Tr. at 2828.) APS criticizes the parties proposing AG-X expansion for not attempting to address the cost-shift risks of the program, which include AG-X customers' currently returning to APS standard service when market conditions are volatile, significant financial challenges from uncollected PSA balances and the APS hedge

[580] Ms. Hobbick acknowledged that the availability of this option was not included in the AG-X POA and indicated a willingness to include it. (*See* Tr. at 2827-2829.)

position, and the appropriate allocation of resource costs to ensure costs are not shifted to non-AG-X customers and do not become stranded. (APS RBr. at 50-51; *see* Ex. APS-30 at 30; Ex. APS-14 at 21-22; Tr. at 1233-1234, 1242-1243.) APS argues that expansion of AG-X would be premature and would be too risky for smaller AG-X customers and non-AG-X customers. (APS RBR. at 51.)

APS characterizes NRG's arguments regarding RA as NRG seeking to avoid responsibility for providing energy that has characteristics of reliability and states that NRG misrepresented evidence submitted by APS, such as by claiming that APS would have been RA deficient if not for AG-X when actually, APS would have procured resources to cover any purported RA deficiency if AG-X did not exist. (APS RBr. at 51; *see* Ex. APS-12 at 44.) APS argues that NRG's claim about the value of liquidated damages under AG-X contracts confuses the value of capacity versus energy, because liquidated damages cannot ensure reliability at the time capacity is needed. (APS RBr. at 51; *see* Ex. APS-12 at 40, 42-43; Ex. APS-14 at 20-21; Ex. RUCO-7 at 285; Tr. at 1309-1310.) In response to NRG's argument that GSPs should not be required to meet RA criteria until APS has fully transitioned into WRAP, APS asserts that APS has already implemented the RA criteria for its summer capacity procurements, with AG-X supplies being the only exception; that GSP deliveries have been curtailed during critical peak hours, which is different from an APS generation outage at a time when APS's resource diversity can ensure continued reliability; and that APS is ensuring that its additional procured resources feature RA characteristics. (APS RBr. at 52; *see* Ex. APS-11 at 33-34; Ex. APS-12 at 41-42; Tr. at 1290, 1313-1316, 1505-1506.) APS adds that it has even modified standard form energy contracts (WSPP contracts) to ensure that its short-term purchases feature RA.[581] (APS RBr. at 52-53; *see* Ex. APS-14 at 20, Att. JMJ-03RJ.) APS argues that, contrary to NRG's assertions, Exhibit NRG-7 was a forward-looking assessment of available resources that did not reflect a lack of RA capacity because APS subsequently filled the gaps with RA-inclusive purchases. (APS RBr. at 53; *see* Tr. at 1282-1283.) APS also argues that NRG mischaracterized Mr. Joiner's testimony concerning the 2,000 MW of seasonal capacity that APS maintains, because Mr. Joiner did not testify that they are not WRAP compliant. (APS RBr. at 53; *see* NRG Br. at 16-17; Ex. APS-14 at 5; Tr. at 1330, 1333-1334.) APS

[581] Mr. Joiner stated that APS has used WSPP Schedule C contracts for energy and supplemented the WSPP contracts to include characteristics of RA (use of a specific resource and firm transmission). (*See* Ex. APS-14 at Att. JMJ-03RJ.)

argues that the evidence of record clearly shows that when APS makes non-WRAP-compliant purchases of energy for economic reasons, APS maintains RA-characteristic resource capacity to back up these purchases to ensure reliability. (APS RBr. at 53-54; *see* Tr. at 1505-1507.) APS argues that AG-X purchases should not be relied upon for grid reliability and RA for the period before APS becomes a binding member of WRAP because AG-X supplies are curtailable during emergency conditions and from 2018 through summer 2023 were curtailed 60% more than APS's capacity purchases and thus are not reliable and cannot be used for RA. (APS RBr. at 54; *see* Ex. NRG-15; Ex. APS-12 at 44; Tr. at 1113.) APS argues that like the rest of APS's resources, the resources used for the AG-X program should be aligned with WRAP-compliant RA requirements so that there is no cost shift to non-AG-X customers. (APS RBr. at 54-55; *see* Ex. APS-11 at 34-35; Ex. APS-12 at 45-46; Tr. at 1113.)

In response to AZLCG's request for AG-X program stability through a requirement for APS to provide notice at least three years before terminating the program, APS agrees that a reasonable period would be needed to unwind the program, but asserts that it is the Commission that must approve the elimination of AG-X and that would determine the appropriate timing. (APS RBr. at 55.) APS asserts that it would be required to file a request for termination, which would give interested persons an opportunity to participate in the Commission's proceedings, and that there is no need or factual basis to set an arbitrary timeline now based on a hypothetical event. (APS RBr. at 55.)

APS strongly disputes AZLCG's argument that APS incorrectly represented the AG-X reserve capacity charge in its proof of revenue calculations. (APS RBr. at 56.) APS argues that its treatment of these charges is appropriate because it was based on the first-year transition reserve capacity charge and applied the increase from the present reserve capacity charge to TY levels of AG-X participants. (APS RBr. at 56; *see* Tr. at 2471-2472.) APS points out that the actual revenue from the APS-supplied RA after the transition period will depend on the RA option AG-X customers select and could be higher or lower than what is shown in proof of revenue. (APS RBr. at 56.) APS further asserts that it was disingenuous for AZLCG to agree with NRG's reserve capacity charge calculation and then argue that APS's proof of revenue should show a high level of participation in APS's RA option (and thus higher revenue). (APS RBr. at 56.)

APS argues that neither the AZLCG nor the NRG reserve capacity charge reflects APS's cost to provide RA capacity service, as both are significantly lower than APS's embedded cost of service for power plant capacity, and the adoption of either would thus result in AG-X customers continuing to rely on APS generation capacity funded by non-AG-X customers for reliable service. (APS RBr. at 57-58; *see* Ex. APS-30 at 27-30.) APS points out that when a GSP delivery fails, APS must provide generation capacity for the entire AG-X customer's load. (APS RBr. at 57; *see* Tr. at 1503-1506.) Because of this, APS states, the reserve capacity charges proposed by AZLCG and NRG would result in a cost shift to non-AG-X customers and an increased risk of reliability events impacting all APS customers and should be rejected. (APS RBr. at 57, 58; *see* Ex. APS-30 at 28.) APS asserts that its proposed reserve capacity charge is designed to ensure appropriate cost recovery for the generation capacity APS must have available to serve the full AG-X customer load[582] and, further, that it is consistent with common industry standards for ensuring the availability of RA-backed capacity. (APS RBr. at 57; *see* Ex. APS-32 at 16; Ex. APS-12 at 42.[583]) APS argues that AZLCG's proposed reserve capacity charge, which represents only the 15% reserve margin, is based on the incorrect premise that the current GSP supply provides RA capacity because it provides more than 99% of AG-X customers' energy needs. (APS RBr. at 58; *see* Ex. APS-30 at 28.) APS points to Mr. Joiner's testimony that neither APS under its current practices nor WRAP consider firm AG-X energy purchases to meet RA capacity requirements and that GSP's supplies are especially susceptible to curtailment during periods of grid stress, which increases the risk that relying on these resources will threaten reliability for all APS customers. (APS RBr. at 58; *see* Ex. APS-12 at 41-44; Tr. at 1290.) APS argues that NRG's proposed reserve capacity charge is "completely theoretical," not based on any evidence from this matter, and actually inconsistent with the evidence because it would offset capacity costs with energy sales margins although the latter are all passed through to customers under the PSA. (APS RBr. at 58-59; *see* Tr. at 1162-1163.) APS states that contrary to NRG's assertion that the reserve capacity charge is a planning concept, APS's reserve capacity charge is based on APS's actual need to provide RA-

[582] Ms. Hobbick testified that the rebuttal COSS supports a generation demand charge of $17.86 for E-34, which is significantly higher than the charge APS proposes. (Ex. APS-32 at 16.)

[583] APS also cited to a FERC rate schedule that is not part of the evidentiary record for this matter, although it was cited in Mr. Joiner's testimony. (*See* Ex. APS-12 at 42, n.8.)

characteristic capacity (100% of load) if a GSP fails to deliver. (APS RBr. at 59; *see* Ex. APS-11 at 36-37; Ex. APS-30 at 28.) APS argues that NRG's proposed charge should be rejected because it would result in RA shortages and failure to meet WRAP requirements and would shift costs to non-AG-X customers. (APS RBr. at 59; *see* Ex. APS-12 at 45-46.)

In response to AZLCG's request for a stakeholder process to craft an AG-X-specific DR program, APS states that it supports the use of DR as part of AG-X customers' efforts to satisfy their RA self-supply obligations, provided that the DR measures are consistent with WRAP criteria and accreditation. (APS RBr. at 60; *see* Ex. APS-12 at 41.) APS states that it uses DR as part of the capacity it relies on to provide reliable service, and that the current WRAP Tariff specifies how DR can be used to provide RA in accordance with WRAP guidelines. (APS RBr. at 60; *see* Ex. APS-85 at 6, 50.) APS states that it is committed to developing a few necessary procedural steps, consistent with WRAP, to implement a DR RA program and is willing to meet with interested customers to obtain their input. (APS RBr. at 60.) APS opines that it is not necessary to create a formal stakeholder process for this purpose based on AZLCG's request. (APS RBr. at 60.)

Finally, APS states that NRG's proposed hybrid RA option would be administratively unworkable and should not be adopted because it would require separate valuations for the two components of RA (base demand/load versus planning reserve margin), and the requirement for APS to provide the RA for the planning reserve margin would come with a significant cost burden for APS. (APS RBr. at 61; *see* Ex. APS-14 at 19-20.) APS argues that there is no reason for the AG-X customer's self-supplied RA not to include both components of RA, because "call option" energy products are available on the market to address capacity needs, whether purchased by APS or a GSP. (APS RBr. at 61.) APS argues that the proposal to require APS to procure a capacity product separately from the GSP-supplied RA for customer demand would add unnecessary complexity to AG-X and should be rejected. (APS RBr. at 61.)

<u>Resolution</u>

In Decision No. 78317, the Commission identified a number of issues with the AG-X program for APS to explore in a collaborative process with AG-X stakeholders. While APS and the stakeholders have not reached consensus as to how all of the issues should be resolved, the Commission is encouraged by the agreement that has been achieved, including the apparent agreement of AG-X stakeholders that RA was an issue that needed to be addressed. The Commission is cognizant of the disagreement about precisely when RA should be addressed completely and how much RA should cost if supplied by APS. Based on the evidence of record and arguments provided herein, the Commission reaches the following conclusions regarding the numerous AG-X-related issues raised in this matter:

- Because APS's proposed APS-supplied RA and GSP/self-supplied RA options address the RA concerns previously expressed about the AG-X program and are expected to address the cost-shift concerns with the program as well, APS's RA options, as provided in Amended Exhibit APS-98, including the notice timing provisions, should be approved, and NRG's proposed third "hybrid" RA option should be rejected as inadequate to address the RA concerns and potentially unworkable.
- Because the reserve capacity charge for APS-supplied RA needs to cover the resources to provide full backup load for an AG-X customer, it is just and reasonable for the reserve capacity charge after the one-year transition period to be set at the level of the unbundled generation demand charge from E-34, the extra large general service schedule available to customers with monthly maximum demand of 3 MW or more for three consecutive months. The alternate reserve capacity charge proposals from intervenors would cover only a fraction of the costs that APS will actually be incurring to ensure RA for AG-X customers that select APS-supplied RA and should be rejected.
- Because it is important for all of the capacity resources serving APS's system to conform to WRAP RA requirements to ensure reliable service for all of APS's customers, it is just and reasonable and in the public interest to require that the RA supplied by GSPs to AG-X customers who do not desire to pay for APS-supplied RA meets WRAP RA requirements. APS has already taken steps to ensure that all of its capacity resources (as opposed to economic energy-only resources) conform to WRAP RA requirements. The AG-X GSP-supplied resources are the only outliers, and that situation needs to be remedied as expediently as possible.

- Because GSPs may need some time to obtain WRAP-compliant RA, it is just and reasonable and in the public interest to allow APS during the 12 months following the effective date of this decision to assess a reserve capacity charge for APS-supplied RA that is equal to its current AG-X reserve capacity charge ($5.248/kW) increased by the system standard revenue increase approved herein.
- Because APS has already proposed to reduce the minimum aggregated peak load threshold to participate in AG-X to 5 MW and newly to allow E-32 S and E-32 TOU S customers to participate in AG-X, the Commission shares APS's concerns that lowering the minimum aggregated peak load threshold down to 1 MW could result in smaller and less sophisticated customers entering into contractual arrangements that may not be in their best interests. The Commission believes that it is necessary to determine how well the smaller customers fare within the AG-X program, which was not designed with them in mind, before reducing the threshold further to allow for even smaller customer groups to become AG-X customers.
- Because the new RA provisions have not yet been tested through actual operations, and there is currently a lack of interest from APS customers to become AG-X customers, the AG-X program should not currently be expanded to 400 MW or incrementally by 50 MW annually until it reaches 400 MW. The time to consider expansion will be APS's next rate case, when data will be available indicating how successful the new RA provisions are in ensuring reliability and preventing cost shifts to non-AG-X customers.
- Because AG-X customers enter into long-term contracts with GSPs for the AG-X program, and could incur significant stranded costs as a result of sudden termination of the AG-X program, it is just and reasonable and in the public interest for the Commission to provide assurances that the AG-X program will not be terminated suddenly except in the case of an emergency situation that makes termination of the program imperative to protect non-AG-X customers and the public interest.[584] APS will be required to include language in the AG-X POA stating that APS must give AG-X customers at least three years' notice, in writing, before filing an application

[584] The Commission cannot think of a scenario that would result in such an emergency but must ensure that APS's customers and the public interest are adequately protected.

with the Commission that proposes termination of the AG-X program, except in case of emergency as described herein.

- Because APS already will allow an AG-X customer to increase its load by more than 10% if the customer requests permission for such expansion, the availability of this provision should be included in the AG-X POA, on the final page as a qualification for the current language setting forth the 10% limit.
- Because APS has agreed to Calpine's proposal for the notice requirements for AG-X customers who desire to change their RA provider—with AG-X customers moving from APS-supplied RA to self-supplied RA required to provide APS notice six months before the WRAP Forward Showing deadline, and AG-X customers moving from self-supplied RA to APS-supplied RA required to provide APS notice three years before the move, though this may be shortened at APS's discretion if there will be no shift of cost or risk to non-AG-X customers—these notice requirements should be included in the AG-X POA so that they are transparent for all AG-X customers and potential AG-X customers.
- Calpine's proposed removal of language regarding termination from AG-X eligibility of a GSP that fails to meet the timing of the Forward Showing Program was made to be consistent with language included in the definition of "Resource Adequacy," which provides for penalty charges under those circumstances and does not mention termination from the AG-X program. A lack of RA jeopardizes reliability for all customers. Because the AG-X POA should be internally consistent, but it is also important for APS to have the option to terminate a GSP's participation in AG-X if the GSP cannot be relied upon to meet its RA obligations, the language regarding failure to meet the timing of the Forward Showing Program contained in the "Default of the Third-Party Generation Provider" section of the AG-X POA should be revised to read as follows: "Failure on the part of the Generation Service Provider who is providing Resource Adequacy to meet the timing of the Forward Showing Program as outlined in the Program Guidelines may result in penalty charges which will be charged to the offending Generation Service Provider as applicable. A Generation Service Provider's repeated failure to meet the timing of the Forward Showing Program may result in termination from the program."

Additionally, for the sake of consistency with AG-X POA definitions, the heading for this section shall be corrected to include "Generation Service Provider" rather than "Generation Provider."

- Because DR is a valuable resource, both APS and interested AG-X stakeholders desire for DR to be available to supply at least a portion of a self-supplied RA, and the DR language in the AG-X POA is insufficiently informative and potentially even inconsistent with how DR measures would actually be structured, it is just and reasonable and in the public interest to approve the DR language currently included in the proposed AG-X POA as a placeholder to ensure that DR is available to AG-X customers for RA and to require APS:
    - To meet and collaborate with AZLCG, NRG, Staff, and any other interested parties concerning the manner in which the DR measures should be structured and described in the AG-X POA to ensure WRAP compliance;
    - To include in the meetings discussion of the merits of the DR program provisions proposed by NRG;
    - To craft language regarding the DR measures for inclusion in the AG-X POA, with the language to be informed by the stakeholder discussions and created by consensus if possible; and
    - To file in this docket, which shall remain open for the purpose, within 180 days after the effective date of this decision, proposed revised AG-X POA language that explains the DR measures in sufficient detail for an AG-X customer, potential AG-X customer, or GSP to understand the applicable requirements and where to find additional information if needed (such as in the WRAP Tariff).
- Because the Commission has heretofore not felt it necessary to review and approve the AG-X Program Guidelines and in this decision requires APS to add to the AG-X POA language that addresses some of the key concerns with the proposed AG-X POA, the Commission does not believe that it is necessary and appropriate and in the public interest for the Commission at this time to require APS to submit the Program Guidelines to the Commission for review and approval. If the Commission determines in the future that it is necessary for the Commission

to review and approve the Program Guidelines, due to a formal complaint or any other reason, the Commission may take action to require that this occurs.

- Because the Commission believes that it is important for the AG-X POA language to be internally consistent and as clear as possible, the Commission will also direct APS to clarify the new RA language in the "Description of Services and Obligations" section specifically to ensure identification of the correct entity or entities as responsible for providing RA, purchasing RA, demonstrating RA, and paying for RA. Currently, in the first new sentence of the section, the GSP is identified as responsible for providing RA by purchasing RA from APS or demonstrating RA seasonally, while in the numbered items that follow, AG-X customers are responsible for paying the reserve capacity charge for APS-supplied RA (meaning that the GSP is not purchasing the RA from APS). APS will be required to provide clarified language for this section in the conforming AG-X POA to be approved in this decision.
- Finally, because the Commission is approving the new RA structure, consistent with Staff's recommendation, the Commission approves removal of the $15 million annual PSA POA off-system sales mitigation provision for AG-X.

5. GS-EV

In Decision No. 78317, the Commission ordered APS to "develop and propose for Commission review and approval a voluntary rate rider or tariff under which customers taking service under the Company's general service rate plans can promote submetered Level-1 and Level-2 electric vehicle charging on their property during off-peak hours that align with solar energy production during the day and consumer and employee behavior during normal business hours." (Ex. RUCO-7 at 442.) APS's GS-EV POA was approved by the Commission in Decision No. 78779 (November 21, 2022) and has been effective for just over one year.[585] The GS-EV POA was not in effect yet during the TY.

<u>APS Proposal</u>

APS does not propose to change the substance of the GS-EV POA and argues that it should not be changed because no party has offered any compelling reasons for modification, it is aligned with

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[585] Official notice is taken of this decision, issued in the 2019 rate case docket.

the directives and goals in Decision No. 78317 to load-build during daytime off-peak hours, and it provides substantial savings opportunities for general service customers who install submetered Level 1 or Level 2 EV chargers on their property. (APS Br. at 75-76; *see* Ex. APS-30 at 23-24; Ex. RUCO-7 at 381, 442; Decision No. 78779 at 3.) APS asserts that a hypothetical customer served under E-32 M TOU that increases load by 13,500 kWh per month based on EV charging during the off-peak discount period under GS-EV, using 75 kW of charge each day, would save $238.41 per month under GS-EV, as compared to an increase in costs of approximately $1,132.31 under E-32 M TOU alone. (APS Br. at 76; *see* Ex. APS-30 at 24.) APS asserts that AriSEIA/SEIA did not provide any evidence questioning this savings calculation and further states that GS-EV does not hinder business customer vehicle electrification efforts. (APS Br. at 76; *see* Tr. at 3914-3915.)

APS argues that the NCP demand charges included in GS-EV, which are a feature of APS's E-32 rates, are an important mechanism for APS to recover fixed costs and capacity costs and thereby to mitigate cost shifts and recover increased production costs associated with rising EV and other general service loads. (APS Br. at 77; *see* Ex. APS-30 at 22; Ex. APS-31.) APS touts its E-32 TOU options, which allow customers to shift loads and reduce their demand charges incurred, pointing out that the incremental increases in customer consumption otherwise will result in increased electric bills due to increased production costs. (APS Br. at 77; *see* Ex. APS-32 at 14-15; Tr. at 3910-3911.) APS argues that modifying GS-EV as proposed by AriSEIA/SEIA, to incentivize off-peak EV charging outside of GS-EV's 9 a.m. to 3 p.m. daytime window, would create rate design problems and be inconsistent with Commission directives in Decision No. 78317. (APS Br. at 78; *see* Ex. AriSEIA-3 at 34-35; Ex. RUCO-7 at 381; Decision No. 78779 at 3.) APS argues that net peak periods are shifting later into the evening and overnight hours, that increased resource scarcity and wholesale prices now occur outside of the traditional TOU peak demand periods, and that APS does not have abundant spare non-summer generation capacity as AriSEIA/SEIA assumes. (APS Br. at 78; *see* Ex. APS-12 at 6-8; Ex. APS-14 at 5.) Thus, APS argues, the Commission should not adjust the daytime EV charging load-building incentives in GS-EV. (APS Br. at 79.)

AriSEIA/SEIA

AriSEIA/SEIA argue that demand charges are a challenge to commercial customers who desire to install high-powered EV chargers for their businesses because E-32 M and E-32 L have NCP demand charges based on the highest 15-minute period in a month,[586] and the E-32 TOU tariffs have a separate peak (3 p.m. to 8 p.m. weekdays) and off-peak (all other hours) demand charge. (AriSEIA Br. at 20.) Although they acknowledge there is some merit to using an NCP demand charge for the cost of secondary distribution assets that are not shared, AriSEIA/SEIA argue that using NCP demand charges for anything that is shared is unreasonable from a cost-causation basis because "[t]he marginal cost of providing energy through the distribution system when it has spare capacity is zero." (AriSEIA Br. at 20-21.)

AriSEIA/SEIA argue that APS's commercial tariff options need to be changed substantially "to accommodate the coming electrification of more end uses such as space heating, industrial process loads, and transportation." (AriSEIA Br. at 21.) According to AriSEIA/SEIA, GS-EV is "fundamentally flawed" and will increase bills for almost all customers who take service on it because of its "completely unreasonable 100% utilization assumption."[587] (AriSEIA Br. at 21.) AriSEIA/SEIA recommend the following three actions to address the problem:

- The Commission should require APS to recalculate the GS-EV tariff credit to reflect a more reasonable revenue-neutral usage pattern because the only way a customer using GS-EV can save money now is by using their EV charging equipment at the maximum level between 9 a.m. and 3 p.m. every day of the year, and any other usage pattern will result in increased demand charges that exceed the volumetric energy discount. (AriSEIA Br. at 21.)
- The Commission should order APS to develop a non-residential tariff/rider designed to support private fleet fast charging ("PFFC") at businesses for the businesses' own use because the need for cost-effective charging will be critical as more businesses switch to electric vehicles, and APS has failed to provide any tariff/rider to address this issue. (AriSEIA Br. at 21.)

[586] We note that customers on E-32 M and E-32 L are not eligible for GS-EV. (*See* Ex. APS-100 at 33.)

[587] Mr. Lucas testified that the GS-EV discount rates/kWh only offset the incremental demand charge if the EV charger has a load factor of 100%, including on weekends. (Ex. AriSEIA-1 at 81.) According to Mr. Lucas, the GS-EV discount rates were calculated to be revenue neutral, subject to the assumption that a customer uses the EV charger at the same power output for every possible six-hour discounted charging period in a month. (*See id.*)

AriSEIA/SEIA state that Mr. Lucas's testimony contains calculations to determine the new rate. (AriSEIA Br. at 21; *see* Ex. AriSEIA-1 at 91.)

- The Commission should investigate whether APS's E-32 tariffs, with their NCP demand charges, are compatible with APS's resource plans and electrification goals. (AriSEIA Br. at 22.) AriSEIA/SEIA argue that "massive bill increases" for commercial customers are counterproductive, that demand charges should be limited to costs related to the infrastructure closest to the businesses, and that a "robust volumetric peak/intermediate/off-peak TOU rate" should be used to recover remaining costs. (AriSEIA Br. at 22.) AriSEIA/SEIA assert that such tariffs would provide appropriate price signals both to manage peak load and to install distributed energy resources that could reduce peak load cost-effectively for all customers. (AriSEIA Br. at 22.) AriSEIA/SEIA urge the Commission to create a stakeholder group to investigate how the E-32 rates can be changed to support the electric industry's transition without subjecting APS to unreasonable risk of inadequate revenues. (AriSEIA Br. at 22.)

<u>APS Response</u>

In its Responsive Brief, APS argues that there is no credible evidence suggesting that the impacts of APS's demand charges on commercial customer electrification efforts should be reevaluated and that the evidence instead establishes that demand charges in the E-32 rates are critical for APS to recover costs associated with generation capacity and other fixed costs to provide service to general service customers. (APS RBr. at 612; *see* Ex. APS-30 at 22-23.) APS points to Ms. Hobbick's testimony that the NCP demand charges on the E-32 rates reflect cost causation.[588] (APS RBr. at 61; *see* Tr. at 2827.) APS also emphasizes that general service customers on E-32 rates have the flexibility to select either TOU or non-TOU rates based on what works best for their business needs and their ability to leverage behind-the-meter technologies. (APS RBr. at 62; *see* Ex. APS-32 at 14-15; Tr. at 2826-2827.)

[588] Ms. Hobbick testified that she did not entirely agree with Mr. Lucas's statement that NCP demand charges do not reflect cost causation and stated that while allocation of demand charges is usually done with CP, it is possible to recover the same level of demand revenue from a more levelized charge, such as APS does with residential customers who are only charged demand charges during on-peak hours, and that either can be done as long as the appropriate billing determinants and revenue target are used. (Tr. at 2827.)

Resolution

The GS-EV tariff has been in place for only a short time and was created by the Commission for a very specific purpose—to encourage the charging of EVs by commercial customers during times of the day when there is a great deal of DG solar production. Commercial customers with EVs are not required to subscribe to GS-EV and have other options available, such as the E-32 TOU tariffs, that may better serve their needs if they desire to charge EVs on-site. Based on the evidence of record and arguments herein, the Commission does not believe that it is necessary at this time to change the GS-EV tariff, to modify or implement other general service tariffs to incentivize customers' transition to EVs, or to explore the use of NCP demand charges in APS's general service tariffs. The Commission will not adopt AriSEIA/SEIA's recommendations.

6. R-Tech

Because R-Tech had been unsuccessful in attracting customers since its adoption in the 2016 rate case (having only 55 as of the 2019 rate case) and had unappealing rate design elements, Decision No. 78317 ordered APS to change the R-Tech POA by:[589]

- Setting its BSC at the same rate as for TOU-E and R-3;
- Adding a super-off-peak energy charge from 11 p.m. to 5 a.m. every day, set at the same level as for R-3;
- Eliminating excess off-peak demand charges during the super off-peak period; and
- Raising the threshold for assessing excess off-peak demand charges to 10 kW.

To that end, APS was ordered to file the revised R-Tech POA as a compliance item in the 2019 rate case docket within 60 days after the effective date of Decision No. 78317 (i.e., by January 8, 2022), "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 recommendation." (*See* Ex. RUCO-7 at 439-440.) APS filed an updated R-Tech POA in the 2019 rate case docket on January 7, 2022, but Commission Staff has not yet taken any action on the revised R-Tech POA. (*See* AriSEIA Br. at 19;

[589] *See* Ex. RUCO-7 at 350-351, 439.

Ex. AriSEIA-1 at ex. KL-34.[590]) As a result, the currently effective R-Tech POA is the same POA that was considered and ordered to be revised in the 2019 rate case. (*See* Ex. APS-36.)

APS Proposal

APS proposes to freeze or cancel the R-Tech tariff, which has had a low level of customers since its adoption in 2017 and had an average of only 52 customers in the TY. (APS Br. at 90; *see* Ex. APS-32 at 9; Ex. APS-30 at 18; Ex. AriSEIA-1 at ex. KL-35.) APS reports that according to analyses performed by Ms. Hobbick, all participants currently on R-Tech would have experienced annual bill savings if they had been on R-3 instead, even when the analysis was performed using the pending R-Tech rates and the current R-3 rates.[591] (APS Br. at 90; *see* Ex. APS-30 at 18.) APS also determined that of the 2,777 residential customers with batteries on its system, only 0.25% selected R-Tech for service, while 19.4% selected R-3 and 63.4% selected TOU-E. (Ex. APS-30 at 18.) APS argues that the proposal to freeze or cancel R-Tech should not be controversial due to the low level of customers and the availability of better rate plan options. (APS Br. at 90.)

APS states that AriSEIA/SEIA's proposed alternative R-Tech design is not revenue neutral and would result in no incremental peak load reduction and a revenue deficiency. (APS Br. at 90.)

AriSEIA/SEIA

AriSEIA/SEIA state that 47 customers were participating in R-Tech in April 2023 and that the currently effective structure is, as the Commission found in Decision No. 78317, "unappealing." (AriSEIA Br. at 19.) AriSEIA/SEIA argue that the Commission should order APS to modify the R-Tech POA as follows:[592]

- By removing the current off-peak demand structure, which AriSEIA/SEIA state has no basis in cost-causation and even at the Commission's previously approved set point of 10 kW could result in large off-peak demand charges for load that does not add costs to the system;

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[590] Official notice is taken of the filing of the revised R-Tech tariff on January 7, 2022, in Docket No. E-01345A-19-0236, which is available here: https://docket.images.azcc.gov/E000017286.pdf?i=1704657916543 Additionally, official notice is taken of the fact that as of January 7, 2024, no Staff or Commission filing has been made concerning any action to be taken on the revised R-Tech tariff filed on January 7, 2022.

[591] It is unclear whether APS was able to perform the analysis using the pending required super off-peak period pricing; the R-Tech POA filed on January 7, 2022, states that the R-Tech rate would be available upon "installation of required metering equipment and implementation of meter changes." This suggests that customers on R-Tech might require meter adjustments to track the required super off-peak period.

[592] AriSEIA Br. at 20; *see* Ex. AriSEIA-1 at 74-76.

- Extending the winter daytime 10 a.m. to 3 p.m. super off-peak period to all days instead of just weekdays because along with the approved year-round night-time super off-peak period, this reflects APS's low-load, low-cost periods;
- Including a small peak demand charge of $2.21/kW that would apply to the on-peak period every day all year, designed to recover the costs of only those distribution assets located closest to the customer, allocated on the sum of individual max allocators;
- Holding the super off-peak rate constant; and
- Pricing the summer peak, winter peak, and off-peak energy rates at a 3:2:1 ratio.

According to AriSEIA/SEIA, their proposed R-Tech rate design would be revenue neutral based on TY billing determinants from TOU-E non-solar customers, who were used as a proxy for customers who have not yet installed qualifying technologies. (AriSEIA Br. at 20.)

APS Response

APS did not further address R-Tech in its Responsive Brief.

Resolution

Because of the low level of customer participation and the availability of better rate plan options like R-3 and TOU-E, the Commission will order APS to cancel R-Tech.

J. Newly Proposed Programs

1. Residential Buy-Through Pilot Program

NRG Proposal

NRG proposes a Residential Buy-Through Pilot Program ("RBT Pilot") that would essentially expand the AG-X program to allow a limited number of residential customers to enter directly into flat-bill or fixed-rate contracts with GSPs. (NRG Br. at 1, 13.) NRG asserts that the RBT Pilot would "allow customers to lock in a price and thereby avoid costly fuel and energy price spikes that have become a feature of APS's pricing due to its exposure to the wholesale market and its ability to pass-through those costs . . . to customers." (NRG Br. at 1.) Specifically, NRG requests that the Commission require APS to file a POA for an RBT Pilot that is an expansion of the AG-X program and that includes the following features:[593]

- The RBT Pilot will be open to all APS customers in good standing on a first come, first served basis and capped at a 10,000 customer enrollment limit, which NRG expects to have a load of 40 MW or less;
- Only fixed-rate and flat-bill options will be available;
- RBT Pilot customers are to pay GSP rates instead of APS generation-related charges, are to pay APS non-generation-related charges, and are to be exempt from the PSA and EIS;
- The fixed rate option will have a set $/kWh generation charge that will not change for the term of the contract;
- The flat-bill option will have the customer's generation charge fixed at a flat dollar amount for the term of the contract;
- The flat-bill option will have a usage cap of 3,000 kWh/month, after which a fixed rate identified in the contract shall apply for any additional usage;[594]
- GSPs will be required to set contract rates to comply with the 35% pricing band requirements of the AG-X POA;
- For the flat-bill option, an estimate of the customer's full usage during the contract period divided by the contract price must result in a price/kWh that falls within the 35% pricing band;
- RBT Pilot customers will receive consolidated billing from APS;
- For a customer considering the flat-bill option, APS must, if and as available, provide a GSP with 12 months of the customer's historic usage data and load shape within three days of the customer's or GSP's request;
- A GSP must comply with the RA provisions of the AG-X POA, including reserve capacity charges;[595]
- A GSP will be required to deliver power to the Palo Verde hub and will be responsible for

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[593] *See* NRG Br. at 7-14; Ex. NRG-5 at 15-18; Tr. at 3197-3205, 3258, 3270.

[594] This is intended to prevent customers from gaming the system by substantially increasing their usage after entering into a flat-bill contract. (*See* NRG Br. at 8; Ex. NRG-5 at 16.)

[595] NRG states that RBT Pilot GSPs would be required to provide RA using one of the options available to GSPs under AG-X, and the reserve capacity charge/s required under AG-X would apply, based on how the Commission resolves the RA and reserve capacity charge issues in this matter. (*See* NRG Br. at 9; Tr. at 3258.)

arranging all transmission to get it there;

- A GSP will be required to pay imbalance penalties or liquidated damages for imbalances in scheduling power or the non-delivery of scheduled power, as in the AG-X POA;
- A GSP will be required to post collateral equal to the difference between the forward market price of energy and capacity and the revenue APS would make from providing standard service to each RBT Pilot customer;[596]
- Contracts will be electronically or physically signed by customers or will be entered into over the telephone using third-party verification;
- Contracts offered will have durations of 12 to 36 months;
- A contract will be renewed automatically, for a term of 12 to 36 months, provided that the GSP provides the customer mailed notice 60 days prior to the end of the current contract term and the customer does not opt out;
- A customer will be able to opt out of contract renewal with no termination fee during the 60-day notice period; and
- APS will be required to enroll a customer on the RBT Pilot the first month following the receipt of notice submitted by a GSP providing the customer's enrollment decision.

NRG asserts that APS is "financially indifferent" to increases in energy and fuel costs beyond what is captured in base rates because the PSA makes customers an "insurance policy to utility shareholders to recoup the costs of energy," leaving APS with no risk when wholesale prices spike. (NRG Br. at 2-3; *see, e.g.,* Decision No. 78877 (increasing PSA).) NRG asserts that the AG-X-like RBT Pilot could change this risk dynamic by allowing a residential customer to select either a "fixed rate" or "flat bill" option without risk that the customer will be billed more later through a surcharge. (NRG Br. at 3.) NRG asserts that it created the RBT Pilot to address concerns Commissioners have expressed with the current system and that the RBT Pilot would make the GSPs stand by their price offers to customers, placing the risk of rising prices on the GSP rather than the customer, providing

[596] The collateral would be released to APS if a GSP defaults or exits the market, so that the RBT Pilot customer returning to APS standard service would not impact or shift costs to other customers. (NRG Br. at 10.) The collateral is intended to replace the AG-X requirement for customers returning to standard service unexpectedly being charged a market-based rate. (NRG Br. at 10-11; *see* Tr. at 3198-3199.) NRG considers the collateral provision to be a key part of the RBT Pilot because it ensures that costs will not be shifted to non-RBT-Pilot customers. (NRG Br. at 11.)

new choices, and giving customers more control over their bills. (NRG Br. at 3-4.[597])

NRG asserts that the PSA is currently at an all-time high level causing a $12.10 bill impact to the average residential customer and points to Mr. Kavulla's testimony that the PSA has risen to comprise nearly 13% of a customer's bill and to include 28% of the total generation-related charges paid by residential customers. (NRG Br. at 4; *see* Ex. NRG-5 at 6-7.) According to NRG, it is the supplier, not the customer, who should shoulder the burden of price spikes and rising fuel costs, and the RBT Pilot would bring this about because customers would only have their prices change after their contracts expire, at which point they could again select from multiple GSPs. (NRG Br. at 5; *see* Ex. NRG-5 at 3, 8-9.) NRG argues that fixed-rate and flat-bill programs are popular with customers in other states, such as in Texas where more than 90% of the plans offered are fixed-rate plans and customers saved an average of $287 each during Winter Storm Uri in 2021, and Oklahoma where customers on a flat-bill plan saved $30 million during Winter Storm Uri in 2021 (versus customers receiving standard service from the Oklahoma utility, who will be paying for $760 million in securitized power and fuel costs caused by Winter Storm Uri over a period of 28 years). (NRG Br. at 5-6; *see* Ex. NRG-5 at 10-12.) NRG states that most AG-X customers contract with GSPs for fixed-rate electric generation service and are thereby protected from price volatility and that residential customers should be provided the same opportunity. (NRG Br. at 6-7; *see* Ex. NRG-5 at 17-18.)

Additionally, NRG asserts, the RBT Pilot would not represent deregulation because APS would remain responsible for the service provided to RBT Pilot customers, and RBT Pilot customers would remain protected by the moratorium on summer shut-offs. (NRG Br. at 12; *see* Ex. NRG-5 at 18; Tr. at 3260.) NRG requests that the Commission require APS to file, as a compliance item in this docket, within 45 days after the effective date of this decision, an RBT Pilot POA that includes the features listed above; that interested parties be provided 30 days to file comments on and identify any deficiencies in the RBT Pilot POA; and that Staff be required to review the RBT Pilot POA and comments and to prepare a Staff Report and Proposed Order for Commission review at an open meeting

[597] NRG cites Commissioner comments from open meetings on January 10, May 2, and May 11, 2023, none of which are part of the record of this matter, although Mr. Kavulla mentioned comments from the May 2, 2023, open meeting in his direct testimony. (*See* Ex. NRG-5 at 9.)

to be held within 45 days after the end of the 30-day comment period. (NRG Br. at 13.)

APS Response

APS asserts that it is not possible for the RBT Pilot proposal to be implemented as proposed because NRG did not provide POA language or sufficient program details. (APS Br. at 91.) APS criticizes NRG's witness for "repeatedly deflect[ing] key questions" about how the RBT Pilot would function in practice,[598] for stating that the issues could be addressed in a future "tariff compliance" proceeding, and for suggesting that further changes could be made to the RBT Pilot POA once it was implemented.[599] (APS Br. at 91; *see* Tr. at 3204-3205, 3215, 3218-3221, 3242, 3254-3256.) The RBT Pilot proposal should be rejected, APS argues, because of the lack of key details about how it would function and impact residential customers and because it would not serve residential customers' interests. (APS Br. at 91-92.) APS argues that customers may not understand that the RBT Pilot proposal could result in significantly higher energy prices than those offered by APS and points out that the RBT Pilot would allow GSPs to charge residential customers a rate up to 35% higher than APS's rate. (APS Br. at 92; *see* Ex. NRG-5 at 21.) APS points out analyses comparing Maine and Massachusetts utilities' prices with retail energy suppliers' prices that showed customers enrolled with retail energy suppliers had higher bills, with Maine customers being charged 70% more in 2021 and Massachusetts customers paying $426 million more from July 2015 through June 2020. (APS Br. at 92; *see* Ex. APS-66; Ex. APS-69.) APS also points to a 2023 Connecticut report offered by NRG that shows customers with an electric retail supplier had overpaid in excess of $198 million since January 2015.[600] (APS Br. at 92; *see* Ex. NRG-10.) APS also points to Mr. Baatz's testimony referring to the flat-bill proposal as an "all you can eat option" that does not send appropriate price signals and that, in other jurisdictions, has led to customers using significantly more electricity than customers on rates

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[598] Mr. Kavulla was asked whether there would be a rate comparison tool for the RBT Pilot, about the estimated costs for APS to be able to and to do the billing for the GSPs' plans, whether there would be an administrative fee paid to APS, the form in which the collateral would be posted, whether the GSPs would be subject to Commission jurisdiction, and what customer usage would be assumed for purposes of calculating collateral. (*See* Tr. at 3215, 3218-3221, 3242, 3254-3256.) Mr. Kavulla did not try to dodge any questions, but it appeared that some issues related to the RBT Pilot had not yet been considered or worked out. (*See id.*)

[599] Mr. Kavulla stated that the RBT Pilot could be reevaluated in the next rate case after it is seen how it performs. (*See* Tr. at 3204.)

[600] The 2023 Connecticut report also shows that customers with retail suppliers saved more than $106 million in the period from July 2022 through June 2023. (*See* Ex. NRG-10.)

that provide price signals and asserting that it would be poor public policy to approve a rate option that will increase consumption and lead to higher costs that will be paid by all customers. (APS Br. at 93; *see* Tr. at 3438-3439.)

Additionally, APS argues, the RBT Pilot would require increased Commission oversight and regulation to protect customers,[601] and yet there are substantial questions about whether the Commission could directly regulate the GSPs, given that they may not be "public service corporations" under the Arizona Constitution. (APS Br. at 93-94.) APS argues that the Commission should reject the RBT Pilot proposal because the Commission may not be able to ensure customer protections for participating retail customers, based on a lack of jurisdiction. (APS Br. at 95.)

Further, APS argues, the RBT Pilot proposal would create reliability risks due to the possibility of GSP service failures that would result in customers being "involuntarily" returned to APS service. (APS Br. at 95; *see* Ex. NRG-5 at 20.) APS argues that the posting of collateral by a GSP does not result in the existence of a physical resource that can provide RA-backed capacity to ensure reliable service when the western region is significantly capacity strained and has few RA-backed resources available in short-term markets. (APS Br. at 95; *see* Ex. APS-14 at 24.) Also, APS asserts, NRG's proposed manner of calculating the collateral to be posted would likely result in collateral insufficient to cover capacity risk or cost because market energy and capacity are separate products, both essential to providing reliable service. (APS Br. at 65-96.) According to APS, the RBT Pilot proposal would create serious risks of resource deficiencies that would impact reliability, and it should be rejected. (APS Br. at 96; *see* Ex. APS-14 at 24.)

In its Responsive Brief, APS states that the RBT Pilot should be rejected because the Commission cannot exert authority over the GSPs that would be dealing directly with residential customers, and it would create significant risks for residential customers. (APS RBr. at 65.) APS argues that NRG did not adequately address this in its Brief and that if the Commission cannot directly

[601] For example, APS cites regulation of marketing, billing disputes, "slamming," and "cramming" and asserts that Mr. Kavulla acknowledged the RBT Pilot program likely would increase the number of customer complaints at the Commission. (APS Br. at 93-94; *see* Tr. at 3245.) To be clear, Mr. Kavulla stated that more complaints would occur if there were more concerns about billing. (Tr. at 3245.) Mr. Kavulla also stated that the "Commission should be able to revoke [or] amend the attached conditions to licensure associated with GSPs, and that part of that consideration should be based on the number of sustained or meritorious complaints that are made." (*Id.*) Mr. Kavulla is not an attorney. (*Id.* at 3257.)

regulate GSPs, the GSPs would be free to operate in a way that is against the public interest. (APS RBr. at 65.) APS again raises the issues of pricing under the RBT Pilot, the value of the RBT Pilot, and administrative costs and, additionally, raises the issue of customers moving on and off of the RBT Pilot. (APS RBr. at 65.) APS argues that NRG's claims about customers benefitting from locked-in rates and fixed-price plans are contrary to the evidence because the plans cited by NRG were utility flat-bill programs and not buy-through programs like the RBT Pilot. (APS RBr. at 66; *see* Tr. at 3226-3227, 3266-3267; Ex. APS-30 at 25.) APS further criticizes the 2022 report provided by NRG because NRG helped to fund it, and NRG's CEO sits on the board of the entity that prepared it, and argues that the Commission should give it little weight because it is not independent. (APS RBr. at 66-67; *see* Ex. NRG-11; Tr. at 3266-3267, 3284.) In contrast, APS argues, the Maine and Massachusetts studies show that customers who enroll with retail energy suppliers pay higher bills, something that NRG's witness acknowledged (stating that customers do not always save money on these plans and that the plans are like an insurance policy against volatility and fluctuations in the wholesale markets). (APS RBr. at 67; *see* Tr. at 3268; Ex. NRG-11.) APS cites to RUCO's questioning of the benefits of the RBT Pilot, in light of history showing that customers have overpaid, and argues that NRG has not presented any persuasive evidence that the RBT Pilot is in the best interest of APS's residential customers. (APS RBr. at 67; *see* Tr. at 3290-3292.) APS also emphasizes that the Commission likely lacks authority to regulate the GSPs under the RBT Pilot and would be unable to ensure customers know what they are buying. (APS RBr. at 68.) APS takes issue with NRG's statement that APS is "financially indifferent" to costs related to fuel and purchased power due to the PSA and points to the evidence and argument APS has provided concerning APS's financial incentives associated with the PSA and the management of fuel, generation, and purchased power expenses. (APS RBr. at 68.) Additionally, APS argues that the RBT Pilot would not support rate stability for customers who leave the RBT Pilot because they would be subject to paying the market index rate for one year, as AG-X customers are, and would not be protected by APS's hedging program, potentially leaving them "blindsided" by price volatility. (APS RBr. at 68-70; *see* Ex. APS-32 at 10.) APS questions whether customers would know the risks. (APS RBr. at 69-70.) APS also questions whether the posted collateral would be available for a situation where a customer voluntarily leaves the RBT Pilot, as opposed to having its GSP default or exit the market. (APS RBr. at 69, n.375; *see* Ex. APS-32 at 10.) Finally, APS argues, NRG has not considered or made provisions for the costs of the billing services to be provided by APS, which would shift costs to non-participating customers unless there is an administrative fee, although NRG's witness acknowledged that adjustments would need to be made to APS's billing system. (APS RBr. at 70; *see* Tr. at 3218-3220; Ex. APS-32 at 10-11.) APS reiterates that the RBT Pilot lacks detail and structure, is not in the public interest, and should be rejected. (APS RBr. at 71.)

NRG Response

In its Responsive Brief, NRG states that APS's argument that the RBT Pilot should be rejected because of an absence of key details for the program should be disregarded because NRG set forth the key elements of the RBT Pilot in the evidence and in its brief, and the RBT Pilot is proposed to be an extension of AG-X, which has a POA that contains most of the necessary details not set out in NRG's evidence. (NRG RBr. at 3-4.) NRG criticizes APS for not responding substantively to the elements of the RBT Pilot, except as to the collateral requirement, and not setting forth revisions to the AG-X POA to address its concerns about the detail needed for the RBT Pilot. (NRG RBr. at 4.) NRG asserts that it is not unusual for the Commission to order submission of tariffs to be reviewed for compliance after key details are set out in a hearing. (NRG RBr. at 4-5; *see* Ex. RUCO-7; Decision No. 76295; Decision No. 76899 (September 20, 2018).[602]) NRG also states that the RBT Pilot's details are clearly set forth and that the RBT Pilot addresses concerns about excessive rate volatility in APS's service territory, citing RUCO's arguments about the PSA. (NRG Br. at 5; *see* RUCO Br. at 13, 16-17.) NRG characterizes as "highly ironic" APS's contention that the RBT Pilot could result in customers being surprised with high prices, asserting that this is what has been occurring with the PSA because the current system does not protect customers. (NRG Br. at 6; *see* Decision No. 78877 at 14.) NRG argues that "certainty and predictability are at the core" of the RBT Pilot proposal because participating customers will receive 12 to 36 months of "total certainty." (NRG RBr. at 6.) NRG adds that the RBT Pilot program would be subject to the same rate regulation employed with AG-X in the form of the

[602] Official notice is taken of this decision, issued in Phase 2 of a 2015 TEP rate case, in which the Commission, *inter alia*, ordered TEP to file as a compliance item "a tariff designed to encourage residential customers to install behind the meter technology that would assist then to reduce their demand similar to the R-Tech-like tariff, within 120 days of the effective date" of the decision. (*See* Decision No. 76899 at 114.)

35% price band, meaning that the Commission maintains its rate regulation power. (NRG RBr. at 6-7.) NRG accuses APS of cherry picking data and ignoring the most recent data available in an attempt to mislead the Commission into believing that customers who choose retail rate plans like the RBT Pilot "always lose." (NRG RBr. at 7.) NRG criticizes APS for focusing on data from five relatively calm and normal years when the most recent information shows that starting with the war in Ukraine, there has been significant volatility in the markets that has resulted in customers on RBT Pilot-like rates saving significantly, such as in Connecticut where customers saved $12.4 million in 2022 and more than $100 million in 2023. (NRG RBr. at 7; *see* Tr. at 3263-3265; Ex. NRG-10 at 2.) NRG also points out that Massachusetts customers of Direct Energy saved $634 on average over the course of last winter and that a report found east coast customers could have saved $2.17 billion if they had been on low-cost competitive plans. (NRG RBr. at 8; *see* Tr. at 3267; Ex. NRG-11 at 12.)

Additionally, NRG states that it was "surprised" to read that APS continues to assert that having customers take service under a flat-bill option from a GSP would shift costs to non-participating customers because Ms. Hobbick conceded at hearing that energy use by customers participating in the RBT Pilot would not shift costs to non-participating customers.[603] (NRG RBr. at 8; *see* Tr. at 2525.) NRG states that APS's argument to the contrary is without merit and that the issue of cost shifts potentially arising from RA requirements will be resolved by the Commission's choice made on the issue in this docket, which will be fully applicable to the RBT Pilot as well as AG-X. (NRG RBr. at 9.)

NRG also challenges APS's speculation that a lack of regulatory oversight for the RBT Pilot would result in inadequate protections for customers, asserting that GSPs will be subject to "robust consumer protection laws" including the Arizona Consumer Fraud Act ("Fraud Act"). (NRG RBr. at 9; *see* A.R.S. § 44-1522(A).) NRG asserts that the Fraud Act has been used by the Arizona Attorney General to protect consumers from APS's misleading claims, noting an agreement for APS to repay

[603] Ms. Hobbick agreed that their consumption or lack of consumption in and of itself (the "energy piece") would not shift costs to other APS customers but also stated that APS would still need to have capacity to serve the customers, and that her reference to a cost shift was in reference to APS needing to supply generation capacity to serve the customers because of APS's status as the provider of last resort. (*See* Tr. at 1524-1526.) Ms. Hobbick also agreed with Mr. Baatz's testimony about the flat-bill option not having price signals to encourage lower usage of energy during constrained times. (*See id.* at 2524-2525.)

225,000 customers $24 million related to the rate plan selection tool, and states that the Fraud Act will also protect the customers who take service under the RBT Pilot. (NRG RBr. at 10; *see* Ex. NRG-13.) NRG argues that the RBT Pilot would provide a safe opportunity for the Commission to see the public's satisfaction with GSPs "instead of relying on the self-serving accusations of a monopoly defending its turf." (NRG RBr. at 10.)

Finally, NRG argues, APS is misdirecting the Commission by expressing concerns about reliability because NRG's proposal is for GSPs under the RBT Pilot to be subject to the same RA requirements as GSPs in AG-X, with the additional protection of the posted collateral. (NRG RBr. at 10.) NRG states that APS's statement that the collateral posting would create serious risks of resource deficiencies is an attempt to "muddy the water" because the collateral posting is an added benefit on top of the RBT Pilot GSPs' compliance with the RA requirements adopted for AG-X in this matter and will avoid any cost shift to other customers should a GSP default. (NRG RBr. at 10-11.) NRG states that it is the GSP's compliance with the RA requirements that will assure reliable service, with the collateral having a different purpose—to protect customers from cost shifts. (NRG RBr. at 11.) NRG argues that in light of APS's substantial existing and anticipated yearly load growth, APS has been unable to serve large customers requesting service today,[604] and the RBT Pilot will help APS and the Commission understand how GSPs can bring additional resources to APS's system and thus improve overall reliability. (NRG RBr. at 11; *see* Tr. at 206-207.) NRG adds: "APS is resource constrained today and represents a single point of failure for resource adequacy for all customers unless diverse sources can be brought to help serve Arizona's growing economy." (NRG RBr. at 11-12.) According to NRG, "APS does not need to be the gatekeeper for all resources coming into the market," and the

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[604] Mr. Geisler asserted that it is not a question of APS not being able to provide service, just a question of when APS can begin providing service. (*See* Tr. at 212.) Mr. Geisler testified that APS has had a "dramatic influx" of applications for service from XHLF customers, mostly data centers, and has had to work with them to create a queueing process to ensure APS has time to build the infrastructure needed to serve them reliably because APS cannot commit to serving new customers until it is certain that it can build the infrastructure needed, as doing otherwise would put all customers at risk. (*See* Tr. at 206-207.) Mr. Geisler acknowledged that APS has told some customers that they cannot get service at the time requested in the near future but asserted that APS is still committed to providing them service and has to be transparent about how long it will take to put the needed infrastructure in place. (*See* Tr. at 207.) Mr. Geisler explained that the XHLF customers are on average requesting service between 200 MW and 400 MW but some are requesting service up to 1,000 MW or more (the equivalent of 1,000 big box stores). (*See* Tr. at 207.) Mr. Geisler stated that APS does not currently have any excess capacity on the grid to serve these XHLF customers, who have load factors of 80% or greater. (*See* Tr. at 207-209.) In total, Mr. Geisler stated, APS had XHLF customers representing more than 4,000 MW showing interest in building in APS's service territory. (*See* Tr. at 210.)

Commission should "leverage GSPs to understand how they can bring additional resources to help stave off the negative economic consequences of APS'[s] existing constraints." (NRG RBr. at 12.)

Resolution

The RBT Pilot would provide residential customers with a buy-through option for generation that they currently do not have. Unfortunately, that buy-through option would come with risks that residential customers may not fully understand before committing themselves to long-term contracts and would result in additional costs to APS that may be shifted to other customers. NRG has not included in its proposal a provision for a residential customer to leave the RBT Pilot of the customer's own volition outside of a renewal period or to define what the consequences of voluntarily leaving outside of a renewal period would be. APS has indicated that customers who unexpectedly leave the RBT Pilot would be subject to market pricing for a full year, the same as an AG-X customer. The Commission is confident that this would come as a rude awakening for a residential customer, as it would represent the opposite of the certainty touted as a prime benefit of the RBT Proposal, and is concerned that it could be extremely financially damaging for a residential customer, depending on how the market behaves. The Commission is also concerned that it would not be able to exercise sufficient regulatory authority over GSPs participating in the RBT Pilot to ensure that RBT Pilot customers would be fully aware of the potential consequences of the deals they would make and to make the RBT Pilot safe for customers. The Fraud Act would offer some protection, but making a complaint to the Attorney General's office does not provide the same opportunity for due process as does making a formal complaint to the Commission, something that would be unavailable for a customer having difficulties with its GSP if the GSP is not considered to be a public service corporation. (*See* A.R.S. § 40-246.) There is also the question of the additional costs that would be incurred by APS for consolidated billing and how those would be covered so that there would not be a cost shift to non-participating customers, something that NRG has not presented evidence to resolve. Additionally, the Commission believes that a flat-bill option would be counterproductive for APS and its non-participating customers at a time when there are constraints on the grid and there is little if any excess capacity to be purchased on the western market. The evidence shows that flat-bill plan customers tend to increase their usage, which makes sense considering that they receive absolutely no price signals indicating that they should not do so for the duration of their long-term contract.[605] For all of these reasons, the Commission concludes that it would be neither just and reasonable nor in the public interest to approve the RBT Pilot.

2. Bring Your Own Device ("BYOD") Program

As of July 2023, more than 2,700 residential energy storage systems ("batteries") had been installed behind-the-meter ("BTM") in APS's service territory. (*See* Ex. APS-27 at 11.) APS currently has a Residential Battery Pilot ("Battery Pilot") that uses an aggregator, EnergyHub; involves several battery manufacturers; and can call on participating customers' BTM batteries as part of APS's virtual power plant ("VPP") when the grid needs the power. (*See* Ex. APS-27 at 13-14.) Customers can enroll in the Battery Pilot as either "capacity share" customers, who agree to have their batteries called upon for dispatch, or as "data share" customers, who only allow data to be obtained. (*See* Ex. APS-27 at 14.) The first tranche of the Battery Pilot was fully subscribed in January 2023, but APS has proposed two additional tranches (one for existing batteries and one for newly installed batteries and only for capacity share) in its 2023 DSM Plan. (*See* Ex. APS-27 at 14.) As originally approved in Decision No. 77762 (October 2, 2020),[606] the Battery Pilot offered a one-time incentive of $500/kW, with a cap of $2,500/home, to customers who installed a new battery system, enrolled in a TOU or TOU with demand plan, agreed to connect their batteries to the APS resource operating platform and to share

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[605] We are aware that NRG has proposed the 3,000 kWh cap on the flat-bill option, after which additional charges would be incurred, and question how a flat-bill plan customer would even know that they had reached 3,000 kWh in a month.

[606] Official notice is taken of this decision, issued in the docket for APS's 2020 REST Plan, Docket No. E-01345A-19-0148. In Decision No. 77762, the Commission stated that while the Battery Pilot would provide direct incentives to customers to install batteries, "a tariff that compensates customers for the specific benefit their systems bring to the grid can also be beneficial and in the public interest . . . [and would be] a forward-looking policy that can benefit all APS ratepayers." (Decision No. 77762 at 7.) The Commission ordered APS to propose the approved Battery Pilot in its 2021 DSM Plan. (*Id.* at 8.) The Commission also ordered APS, within 60 days, to file for review and approval a tariff "permitting the aggregation of distributed energy storage systems that provides compensation for the value each system provides, including, but not limited to, compensation for capacity, demand reduction, load shifting, locational value, voltage support, ancillary and grid services, and any other operating characteristic the Commission may deem appropriate." (*Id.*) APS filed a Demand-Side Resource Aggregation Tariff ("DDSR Aggregation Tariff") for approval in Docket No. E-01345A-22-0143. (Decision No. 78878 (March 16, 2023).) Decision No. 78878 was admitted as Exhibit APS-83 herein. In Decision No. 78878, the Commission rejected APS's DDSR Aggregation Tariff, which the Commission asserted "was not what we had expected or hoped for." (Ex. APS-83 at 6.) The Commission ordered APS to issue a new RFP for its DDSR Aggregation Tariff and to consult with Berkeley Lab in developing the RFP for the DDSR Aggregation Tariff and in evaluating the responses to the RFP. (*Id.* at 6-7.) The Commission ordered that APS could submit a revised DDSR Aggregation Tariff by October 1, 2023. (*Id.* at 8.) In a filing made on September 29, 2023, APS declined to do so, stating that it instead desired to have its Battery Pilot expanded through its Amended 2023 DSM Plan. (Official notice is taken of this filing, available at https://docket.images.azcc.gov/E000031037.pdf?i=1704999161462.)

battery information, and committed to discharging their batteries during on-peak periods. (Decision No. 78164 (July 28, 2021)[607] at 7.) The Battery Pilot was subsequently modified in Decision No. 78164 to provide an additional $1,250 up-front incentive to customers who enter into a three-year commitment to share up to 80% of their battery capacity for a maximum of 100 events per year. (Decision No. 78164 at 7-8, 26.) According to Mr. Geisler, the Battery Pilot had 650 customers enrolled at the time of hearing, APS's DSM application was requesting to expand that by another 300 customers, and the Battery Pilot was not deferring the need for infrastructure because customers are incentivized to use their batteries during the on-peak period and begin using full grid power immediately afterward. (Tr. at 484-485.) According to Mr. Geisler, this creates a cost shift to non-participating customers, unlike demand response programs like Cool Rewards or Peak Solutions,[608] which defer the need for infrastructure and save costs for all customers. (Tr. at 485.) According to Ms. Carnes, although the Battery Pilot was launched in October 2021, no batteries received permission to operate until January 2022, and APS saw fewer customers agree to share their capacity than APS had anticipated. (*See* Ex. AriSEIA-3 at ex. KL-37.) APS called six events in September and October 2022, and the participant rate for each was only 13 to 18 participants. (*See* Ex. AriSEIA-3 at ex. KL-36.) APS also called six events in July 2023 but did not yet have data to report at the time of hearing. (*See id.*; Tr. at 2166.)

<u>AriSEIA/SEIA Proposal</u>

AriSEIA/SEIA argue that the benefits of BTM solar plus storage are clear and that APS urgently needs these resources in its service territory because of its current inability to meet future customer demand. (AriSEIA Br. at 7.) AriSEIA/SEIA argue that batteries can absorb low-cost energy and excess solar generation and then provide it for use in evening peak hours when prices are higher, saving all ratepayers money. (AriSEIA Br. at 7.) AriSEIA/SEIA point to Mr. Joiner's testimony that solar plus storage provides dispatchability and allows for the battery to be discharged during net peak hours when

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[607] Official notice is taken of this decision, issued in the docket for APS's 2021 DSM Implementation Plan, Docket No. E-01345A-20-0151.

[608] Cool Rewards is a residential smart-thermostat-driven demand response program, and Peak Solutions is a commercial demand response program. (Tr. at 480.) APS considers such demand response programs to be among the most efficient ways to save money by reducing the infrastructure needed to serve peak demand. (Tr. at 480.) Mr. Geisler distinguished between APS's ability to control the thermostats enrolled and dispatch the demand reductions over the entire evening peak hours, essentially resulting in a power plant that APS did not have to build or buy, versus having a homeowner control and dispatch their own battery storage to save money on their own electric bill. (Tr. at 485-486.)

there is a threat to reliability, prices are highest, and the discharge has the most impact. (AriSEIA Br. at 7; *see* Tr. at 1317-1318.) AriSEIA/SEIA assert that "APS dodged and obfuscated" when asked to confirm that aggregated batteries can be a reliable capacity resource but point to APS's 2023 IRP, which asserts that the Battery Pilot includes 263 batteries that share capacity and provide close to 1 MW of "dispatchable capacity" for up to three hours. (AriSEIA Br. at 7; *see* Tr. at 230, 2080-2081; 2023 IRP at 34.) AriSEIA/SEIA argue that APS's rate plans provide customers incentives to use their batteries to reduce their own bills rather than to provide maximum benefit to the grid because the resource comparison proxy ("RCP") export rate is lower than APS's off-peak energy rates. (AriSEIA Br. at 8; *see* Ex. AriSEIA-1 at 22, 25.)

AriSEIA/SEIA propose approval of a BYOD Program, which they state would have a lower cost than utility-owned batteries and thus would save ratepayers money by leveraging the private investments made by homeowners to benefit all customers. (AriSEIA Br. at 8-9.) AriSEIA/SEIA point to Mr. Lucas's testimony that APS calculated the 20-year revenue requirement for a four-hour utility-scale battery installed in 2023 to be $208/kW, while the BYOD Program would have a cost of $150/kW over five years. (AriSEIA Br. at 8-9; *see* Tr. at 3871-3872; Ex. AriSEIA-1 at 36.) AriSEIA/SEIA argue that now is the time to approve the BYOD Program because APS plans to add 2,000 MW of utility-scale batteries in the next three years, and the BYOD Program can help APS meet its capacity needs using already existing residential batteries and can even incentivize the installation of new batteries. (AriSEIA Br. at 9; *see* 2023 IRP at 10.)

AriSEIA/SEIA emphasize that the BYOD Program only compensates participating customers when they actually deploy their batteries in a manner to benefit all ratepayers at APS's request at times of high prices or grid stress. (AriSEIA Br. at 9.) Under the BYOD Program, AriSEIA/SEIA state, owners are paid to maximize the discharge of their batteries during an event, independent of their on-site usage, thereby reducing the overall costs of operating the grid and benefiting all customers. (AriSEIA Br. at 9-10.) The BYOD Program would provide a $150/kW credit for the average annual storage discharge performance during called events, so if APS called 60 events in a year, and a customer's battery averaged 3 kW of production per event, the customer would receive $450 at the end of the year. (AriSEIA Br. at 10.) If a customer's battery were not discharged during events, the customer would receive no payment, as the BYOD Program is not an incentive program and only pays for actual use. (AriSEIA Br. at 10.) AriSEIA/SEIA propose for the credit rate to be recalculated each year but to be locked in for each customer for a five-year period to provide certainty. (AriSEIA Br. at 10.) AriSEIA/SEIA propose for the BYOD Program to allow APS to call up to 60 events per year, with a duration of up to three hours each, only during the summer months, and to require APS to work with a third-party aggregator to develop the appropriate control signal and measurement protocols. (AriSEIA Br. at 10.)

AriSEIA/SEIA touts the following advantages of BTM batteries under the BYOD Program that are not offered by utility-scale batteries: (1) the credits paid to customers would be a fraction of the avoided revenues associated with utility-owned utility-scale storage; (2) the credits paid under the BYOD Program would last for only 5 years, as compared to payments for utility-owned batteries that could go on for 15 years or more; and (3) BTM batteries avoid the line losses incurred with utility-scale batteries because the BTM batteries are deployed at the point of consumption. (AriSEIA Br. at 10-11; *see* Ex. AriSEIA-1 at 36; Tr. at 3875-3876.) AriSEIA/SEIA argue that "[a]lmost every aspect of the BYOD Program is supported in the record" and criticize APS for opposing the BYOD Program "under the guise of needing more time," although APS does not seem to have researched other BYOD programs around the country, and not producing evidence to contradict the benefits of the BYOD Program. (AriSEIA Br. at 11-12; *see* Tr. at 2078-2081.) AriSEIA/SEIA also call out as "difficult to believe" APS's testimony that it is uncertain whether distributed batteries can and do respond to control signals because APS currently uses EnergyHub as an aggregator, and EnergyHub is the aggregator that controls the batteries participating in ConnectedSolutions, the largest behind-the-meter battery aggregation program in the country and the inspiration for the BYOD Program. (AriSEIA Br. at 12; *see* Tr. at 2095, 3864, 3866-3867.) AriSEIA/SEIA argue that Mr. Geisler's testimony that APS could not count residential battery storage as capacity because it cannot be dispatched by APS was false and criticize Mr. Geisler's attempts to assert that there is a fundamental difference between batteries depending on their scale because APS's 2023 IRP now includes aggregated residential batteries as dispatchable capacity. (AriSEIA Br. at 12-13; *see* Tr. at 488-492; 2023 IRP at 34.) AriSEIA/SEIA also call out as suspect Ms. Carnes's testimony stating that APS only had viable Battery Pilot data from

12 participating batteries,[609] although APS's 2023 IRP reveals that there are 263 batteries sharing capacity in the Battery Pilot.[610] (AriSEIA Br. at 13; *see* Tr. at 2168-2169, 2215; 2023 IRP at 34.) AriSEIA/SEIA argue that APS "most likely" opposes the BYOD Program for financial reasons because APS would not earn a return on the assets used and cite as support both Mr. Lucas's testimony that BTM batteries are a missed opportunity for APS to put assets into rate base and Dr. Morin's testimony that one of the reasons many utilities oppose customer-sited technologies is because they supplant investments the utility could otherwise make and earn a return on for shareholders. (AriSEIA Br. at 13; *see* Tr. at 2722-2723, 3873-3874.) AriSEIA/SEIA also criticize APS's argument that it needs more data on batteries and that the data set it has is not statistically relevant because of the small customer group because at hearing, APS was not willing to commit to doing anything with the Battery Pilot after it concludes in 2024. (AriSEIA Br. at 13-14; *see* Tr. at, 2169, 2237, 2262-2263.) AriSEIA/SEIA note Mr. Geisler's praise for DR programs as efficient ways to reduce the infrastructure needed to serve peak usage and save customers money and Mr. Tetlow's testimony that battery storage is necessary to take advantage of non-dispatchable resources like renewables. (AriSEIA Br. at 14; *see* Tr. at 480, 485, 960.) AriSEIA/SEIA argue that because APS's Battery Pilot is an upfront incentive and closed to new customers, it cannot help with increasing capacity needs and is not a reason to reject the BYOD Program. (AriSEIA Br. at 14; *see* Tr. 2262.) Further, AriSEIA/SEIA argue, Mr. Geisler stated that the Battery Pilot is too small to defer infrastructure in any event.[611] (AriSEIA Br. at 14; *see* Tr. at 484.) AriSEIA/SEIA argue that the Commission should approve the BYOD Program because it obtains capacity resources installed by individual ratepayers and costs a fraction of what APS pays for utility scale storage. (AriSEIA Br. at 14.)

<u>Ms. Nelson</u>

Ms. Nelson asserts that the Commission should allow a BYOD Program. (KN Br. at 2.)

. . .

[609] Ms. Carnes testified that as of September 2022, there were only 12 participating batteries sharing capacity, and they all reacted to the signals that were sent in the couple of events called. (Tr. at 2168-2169.)

[610] This is consistent with Ms. Carnes's testimony that the Battery Pilot included 600 customers and approximately 1,000 batteries, with approximately 25% of the batteries sharing capacity (not just data). (*See* Tr. at 2256.)

[611] Although Mr. Geisler mentioned the number of customers participating in the Battery Pilot, he testified that the Battery Pilot is not deferring infrastructure because customers are incentivized to use their batteries from 4 p.m. to 7 p.m. (*See* Tr. at 484.)

Sierra Club

Sierra Club argues that APS's opposition to the BYOD Program ignores that APS would control whether a BYOD Program was successful or unsuccessful and falsely assumes that APS would be unable to influence the BYOD Program and would be at the mercy of battery owners who may not respond to rate changes. (SC RBr. at 24.) Sierra Club points to the evidence that battery storage programs in the U.S. have been successfully implemented at a larger (non-pilot) scale. (SC RBr. at 24; *see* Ex. AriSEIA-1 at 32-34.) Sierra Club also points to Ms. Carnes's acknowledgments that cross-subsidy calculations do not consider grid benefits from reduced peak demand and that individual customers do not shift costs to others simply by reducing their own energy consumption. (SC RBr. at 24; *see* Tr. at 2069.) Sierra Club argues that because APS is requesting an 11.2% rate increase and projecting great load growth, APS should be encouraging and expanding programs that can reduce and flatten load, and the Commission should approve the BYOD Program. (SC RBr. at 24-25.)

Tesla

Tesla supports and encourages the Commission to require APS to implement the BYOD Program[612] in this matter, with an effective date 90 days after this decision. (Tesla Br. at 1.) Tesla argues that a BYOD Program will save money for all ratepayers, "unlock the untapped potential of grid services and capacity support from existing Tesla Powerwall customers and other [battery] customers," provide such customers compensation when APS uses their batteries, and leverage private investment and use batteries at a cost significantly lower than the cost of utility-owned storage. (Tesla Br. at 1-2; *see* Tr. at 3871-3872.) Tesla asserts that the BYOD Program is consistent with the Commission's recent decision to reopen the Value of Solar proceeding,[613] which Tesla believes to indicate that the Commission is interested in ensuring that compensation provided to solar customers for exports reflects the value that all ratepayers receive. (Tesla Br. at 2.) Tesla asserts that the BYOD Program would result in customers' being compensated for dispatching energy at times when it provides maximum

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[612] Tesla refers to a "BYOD Tariff," but no such tariff has been provided.

[613] The Commission's reopening of Docket No. E-00000J-14-0023 is not part of the evidentiary record in this matter. Official notice is taken that the Commission, at its October 11, 2023, Open Meeting, directed the Hearing Division to open a new docket to explore changes to the 10% annual reduction in the export rate and the 10-year export rate effective period under the RCP for future tranches of rooftop solar customers and that the Hearing Division opened Docket No. AHD-00000J-23-0273 for this purpose.

value to the grid and other ratepayers. (Tesla Br. at 2.) Tesla asserts that 430 of its batteries are enrolled in APS's Battery Pilot[614] and that the Battery Pilot has been "useful as a proof of concept." (Tesla Br. at 2.) Tesla opines that the Commission has sufficient information to direct APS to implement a VPP program like the BYOD Program. (Tesla Br. at 3.) Tesla acknowledges that as a manufacturer of residential batteries, it has an interest in the approval of a BYOD Program that provides its customers the ability to leverage their batteries as a resource for the grid. (Tesla Br. at 3.) Tesla asserts that its software services and direct integration with its batteries ensure the same level of granularity and accuracy of response from its batteries as from a utility-owned battery system or conventional dispatchable resource. (Tesla Br. at 3.)

Tesla provides the same arguments as AriSEIA/SEIA about the price signals sent to customers with batteries under APS's current rate designs. (Tesla Br. at 4-6.) Tesla also provides the same arguments as AriSEIA/SEIA about the ability of individually owned residential batteries under a BYOD Program to avoid line losses and supplant the need for expensive utility investments, thus providing savings to all customers. (Tesla Br. at 7-10.) Tesla expresses its approval of the BYOD Program features described by Mr. Lucas, including those that differ from the ConnectedSolutions program due to APS's different regional conditions. (Tesla Br. at 10-12.) Tesla also provides the same arguments as AriSEIA/SEIA about the need for the BYOD Program because APS is "currently turning away customers and has an urgent need for new capacity" and about the inability of the Battery Pilot to incentivize beneficial use of existing residential batteries. (Tesla Br. at 13-14.) Tesla urges the Commission to require APS to file as a compliance item in this docket, within 60 days after this decision, a BYOD Tariff that implements the BYOD Program proposed by AriSEIA/SEIA, to take effect 30 days after the filing unless a party files a protest arguing that the BYOD Tariff does not comply with the BYOD Program proposal. (Tesla Br. at 14.) Tesla requests that if a protest is filed, the BYOD Tariff be placed on the next Open Meeting agenda for the Commission's consideration and provision of direction to APS on how to correct the BYOD Tariff. (Tesla Br. at 14.)

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[614] This data is not part of the evidentiary record in this matter.

Vote Solar

Vote Solar describes the BYOD Program as "an evolution" of the Battery Pilot. (VS Br. at 8.) Vote Solar notes APS's objection to the timing of events proposed in the BYOD Program to coincide with residential rate on-peak hours and asserts that if a different time provides more value, the time for dispatch of batteries could be changed, and battery discharge could be staggered or spread over a wider range of hours as is currently done with APS's Cool Rewards program. (VS Br. at 9; *see* Tr. at 484-485.) Vote Solar notes the Commission's prior recognition of the value of BTM distributed storage to the grid, expressed in Decision No. 77762, and asserts that the BYOD Program is aligned with the intent of that decision. (VS Br. at 9.) Vote Solar asserts that it supports the BYOD Program and recommends that the Commission direct APS to propose a comparable tariff that would compensate customers for dispatching their batteries to provide energy and grid services on an ongoing basis. (VS Br. at 9; VS RBr. at 2.)

APS

APS argues that "it would be premature and wasteful" for APS to have a BYOD Program while it is still gathering data from its Battery Pilot. (APS Br. at 100-101.) APS asserts that to ensure no subsidization would occur from leveraging customer-owned batteries to provide capacity and grid services, it must first understand the value these batteries bring to the grid. (APS Br. at 101; *see* Ex. APS-27 at 13-14.) APS points to the Commission's prior directives that residential customer incentive programs for distributed demand side resources should not be adopted if they would create subsidization and should pay incentives to program participants at the lowest possible cost for the resource. (APS Br. at 101; *see* Ex. APS-84 at 90-91; Ex. APS-83; Ex. APS-82.[615]) APS asserts that

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[615] In Decision No. 78165, the Commission stated:

> 18. We find that the tariff must be based on values and rate designs that are accurate, based on data, not artificially adjusted to accomplish goals or objectives the Commission has not expressly adopted, and consistent with the actual values eligible devices provide the grid, based on the devices' unique operating characteristics and APS's unique system needs.
>
> 19. We find that a tariff that is "designed to promote technology adoption and not to account for valuation of grid benefits" would be contrary to the requirements of Decision Nos. 77762 and 77855.
>
> 20. We find that it is important to clarify that, while Decision No. 77855 does not preclude APS from proposing additional amounts to compensate participants for promoting the adoption of technologies, such compensation, if any, must be calculated and listed as a separate and disaggregated figure, so Staff can evaluate and make an informed recommendation on the

its Battery Pilot is designed to gather real-world operational data for residential batteries within its service territory and that APS expects to complete its data gathering and analysis of next steps, including potential program expansion, by fall 2024. (APS Br. at 101-102; *see* Ex. APS-27 at 15-17; Ex. APS-28 at 5-6; Tr. at 2067-2068, 2075.) APS asserts that the data from the Battery Pilot is needed for it to determine the types and quantities of value that a BYOD program can provide to the grid and that without the data from the Battery Pilot APS would not be able to determine how to structure a broader program to avoid cost shifts. (APS Br. at 102; *see* Tr. at 1512-1513, 2074-2075.) APS argues that no evidence in this matter compels a different approach than it proposes. (APS Br. at 102.)

Additionally, APS criticizes the BYOD Program as an "off the shelf" program adapted from a program in a different region and states that crucial information about how the program would work in APS's service territory is unavailable. (APS Br. at 102.) "APS does not dispute that the benefits to APS customers from such a program are potentially significant," but states that at least the following additional information about how the program would function in Arizona is needed:[616]

- Capacity value of the battery systems enrolled, as there is no data about opt-out rates or the levels of charge available for dispatch;
- Appropriate pricing for incentives, whether to be set based on comparison to a utility-scale battery system or based on least-cost resource value;
- Compliance of the BYOD Program with the Commission's cost-effectiveness requirement for

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> amount and the Commission can make an informed decision on whether to amend, reject, or adopt it.

Ex. APS-82 at 4.

In Decision No. 79065, in the 2022 TEP rate case, the Commission stated:

> We agree with AriSEIA that [behind-the-meter] battery systems could have some role in aiding the Company in meeting its peak demand needs, but we believe that AriSEIA's BYOD proposal requires stakeholder vetting before it can be considered for adoption. Such scrutiny can be had through behind-the-scenes stakeholder meetings. Thus, we find that it is reasonable to direct TEP to convene stakeholder meetings to discuss the issues related to a possible BYOD-type program within 90 days of the effective date of this Decision. Any vetted program agreed upon by the stakeholders should be presented for possible Commission approval in the Company's next rate case. . . . Any BYOD proposal should include the following consumer protections: (1) the Company should place emphasis on consumer education and disclosures, and any benefit provided to program participants should be at the lowest cost possible for the resources, and (2) the Company should place emphasis on ratepayer protection from cross-subsidization.

Ex. APS-84 at 90-91.

[616] APS Br. at 102-103; *see* Tr. at 1513, 2081-2082, 2086, 2089-2090, 2092-2094, 2281-2282, 3926-3927, 3930-3932, 3942-3943.

demand-side customer programs;

- The optimal time period over which to dispatch battery systems; and
- The value of non-capacity grid benefits that could be derived from residential battery aggregation and how it should be used to determine customer incentive levels.

APS asserts that Mr. Lucas acknowledged these gaps in data. (APS Br. at 103; *see* Tr. at 3926-3927, 3930-3932, 3942-3943.) According to APS, an uncapped program like the BYOD Program should not be adopted in this matter because APS's Battery Pilot has not yet concluded and because the Commission has already rejected the same type of AriSEIA/SEIA proposal in the 2022 TEP rate case. (APS Br. at 103; *see* Ex. APS-84 at 90-91.) APS asserts that the information from its Battery Pilot will be used to determine future opportunities to expand cost-effective aggregation of residential customer battery programs. (APS Br. at 103.)

In its Responsive Brief, APS argues that the uncapped BYOD Program would create a substantial risk of shifting costs to non-participating customers and that none of the parties supporting it have challenged this assertion. (APS RBr. at 74.) APS reiterates that there are too many unknowns with the BYOD Program and states that they are not resolved by the other parties' Briefs. (APS RBr. at 75.) APS asserts that study was needed for the Cool Rewards program and that "additional study is required through ongoing pilot programs before an uncapped customer program can be established that leverages residential customer [batteries]." (APS RBr. at 75; *see* Tr. at 2280-2282.[617])

APS argues that it is erroneous to compare the capacity value of grid-scale batteries with the capacity value of BTM batteries because the value of BTM batteries is determined based on independent customer behavior that cannot be controlled by APS, whereas APS has full control over the dispatch of grid-scale batteries. (APS RBr. at 75; *see* Tr. at 488-490, 1512-1513, 2080-2082.) APS argues that this undermines AriSEIA/SEIA's claim that the BYOD Program would provide less expensive capacity than grid-scale batteries. (APS RBr. at 76.) APS argues that additional study through existing pilot programs is needed to understand capacity value and that without that data, a

[617] Ms. Carnes testified that the Cool Rewards started as a pilot, before which APS could not predict with certainty how customers would behave under the pilot and through which APS learned the capacity values that could be derived and that it could be a reliable resource. (*See* Tr. at 2281-2282.)

comparison of costs/kW between the BYOD Program and grid-scale batteries has no merit. (APS RBr. at 76; *see* Tr. at 2080-2082.) APS further argues that AriSEIA/SEIA's claim that APS does not understand how battery dispatch control signals work lacks merit and shows that AriSEIA/SEIA fundamentally do not understand the risks associated with adopting the BYOD Program in APS's service territory. (APS RBr. at 76-77; *see* Tr. at 2079, 2095-2096, 2165-2166, 2293; Ex. APS-27 at 3-5; Ex. APS-77 at 75.) APS also takes issue with parties' assertions that APS's rate designs serve as a disincentive to residential customers using their batteries to provide grid value and states that the record shows that using the batteries during confined three-hour periods may not be optimal for APS's system. (APS RBr. at 77; *see* Ex. APS-27 at 12-13.) APS argues that if current rate designs incentivize customers with solar plus batteries to rely on their batteries into the evening rather than discharging excess capacity to the grid before 7 p.m., this usage would provide grid value without the need for incentives because APS's grid strain and periods of resource scarcity are moving later into the evening, well after 7 p.m. (APS RBr. at 77-78; *see* Ex. APS-12 at 6-8.) Finally, APS argues that it is not telling customers that they cannot get service, just telling some very large high-load-factor customers that they cannot get service right away, and that the BYOD Program would not significantly address the challenges APS faces from these very large high-load-factor customers, as APS states AriSEIA/SEIA acknowledged in their Brief. (APS RBr. at 78; *see* Tr. at 206-208; *see* AriSEIA Br. at 9.)

<u>AriSEIA/SEIA Response</u>

In their Responsive Brief, AriSEIA/SEIA propose that if the Commission is uncomfortable approving the uncapped BYOD Program, the Commission could instead approve a smaller program size as a pilot, with a cap of 10,000 customers that could be removed in the future if the Commission determines it appropriate. (AriSEIA RBr. at 1, 5.) AriSEIA/SEIA argue that APS's Battery Pilot does not conflict with the BYOD Program and that because it is currently maxed out, it cannot provide APS any additional capacity (although APS has now acknowledged that it provides capacity). (AriSEIA RBr. at 1.) AriSEIA/SEIA dispute APS's characterization of the BYOD Program as an incentive program because unlike the Battery Pilot, the BYOD Program is a pay-for-performance program with no upfront incentives and no payments unless a battery provides capacity to APS. (AriSEIA RBr. at 1.) AriSEIA/SEIA argue that while APS raises the issue of cost shifts and subsidization, APS has produced no evidence to support these concerns. (AriSEIA RBr. at 1-2.) Additionally, AriSEIA/SEIA argue, APS's opposition to the BYOD Program must be viewed in light of APS's disincentive to support programs that avoid utility investment opportunities. (AriSEIA RBr. at 2.) AriSEIA/SEIA question APS's assertions that it lacks data to move ahead with a VPP program, asserting that these programs exist across the country, that APS itself has been conducting its Battery Pilot for more than two years, and that the data from such programs is available almost immediately. (AriSEIA RBr. at 2.) AriSEIA/SEIA also question APS's assertion that the Battery Pilot will be expanded soon, noting that APS has proposed an expansion of 250 new batteries in its 2023 DSM Plan but that it is unclear whether the expansion will be approved or when. (AriSEIA RBr. at 2.) In response to APS's criticism of the BYOD Program being based on another program, AriSEIA/SEIA assert that the other program has been successful and that there is no need to "reinvent the wheel" when a successful program design is available. (AriSEIA RBr. at 2.) AriSEIA/SEIA dispute APS's characterization of the BYOD Program as "off the shelf" because AriSEIA/SEIA have made key modifications to adapt the ConnectedSolutions program design to APS's service territory and further opine that APS would criticize a completely original program as well. (AriSEIA RBr. at 2.) AriSEIA/SEIA assert that the BYOD Program is proposed to use the same aggregator that APS uses for Cool Rewards and the Battery Pilot. (AriSEIA RBr. at 2-3.) AriSEIA/SEIA criticize APS for proposing to wait to implement a more expansive VPP program even though APS has acknowledged that the benefits to ratepayers are potentially significant, the Battery Pilot is at capacity, and the APS system has recently hit peak load records. (AriSEIA RBr. at 3.) AriSEIA/SEIA also criticize APS's argument that the resolution of this issue in the 2022 TEP rate case should govern the resolution of the issue in this matter and assert that there are factual distinctions between the two cases and companies. (AriSEIA RBr. at 3.) AriSEIA/SEIA assert that the following APS characteristics are not shared by TEP: (1) APS has a "dire shortage of capacity" and is "unable to provide service to large customers seeking to locate and invest in Arizona," (2) APS has substantial experience with batteries and has had a Battery Pilot in place for more than two years, and (3) APS has significant experience with aggregation through Cool Rewards. (AriSEIA RBr. at 3; *see* Tr. at 484-485, 2073, 2094, 2327; Ex. APS-84.)

AriSEIA/SEIA also refute APS's list of things that are unknown about the BYOD Program, stating that by assigning a capacity value to the batteries in the Battery Pilot in its 2023 IRP, APS shows that it does not have any problem assigning such a capacity value, despite its claims about a lack of data; that the question of how to price pay-for-performance incentives should not be an issue because AriSEIA/SEIA have proposed a pricing structure that is lower than APS's calculation of the revenue requirement for its own batteries; that whether the BYOD Program would meet Commission cost-effectiveness should not be an issue because the incentives under the BYOD Program are less expensive than the APS-owned batteries that APS plans to install; that the optimal time period for dispatch of the batteries should not be an obstacle because although the BYOD Program proposed discharge during TOU on-peak hours, it can evolve to address different time periods; and that not knowing non-capacity grid values should not be an obstacle because the energy and capacity benefits are value enough to justify launching the BYOD Program, and APS can factor in these additional values once data from the BYOD Program is available. (AriSEIA RBr. at 3-5.)

Resolution

The BYOD Program appears to be better designed to obtain grid benefits than is APS's Battery Pilot, which provides upfront incentives, has a very poor capacity sharing rate, has poor participation in called events, encourages customers to discharge their batteries during on-peak hours, and is currently at capacity. APS has already had the Battery Pilot in place for long enough to determine these things, as they are made clear by the record in this matter. Ms. Carnes even acknowledged in her testimony that the reason for the low levels of capacity sharing could be because people got $2,500 up front with no requirement to change anything about their habits. (*See* Tr. at 2257.) If the objective of the Battery Pilot was to incentivize customers to install new BTM batteries, its design may have done that. But APS should set its sights higher, particularly in the face of impending unprecedented levels of growth, to incentivizing customers with BTM batteries to use those batteries to benefit the grid and all customers. APS apparently has enough data from its Battery Pilot now to declare the Battery Pilot capacity-sharing batteries as a capacity resource, and we are not convinced by APS's arguments that more data is needed before a BYOD Program can be implemented. As AriSEIA/SEIA noted, APS is in a very different situation than TEP was, making it appropriate for the resolution of this issue for APS to be different than it was for TEP.

We conclude that it is just and reasonable and in the public interest to require APS to implement a BYOD Program Pilot ("BYOD Pilot") based on the BYOD Program proposed by AriSEIA/SEIA, with the BYOD Pilot to be capped at 5,000 customers; EnergyHub to serve as the aggregator for the BYOD Pilot; and the BYOD Pilot to require battery discharge periods of up to four hours that can be scheduled together or staggered within the period from 4 p.m. to 10 p.m., depending on APS's capacity needs for an event. APS will be required, within 180 days after this decision, to file as a compliance item in this docket a BYOD Pilot POA. APS will be required, prior to this filing and within 60 days after this decision, to meet with AriSEIA/SEIA and any other interested parties to discuss collaboratively and attempt to reach agreement on the language of the BYOD Pilot POA. During these collaborative discussions, the participants shall analyze whether incentive pricing should be based on kWh or kW, whether there should be differences in on-peak vs. off-peak pricing for incentives, and whether any on-peak and off-peak times used for incentive pricing should be different than those established for TOU customers. It is the Commission's desire that the BYOD Pilot POA be a document upon which the interested parties have reached agreement. The BYOD Pilot POA shall establish pricing which does not result in a cost shift to non-participating customers.

Staff will be required to review the BYOD Pilot POA within 120 days after it is filed and to file no later than 180 days after it is filed a Staff Report and Proposed Order, for Commission consideration at a subsequent open meeting, that provides Staff's analysis of the BYOD Pilot POA and the issues prescribed above and recommends whether the BYOD Pilot POA should be approved as written or further modified. The POA shall address how and when adjustments shall be made, if necessary, to the capacity value.

K. Solar Communities Program & Community Solar

1. Solar Communities Program

APS's Solar Communities Program was approved as part of the Settlement Agreement in the 2016 rate case. (Tr. at 2265.) Under APS's Solar Communities Program, APS installs APS-owned rooftop solar systems on the properties of APS customers and provides monthly bill credits to the customers for a period of 20 years or until the customer elects no longer to participate. (*See* Tr. at 240-241; Ex. APS-27 at 10; Ex. APS-49.) The following APS customers can participate in the Solar

Communities Program:[618]

- A limited or moderate income residential customer, on whose home APS will install a solar array at no cost to the customer, and to whom APS will then provide a monthly bill credit of $49.99;
- A multi-family facility serving limited and moderate income residents, which can have a solar covered parking structure installed at the facility, and which can receive a $1,000 annual bill credit while its tenants receive a $15 monthly bill credit each;[619] and
- Any of the following customers, which can receive a solar covered parking structure and a bill credit based on the size of the solar system and valued at $2.50/kW-AC:
    - A nonprofit that serves limited and moderate income populations,
    - A rural government entity, or
    - A Title I school.

The Solar Communities systems are located in front of the meter, meaning that the electricity generated belongs to APS rather than the customer who is hosting the facility, and the customer hosting the facility does not own the renewable energy credits for the system. (Tr. at 963-964.) Because APS controls the inverters for the Solar Communities solar systems, APS can study the data to determine how best to do hosting capacity,[620] while also getting the energy from the systems. (Tr. at 961.)

The Solar Communities Program included fewer than 1,000 systems as of the hearing in this matter. (Tr. at 962.) APS acknowledges that the energy obtained through the Solar Communities Program systems costs more on a per-unit basis than solar energy produced using utility-scale solar. (Tr. at 241, 962.) Mr. Geisler likened the Solar Communities Program to the bill assistance programs that APS provides for limited income customers who need energy support and stated that the Solar Communities Program allows APS to increase its solar portfolio in a meaningful way while helping customers who might otherwise not be able to afford rooftop solar. (Tr. at 241-242, 244-245.)

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[618] Ex. APS-27 at 23-24; Ex. APS-49.

[619] While Ms. Carnes testified to these credit amounts for multi-family housing facilities, the Solar Communities Program POA includes only a $49.99 monthly bill credit for residential customers and a $2.50/kW-AC monthly bill credit for non-residential customers. (*See* Ex. APS-49.)

[620] Hosting capacity is a measure of how much DG could be interconnected on a given distribution feeder, as each feeder has a limited amount of hosting capacity. (Tr. at 953, 955.)

Investments in the Solar Communities Program are not required to meet a cost-effectiveness standard. (Tr. at 963.) Ratepayers pay for the solar systems installed through the Solar Communities Program and pay APS a return on those solar facilities, which are included in rate base. (Tr. at 243-245.) In the last rate case, the Commission ordered APS to spend $20 to $30 million per year on the Solar Communities Program. (Tr. at 961, 1069.) The reasonable and prudent costs incurred by APS for the Solar Communities Program are recoverable through the REAC until the next APS rate case. (Ex. APS-49.)

APS Proposal

APS proposes the following changes for the Solar Communities Program:[621]

- Expansion to allow multiple limited and moderate income residential customers to receive bill credits associated with a single solar project such as a community shade structure or another type of solar array constructed within a park, community center, or other shared space;
- Expansion to allow all municipal governments within APS's service territory to participate; and
- Extension of the Solar Communities Program for another three years, at the same level of funding.

APS asserts that the expanded Solar Communities Program would deliver enhanced benefits to APS customers without requiring a new program with new administrative expenses that would ultimately be paid by ratepayers. (APS Br. at 96-97; Ex. APS-27 at 24.)

AriSEIA/SEIA

AriSEIA/SEIA argue that the Solar Communities Program infringes on a competitive industry because the definition of "moderate income" used makes "fully half of the residential customers in the state" eligible to participate. (AriSEIA Br. at 29; *see* Tr. at 3887.) AriSEIA/SEIA assert that although the Solar Communities Program has been described as a low-income program, it is already available to half of all residential customers and is proposed to be made available to "every single governmental

[621] APS Br. at 96-97; *see* Ex. APS-27 at 24-25.

entity in the state."[622] (AriSEIA Br. at 30.) AriSEIA/SEIA assert that governmental customers are "the most bankable counterparty for the competitive industry." (AriSEIA Br. at 30.) AriSEIA/SEIA also take issue with the Solar Communities Program's "must spend" budget and the fact that it is not subjected to ASRFPs. (AriSEIA Br. at 30.) AriSEIA/SEIA argue that it is both "a bad deal for ratepayers" and "unfair and unjustified monopoly competition with the private sector." (AriSEIA Br. at 30.) According to AriSEIA/SEIA, the Commission should "prevent APS from leveraging its monopoly power in competitive industries"; should deny an extension of the Solar Communities Program; or if it desires to continue the Solar Communities Program, should limit new enrollment to only low-income residential customers. (AriSEIA Br. at 30.)

In their Responsive Brief, AriSEIA/SEIA point out that the Solar Communities Program is not "community solar"; that there is no mechanism currently in place to ensure that the customers participating in the program are unable to install solar on their homes without the program; and that there has been no evidence presented to establish that the customers would be unable to install solar without the program.[623] (AriSEIA RBr. at 10-11.) AriSEIA/SEIA argue that APS's proposed expansion of the program to all municipal governments within the APS service territory defies the original purpose of the program and "allows a monopoly to unfairly compete in the free market." (AriSEIA RBr. at 11.) Additionally, AriSEIA/SEIA assert it is "perplexing" that APS alleges cost shifts whenever another stakeholder proposes a solar program, but not for this program, which literally requires ratepayers to pay for the installation (or removal) of solar on other customers' roofs at a cost of $20 to $30 million per year while also paying a fee to rent the roof. (AriSEIA RBr. at 11; *see* Tr. at 2263-2264.) AriSEIA/SEIA argue that the Solar Communities Program would not exist if APS had not "tak[en] advantage of the settlement agreement opportunity in its 2016 rate case" and calls the Solar Communities Program "uniquely expensive and unneeded" and "a boondoggle that is inefficient and wasteful" and that benefits shareholders at the expense of ratepayers. (AriSEIA RBr. at 11-12.)

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[622] This appears to be an overstatement, as the expanded Solar Communities Program would not appear to be available to state or county governmental entities unless they are rural.
[623] Obviously, this is an assumption that is made based on income level.

Ms. Nelson

Ms. Nelson asserts that APS should not be allowed to use ratepayers' money to buy APS-owned solar installed on low-income residential rooftops, government buildings, schools, and the like. (KN Br. at 2.) Ms. Nelson states that the Commission should regulate whether such installations are APS-owned or ratepayer-owned and, if they are ratepayer-owned, should require that the solar be credited to ratepayers for the life of the solar installations. (*Id.*)

Sierra Club

Sierra Club asserts that AriSEIA/SEIA have presented substantial evidence showing that the Solar Communities Program is not attractive to customers[624] and is overly expensive. (SC RBr. at 25.) Sierra Club argues that the Commission should not allow the expansion of the Solar Communities Program because it is not community solar and does not provide similar benefits to participants. (SC RBr. at 25.)

APS Response

APS argues that substantial evidence of record supports expanding the eligibility for the Solar Communities Program and that no party has disputed the proposal would expand access to greater numbers of customers while maintaining current spending limits. (APS RBr. at 71.) APS argues that AriSEIA/SEIA make "unsubstantiated claims about anti-competitive impacts on third-party solar developers" and seek to cancel the benefits the Solar Communities Program offers to APS customers. (APS RBr. at 71.) APS argues that AriSEIA/SEIA's claims that the Solar Communities Program is unreasonably expensive, not in the public interest, beyond APS's monopoly purview, and anticompetitive disregard the current Solar Communities Program and the fact that APS proposes to expand the program while maintaining the same level of funding for it. (APS RBr. at 73-74.) APS points out that it issues competitive RFPs[625] for local solar installers to do the Solar Communities Program installations, meaning that it is not competing with third-party solar installers for this work. (APS RBr. at 74; *see* Tr. at 2195-2196.) APS suggests that the program makes it possible for these

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[624] It is unclear to what evidence Sierra Club refers concerning the attractiveness of the program.

[625] APS erroneously used the term "ASRFPs" in its Responsive Brief. In this context, the correct term is "RFPs," consistent with Mr. Geisler's testimony. (*See* Tr. at 245.)

solar installers to obtain more work than they would otherwise because the Solar Communities Program participants otherwise might not have been able to participate in the solar market. (APS RBr. at 74; *see* Tr. at 2194-2195.) Further, APS argues, AriSEIA/SEIA's claims that the program costs are "excessive" or "unreasonable" are without merit because APS uses competitive bids for these installations, which ensures the lowest cost installation. (APS RBr. at 74.)

Resolution

APS characterizes the Solar Communities Program as a program to benefit limited or moderate income customers, similar to the limited income programs E-3 and E-4, but would have the Commission expand the program to all municipal governments and to include additional types of solar system installations. The Commission understands the "charitable" nature of the program to be presented as the reason why it is appropriate for the program not to be subject to a cost-effectiveness test or ASRFPs. The Commission suspects that the Solar Communities Program solar systems would not pass either of these tests because of APS's own evidence regarding the value of non-utility-scale solar to the grid, as reflected for example in relation to APS's solar COSS. APS does not appear to bestow much value on non-utility-scale solar systems unless APS owns them. This could be because APS's ownership and control of these solar systems in front of the meter allow it to obtain data that it is not able to obtain with BTM solar systems, or it could be (as AriSEIA/SEIA argue) because APS prefers assets upon which it can earn a return for its shareholders. Whatever the reason, we are not convinced that the Solar Communities Program solar systems are a good deal for ratepayers other than those who obtain credits through the program. APS has conceded that on a per-unit basis, the energy from the Solar Communities Program is more expensive. APS's justification for this is the charitable nature of the program. But it is difficult to see the program as charitable in light of AriSEIA/SEIA's observation that it is already available to half of APS's residential customers[626] and when APS is requesting to expand it to all municipal governments in the state. Additionally, APS has not provided evidence herein of the program's actual benefits to APS ratepayers, aside from the credits received by participants and the good feelings participants may enjoy from believing they are receiving solar

[626] *See* Ex. APS-49.

energy. We believe that the Solar Communities Program is overly expensive for ratepayers in light of the benefits that it provides to ratepayers, and we will not approve its expansion or its extension for another three years. Therefore, APS shall not add any new participants to the Solar Communities Program as of the effective date of this Decision.

2. Community Solar

In Decision No. 78899 (March 23, 2023),[627] the Commission adopted a Policy Statement Regarding Statewide Community Solar and Storage ("Community Solar Policy") that, *inter alia*, does not require a regulated electric utility to participate in a Community Solar Program, allows a regulated electric utility to offer community solar itself or via partnership with a third party, requires that any bill credit offered be at the lowest possible cost for the resource not to exceed avoided cost, requires that 50% of the MWs from a community solar project be dedicated to low and moderate income customers, emphasizes the need to protect customers from cross-subsidization, and does not include a must-take requirement. (*See* Ex. APS-27 at Att. KC-01RB.) In Decision No. 78900 (March 23, 2023),[628] the Commission directed that any evaluation of a community solar program should take place in a rate case because of the impact such programs will have on rates. (Decision No. 78900 at 2, 3.)

APS does not propose a community solar program in this matter. (*See* Ex. APS-27 at 20.)

<u>AriSEIA/SEIA Proposal</u>

AriSEIA/SEIA argue that the Community Solar Policy will not lead to a successful community solar program in Arizona, primarily because the Community Solar Policy does not require a regulated electric utility to participate in community solar. (AriSEIA Br. at 28.) AriSEIA/SEIA argue that by providing production services, community solar projects compete with APS, and assert that APS does not like competition and is unlikely to make a traditional third-party community solar proposal unless it is required to do so. (AriSEIA Br. at 28.) Additionally, AriSEIA/SEIA argue that because APS can decide to create its own community solar program, without the involvement of a third-party developer, and thereby increase its rate base, this is the approach APS is likely to take. (AriSEIA Br. at 28.)

[627] This decision was included as Attachment KC-01RB to Exhibit APS-27.

[628] Official notice was previously taken of this decision, issued in Docket No. E-00000A-22-0103, which amended Decision No. 78784 (November 22, 2022), which had rejected APS's Community Solar Implementation Proposal. Official notice was also previously taken of Decision No. 78784.

According to AriSEIA/SEIA, allowing APS to "expan[d] its monopoly into a competitive market is antithetical to the regulatory compact." (AriSEIA Br. at 28-29.) AriSEIA/SEIA criticize the "avoided cost" bill limitation from the Community Solar Policy as problematic because it is unknown whether such credits would provide enough "headroom" to allow community solar developers to charge subscriptions to cover their costs, particularly because the Community Solar Policy requires a carveout of 50% for low- to moderate- income customers and for developers to pay all interconnection costs.[629] (AriSEIA Br. at 29.) AriSEIA/SEIA urge the Commission to reconsider the Community Solar Policy. (AriSEIA Br. at 33.)

Vote Solar Proposal

Vote Solar urges the Commission to direct APS to propose a tariff to enable development of community solar projects that will allow APS customers to access solar energy through a subscription model.[630] (VS Br. at 3.) Vote Solar asserts that 22 states and Washington, D.C. have policies that support community solar and that more than 3,200 MW-AC of community solar capacity have been installed in those jurisdictions. (VS Br. at 3; *see* Ex. VS-2 at 2.) Vote Solar argues that through community solar programs, utility customers who are unable to install their own rooftop solar[631] gain access to the benefits of solar, and competition is leveraged to provide energy and grid benefits that will help APS meet its future resource needs. (VS Br. at 4.) According to Vote Solar, APS has not provided a coherent explanation for why it does not support community solar, particularly when APS has expressed that it faces challenges in meeting the anticipated growth on its system. (VS Br. at 4.) Vote Solar states that community solar would "unlock the market for small- and mid-sized solar projects" and diversify the resources available to APS to meet customer needs. (VS Br. at 4.) Vote Solar cites the testimony of Mr. Geisler touting new clean energy resources as affordable and reliable

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629 The Community Solar Policy does not address interconnection costs. (*See* Ex. APS-27 at Att. KC-01RB.)

630 Ms. Bowman recommended that APS propose a community solar tariff and rate design informed by the stakeholder workshops, written comments, and national best practices shared in Docket No. E-00000A-22-0103. (Ex. VS-2 at 6-7.) Ms. Bowman included with her testimony a community solar program proposal developed by a coalition of solar industry stakeholders (exhibit KB-2), recommendations regarding rate design for a community solar tariff (exhibit KB-4), and the Brattle Group's estimate of the value community solar projects would provide to APS's grid (exhibit KB-3). (*See* Ex. VS-2 at 7, ex. KB-2, ex. KB-3, ex. KB-4.)

631 Vote Solar asserts that nearly half of households and businesses cannot have rooftop solar installed for various reasons and that community solar can provide them access to distributed solar through subscriptions. (VS Br. at 6; *see* Ex. VS-2 at 3.)

and the lowest cost options that provide the greatest value to customers over their lifetimes, stating that APS is procuring as much solar and storage as can be developed and needs to procure much more, and reporting that 65% of APS's contracted utility-scale projects have been canceled or delayed. (VS Br. at 5; *see* Tr. at 247-251, 412-413, 450.) Vote Solar asserts that adding new, locally sited community solar projects would help meet APS's growing energy needs and provide it more flexibility to meet the rest of its needs with large-scale resources. (VS Br. at 5.)

Vote Solar asserts that community solar programs can add new resources without adding to APS's revenue requirement because community solar projects can be built and maintained by third-party developers, who are responsible for any cost overruns or performance issues, and ratepayers pay only the cost of the bill credits provided to community solar subscribers. (VS Br. at 6.) Vote Solar asserts that when the bill credit value is equal to the value of the energy and grid services provided by a community solar project, ratepayers are indifferent whether the energy is delivered from a community solar project or another source. (VS Br. at 6.)

Vote Solar disputes APS's argument that community solar is not needed because of the level of solar installations already in Arizona and argues that the purpose of community solar is not to spur solar adoption but to increase competition and provide more equitable access to the opportunity for bill savings through distributed solar. (VS Br. at 7; *see* Ex. APS-27 at 22.) In response to APS's opposition to being required to incorporate 400 MW of community solar each year, Vote Solar points to APS's plan to procure gigawatts of solar in the coming years. (VS Br. at 7; *see* Ex. APS-27 at 20.) In response to APS's opposition to having a "must take" requirement for the energy from community solar, Vote Solar points to APS's plans to build substantial battery storage in the coming years. (VS Br. at 7; *see* Ex. APS-27 at 20.) Vote Solar argues that the main difference between community solar and APS's plans is that community solar would involve competitive, third-party, community-owned solar projects to be deployed at the distribution system level. (VS Br. at 8.)

If community solar is not addressed in this rate case, Vote Solar argues, there will not be another opportunity to evaluate it until APS's next rate case. (VS Br. at 8.) Vote Solar recommends that the Commission hold open this docket for a Phase 2 proceeding to provide APS time to file with the Commission, for its review and consideration, a community solar tariff proposal that complies with the

Community Solar Policy. (VS Br. at 8.)

Ms. Nelson

Ms. Nelson asserts that community solar projects should be encouraged because all APS customers could benefit from the reduced costs and credits. (KN Br. at 2.) Ms. Nelson argues that homeowners who desire to buy solar for themselves or neighborhoods are being pushed out of the market because of the reduction of the export rate since 2018 and that APS's ownership of solar eliminates the chance for prices to be lower in the future. (KN Br. at 3.)

Sierra Club

Sierra Club argues that APS's opposition to community solar is contrary to the interests of its ratepayers, who would benefit from the lower energy bills that could be achieved through community solar. (SC RBr. at 25.)

APS

APS asserts that Arizona's residential solar market has grown each year since 2019 and that Arizona is among the top five states in the country for solar installations. (APS Br. at 97; *see* Ex. APS-27 at 22.) APS points out that as of June 1, 2023, APS had connected nearly 165,000 solar systems (residential and non-residential) with a capacity of 1,497 MW-AC and that 140,166 residential systems (1,085 MW-AC) and 1,036 non-residential systems (96 MW-AC) had been installed and interconnected without incentives. (APS Br. at 97; *see* Ex. APS-27 at 22.) Because APS's service territory has robust solar already, APS asserts, community solar programs are not needed to incentivize solar installations. (APS Br. at 97-98.) Further, APS argues, community solar programs are not needed to further customers' clean energy goals because in 2022, APS's customers were served with 50% clean energy, APS continues to add clean energy resources, approximately 13% of APS's residential customers have rooftop solar, and APS provides programs such as Green Choice and Green Power Partners to allow customers to align their energy consumption with their goals. (APS Br. at 98; *see* Ex. APS-27 at 18-19.)

APS points out that that the Commission's Community Solar Policy makes utilities' participation in community solar programs voluntary and that the Commission recently rejected similar community solar proposals from AriSEIA/SEIA and Vote Solar in the 2022 TEP rate case. (APS Br.

at 98; *see* Ex. APS-84 at 133-134.) Further, APS argues that the community solar program proposals advocated by AriSEIA/SEIA and Vote Solar would be harmful to APS's customers because they include a "must take" provision of at least 400 MW regardless of need or economics,[632] would create a net present value cost shift of approximately $541 million over 20 years, would be administratively cumbersome and thus shift further costs to non-participating customers, and would remove the Commission from its consumer protection role and thereby increase the risk that APS's customers would not have traditional means of redress. (APS Br. at 99-100; *see* Ex. APS-27 at 20.) APS argues that Vote Solar's proposed community solar program would not create a competitive market but would require APS to accept all projects, would guarantee developers payment for unsold subscriptions, would compensate customers for participating, and would require APS's ratepayers to purchase the community solar projects' energy at a higher rate than would be paid for resources procured through a competitive ASRFP. (APS Br. at 100; *see* Ex. APS-28 at 9.)

In its Responsive Brief, APS argues that the community solar programs advocated by AriSEIA/SEIA and Vote Solar would violate the Community Solar Policy,[633] would create substantial cost shifts, and would not be in APS customers' best interests. (APS RBr. at 71.) APS argues that AriSEIA/SEIA and Vote Solar's argument that their community solar proposals would promote competition is misguided because APS would be required to accept all projects, which AriSEIA/SEIA recognize is contrary to the Community Solar Policy. (APS RBr. at 72; *see* Ex. APS-28 at 9; AriSEIA Br. at 28.) APS reiterates that the community solar projects would not be subject to the ASRFP process and that the energy from the projects would not be economical. (APS RBr. at 72; *see* Ex. APS-28 at 8.) APS adds that although the Commission would have oversight for APS's rates related to a community solar program, the Commission would not have jurisdiction over community solar third-party developers or subscriber organizations, and thus would be unable to ensure consumer protections. (APS RBr. at 73; Ex. APS-28 at 10.) APS argues that AriSEIA/SEIA and Vote Solar's arguments that community solar is the only way to provide a competitive market without excessive costs is not

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[632] Because Vote Solar appears to advocate for a community solar program that would conform to the Community Solar Policy, Vote Solar does not appear to be advocating for a "must take" provision.

[633] Unlike AriSEIA/SEIA, Vote Solar appears to advocate for a community solar tariff that would conform to the Community Solar Policy.

supported by the evidence in this record or any other record and should be rejected. (APS RBr. at 73.)

AriSEIA/SEIA Response

In their Responsive Brief, AriSEIA/SEIA argue that the Commission should disregard APS's metrics about the health of the Arizona solar market[634] because community solar is different from rooftop solar, and Arizona does not have a community solar market. (AriSEIA RBr. at 12.) AriSEIA/SEIA assert that community solar is for those who cannot install solar on their roofs, largely because they do not live in a single-family home. (AriSEIA RBr. at 12.) Further, AriSEIA/SEIA argue, the Commission's Community Solar Policy will not result in any community solar in Arizona. (AriSEIA RBr. at 12; *see* Ex. AriSEIA-1 at 137-140.) AriSEIA/SEIA assert that APS mischaracterizes the community solar proposal supported by AriSEIA/SEIA, in particular by questioning whether it is competitive. (AriSEIA RBr. at 12.) Finally, AriSEIA/SEIA assert that the community solar advocates have never recommended subsidies for community solar programs and that they hired the Brattle Group, which APS has also hired as a consultant, to analyze the value of distributed resources. (AriSEIA RBr. at 12.)

Vote Solar Response

In its Responsive Brief, Vote Solar reiterates that the Commission should direct APS to propose a tariff for community solar development. (VS RBr. at 2.) Vote Solar argues that APS has failed to rebut Vote Solar's demonstration that a community solar program would benefit customers and that APS has mischaracterized Vote Solar's proposed community solar program guidelines. (VS RBr. at 2-3.)

Vote Solar argues that Solar Communities is not comparable to community solar because it is unavailable to those who cannot install rooftop solar due to shade or other technical reasons. (VS RBr. at 3; *see* Ex. VS-2 at 3.) With community solar, Vote Solar asserts, these residential customers could subscribe to a share of the output from a distributed solar project located in their community or neighborhood. (VS RBr. at 3.) Vote Solar asserts that APS's Green Choice and Green Power Programs also are not comparable to community solar because they simply allow customers to purchase

[634] AriSEIA/SEIA also question the health of the rooftop solar market, citing to comments filed in another docket that are not a part of the evidentiary record in this matter. (AriSEIA RBr. at 12.)

renewable energy certificates at a premium. (VS RBr. at 3; *see* Ex. VS-3 at 7-8.)

Vote Solar refutes APS's argument that community solar would result in administrative expenses to be paid by all of APS's customers, stating first that APS has not quantified any such costs or provided any evidence that they would be substantial or onerous and, second, that Vote Solar's program proposal would permit APS to recover administrative costs from community solar participants, provided that the costs were justified by data. (VS RBr. at 3; *see* Ex. VS-3 at 5.) Vote Solar also refutes APS's assertion that community solar would benefit participants at the expense of non-participants, stating that Vote Solar has not proposed incentives or subsidies for participating customers in this matter and that community solar programs do not result in cost shifts between participating and non-participating customers. (VS RBr. at 4.) Vote Solar argues that APS mischaracterizes the bill credits provided to participating customers in exchange for the energy delivered to the grid and asserts that providing fair compensation for exports commensurate with actual value of the energy and grid services is not subsidization. (VS RBr. at 4.) Vote Solar also criticizes APS for implying that energy from a local distributed community solar project is equivalent to energy from a distant utility-scale solar resource because, Vote Solar states, distributed energy resources located close to customer load avoid transmission costs, distribution costs, and line losses that are incurred to deliver utility-scale energy long distances, making the value of a kWh from distributed solar greater than the value of a kWh generated by utility-scale solar. (VS RBr. at 4; *see* Decision No. 75859 at 151.) Vote Solar states that because there is little difference between the value of a kWh exported from a homeowner's rooftop solar and a kWh exported from a community solar project connected to the distribution system, it is reasonable to value energy exported from community solar commensurate with the Commission-approved export rate for rooftop solar. (VS RBr. at 4.)

<u>Resolution</u>

The Commission recently adopted a Community Solar Policy, which allows APS not to participate in community solar programs. APS has indicated, consistent with the Community Solar Policy, that it does not currently intend to propose a community solar program tariff. The Commission understands that the Community Solar Policy was disappointing for the community solar advocates, such as AriSEIA/SEIA and Vote Solar, who wholeheartedly believe in its value for the grid and ratepayers. Vote Solar has again provided the Commission with the August 2022 joint community solar program proposal, the Brattle Group's contemporaneous determination of community solar value, and the September 2022 RCP proxy proposal for community solar, all of which were previously provided to the Commission in other dockets by the community solar advocates. (*See* Ex. VS-2 at ex. KB-2, ex. KB-3, ex. KB-4.) The Commission understands that there is value to distributed solar generation, whether it comes from a rooftop or from a community solar facility. The Commission also understands, however, that under the community solar advocates' proposal, the Commission would not have jurisdiction over the third-party Subscriber Organization who would own and operate a community solar facility, although that Subscriber Organization would contract directly with APS's participating customers and would collect from those customers subscription fees that could be higher than 90% of the bill credits to be received by the customers. If those customers had a problem with the Subscriber Organization, the customers' proposed recourse would be first to go to the Subscriber Organization, second to go to APS, and third to complain to the Attorney General's office.[635] As we stated in our Resolution concerning the RBT Pilot, making a complaint to the Attorney General's office does not provide the same opportunity for due process as does making a formal complaint to the Commission, something that would be unavailable for a customer having difficulties with its Subscriber Organization because the Subscriber Organization (in the community solar advocates' proposal) would not be considered a public service corporation. (*See* A.R.S. § 40-246.)

Although Vote Solar appears to have stepped back from the community solar advocates' proposal, by recommending that APS be required to file a community solar tariff that complies with the Community Solar Policy, the Commission remains concerned about the community solar advocates' proposal that would have required APS to interconnect each community solar project regardless of whether it was located in an area of the distribution system that made it helpful to APS's grid, would have required APS to accept all of the exported energy from that community solar project regardless of whether the energy was needed at any given time, and would have included an export rate for community solar projects set higher than the current RCP rate paid to customers with rooftop solar.

[635] *See* Ex. VS-2 at ex. KB-2 at 12.

Because the Commission is concerned about the lack of protections available to APS customers under a third-party community solar model, the Commission does not believe that it would be just and reasonable and in the public interest to require APS to submit a community solar program proposal. Additionally, because of the lack of customer protections and the Commission's concerns about must take provisions and export rates, the Commission does not believe that it would be just and reasonable and in the public interest to reconsider the Commission's Community Solar Policy at this time.

L. Microgrids

In its application, APS included in PTYP a microgrid project APS is building for the City of Phoenix ("Phoenix Microgrid") and that APS described as "on-site back-up generation for critical infrastructure." (*See* Ex. APS-8 at 16.) APS eliminated the Phoenix Microgrid project from PTYP on rebuttal because it was not going to be in service by June 30, 2023. (Ex. APS-27 at 25.) Ms. Carnes testified that APS already has two successful microgrids in operation—one with the Marine Corps Air Station in Yuma and one with Aligned Data Centers in metro Phoenix. (Ex. APS-27 at 26.) Ms. Carnes stated that these microgrids were approved in APS's 2016 rate case, can respond in seconds when needed, and have responded to numerous frequency events and provided 891 hours of support since 2017, including when Palo Verde Unit 1 tripped offline in April 2023. (Ex. APS-27 at 26-27.) APS becomes involved in microgrid projects at customer request, and there is no preferred technology for microgrids. (Ex. APS-27 at 27.) According to Ms. Carnes, if a customer partners with APS on a microgrid as a shared resource, together they can put in more flexible, dispatchable, cleaner generation configured as a microgrid with the capability to export power when needed to support the grid. (Ex. APS-27 at 26, 28.) Ms. Carnes testified that third-party developers have the same opportunities to enter into partnerships with APS customers who desire microgrids and can arrange to have the microgrids interconnected to the grid so that the customer can sell capacity and energy to APS; that APS is willing to work with third-party developers who offer microgrids; and that third-party developers do not need customer billing or feeder information to develop microgrids because the shared microgrids are initiated by the customer. (Ex. APS-27 at 28-29.) Ms. Carnes added that third-party developers can obtain this information like they do for any other interconnected DG project under the Commission's interconnection rules and that each customer also has access to and can share its own billing information as well as its critical load and the duration of power needed. (Ex. APS-27 at 29-30.) Ms. Carnes also noted that a number of APS customers have developed their own on-site backup generation without working with APS on a capacity sharing arrangement. (Ex. APS-27 at 30.)

AriSEIA/SEIA Proposal

AriSEIA/SEIA request for the Commission to declare that APS's "foray into the competitive microgrid industry is an improper expansion of its monopoly and should be stopped." (AriSEIA Br. at 16.) AriSEIA/SEIA argue that APS has an inherent advantage as the monopoly provider and is not obligated to provide microgrid services to customers as part of its obligation to provide reliable service. (AriSEIA Br. at 16; *see* Tr. at 3882.) At the hearing, Mr. Lucas stated:

> So what we're concerned about is APS is in a position to leverage information that it and only it has access to. To be able to go out and leverage its rate base, to leverage its financing ability, to leverage its creditworthiness, and to produce . . . submarket-priced assets in projects in a competitive industry, that is the definition of a monopoly exercising market power.
>
> And part of the rule of utility oversight is to make sure that regulations are in place that prevent that exercise of monopoly . . . power. So our recommendation here is for customer sited microgrids to be left to the competitive market. There are competitive developers out there who [are] at a disadvantage – a fundamental and inherent disadvantage to APS, who shouldn't have to compete with a monopoly that is leveraging data from other parts of its operation.[636]

Mr. Lucas expressed concern that APS had been unwilling to commit to not using its information to solicit microgrid customers, although APS had said that it was not currently using the information in that manner, and that APS intended to become involved in more microgrid projects. (*See* Tr. at 3882.)

Ms. Nelson

Ms. Nelson states that APS should not be allowed to expand its monopoly into microgrids. (KN Br. at 2.)

APS

APS asserts that customers currently have a choice of whether they partner with APS or a third-party microgrid developer to build a microgrid to support their critical infrastructure and that AriSEIA/SEIA desire to restrict that choice by having the Commission prohibit APS's provision of

636 Tr. at 3880-3881.

microgrid services. (APS Br. at 130.) APS argues that AriSEIA/SEIA's "anti-competitive recommendations should be rejected" so that customers continue to have a choice. (APS Br. at 130.) APS disagrees with AriSEIA/SEIA's claim that APS's microgrid program has an unfair competitive advantage over third-party developers and states that adding choices is actually "procompetitive." (APS Br. at 130.) APS asserts that it does not prevent third-party developers from providing microgrid services to APS customers and that AriSEIA/SEIA have provided no evidence that any third-party microgrid developer has been hampered in its ability to provide such services. (APS Br. at 131.) APS notes Ms. Carnes's testimony about the opportunities third-party developers have to obtain the same benefits for their projects as APS receives, including by developing capacity-sharing agreements and project cost sharing arrangements. (APS Br. at 131-132; *see* Ex. APS-27 at 28-31.) According to APS, AriSEIA/SEIA's position is wholly based on speculation and not supported by any evidence of record, whereas APS has provided evidence that third-party-developed microgrids have been built in APS's service territory and that APS is not actively seeking out microgrid opportunities and is not using non-public information for marketing. (APS Br. at 132; *see* Tr. at 2188-2189.) APS adds that a third-party developer would know as well as APS where a potential microgrid customer is located because the primary factor is whether the customer has significant resiliency needs (for example such as a hospital or data center), and no hosting capacity map is necessary to provide that information. (APS Br. at 133; *see* Ex. APS-28 at 12; Ex. APS-27 at 30; Tr. at 2189-2190. 2205-2206.) APS notes Mr. Lucas's acknowledgment that a customer's critical load cannot be determined from billing data and that a customer would be able to provide its billing data to a developer. (APS Br. at 134; *see* Tr. at 3990-3992.) APS adds that a third-party developer working with a microgrid customer can obtain all the necessary feeder and distribution information needed to interconnect and determine the need for distribution system upgrades, under the Commission's Interconnection Rules. (APS Br. at 134; *see* Ex. APS-28 at 11; A.A.C. R14-2-2616.) APS argues that AriSEIA/SEIA's request should be rejected. (APS Br. at 134.)

In its Responsive Brief, APS reiterates the same information and arguments but also adds that AriSEIA/SEIA not only do not have any evidence to support their position, they also do not cite any legal authority (case law, statute, regulation, or other) to support their position. (APS RBr. at 100.)

AriSEIA/SEIA Response

In its Responsive Brief, AriSEIA/SEIA argue that APS's microgrid projects directly conflict with the regulatory compact because building microgrids is not a necessary part of APS's provision of service, and the free market is capable of building microgrids. (AriSEIA RBr. at 8.) AriSEIA/SEIA state that APS's argument that APS's involvement in microgrids increases competition is "paradoxical." (AriSEIA RBr. at 8-9.) AriSEIA/SEIA assert: "APS has information only available to it, a captive customer base, a guaranteed rate of return, and other market advantages that do not allow other market participants to engage on an equal playing field." (AriSEIA RBr. at 9.) AriSEIA/SEIA question APS's support of "customer freedom" and "customer choice," in light of APS's position on community solar and the BYOD Program, and argue that AriSEIA/SEIA's position is not that APS is prohibiting third-party microgrid development but that it has an unfair advantage and should not be able to use non-public data to market its microgrid program. (*See* AriSEIA RBr. at 9.) AriSEIA/SEIA urge the Commission to disallow APS from engaging in microgrid programs going forward. (AriSEIA RBr. at 9.)

Resolution

AriSEIA/SEIA have provided abundant argument to support their position that the Commission should prohibit APS prospectively from providing microgrid services. The Commission understands that AriSEIA/SEIA believe strongly that APS has a competitive advantage. The Commission will prohibit APS from providing microgrid services.

M. Resource Acquisition Practices & Schedule; Regional Markets

1. Resource Acquisition Practices & Schedule

Sierra Club Proposal

Sierra Club argues that APS has been under-procuring resources and that this has subjected customers to expensive contracts for firm capacity needs. (SC Br. at 54; *see* Ex. SC-1 at 76-77.) Sierra Club also asserts that APS is "leaving potential savings on the table" by not evaluating its existing resources against new resources on a rolling basis. (SC Br. at 54-55.) According to Sierra Club, the Commission should require APS to procure "elevated resource needs . . . [by] proactively soliciting and procuring resources ***before*** they are needed" and should require APS continuously to reevaluate its existing resources and to take advantage of any savings that could be achieved from early retirement of existing resources. (SC Br. at 55.) Sierra Club argues that "building beyond projected peak demand to avoid expensive short-term capacity contracts" would present little risk and could result in considerable savings because new renewable resources are less expensive than short-term contracts for firm capacity. (SC Br. at 55; *see* Ex. SC-1HC at 76; Ex. SC-1 at 76-77.) Sierra Club notes that APS needs to procure substantial new resources over the next decade and asserts that its procurement practices should reflect this. (SC Br. at 55.) Sierra Club also notes Ms. Glick's testimony that because new resources take time to bring online, APS will likely need them by the time they are completed and, if not, could sell their energy to other entities in the region. (*See* SC Br. at 56; Ex. SC-1 at 77.) Sierra Club recommends a "rolling procurement framework," which it states would enable APS to take expensive resources offline in favor of more cost-effective resources and would provide a buffer against transmission, interconnection, or supply chain challenges. (SC Br. at 56; *see* Ex. SC-1 at 79-80.) Sierra Club recommends that before issuing an ASRFP (and at least annually), APS analyze the costs of existing resources by individual unit and, if a resource has a "negative" net present value revenue requirement compared to baseline or a relatively high LCOE and high capacity value need, APS evaluate whether APS can replace the existing resource with ASRFP resources that can supply energy or capacity less expensively and pursue early retirement of the resource while also increasing the ASRFP to include increased need from the early retirement. (SC Br. at 56-57.) Sierra Club urges the Commission to direct APS to issue ASRFPs for new resources that slightly exceed its anticipated need (such as by 25%), based on the additional existing resource analysis Sierra Club recommends. (SC Br. at 56.) Sierra Club concludes that the Commission should direct APS to implement a more proactive rolling resource procurement process. (SC Br. at 57; SC RBr. at 26.)

<u>APS</u>

APS asserts that its procurement process uses competitive ASRFPs to ensure customers benefit from the least cost, best fit resources available and notes that recent ASRFPs have shown that cleaner and more diverse resources are cost-competitive and a better long-term value compared to alternatives. (APS Br. at 105; *see* Tr. at 175, 247-250, 267, 4607-4609.) APS states that due to its need to obtain significant additional resources, it is using a year-round process[637] for procurement that cycles annually. (APS Br. at 105; *see* Ex. APS-12 at 5-6; Tr. at 1355-1356.) APS states that it is willing to consider enhancements to its resource procurement processes, such as those suggested by Sierra Club, through the RPAC (in which Sierra Club is an active member). (APS Br. at 105-106; *see* Ex. APS-12 at 5-6; Ex. SC-1 at 7.)

Resolution

The evidence shows that APS currently engages in a nearly year-round, if not year-round, procurement process using ASRFPs. Sierra Club wants APS to be more proactive in its procurement and to procure slightly more than the resources it knows it needs. Under normal circumstances, this would appear to be a bad idea due to the risk of acquiring excess plant or excess capacity. But in light of APS's projected growth and resource needs, it may be wise. Nonetheless, the Commission does not believe that it is necessary or appropriate for the Commission to direct APS how to engage in its resource planning and procurement, beyond stating that it must comply with the existing IRP rules and all applicable Commission decisions. APS has indicated a willingness to consider enhancements to its resource procurement processes, such as those suggested by Sierra Club, and APS's suggestion for these potential enhancements to be vetted through the RPAC, in which Sierra Club actively participates and Staff soon will also be participating, is sound. The Commission will not adopt Sierra Club's recommendations.

2. Regional Market Participation

APS is a member of the California Independent System Operator- ("CAISO-") led WEIM, which allows APS to import inexpensive or even negatively priced energy from California when California has excess energy on its system and to sell power to California in the evening when the California purchase prices are higher than APS's costs to generate. (Tr. at 1162.) The WEIM is an automated platform that helps balance WEIM members' fluctuations in generation and demand on an inter-hour basis. (Tr. at 1163.) As previously stated in reference to the PSA, APS's participation in the WEIM has saved APS ratepayers hundreds of millions of dollars in fuel and purchased power costs.

[637] Mr. Joiner testified that it is "almost a year-round process." (Tr. at 1355.)

(Ex. APS-11 at 13; Tr. at 1164.) APS believes that expanding its participation to markets beyond the WEIM could potentially enhance reliability and provide additional savings. (Tr. at 1164.) To that end, APS has become a member of the WRAP, although it will not become fully bound by WRAP requirements until 2026, and is actively involved in the development of two different western day-ahead markets: (1) the CAISO-led day-ahead market called the Extended Day-Ahead Market ("EDAM"), and (2) the Southwest Power Pool's ("SPP's") day-ahead market called Markets+. (*See* Tr. at 1165-1170.) As of the hearing in this matter, CAISO had just filed its EDAM tariff application with FERC, but the SPP had not yet filed its Markets+ tariff application and was expected to do so by the end of 2023. (Tr. at 1169-1170, 3377, 3381.) CAISO will be the market operator for the EDAM, and the SPP will be the grid and market operator for Markets+. (Tr. at 1172-1173.) Mr. Joiner testified that although the EDAM and Markets+ RA constructs may be different, a WRAP member can be a member of either the EDAM or Markets+. (Tr. at 1172-1174.) Mr. Joiner further testified that the governance structures of the EDAM and Markets+ will be different, as Markets+ will have the same type of governance structure as the SPP (as a regional transmission organization ("RTO")), and the EDAM will have a joint authority governance structure with the CAISO Board of Governors. (Tr. at 1174.) The costs to participate in the EDAM and Markets+ are also likely to be different, although Mr. Joiner was unaware of the specifics. (Tr. at 1174-1175.) APS is very actively involved in the design of Markets+, as it has a seat on every working group and task force for Markets+. (Tr. at 1175-1176.) APS has also provided comments on the EDAM's design. (Tr. at 1176.) APS is not currently committed to joining either the EDAM or Markets+. (Tr. at 1177-1178.) APS has advocated with both CAISO and the SPP concerning the importance of having a good "seams"[638] agreement between the EDAM and Markets+ because otherwise there will be an inefficient flow of power, costly power, and areas that cannot access the power and there could also be "sort of a jigsaw puzzle of transmission." (Tr. at 1182-1184.) Mr. Joiner testified that one market without seams would offer the best value, all things being equal, but that he believes governance concerns and other details caused a second market option to arise and that the next best thing to a single market is a good seams agreement. (Tr. at 1184-

[638] A seam is the interface between two wholesale electricity markets or balancing authorities that have different operating practices. (Tr. at 1183-1184.)

1185.) Mr. Joiner indicated that it would not be possible for APS to participate in both EDAM and Markets+ unless there is a good enough seams agreement. (Tr. at 1474-1475.) APS contemplates being in one real-time market and one day-ahead market and has already committed to WRAP, but APS will not join either day-ahead market unless the details are beneficial to APS's customers. (Tr. at 1474.)

APS is also exploring participation in an RTO, although there currently is no RTO available,[639] and Mr. Joiner testified that an RTO would be the "final kind of ultimate step" and a big commitment that APS would consider only after a lengthy process that would involve sharing information with the Commission, Staff, and APS customers. (Tr. at 1185-1186, 1473.) Because the costs of joining an RTO are in the hundreds of millions of dollars, unlike the minimal commitment with a day-ahead market, it would be impractical for APS to leave an RTO once joined. (Tr. at 1186-1188.) Mr. Joiner testified that because there is not a legal mandate for an RTO in Arizona, APS has time to evaluate its operations fully and has some leverage while negotiating with the SPP and CAISO. (Tr. at 1188.)

APS is also a member of the Western Markets Exploratory Group ("WMEG"), which is considering how various future potential markets and other regional constructs could support member utilities. (Tr. at 1178-1179.) As of the hearing in this matter, WMEG had commissioned a cost-benefit study concerning how different members might benefit from different market footprints and features, and the APS-specific report had been completed. (Tr. at 1179-1181.) The APS-specific report included confidential information, and APS was planning first to share the report with the Commission and then to share non-confidential portions of the report with its RPAC and other stakeholder groups. (Tr. at 1180-1182.)

Mr. Joiner testified that APS intends to keep the Commission, Staff, and its RPAC informed about regional market developments, to receive input in the IRP stakeholder process, and to host workshops once certain milestones are reached so that additional stakeholder customer feedback can be obtained. (Tr. at 1120-1121.) Mr. Joiner anticipated that those milestones might be reached in mid-

[639] CAISO and SPP each has publicly indicated that it is willing to look at forming an RTO if that is what day-ahead market members and regulatory commissions want. (Tr. at 1473.) Mr. Joiner anticipates that each would form its own RTO. (Tr. at 1473-1474.)

2024 but stated that depended greatly on the SPP and CAISO providing APS the level of detail that APS is requesting. (Tr. at 1122.) In this matter, APS is seeking recovery of approximately $788,000 related to day-ahead and real-time market facilitation. (Tr. at 1159.)

Mr. Joiner agreed that the Commission has an interest in actions APS takes that could affect reliability or energy costs to be paid by APS ratepayers and that transparency is important, although he pointed out that during this exploratory phase APS is subject to nondisclosure agreements with other entities. (Tr. at 1159-1160.) According to Mr. Joiner, one of the benefits of broader regional wholesale market development for APS customers would be enhanced reliability through "the power of many" because resources could be pooled together for the entire western interconnect, allowing one entity that needs new resources to rely on another entity that has more resources than it currently needs. (Tr. at 1160.) Additionally, Mr. Joiner said, the diversity in resource types (Arizona's solar, the northwest's hydropower, and the plains' wind) and in peak load periods (APS's summer peak, the northwest's winter peak, and the different peak hours) would allow optimal use of resources. (Tr. at 1160-1161.) Mr. Joiner stated that once the regional market is mature, it will lead to reduced reserve margins, which result in lower costs, and deferred generation costs. (Tr. at 1161.) Mr. Joiner testified that another benefit would be that planning could go beyond the 15 minutes used in the WEIM now to day-ahead and then seasonal planning (almost a year in advance) and that more economic decisions can be made the further out one can plan. (Tr. at 1161.) Eventually, Mr. Joiner added, transmission planning and cost allocation could be coordinated as well. (Tr. at 1161.) Mr. Joiner agreed that greater western market integration would provide APS access to lower cost power and a larger market for the sale of its excess energy. (Tr. at 1162.)

<u>SWEEP & WRA Proposal</u>

SWEEP/WRA assert that the Commission should approve APS's requested cost recovery for regional market engagement activities as prudent, but only if the Commission also imposes reporting requirements to increase transparency and provide opportunities for Commission and stakeholder input on APS's market activities. (SWEEP/WRA Br. at 3.) SWEEP/WRA argue that APS's positions taken in the development of EDAM and Markets+ will impact APS's customers and that the Commission should be proactive and establish a reporting structure for APS's decision-making and participation in the wholesale electricity markets. (SWEEP/WRA Br. at 3.) WRA/SWEEP argue that APS's participation in a day-ahead market or an RTO[640] would result in operational changes for APS and, with an RTO, also implications for the Commission's jurisdiction. (SWEEP/WRA Br. at 4; *see* Tr. at 1189, 3464.) SWEEP/WRA assert that they support APS's exploration in the development of wholesale regional markets but that "it cannot and should not be absent Commission and stakeholder review and opportunity for public input." (SWEEP/WRA Br. at 4.) WRA/SWEEP also support APS's participation in WRAP and assert that APS's participation in WRAP and a day-ahead market or RTO (or both) would be a positive step for lower cost, more reliable, and cleaner power. (SWEEP/WRA Br. at 7; *see* Tr. at 1189, 3438.) SWEEP/WRA note that there are currently no requirements for APS to report to the Commission or stakeholders on its market engagement activities and assert that APS only shares select information on an ad hoc basis at its discretion. (SWEEP/WRA Br. at 7.) SWEEP/WRA argue that the Commission and stakeholders need "a better line of sight on APS's market engagement activities" because the positions taken by APS will influence the design of the market and will impact the level of benefits that APS customers receive. (SWEEP/WRA Br. at 7; Tr. at 1186-1187.) SWEEP/WRA criticize APS for only describing the $788,927 in costs for market engagement activity as "day-ahead and real time market facilitation" but acknowledge that additional information was obtained through discovery and cross-examination of APS witnesses. (SWEEP/WRA Br. at 8; *see* Ex. APS-37 at Sched. E-9 at 512-513.) SWEEP/WRA assert that at a minimum, the Commission should require APS to provide the Commission and stakeholders regular updates on APS's ongoing activities in exploring broader market participation (including transparency and metrics on cost savings, reliability, transmission, and environmental benefits) and should require opportunities for meaningful Commission and stakeholder input on market participation. (SWEEP/WRA Br. at 8.) SWEEP/WRA emphasize the important of market design and governance to the benefits ratepayers will attain from APS's market participation and assert that "there should be an established transparent

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[640] SWEEP/WRA assert that two RTO constructs are being explored by stakeholders, one a CAISO-operated RTO and the other a SPP-operated RTO, and that there is also an initiative called the West-Wide Governance Pathways Initiative to establish an independent RTO governance structure, which has been supported by regulators in Oregon, New Mexico, Washington, and Arizona. (SWEEP/WRA Br. at 9; *see* Ex. SWEEP-2 at att. BJB-3.) Commissioner Thompson was among the PUC Commissioners who signed a letter to leadership of the Committee on Regional Electric Power Cooperation and the Western Interstate Energy Board calling for creation of an entity with independent governance that could serve as a means for delivering a market to include all states in the Western Interconnection. (Ex. SWEEP-2 at att. BJB-3.)

process where APS informs the Commission and stakeholders on the market development process, and its planned positions therein, and then seeks input from [C]ommissioners and stakeholders." (SWEEP/WRA Br. at 10.) SWEEP/WRA also note APS's membership in the WMEG and assert that there are important questions for the Commission to consider in evaluating the WMEG report, including the following:

- To what extent should the WMEG report be relied on if it is limited to measuring production cost savings, but does not account for long-term capacity savings?
- To what extent should the WMEG report be relied upon if it does not account for transmission benefits and constraints on a granular level?
- To what extent should the WMEG report be relied upon if it doesn't account for the significant lost benefits to APS and its customers . . . due to APS exiting the WEIM?[641]

SWEEP/WRA assert that these are the types of policy issues that should be discussed in an open and transparent forum that includes input from Commissioners and stakeholders and that APS's providing the WMEG report and its opinions thereon to Commissioners privately does not eliminate the need for an established, open information-sharing process and also obliges stakeholders to approach the Commissioners for private meetings, "creating an unfair process outside of public view." (SWEEP/WRA Br. at 11; *see* Tr. at 1179-1180.)

SWEEP/WRA oppose APS's suggestion to use the RPAC as the forum for sharing information on its regional market plans with the public because APS controls the RPAC process (deciding when to present information, what to present, and whether and what feedback to take), and the RPAC process is not governed by statutory authority or a Commission order, having first been introduced in the Energy Rules Docket[642] that did not result in the adoption of rules. (SWEEP/WRA Br. at 11-12; *see* Tr. at 1182, 3369.) SWEEP/WRA argue that the Commission should be the forum and that there should be a structure established for regular updates and deliberation to understand market changes and the decisions APS must make and when concerning which market to join. (SWEEP/WRA Br. at 12; *see*

[641] SWEEP/WRA Br. at 11. It is not clear that APS would leave the WEIM. APS has indicated that it would not be possible to be in two day-ahead markets unless there is a good enough seams agreement to allow for the markets to interface and have flows. (*See* Tr. at 1474-1475.) APS also has indicated that it does not believe it would be possible to be in two real-time markets and that it contemplates being in one day-ahead market and one real-time market and has already committed to WRAP. (*See* Tr. at 1474.)

[642] Docket No. RU-00000A-18-0284. Official notice is taken of the fact that the RPAC concept was included in the proposed rules considered for adoption in this docket.

Tr. at 3368-3369.) SWEEP/WRA argue that APS's decision to join a market should also be evaluated and that the information-sharing process at the Commission should continue even after APS joins a market. (SWEEP/WRA Br. at 12; *see* Tr. at 3368-3369.)

SWEEP/WRA assert that the Commission has legal authority under the Arizona Constitution, statutes, and case law to require reporting by APS "as part of an approval of market engagement costs" and to implement a forum at the Commission for the periodic review of APS's exploration of day-ahead markets and other market activities. (SWEEP/WRA Br. at 12.) Specifically, SWEEP/WRA cite Arizona Constitution Article 15, § 3, A.R.S. §§ 40-202(A) and 40-204(A), and *Johnson Utilities, L.L.C. v. Arizona Corp. Comm'n*, 249 Ariz. 215, 221-222 (2020) ("*Johnson*"), as support for the Commission's authority to require a reporting and evaluation process intended to ensure that APS's market activities "maximize the benefits for Arizonans and promote just and reasonable rates." (SWEEP/WRA Br. at 12-14.) SWEEP/WRA note that the Commission has directed TEP to account for its market engagement by filing annual reports containing information such as deferred costs, as well as the annual revenues and associated savings derived from its WEIM membership. (SWEEP/WRA Br. at 14; *see* Ex. APS-84; Decision No. 77746 (October 2, 2020);[643] Decision No. 78551 (April 28, 2022).[644])

SWEEP/WRA state that to enhance transparency and the opportunity for the Commission and stakeholders to provide input on APS's market exploration and participation, it is in the public interest for the Commission to establish:[645]

- A framework for APS regularly to update the Commission and stakeholders on APS's ongoing activities in exploring market participation (providing metrics on cost savings, reliability, transmission, and environmental benefits) and to allow meaningful Commission and stakeholder input;

[643] In Decision No. 77746, of which official notice is taken, the Commission approved an accounting order for TEP to record and defer costs associated with the implementation phase of its proposed membership in WEIM, for recovery of 2022, 2023, and 2024 of cost amounts capped based on the total gross energy cost savings derived from its membership each year and without the option to seek recovery from ratepayers through other means. The Commission also required TEP annually to submit a compliance filing with the costs and savings, along with its annual fuel adjustor clause application.
[644] In Decision No. 78551, of which official notice is taken, the Commission ordered TEP, until further order, to file semi-annually its cost savings resulting from participation in the WEIM as well as an economic dispatch analysis.
[645] SWEEP/WRA Br. at 15-16; *see* Ex. WRA-1 at 7-9.)

- That the Commission is to serve as the forum for periodic review of regional market reliability, economic, and environmental benefits both before participation and after participation begins;
- Commission policy guidance on the guiding considerations for APS in selecting a day-ahead energy market, which should reflect public and consumer interests on governance structure, transparency in market design, incentives for clean energy development, and mitigation of seams;
- A requirement for APS to file with the Commission for approval, before joining a day-ahead market, a request that includes thorough evaluation of the value proposition, economic and environmental benefits, associated trade-offs from leaving the WEIM, and grid reliability considerations from joining the day-ahead market; and
- A requirement for a Commission workshop to be held in Docket No. E-00000A-21-0271[646] to review and discuss the WMEG studies' goals, approach, assumptions on geographic footprint, and findings.

AZLCG Proposal

According to AZLCG, APS is actively involved in discussions to shape and design two separate day-ahead markets and considering whether to join one and "committed to evaluating and joining" an RTO.[647] (AZLCG Br. at 92; *see* Tr. at 203; Ex. APS-11 at 14.) AZLCG notes Mr. Joiner's testimony that APS is "a thought leader, a design leader" in the development of the western market and Mr. Geisler's and Mr. Joiner's testimony about APS's belief that it is in ratepayers' best interests for APS to participate in broader markets and that regional wholesale market participation could enhance reliability, reduce costs, and allow for more efficient integration of clean energy resources through regional generation and transmission planning. (AZLCG Br. at 93; *see* Tr. at 203, 1160-1161, 1164;

[646] This is the docket In the Matter of the Commission's Investigation into Regional Planning, Markets, and Collaboration Among Load-Serving Entities in the Western Interconnection; Investigation into the Question of Mandatory or Voluntary Participation in Regional Transmission Organizations, Energy Imbalance Markets, Extended Day-Ahead Markets, and Other Organized Wholesale Energy Markets by Arizona's Load-Serving Entities: Consideration of the Cost and Reliability Impacts and Benefits of Participation to the Grid, Arizona Ratepayers, Utility Shareholders, and the State Of Arizona; Consideration of the Needs, Goals, Objectives, and Purposes of Participation; and Consideration of the Issues of Cost Allocation, Resource Adequacy, and Governance Associated with Participation, as Well as Any Other Issue the Commission May Deem Relevant to its Investigation. Official notice is taken of the existence of this generic docket, which was opened at the request of then-Chairwoman Márquez Peterson to be applicable to APS, TEP, UniSource Energy Services, and AEPCO.

[647] APS has not committed to joining an RTO. (*See, e.g.*, Ex. APS-11 at 14.)

Ex. APS-11 at 14.)

AZLCG praises APS's commitment to the evolution of the regional market but states that meaningful evaluation of regional markets must occur to ensure that the market rules and governance structures will deliver benefits to ratepayers and that "APS would benefit from involving stakeholders in this evaluation process." (AZLCG Br. at 93; *see* Ex. APS-11 at 14; Tr. at 1186-1187.) AZLCG does not question APS's intention to explore regional markets in a transparent manner but asserts that APS has not explained a process through which stakeholders could participate in APS's evaluation and instead has proposed to perform the analysis itself and to present "milestones" as they arise. (AZLCG Br. at 93-94; *see* Tr. at 1119-1122, 1159.) According to AZLCG, this process would not result in stakeholders being integrated into APS's regional market decisions, although the decisions will significantly impact APS and its ratepayers. (AZLCG Br. at 94; *see* Tr. at 3380, 3385.)

AZLCG recommends that the Commission require APS to implement a stakeholder workgroup, in which AZLCG desires to participate, to evaluate the adoption of regional markets and ensure that APS implements market initiatives that will provide ratepayers the greatest benefits. (AZLCG Br. at 94.)

<u>APS</u>

APS asserts that because both EDAM and Markets+ are still developing and subject to change, as Dr. Satyal acknowledged, and APS's evaluation of EDAM and Markets+ is ongoing, it would be premature to define the process and approvals needed for APS's eventual market participation. (APS Br. at 114; *see* Ex. APS-14 at 23; Tr. at 3377-3379.) APS states that it is committed to keeping stakeholders and the Commission fully informed as it explores the different market opportunities and that it will continue to facilitate robust stakeholder input and engagement with the Commission, such as through workshops and reporting. (APS Br. at 115; *see* Tr. at 3367-3373.) APS argues that there is no need for the Commission to establish formal requirements for future procedures or approvals associated with APS's potential participation in a wholesale day-ahead market. (APS Br. at 115.)

In its Responsive Brief, APS argues that it would be premature for the Commission to define in this matter the specific contours of the Commission's oversight of APS's evaluation of western regional markets because APS supports transparency in this area, APS offers and will continue to offer extensive opportunities for stakeholder involvement through its RPAC and IRP proceedings, and the regional markets are still under development. (APS RBr. at 92.) APS suggests that it could work with the Commission to determine how best to implement greater Commission oversight and argues that, contrary to the assertions of WRA, SWEEP, and AZLCG, no Commission action is needed in this matter. (APS RBr. at 92.)

SWEEP and WRA Responses

In its Responsive Brief, SWEEP points to AZLCG's recommendation for the Commission to require a stakeholder workgroup for evaluating the regional market proposals APS considers. (SWEEP RBr. at 2; *see* Ex. AZLCG-3 at 35-36; Ex. AZLCG-5 at 9-11; AZLCG Br. at 92-94.) SWEEP maintains its support for the recommendations made in the SWEEP/WRA Brief, which SWEEP states are needed to ensure prudent decision-making by APS. (SWEEP RBr. at 2-3.)

In its Responsive Brief, WRA argues that APS's opposition to providing the Commission regular reports on its market activities and to providing stakeholders and the Commission meaningful opportunities to provide input on next steps is tantamount to APS arguing "that the Commission should take a back seat on consequential market development decisions, and that it should simply be informed of market developments and APS's decisions after-the-fact, on APS's timetable." (WRA RBr. at 3.) According to WRA, APS's position would ensure a process with limited transparency and little meaningful input from the Commission and stakeholders. (WRA RBr. at 3.) WRA cites with approval AZLCG's Brief arguing that the Commission should require APS to engage with stakeholders in evaluating participation in regional markets. (WRA RBr. at 3.) WRA reiterates that APS should be required to provide transparency in exchange for market engagement cost recovery. (WRA RBr. at 3-4.)

AZLCG Response

In its Responsive Brief, AZLCG points out APS's error in stating that only SWEEP/WRA have taken a position on APS's market involvement and states that AZLCG fully agrees with WRA and SWEEP regarding market participation and submitted testimony on the subject. (AZLCG RBr. at 12-13; *see* Ex. AZLCG-3 at 35-36; Ex. AZLCG-5 at 9.) AZLCG argues that stakeholders' engagement in APS's exploration and design of markets is essential to ensuring that APS joins a market (or markets) that is in the best interests of the ratepayers who will pay for APS's market participation, as evidenced by APS's request to recover for market exploration costs in this matter. (AZLCG RBr. at 13; *see* Tr. at 1159.) AZLCG argues that because APS is essentially requesting ratepayers to "pre-fund"[648] market exploration activities without meaningful insight into whether APS's decisions are prudent, it is imperative for stakeholders and the Commission to "have a seat at the table." (AZLCG RBr. at 13.) AZLCG asserts that APS's stakeholders have great interest and expertise related to market development; that their contributions will serve the public interest; and that because APS anticipates milestones to occur in 2024, now is the time for stakeholders to become involved. (AZLCG RBr. at 13-14; *see* Tr. at 1122.) Due to APS's opposition to the Commission's requiring a stakeholder process and Commission involvement, AZLCG questions APS's commitment to keeping stakeholders and the Commission fully informed about its market exploration. (AZLCG RBr. at 14.) AZLCG argues that other PUCs are imposing orders such as that requested by AZLCG and SWEEP/WRA. (AZLCG RBr. at 14-15; *see* Nevada PUC Docket No. 22-09006, Order (March 23, 2023) at 156.[649]) Specifically, AZLCG cites directives issued by the Nevada PUC requiring NV Energy to "file . . . information detailing how it will implement more robust information sharing of [RTO] and market-related analyses" with stakeholders and to develop a "comprehensive plan" to join an RTO by 2030[650] as a component of its next IRP. (AZLCG RBr. at 14-15; *see* Nevada PUC Docket No. 22-09006, Order (March 23, 2023) at 156.) AZLCG states that NV Energy also committed to developing a plan no later than Q1 2025 to join an extended day-ahead market, provided that the timelines of the SPP and CAISO to offer such markets do not materially change.[651] (AZLCG RBr. at 15.) AZLCG states: "These requirements are all reasonable and should be adopted by the Commission in this proceeding." (AZLCG RBr. at 15.) AZLCG argues that because it, SWEEP, and WRA agree, the Commission

[648] The market exploration costs included in expenses in this case are understood to have been incurred during the TY. (*See* Ex. APS-37 at Sched. E-9 at 512-513.) Thus, if ratepayers are being asked to "pre-fund" these costs, the same can be said for all operating expenses included in base rates.

[649] Official notice is taken of this Order issued by the Nevada PUC in a case involving the 2021 Joint Integrated Resource Plan of Nevada Power Company dba NV Energy and Sierra Pacific Company dba NV Energy.

[650] AZLCG neglects to mention that it is "a comprehensive plan to meet Senate Bill 448's (2021) requirement to join a [RTO] by 2030." (*See* Nevada PUC Docket No. 22-09006, Order (March 23, 2023) at 156.)

[651] Specifically, NV Energy stated that it would make a recommendation on joining an RTO or day-ahead market once tariff language was drafted, a cost-benefit study by E3 was completed and reviewed, discussions have taken place with the Commission and stakeholders, and "approval," and stated that it anticipated recommending a day-ahead market in 2025. (Nevada PUC Docket No. 22-09006, Order (March 23, 2023) at 150.)

should require APS to engage more meaningfully with the Commission and stakeholders on regional market design and participation, as described in the parties' Briefs. (AZLCG RBr. at 15.)

Resolution

The evidence in this matter establishes the importance of the ultimate structures of the EDAM and Markets+, both as to operations and governance, to determining the benefits that would be available to APS and its ratepayers as a result of APS's participation in either of these day-ahead markets. It is an exciting and transformative time in the western region, and the Commission believes it important for the Commission to continue to remain engaged and informed of developments as they occur. However, the Commission does not believe that it is reasonable to require APS to file regular reports with the Commission, but does encourage APS, as appropriate, to continue to update the Commissioners on its concerns or decisions with the respective market developments.

N. Miscellaneous Issues

1. Securitization[652]

Sierra Club Proposal

Sierra Club asserts that because the 4CPP and Cholla are likely to have undepreciated net book value after their retirements, the Commission will need to decide whether to allow further recovery and could, rather than approving accelerated depreciation or the creation of a regulatory asset, require APS to reduce costs by using securitization or refinancing through the U.S. Department of Energy's ("DOE's") Energy Infrastructure Reinvestment Financing Program ("EIR Program").[653] (SC Br. at 49; *see* Ex. VS-1 at 23.) Sierra Club argues that although APS agrees that securitization or the EIR Program could save ratepayers money and help APS transition to lower cost energy resources, APS has not yet fully evaluated these options.[654] (SC Br. at 49-50; *see* Tr. at 636-638.) Sierra Club urges the Commission to order APS to evaluate how securitization and the EIR Program can be used to address

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[652] We note that both RUCO and the Nation included some discussion of securitization in the context of CCT, as provided above in Section VI(D). Because neither made a proposal concerning securitization that was not specifically tied to CCT, those discussions are not repeated here.

[653] Ms. Bowman testified that the EIR Program will provide up to $250 billion in low-cost loan guarantees for the retooling, repowering, repurposing, or replacement of retired energy infrastructure to operate with cleaner alternatives. (Ex. VS-1 at 23.)

[654] Mr. Cooper testified that APS was actively exploring both the EIR Program and securitization for potential future use. (Tr. at 638.)

the costs associated with coal plant retirements, without directing APS to take any specific further action. (SC Br. at 50.)

Sierra Club argues that the Commission has the authority to implement securitization, without any enabling legislation, under its Article 15, § 3 constitutional ratemaking authority because securitization "is essentially a financing and billing tool, just like approval of a regulatory asset or surcharge," or even under its Article 15, § 3 permissive constitutional authority because securitization is in the public interest. (SC Br. at 50-52; *see* Ariz. Const. Art. 15, § 3; *Johnson*, 249 Ariz. at 220-223.) Sierra Club reasons that because the Commission's plenary ratemaking authority is self-executing, and securitization is a financing mechanism, the Commission could determine that a regulatory asset debt will be recovered through base rates or instead through securitization. (SC Br. at 50-51.) Sierra Club argues: "Because the Arizona legislature has not enacted any legislation on securitization, there is no impediment to the Commission moving forward under its permissive authority."[655] (SC Br. at 52.)

Sierra Club asserts that securitization is appropriate to use with large, well-defined, non-recurring costs and would be implemented by the Commission's issuing "a financing order authorizing the issuance of ratepayer-backed bonds, payment on which would become the property right of a bankruptcy-remote 'special purpose entity.' . . . created to facilitate securitization."[656] (SC Br. at 52.) Sierra Club asserts that because securitization would immediately save ratepayers money by reducing the cost of debt, it should be explored in full for undepreciated coal assets. (SC Br. at 52.)

Sierra Club further urges the Commission to carefully consider the EIR Program, which it states can reduce the interest rate on the remaining debt on a resource but is more straightforward than and avoids the complicated legal issues associated with securitization. (SC Br. at 52.) Sierra Club acknowledges that EIR Program regulations are pending but states that the statutory language indicates the EIR Program will allow utilities to refinance existing debt on a fossil asset using a DOE loan at a lower interest rate and/or to obtain low-cost loans to build clean generation resources to replace retiring fossil resources. (SC Br. at 52.) Sierra Club asserts that the EIR Program could bring even more

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[655] We note that if the Commission could authorize the use of securitization under its plenary ratemaking authority, its permissive authority would not be at issue.

[656] Sierra Club does not address how the Commission would have legal authority to create a special purpose entity that would be bankruptcy-remote.

benefits than securitization due to its dual purposes and "would not require enabling legislation, because unlike securitization, there are no legal hurdles such as authorization of ratepayer-backed bonds or the creation of a special purpose entity." (SC Br. at 52-53.)

Sierra Club argues that the Commission should direct APS to evaluate securitization and financing through the EIR Program for depreciated assets and to submit an analysis into Docket No. E-99999A-22-0046, the ("IRP Docket"). (SC Br. at 54; *see* Ex. VS-1 at 24.) Sierra Club argues that the IRP Docket is the appropriate forum for the filing of APS's evaluation because Staff and stakeholders must have an opportunity to weigh in on the assumptions made and projects considered, and the use of either securitization or the EIR Program would impact the economic analyses associated with replacing fossil generation resources with clean energy. (SC Br. at 54.) Additionally, Sierra Club argues, because the EIR Program will only be available through September 2026, APS cannot wait until its next rate case to analyze the EIR Program's cost implications, and the Commission must push APS to act while the federal funds are available. (SC Br. at 54.)

<u>APS</u>

APS is not making any proposal regarding securitization in this matter. (Tr. at 749.) Because it anticipates having unrecovered book value of its retired coal-fired generation assets, APS has been assessing how securitization could be accomplished in Arizona, through discussions with credit rating agencies, bank underwriters of securitized financings, local community members, lawmakers, and others, and has concluded that to obtain the necessary low-cost AAA rating for securitization debt, there would need to be enabling legislation that creates a property right in repayment of the principal and interest on the debt and a pledge that the financing order for the securitization could not be revoked by the Commission. (Tr. at 658-660.) Mr. Cooper stated that the discussions have been exploratory, and he was not aware of any specific plans for APS lobbying regarding securitization during the next legislative session. (Tr. at 660, 748-749.)

Mr. Cooper's prior utility employer had a securitization bond in place, and he has worked on securitization bonds on Wall Street as well. (Tr. at 720.) Mr. Cooper stated that over the past five years, the industry has seen more securitizations related to plant retirement, particularly retirement of generation resources. (Tr. at 721.) Mr. Cooper testified that the credit rating agencies set very prescriptive requirements for securitization, including the AAA bond rating, that the principal and interest must be separate from regular rates charged to customers, and that the bond must be sized precisely to meet the principal and interest associated with the securitization debt. (Tr. at 722-723.) Mr. Cooper believes that in addition to enabling legislation for securitization, APS would need to obtain a financing order from the Commission allowing APS to complete the bond issuance. (Tr. at 723.)

APS has also been exploring the DOE loans possible under the IRA. (Tr. at 773.) APS is looking at the costs and benefits of both the DOE loans and securitization, does not currently have a preference for either, does not believe that the use of either is mutually exclusive, and stated that it will involve the Commission in whatever option it pursues. (Tr. at 773-774.) APS's goal in using either approach would be to eliminate the COE component associated with the unrecovered book value of assets by effectively changing the capital structure for the assets to 100% low-cost debt. (Tr. at 775.) Mr. Cooper stated that because the DOE is not required to start disbursing funds under the loan program until 2026, there is time for APS to continue evaluating it. (Tr. at 776.) Likewise, because enabling legislation is needed for securitization, it cannot be used right away. (Tr. at 776-777.) Mr. Cooper noted that more traditional ratemaking mechanisms could also be used, such as acceleration of depreciation for an asset's unrecovered book value or creating a regulatory asset and amortizing it over a lengthy period of time. (Tr. at 777.)

In its Responsive Brief, APS states that in 2031, it will have remaining 4CPP book value that must be recovered from customers and that it is still exploring financial mechanisms, such as securitization or DOE loans under the EIR Program, to reduce the cost impacts to customers. (*See* APS RBr. at 92-93; Ex. APS-5 at 14-15; Ex. APS-6 at 21-22.) APS agrees with Sierra Club that these mechanisms should be further evaluated because they could be valuable to customers. (APS RBr. at 93.) APS states that because the 4CPP closure will not occur until 2031, APS has time to continue exploring these potential cost-recovery mechanisms, and it is not appropriate for the Commission to direct and supervise APS's evaluation of them at this time. (APS RBr. at 93.) APS states that having Staff spend time to oversee APS's efforts in this area "would likely be wasteful." (APS RBr. at 93.) APS further states that Sierra Club is incorrect that no enabling legislation is needed for securitization to be implemented in Arizona, pointing out that the Commission expressly made th determination that enabling legislation is required in the 2022 TEP rate case. (APS RBr. at 93; *see* Ex. APS-6 at 22-23; Ex. APS-84 at 133.) APS argues that Sierra Club's mistake is due to its misinterpretation of *Johnson* and its limited understanding of securitization, which requires the establishment of complicated legal structures. (APS RBr. at 93.) APS asserts that it is unaware of any jurisdiction in the U.S. that has securitization for utilities without legislation to address the expectations and requirements of credit rating agencies, underwriting financial institutions, and the IRS. (APS RBr. at 93; *see* Ex. APS-6 at 22-23.)

<u>Sierra Club Response</u>

In its Responsive Brief, Sierra Club again urges the Commission to direct APS to evaluate both securitization and financing under the EIR Program for its stranded coal assets. (SC RBr. at 26.)

<u>Resolution</u>

Sierra Club is incorrect about the Commission's ability to implement securitization in the absence of enabling legislation. (*See* Ex. APS-84 at 133.) Sierra Club is correct, however, that APS should be thoroughly analyzing the extent to which it may be able to take advantage of securitization (assuming enabling legislation) and the EIR Program to ensure its own recovery of the remaining book value of retired coal-fired generation assets and to benefit its ratepayers. Mr. Cooper indicated that APS is exploring both of these possibilities, and the Commission has no reason not to believe him. The Commission encourages APS to keep the Commission and stakeholders informed of its efforts, through filings made in this docket and/or the IRP Docket, but does not believe it is necessary at this time to prescribe any particular actions for APS.

2. Workforce Planning Report & Workforce Qualifications

<u>IBEW Locals Proposal</u>

The IBEW Locals request for the Commission to order APS to file annual workforce planning reports and to adopt minimum qualifications for employees, contractors, and subcontractors working on APS's AZ Sun Battery Phase 1 and Phase 2 Projects, the Agave Solar Project, and any electric vehicle ("EV") infrastructure. (IBEW Br. at 1.)

Specifically, with regard to the annual workforce planning reports, the IBEW Locals request the Commission to adopt the following language:[657]

> APS shall file a workforce planning report with the Commission containing the following information: (i) the identification of each of the specific challenges or issues APS faces regarding workforce planning; (ii) the specific action(s) APS is taking to address each challenge or issue; and (iii) an update of the progress APS has made toward resolving each challenge or issue. The workforce planning report shall be filed on an annual basis, in this Docket, on or before DATE TBD, until the conclusion of the next APS general rate case and shall be limited to the following job classifications: designers, lineman/cableman, substations, E&I technicians, customer care representatives, control room operators, field technicians, and line locators. At a minimum, the workforce planning report shall set forth: (i) the number of employees then currently holding these positions; (ii) the present mean and median ages of APS's workforce with respect to these job classifications; (iii) the share of retirement-eligible employees, both as a percentage and in absolute terms, in each of these job classifications; and (iv) the anticipated hiring level and attrition level for each of these job classifications.

The IBEW Locals state that APS employs nearly 6,000 workers throughout the state and that APS must proactively hire and recruit to replace its retiring workforce because otherwise, APS's infrastructure (the grid, power plants, warehouses, control rooms, etc.) will not be adequately maintained and expanded. (IBEW Br. at 5.) The IBEW Locals state that the workforce planning report "will ensure APS receives adequate funds to prevent understaffing and that such reports have been required by the Commission in the past and have been useful and not overly onerous for APS. (IBEW Br. at 6; *see* Decision No. 76374 (September 19, 2017)[658] at ex. A at 14-15; Decision No. 74876 (December 23, 2014)[659] at ex. A at 19-20; Decision No. 73183 (May 24, 2012)[660] at 31, ex. A at 19-21.) The IBEW Locals assert that APS has acknowledged it tracks its retirement-eligible workforce and affirmatively plans how to fill the positions through talent development, training programs, identification of key at-risk positions, and knowledge transfer. (IBEW Br. at 6; *see* Tr. at 157.)

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[657] IBEW Br. at 5; *see* Ex. IBEW-1 at 13-14.

[658] Official notice is taken of this decision, issued in APS's 2016 rate case, in which the Commission approved a settlement agreement that included an annual workforce planning report requirement substantially similar to the one proposed by the IBEW Locals in this matter. The IBEW Locals were signatories to the settlement agreement.

[659] Official notice is taken of this decision, issued in APS's 2011 rate case, specifically concerning the 4CPP Rate Rider, in which the Commission approved a settlement agreement that included an annual workforce planning report requirement substantially similar to the one proposed by the IBEW Locals in this matter. The IBEW Locals were signatories to the settlement agreement.

[660] This decision was admitted as Exhibit RUCO-13. The Commission notes that this decision, issued in APS's 2012 rate case, approved a settlement agreement that included an annual workforce planning report requirement substantially similar to the one proposed by the IBEW Locals in this matter. The IBEW Locals were signatories to the settlement agreement.

The IBEW Locals assert that under A.R.S. §§ 23-403(A),[661] 40-321(A),[662] and 40-361(B),[663] the Commission and public service corporations have a legal duty to protect Arizona workers and citizens and that under Arizona Constitution Article 15, § 3, the Commission also has the legal authority to impose requirements to protect the safety and health of public service corporation employees and patrons. (IBEW Br. at 6-7.) The IBEW Locals state that APS has requested recovery for its AZ Sun Battery Phase 1 and Phase 2 Projects, Agave Solar Project, and EV infrastructure in this matter and request that APS be required to adopt the following qualification standards for those contracted or hired to work on this infrastructure:[664]

> (1) the qualified contractor/subcontractor must have a valid certificate of insurance showing the following coverages: general liability, professional liability, product liability, worker's compensation, completed operations, hazardous occupation, and automobile; (2) the qualified contractor/subcontractor must assure that all its employee safety training is completed in compliance with public service corporation guidelines, policies and 29 C.F.R. 1926; and (3) the qualified contractor/subcontractor must provide evidence of its participation in apprenticeship and training programs, applicable to the work to be performed on the project, which are approved by and registered with the United States Department of Labor's Office of Apprenticeship, or its successor organization.

The IBEW Locals assert that these standards are specifically aimed at ensuring that workers on Arizona's energy infrastructure are well trained, certified, and insured, which will ensure that ratepayers are paying for the most productive, safe, and best trained workforce. (IBEW Br. at 7.) According to the IBEW Locals, Arizona is experiencing a "boom in competition" between utilities and electrical contractors for a limited pool of experienced, qualified workers, and the Commission's taking a "proactive approach . . . to regulate this workforce will incentivize an uptick in training within this group of workers and . . . in turn will produce a bigger pool of highly skilled workers in Arizona." (IBEW Br. at 8; *see* Ex. IBEW-1 at 15-16.)

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[661] This statute generally requires employers to provide work and places of employment that are free from recognized hazards that cause or are likely to cause death or serious physical harm and to comply with occupational safety and health standards, regulations, and orders.

[662] A.R.S. § 40-321(A) requires the Commission, after finding that the equipment, appliances, facilities, or service of a public service corporation or the methods of manufacture, distribution, transmission, storage, or supply used by the public service corporation are unjust, unreasonable, unsafe, improper, inadequate, or insufficient, to determine what is just, reasonable, safe, proper, adequate, or sufficient and to enforce its determination by order or regulation.

[663] A.R.S. § 40-361(B) requires each public service corporation to furnish and maintain service, equipment, and facilities that will promote the safety, health, comfort, and convenience of its patrons, employees, and the public and that will be in all respects adequate, efficient, and reasonable.

[664] IBEW Br. at 7.

APS

APS states that safety is its highest priority; that it has robust programs and procedures in place to minimize incidents affecting employees, customers, and the public; and that it consistently delivers at or better than annual EEI top quartile reliability. (APS Br. at 135; *see* Ex. APS-9 at 12.) According to APS, this is partially due to APS's ensuring that it maintains appropriate staffing levels of qualified individuals. (APS Br. at 135; *see* Ex. APS-9 at 12.) APS states that its pre-apprenticeship training program is in demand, as evidenced by the 657 applications received for 25 positions in 2022 and the 907 applications received for 30 positions in 2023. (APS Br. at 135; *see* Ex. APS-9 at 12.) APS asserts that it has also increased the class sizes for lineman and substation electrician apprentices to ensure it can meet openings caused by attrition and uses contract labor when necessary to ensure adequate coverage. (APS Br. at 135; *see* Ex. APS-9 at 12.) APS does not believe that a workforce planning report is necessary or in the best interests of its ratepayers. (APS Br. at 136.)

In its Responsive Brief, APS asserts that the IBEW Locals have acknowledged that the workforce planning report requirement would be an expensive effort. (APS RBr. at 102; *see* IBEW Br. at 5-6.) APS reiterates that APS ensures appropriate staffing levels of qualified individuals through training programs, talent development, and use of contract labor as necessary and asserts that given there is no evidence of understaffing, it would not be in the best interest of APS's ratepayers for APS to be required to comply with the proposed reporting obligation. (APS RBr. at 102.)

In response to the minimum qualification requirements proposed by the IBEW Locals for specific projects and types of projects, APS states that because the PTYP projects named are already used and useful, it would be "inappropriate and nonsensical" to impose minimum qualification requirements now and, further, that APS has no plans to install additional DCFC EV charging equipment at this time. (APS RBr. at 103; *see* Ex. APS-9 at 12; Ex. APS-10 at 5.) Additionally, APS states that APS uses an ASRFP process to ensure that all factors, including customers' paying for the most productive, safe, and best trained workforce, are adequately evaluated and considered at the outset for a project and that the Commission's ordering potentially unnecessary minimum requirements would not benefit customers and would only limit APS's ability to find the most effective ways of providing safe and reliable electricity at a reasonable cost. (APS RBr. at 103; *see* Ex. APS-9 at 11-12; Ex. APS-

10 at 5.)

Resolution

Mr. Geisler questioned whether a workforce planning report would be meaningful or accurate because APS's use of an ASRFP process makes it difficult to predict in advance the generation that APS will be procuring (APS-owned or market-acquired) and thus the labor necessary to support the generation, as different types of generation require different amounts of labor. (Tr. at 154-157.) As acknowledged by the IBEW Locals, Mr. Geisler also testified that APS tracks retirement eligibility among its employees and uses talent development, training programs, succession planning, and knowledge transfer to fill gaps as they occur. (Tr. at 157.) The evidence supports that APS is already paying attention to its retirement-eligible workforce, is already engaged in succession planning, and is already providing training to fill worker gaps that occur. Additionally, the evidence supports that APS's pre-apprenticeship program is highly in demand, which indicates that APS should be well positioned to find qualified workers when they are needed. The Commission is aware that the workforce planning requirement has previously been approved by the Commission, but the Commission is not aware of its having been approved other than as a component of a settlement agreement. Because the workforce planning report is not something that the Commission needs to perform its duties, and its accuracy and thus value is questionable in any event, the Commission will not adopt the IBEW Locals' workforce planning report requirement.

Both the Agave Solar and AZ Sun Battery I and II projects have been included in PTYP. (*See* Ex. APS-8 at 15; Tr. at 787.) APS also included in PTYP EV charging infrastructure under the Take Charge AZ program and the Interstate Electric Vehicle DCFC Project. (Ex. APS-8 at 16-18; Ex. APS-9 at 7; Ex. APS-10 at Att. JT-01RJ; Tr. at 992-995.) These projects have been completed and were in service by June 30, 2023. (*See* Ex. APS-10 at Att. JT-06RJ.) Additionally, APS has indicated that it does not intend to install any additional DCFC EV charging equipment at this time. For these reasons, it would not make sense to impose worker qualifications on these specific projects or types of projects. Additionally, no evidence has provided the Commission any reason to conclude that the worker qualification requirements APS currently imposes for its various projects have resulted or will result in services that are unjust, unreasonable, unsafe, improper, inadequate, or insufficient; have resulted or will result in equipment or facilities that are not in all respects adequate, efficient, and reasonable; or have resulted or will result in conditions that would adversely impact the convenience, comfort, safety, or health of APS's employees or patrons. The Commission will not adopt the IBEW Locals' proposed worker qualification requirements.

3. Public Access to Documents

AZLCG Proposal

AZLCCG asserts that while APS posts its rate schedules on its website, it has not been required to and historically has not posted its POAs or the AG-X Program Guidelines, even though the rate schedules refer to these documents, and they include important information on the operation of APS's rates. (AZLCG Br. at 106; Tr. at 2368-2370, 2497, 2501-2506, 2814.) AZLCG recommends that the Commission require APS to post on its website all documents that affect the operation of or the terms and conditions related to the rates APS charges its customers. (AZLCG Br. at 106.) AZLCG notes that APS does not oppose this recommendation and that, during the hearing, APS filed a notice in the docket stating that its website now includes all POAs and the AG-X Program Guidelines.[665] (AZLCG Br. at 106.)

Resolution

AZLCG's proposal is reasonable and in the public interest. Thus, the Commission will order APS to ensure going forward that all of the documents that affect the operation of or the terms and conditions related to the rates APS charges its customers (such as its POAs and Program Guidelines) are posted on its website so that they may be accessed by the public.

4. Marketing

Ms. Nelson's Proposal

Ms. Nelson asserts that the Commission should not allow APS to market on billboards, on TV, on radio, at sporting events, or through similar forms of media because no amount of marketing allows customers to change to a new provider. (KN Br. at 4.) Ms. Nelson also appears to criticize APS's inclusion in billing statements of fliers providing information on programs, reducing bills, and rate

[665] Official notice is taken of this filing made by APS after business hours on September 7, 2023, and available at https://docket.images.azcc.gov/E000030589.pdf?i=1705524147791.

plans. (*See id.*)

Resolution

The Commission understands Ms. Nelson's consternation with APS marketing itself, as it is a regulated monopoly with a defined service area and has no need to solicit customers. The subject of APS's marketing arose within the public comments in this matter, indicating that Ms. Nelson is not alone in feeling this way. When asked about APS's marketing activities, Mr. Geisler testified that APS only requests recovery in rates for marketing that educates customers or that encourages customers to consider enrolling in a program from which APS believes customers will benefit. (Tr. at 426-427.) Mr. Geisler stated that when APS was meeting with peer utilities, consultants, customer working groups, and stakeholder groups, it heard that APS should communicate with its customers more frequently concerning how to save, where to go for resources, and how to enroll in programs. (Tr. at 427.) Mr. Geisler distinguished this marketing from APS's advertisements at stadiums, sponsorship of events, commercials that are not educational,[666] and merchandise distributed at community events, stating that APS does not request recovery of these costs through rates. (*See* Tr. at 428-429.) Exhibit APS-40 shows that APS included in TY expenses approximately $8.2 million for General Advertising Expenses and includes copies and scripts from the various advertising included within the request. The various media advertising included in costs for the TY direct the viewer/reader either to an event or to APS's website for additional information on a feature or program. Although the Commission will allow recovery of the approximately $8.2 million in advertising costs for this rate case, the Commission considers some of the examples of advertising included to be of questionable educational value to the ratepayer. The Commission cautions APS that going forward, such advertising expenses will not be considered an appropriate expenditure of ratepayer dollars. The Commission will direct APS not to use ratepayer-derived funds on marketing, advertising, media production, advertising retainers, or advertising research, or for any other marketing- or advertising-related purposes (collectively "marketing/advertising") unless the content of the marketing/advertising is educational and directly

[666] During the hearing, it was apparent that there could be reasonable differences of opinion on whether certain advertising is educational as opposed to "feel-good" advertising. (*See* Tr. at 428-429.) APS's position has been that if advertising is pointing people to APS's website for additional information, for example to sign up for outage alerts, it is educational and its costs are appropriately included in requested rate recovery. (*See* Tr. at 429.)

related to a specific Commission-approved program, rate plan, or tariff. Additionally, the Commission directs APS to consider taking steps to ensure a proper and thorough accounting of ratepayer-funded advertising/marketing expenses going forward, so that the programs and funds such efforts are associated with are more easily trackable in a future review.

While the Commission declines to direct APS to cease the other forms of advertising/marketing for which APS does not request recovery through rates, APS has been made aware that at least some of its customers are concerned about the money APS presumably is spending on such advertising/marketing and how it impacts their bills. The Commission believes it would behoove APS to make it clear to the public that such advertising/marketing (sponsorships, advertisements at sporting events, swag at meetings, etc.) is not paid for by ratepayers but will leave it to APS to determine whether and in what manner it chooses to do so.

5. Billing

Ms. Nelson's Proposal

Ms. Nelson asserts that the Commission should address customer complaints of years of confusing billing.

Resolution

Mr. Geisler acknowledged that APS's billing format could be greatly improved and that APS had worked with stakeholders on a new bill format for which the coding and printing algorithms were being developed as of the hearing. (Tr. at 416.) Mr. Geisler noted that the new format had recently been reviewed and approved by the Commission and that it would be put into use later in 2023 or early in 2024. (Tr. at 416-417, 468.) APS provided mock-ups of the new bill format, and they are significantly improved. (*See* Ex. APS-41; Tr. at 466-467.) The Commission considers APS to be in the process of addressing the customer complaints about confusing billing and does not believe that it is necessary to provide APS any further direction concerning its billing format or practices at this time.

VII. Rate Base & TY Revenues and Operating Expenses

A. Rate Base Determinations

The parties who presented schedules on APS's rate base proposed the following final positions ($ amounts are in thousands):

	APS Final[667]	AZLCG[668]	RUCO[669]	Staff[670]
OCRB	$10,359,616	$9,897,373	$10,026,234	$10,366,281
RCND	$22,497,874	$22,061,326	$22,163,388	$22,503,435
FVRB	$16,428,745	$15,979,349	$16,094,811	$16,434,858
FVI	$6,069,129	$6,081,976	$6,068,577	$6,068,577

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	$10,355,411
RCND	$22,493,669
FVRB	$16,424,540
FVI	$6,069,129

B. TY Revenues and Operating Expenses

The parties who presented schedules on APS's TY operating revenues, operating expenses, and operating income proposed the following final positions ($ amounts are in thousands):

	APS Final[671]	AZLCG[672]	RUCO[673]	Staff[674]
Total Operating Revenues	$3,629,625	$3,669,029	$3,833,163	$3,628,663
Total Operating Expenses	$3,373,189	$3,276,878	$3,366,404	$3,344,772
Operating Income	$256,436	$392,152	$466,759	$283,891

Based on our resolutions of the contested issues above, we conclude that APS's adjusted TY total operating revenues, operating expenses, and operating income were as follows ($ amounts are in thousands)::

	Commission Determination
Total Operating Revenues	$3,629,625
Total Operating Expenses	$3,277,015
Operating Income	$352,610

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667 *See* APS Br. at Att. B at Sched. A-1, Sched. B-1.
668 *See* AZLCG Br. at ex. KCH-1-F at 1, 5.
669 *See* RUCO Final Sched. at Sched. A-1, Sched. B-1.
670 *See* Staff Br. at Att. B at Att. RCS-15 at 2, 5.
671 *See* APS Br. at Att. B at Sched. A-1, Sched. C-1.
672 *See* AZLCG Br. at ex. KCH-1-F at 1, 8.
673 *See* RUCO Final Sched. at Sched. A-1, Sched. C-1.
674 *See* Staff Br. at Att. B at Att. RCS-15 at 2, 8. Staff's Brief shows the same adjusted operating revenues figure for APS and did not propose any adjustments to APS's operating revenues. (*See* Staff Br. at Att. B at Att. RCS-15 at 8.)

VIII. Cost of Capital

A. Capital Structure & Cost of Debt

APS Proposal

APS proposes to use its TY capital structure, consisting of 51.93% equity and 48.07% long-term debt, and its TY embedded cost of long-term debt of 3.85%. (APS Br. at Att. B at Sched. D-1.) APS argues that using its actual capital structure is consistent with use of a historical TY and appropriate because the capital structure represents the expected average capital structure for the time when new rates from this matter will be in effect. (APS Br. at 13.) APS notes that its capital structure in this matter has lower equity than its currently authorized capital structure from the 2019 rate case, which was 54.67%. (APS Br. at 13; *see* Ex. RUCO-7 at 304.) APS describes RUCO's position as "an alarmingly outlier perspective" and notes that RUCO also proposes a "significant and punitive adjustment" to APS's ROE to be made through a Hamada adjustment if the Commission approves APS's actual capital structure. (APS Br. at 13-14; *see* Tr. at 3664.) APS argues that RUCO is mistaken in its belief that the proxy group has a higher debt ratio than APS and argues that this is based on RUCO comparing APS's capital structure to that of the holding companies in the proxy group rather than of the actual operating utilities. (APS Br. at 14; *see* Ex. APS-7 at 4-5.) APS argues that the average common equity ratio reported for operating electric utilities in 2022 was 53% equity. (APS Br. at 14; *see* Ex. APS-34 at 91, att. RAM-02RB.) APS also argues that RUCO's imputed capital structure would put pressure on APS's credit metrics and ultimately increase costs for APS to access capital. (APS Br. at 14; *see* Ex. APS-6 at 8-9.) APS states that its capital structure is consistent with those of its peer operating utilities and that using it will promote cost-effective access to capital. (APS Br. at 14.) APS cites Dr. Morin's testimony that RUCO's low recommended common equity ratio "would sink the Company's bond ratings even further down the path of credit deterioration at the expense of ratepayers" and argues that RUCO's imputed capital structure ignores reality, is harmful to APS and ratepayers, and should not be adopted. (APS Br. at 14.)

APS states that using its embedded cost of long-term debt is consistent with the use of a historical TY and should be approved. (APS Br. at 14.) No party opposes APS's use of its actual embedded cost of long-term debt. (APS Br. at 12, 14.)

RUCO

RUCO argues that APS's rates should be set using an imputed ratemaking capital structure of 54% debt and 46% equity, which is the average capital structure for the proxy group APS used to calculate its recommended ROE. (RUCO Br. at 27; *see* Ex. RUCO-5 at 3-4, ex. DJG-17.) In the alternative, RUCO argues, if the Commission accepts APS's proposed capital structure, the Commission should award a lower ROE of 8.2% (as opposed to RUCO's main recommendation for an ROE of 8.7%.). (RUCO Br. at 27, 30; Ex. RUCO-5 at 3-4, ex. DJG-17.) Mr. Garrett testified that because the Commission stands in the place of competition, it must ensure that a utility operates at the lowest reasonable WACC. (Ex. RUCO-5 at 46.) Mr. Garrett also testified that regulated utilities can afford to have higher debt ratios and should generally operate with relatively high debt ratios to achieve their optimal capital structure. (*Id.* at 46-47.) To determine the recommended capital structure for APS, Mr. Garrett examined the capital structures of the proxy group companies and PNW and determined that the average debt ratio for the proxy group was 54% and that PNW's debt ratio was 55%. (*Id.* at 47-48.) This indicates, Mr. Garrett stated, that PNW is using debt to finance the purchase of APS's equity ("double-leveraging"), and that approval of APS's proposed capital structure would allow PNW to earn a "windfall equity return" on debt that was borrowed at lower rates, at the expense of ratepayers. (*Id.* at 48.) Mr. Garrett determined that APS's proposed debt ratio is clearly too low and recommended the imputed capital structure of 54% debt and 46% equity. (*Id.* at 50.)

In its Responsive Brief, RUCO acknowledges that it compared APS's capital structure to the equity ratio of the proxy holding companies. (RUCO RBr. at 3.) RUCO reiterates its argument that because APS's equity is funded by PNW, which has a debt ratio of 55%, allowing APS to use its actual capital structure will result in excess profits to APS. (RUCO RBr. at 3.) RUCO argues that because PNW funds APS's equity, PNW's capital structure directly impacts APS's capital structure, which directly impacts APS's WACC and proposed revenue increase. (RUCO RBr. at 3.) RUCO asserts that APS has not shown or argued that the same dynamic exists with the other utilities in the proxy group and that it would be counterintuitive to suggest that the relationship should be ignored because PNW has a different capital structure. (RUCO RBr. at 3.) RUCO argues that this relationship between parent and utility is "precisely what the Hamada adjustment is designed to address."[675] (RUCO RBr. at 3.)

Resolution

RUCO's concerns about APS's capital structure are based upon the debt ratio in APS's TY capital structure (48.07%) as compared to the debt ratios of PNW (55%) and of the proxy group companies (holding companies) used by Dr. Morin in his cost of capital analyses (average 54%). (*See* Ex. RUCO-5 at 47-50.) Dr. Morin performed an analysis to compare the capital structures of the operating utilities owned by the proxy group holding companies, which shows that the operating utilities had an average common equity ratio of 53.48% and thus an average debt ratio of 46.52%.[676] (*See* Ex. APS-34 at Att. RAM-02RB). This is very much in keeping with APS's debt ratio, and the Commission finds that there is not sufficient evidence to determine that APS's actual capital structure should not be used. Thus, the Commission will use APS's actual TY capital structure of 51.93% equity and 48.07% long-term debt. Additionally, as there is no dispute, and APS is proposing to use its actual TY embedded cost of long-term debt, the Commission will use APS's actual TY embedded cost of long-term debt of 3.85%.

B. Cost of Equity

The parties who presented COE calculations produced the following results and recommendations using the analytical methods shown:[677]

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[675] RUCO states that the Hamada formula is used to analyze changes in APS's cost of capital as financial leverage (debt) changes in its capital structure by starting with an "unlevered" beta and then "relevering" the beta at different debt ratios. (RUCO RBr. at 3-4; *see* Ex. RUCO-5 at 51.) RUCO states that with higher leverage comes higher risk and thus higher betas. (RUCO RBr. at 4.) According to RUCO, the Hamada formula removes the effects of leverage. (RUCO RBr. at 4; *see* Ex. RUCO-5 at 51.)

[676] When Evergy Kansas South, which has a common equity ratio of 83.34% and thus appears to be a clear outlier, is excluded, the average common equity ratio is 52.97% and the average debt ratio is 47.03%, even closer to APS's capital structure. (*See* Ex. APS-34 at Att. RAM-02RB.)

[677] Ex. APS-34 at 99; Ex. AZLCG&FEA-3 at 57; Ex. AZLCG&FEA-1 at 58; Ex. RUCO-5 at 4, ex. DJG-12; Ex. S-2 at 16. We acknowledge that there were differences in their applications of the different methods.

	APS[678]	AZLCG & FEA	RUCO	Staff
DCF[679]	9.9%, 10.0%	9.20%	7.7%, 8.7%	9.55%
CAPM[680]	10.7%	9.50%	8.20%[681]	9.65%
ECAPM[682]	10.9%	-	-	-
Risk Premium[683]	10.3%, 10.4%	9.90%	-	10.15%[684]
Comparable Earnings[685]	-	-	-	9.5%
Recommended ROE	**10.25%[686]**	**9.55%**	**8.20%[687]**	**9.68%**

APS, AZLCG and FEA, and RUCO all used the same 24-company proxy group to perform their analyses. (*See* Ex. APS-33 at Att. RAM-02DR; Ex. AZLCG&FEA-1 at 30; Ex. RUCO-5 at 13.) Staff used an 11-company proxy group comprised of nine of the companies from the other parties' proxy group plus PNW and Hawaiian Electric Industries. (*See* Ex. S-1 at ex. DCP-1 at Sched. 5.)

<u>APS Proposal</u>

APS proposes an ROE of 10.25%, which it states is "conservative" given APS's higher regulatory risks as compared to the proxy group, its need for significant external financing for

[678] The ROEs presented by Dr. Morin were adjusted upward to include "flotation costs." (*See* Ex. APS-33 at 65, 69-74, Att. RAM-03DR, Att. RAM-07DR.)

[679] The Discounted Cash Flow model ("DCF") is based on the theory that a stock's current price represents the present value of all expected future cash flows. (Ex. RUCO-7 at 305 n.370.) The most common DCF model assumes a constant rate of growth. (Ex. S-1 at 22.)

[680] The Capital Asset Pricing Model ("CAPM") is a risk premium approach that estimates the COE for a security as a function of a risk-free return plus a risk premium, to compensate investors for the security's non-diversifiable or systemic risk. (Ex. RUCO-7 at 306 n.371.) The risk premium is the product of the market risk premium and the Beta coefficient, which represents the relative riskiness of the security. (*Id.*)

[681] This COE assumes APS's proposed capital structure. (*See* Ex. RUCO-5 at ex. DJG-12.)

[682] The Empirical CAPM ("ECAPM") is a modified CAPM designed to address the conclusion that the CAPM "underestimates the return required from low-beta securities and overstates the return required from high-beta securities." (Ex. APS-33 at 61.)

[683] The historical Risk Premium model used by Dr. Morin analyzed the period from 1931 through 2021 and involved determining the risk premium for each year by calculating the difference between the actual realized ROE capital each year using actual stock prices and dividends from the S&P Utilities Index (proxy for electric utility returns) and the income component of the long-term Treasury bond yield for the year. (Ex. APS-33 at 64-65, Att. RAM-08DR.) Dr. Morin then added the risk premium to the risk-free rate. (*Id.*) The allowed Risk Premium model used by Dr. Morin determined the risk premium by calculating the difference between the average authorized ROE for major rate cases each year from 1986 through 2021 and the long-term Treasury bond yield for the year. (Ex. APS-33 at 6-67, Att. RAM-09DR.) Dr. Morin calculated a statistical relationship between the risk premium and interest rates and used the resulting formula to increase the risk premium, to which he added the risk-free rate. (*Id.*)

[684] Mr. Parcell identified this result as an "outlier." (Ex. S-2 at 12.)

[685] The Comparable Earnings method is based on the economic concept of opportunity cost and designed to measure the returns expected to be earned on the original cost book value of enterprises with similar risks. (Ex. S-1 at 34.) Mr. Parcell's Comparable Earnings analysis examined realized ROEs for the proxy utilities and unregulated companies and evaluated investor acceptance of the returns by referring to the resulting market-to-book ratios. (Ex. S-1 at 35.) Mr. Parcell stated that a market-to-book ratio of greater than one (i.e. greater than 100%) indicates that a company is able to attract new equity capital without dilution. (*Id.*)

[686] We note that Dr. Morin testified a reasonable ROE for APS would be 10.4%, but that APS desired to maintain its ROE request of 10.25%. (*See* Ex. APS-34 at 99.)

[687] This ROE assumes APS's proposed capital structure. (*See* Ex. RUCO-5 at 4.)

infrastructure, rising interests rates, and a generally heightened risk environment for the electric utility industry. (APS Br. at 16; *see* Ex. APS-33 at 12-13.) APS recounts Dr. Morin's testimony about the "Perfect Storm" facing utilities like APS due to the U.S.'s economic growth outpacing energy consumption growth over the past decade; the need for record amounts of new capital to replace aging infrastructure, improve reliability, and incorporate new technologies; the higher business risks facing utilities from customers who both purchase and generate electricity; and the upward trend in operating costs caused by inflation and supply chain bottlenecks. (APS Br. at 16; *see* Ex. APS-33 at 9-11; Tr. at 2675-2676.) APS also recounts Dr. Morin's testimony that it is important for a utility to maintain a good credit rating because the cost-of-debt difference between a single "A" rated company and a "BBB" rated company is approximately 30 basis points, meaning that APS customers would pay more than $200 million in extra costs if APS were to issue $3.5 billion in bonds as a "BBB" rated utility rather than as an "A" rated utility. (APS Br. at 17; *see* Ex. APS-33 at 84; Tr. at 2679.) APS argues that its credit ratings are at risk due to its negative ratings outlook from both Moody's Investor Services ("Moody's") and Standard & Poor's Global Ratings ("S&P") [688] and that it needs regulatory support and approval of its capital structure and ROE to improve its financial stability. (APS Br. at 17; *see* Tr. at 2678; Ex. APS-33 at 76-80.) APS argues that customers benefit when APS is financially stable and can continue to attract on reasonable terms the capital needed to provide electricity to its customers. (APS Br. at 17.)

APS asserts that although APS's proposed 10.25% falls within the range of Staff's ROE analysis results, Mr. Parcell understates the appropriate ROE due to the composition of his proxy group, his calculation of the DCF dividend yield component, his failure to use a flotation cost adjustment, his use of earnings retention growth in the DCF, his use of historical growth proxies in the DCF, his market risk premium estimate in the CAPM, his failure to use the ECAPM, and his position on the relationship between ROE and market-to-book ratios. (APS Br. at 17-18; *see* Ex. APS-34 at 6, 39-68.) APS asserts that if Mr. Parcell's analyses were corrected, they would produce an ROE of 10.35%.[689] (APS Br. at

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[688] In October 2021 and November 2021, Fitch Ratings, Moody's, and S&P downgraded PNW and APS from A- to BBB+ with a negative outlook. (Ex. APS-33 at 77-78.)

[689] Dr. Morin's testimony showed that the average ROE after his "corrections" to Mr. Parcell's analyses would be 10.39%. (*See* Ex. APS-34 at 68.)

18; *see* Ex. APS-34 at 68.)

APS asserts that although APS's proposed 10.25% ROE also falls within FEA's range of ROE analysis results, Mr. Walters's cost of capital analyses understated results from between 20 and 100 basis points. (APS Br. at 18; *see* Ex. APS-34 at 35-36.) APS points to Dr. Morin's criticism of Mr. Walters's analyses based on Mr. Walters's failure to use a flotation cost adjustment, his "understatement" of the beta estimate in the CAPM and Risk Premium analyses, his failure to use the ECAPM, and his failure to account for the inverse relationship between the allowed Risk Premium and the level of interest rates. (APS Br. at 18; *see* Ex. APS-34 at 5, 9-36.) APS points to Dr. Morin's testimony asserting that if Mr. Walters's analyses were corrected, they would produce an ROE of 10.23%. (APS Br. at 18-19; *see* Ex. APS-34 at 36.)

Regarding RUCO's recommendation, APS points to Dr. Morin's testimony that Mr. Garrett's recommendations are "draconian" and should be "disregarded entirely" because they contain numerous analytical flaws and would have severe financial consequences if they were adopted. (APS Br. at 19; *see* Ex. APS-34 at 94-96.) APS argues that Mr. Garrett's recommendations should be disregarded because he has routinely made upward adjustments to his low ROE recommendations in other cases, but not in this one; he acknowledged that he generally does not work with utilities because it would not be in their shareholders' best interests to hire him; and he used a lottery analogy that APS asserts was inappropriate[690] because "APS does not gamble with its financial health or its ability to provide safe and reliable service to its customers." (APS Br. at 19-20; *see* Tr. at 3625, 3633-3641, 3654-3655, 3661.) APS argues that Mr. Garrett's analyses "are not rooted in any objective methodology, but rather are biased towards the lowest possible ROE irrespective of the financial impact on the utility."[691] (APS Br. at 20; *see* Tr. at 3651-3652.) APS notes Dr. Morin's testimony that RUCO's ROE, if adopted, would be the lowest ROE authorized in the vertically integrated electric utility industry and would adversely impact APS's creditworthiness, financial integrity, ability to raise capital, and customers.

[690] Mr. Garrett provided this analogy while explaining his issues with the comparable earnings model used by Mr. Parcell, which he essentially stated confuses the concepts of earned ROEs and cost of equity, which are distinct concepts. (*See* Tr. at 3654-3656.)

[691] This is not supported by the transcript portion cited by APS, which includes Mr. Garrett stating that other expert witnesses' COE estimates should have been lower over the past few years, as his have been, due to historically low capital costs, based on running the CAPM model correctly. (*See* Tr. at 3651-3652.) Mr. Garrett also testified that while he primarily represents non-utility parties, Dr. Morin almost exclusively or exclusively represents utilities. (Tr. at 3652.)

(APS Br. at 20; *see* Ex. APS-34 at 94-95.) APS argues that due to its current "negative outlook" from credit rating agencies, adoption of RUCO's ROE would almost certainly result in a further downgrade of its credit rating. (APS Br. at 20; *see* Ex. APS-34 at 95-96.) APS cites Dr. Morin's testimony that RUCO's recommendation is an outlier and argues that it is "shocking" in light of RUCO's recommended ROE of 9.13% in the 2022 TEP rate case. (APS Br. at 20-21; *see* Ex. APS-34 at 71-73; Ex. APS-84 at 35.[692]) APS argues that Mr. Garrett's entire cost of capital analysis should be completely rejected. (APS Br. at 21.)

<u>AARP</u>

AARP states that RUCO's recommended ROE of 8.7% is more reasonable than the ROE proposed by APS and that it would be "outrageous" for APS to collect a "double-digit profit" from its ratepayers. (AARP Br. at 2.) Further, AARP states that APS's lower debt ratio compared to its peers shows that it has significantly less financial risk, that failure to recognize this would transfer wealth from APS's ratepayers to its shareholders, and that the Commission should approve RUCO's 8.2% ROE if the Commission does not adopt the RUCO-recommended imputed capital structure for APS. (AARP Br. at 2-3.)

<u>AZLCG & FEA</u>

AZLCG and FEA jointly present their position on cost of capital, with FEA joining in AZLCG's Brief on the issue. (FEA Br. at 8.) AZLCG urges the Commission to reject APS's proposed ROE as unjust, unreasonable, and not reflective of APS's COE. (AZLCG Br. at 95.) AZLCG argues that Dr. Morin's analyses include faulty assumptions. (AZLCG Br. at 96.) First, AZLCG argues, Dr. Morin's flotation cost adjustment, which adds approximately 20 basis points to his ROE recommendations, is not based on actual flotation costs, is inappropriate to include as an adder to a regulated utility's return, and is an adjustment that has never before been approved by the Commission. (AZLCG Br. at 96; *see* Ex. AZLCG&FEA-1 at 63-64; Ex. S-1 at 28; Ex. RUCO-5 at 29, 31; Tr. at 2708, 2728.)

AZLCG argues that Dr. Morin's DCF analysis inappropriately assumes growth rates that exceed the long-term growth of the U.S. economy and thus cannot be sustained long-term, something

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[692] APS also cited RUCO's recommendation in the UNS Electric rate case, which is not part of the evidentiary record in this matter. (*See* APS Br. at 21.)

that Dr. Morin has recognized in his finance textbook but not in this matter. (AZLCG Br. at 96; *see* Ex. AZLCG&FEA-1 at 65-66; Ex. RUCO-5 at 25, 28; Ex. AZLCG&FEA-2 at 5-7.) Additionally, AZLCG criticizes Dr. Morin's DCF analysis for relying on *Value Line* growth rates, although they are based on and thus give excessive weight to the estimates of a single analyst, and using the mean rather than the median of *Value Line* analyst growth rates, which results in heavy impact from outliers. (AZLCG Br. at 96-97; *see* Ex. AZLCG&FEA-1 at 65-66.) AZLCG further criticizes Dr. Morin for using only a constant growth DCF analysis and not performing a multi-stage DCF analysis. (AZLCG Br. at 97; *see* Ex. AZLCG&FEA-1 at 66.) AZLCG points out that Dr. Morin's *Zacks* DCF analysis, which relies on consensus estimates from analysts, produced an ROE of 9.10%, not including the flotation cost adder. (AZLCG Br. at 97; *see* Ex. AZLCG&FEA-1 at 64-65.) AZLCG points to Mr. Walters's testimony that when Dr. Morin's DCF analyses are modified by using a median approach, using a multi-stage DCF analysis, and removing the flotation cost adder, the results range from 8.2% to 9.45%. (Ex. AZLCG&FEA-1 at 67.)

AZLCG argues that Dr. Morin's CAPM and ECAPM analyses also include faulty assumptions (beyond the flotation cost adder) and are "upwardly biased" because Dr. Morin improperly relies on excessive current *Value Line* beta estimates in his CAPM, using a historical beta estimate of 0.87 although historical levels of utility betas are 0.60 to 0.70, which Dr. Morin acknowledged in his testimony.[693] (AZLCG Br. at 97, 98; *see* Ex. AZLCG&FEA-1 at 67-68; Ex. APS-33 at 53.) AZLCG asserts that Dr. Morin also relied on an artificially inflated beta estimate for the ECAPM, using a beta of 0.92, resulting in Mr. Walters, Mr. Parcell, and Mr. Garrett fundamentally disagreeing with the ECAPM. (AZLCG Br. at 97; *see* Ex. AZLCG&FEA-1 at 69-71; Ex. S-1 at 34; Ex. RUCO-5 at 41-42.) AZLCG argues that other PUCs have also rejected the ECAPM because of the inflated beta, which guarantees a higher ROE. (AZLCG Br. at 97-98; *see* Ex. AZCLG&FEA-1 at 70-71.[694]

AZLCG argues that Dr. Morin's allowed Risk Premium analysis should be disregarded entirely because it is predicated on the inverse relationship between authorized ROEs and long-term U.S.

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[693] Dr. Morin stated that the significantly higher average beta of 0.87 was not surprising due to the "Perfect Storm" situation in the electric utility industry. (*See* Ex. APS-33 at 53.)

[694] AZLCG cites to several PUC decisions from other jurisdictions, which are not part of the evidentiary record in this matter, except to the extent they were quoted in Mr. Walters's testimony. (*See* AZLCG Br. at 98; Ex. AZLCG&FEA-1 at 70-71.)

Treasury yields, and this simple formula fails to consider the impact of market anomalies and "skewed" risk premiums. (AZLCG Br. at 98; *see* Ex. AZLCG&FEA-1 at 73.) AZLCG notes that Mr. Garrett also disagrees with the premise of the allowed Risk Premium analysis. (AZLCG Br. at 98; *see* Ex. RUCO-5 at 42-44.)

AZLCG asserts that Dr. Morin's market risk discussion should not impact the ROE awarded to APS because Dr. Morin's testimony about the current risk environment is outdated and inconsistent with future expectations due to Dr. Morin's opinions and the data used to support them being heavily influenced by the volatility experienced at the beginning of the pandemic. (AZLCG Br. at 98; *see* Ex. AZLCG&FEA-1 at 73-75.) AZLCG argues that the market risks identified by Dr. Morin are actually faced by all companies and thus already factored into credit ratings and COE calculation model inputs and reflected in the proxy group. (AZLCG Br. at 98; *see* Ex. AZLCG&FEA-1 at 76.)

AZLCG also argues, essentially, that the Commission should ignore Dr. Morin's assertion that his recommended ROE in this matter assumes approval of the proposed SRB and that the Commission's failure to approve the SRB would necessitate a 10-to-20-basis point upward adjustment to APS's ROE. (AZLCG Br. at 99; *see* Tr. at 2743-2744.) AZLCG argues that Dr. Morin could not have assumed approval of the SRB in his original COE analyses because APS had not yet proposed the SRB and did not do so until its rebuttal testimony was filed.[695] (AZLCG Br. at 99; *see* Tr. at 2848-2851.) AZLCG points out that Dr. Morin was unable to identify which proxy group companies had capital trackers for traditional generation and asserts that although Dr. Morin testified that all of the proxy group companies had "such mechanisms,"[696] only two of the proxy group companies actually have trackers for traditional generation in all of their jurisdictions. (AZLCG Br. at 99; *see* Tr. at 2743-2744, 2746-2748; Ex. APS-33 at Att. RAM-02DR; Ex. APS-61 at 6-15; Ex. APS-102.) AZLCG asserts that contrary to APS's position that many of the proxy companies have trackers for traditional generation, the evidence shows that the existence of such trackers is limited and that the trackers that do exist are not as favorable to the utilities as APS's proposed SRB. (AZLCG Br. at 99-100; *see* Ex.

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[695] APS had proposed in its original application that the REAC be expanded to allow recovery of the capital carrying costs of new APS-owned clean energy resources and energy storage facilities. (*See* Ex. APS-2 at 25, 27.)

[696] Dr. Morin testified that of the 23 proxy group companies, "15 of them have generation trackers[,] 13 of them have distribution trackers[,] 19 of them are forward test year[, and] so on and so forth." (Tr. at 2743.)

APS-61 at 17, 18, 25, 26, 27.) AZLCG argues that APS's COE analysis reveals bias, is built on faulty assumptions, and should be ignored. (AZLCG Br. at 100.)

Further, AZLCG takes issue with the proxy group used by Dr. Morin because it includes many companies with equity ratios lower than 40% and has an average equity ratio of 40.1%, thus unreasonably inflating APS's perceived risk. (AZLCG Br. at 100; *see* Ex. RUCO-5 at 47; Ex. AZLCG&FEA-1 at 28; Tr. at 3482-3483, 3616, 3618.) AZLCG argues that because APS has an equity-rich capital structure, it is appropriate to adjust the COE, the capital structure, or both. (AZLCG Br. at 100; *see* Tr. at 3588.)

Finally, AZLCG criticizes "APS's credit downgrade rhetoric" as unpersuasive, specifically taking issue with APS's assertion that a higher ROE will result in a lower cost of capital for ratepayers. (AZLG Br. at 101; *see* Ex. APS-5 at 4-5; Tr. at 307.) AZLCG asserts that APS's credit rating is better than that of most utility operating companies.[697] (AZLCG Br. at 101; Tr. at 3518.) AZLCG argues that a high WACC may increase credit ratings but will harm ratepayers because while debt costs may increase as a result of a lower ROE and potential downgrade, ratepayers will still pay less through the lower WACC. (AZLCG Br. at 101; Tr. at 3585, 3621-3622.) AZLCG points out that despite the 8.7% ROE awarded in Decision No. 78317, APS was able to reduce its cost of debt substantially. (AZLCG Br. at 101; *see* Ex. APS-5 at 11; Tr. at 2697.) AZLCG also argues that speculation is not evidence and that APS's witnesses cannot predict whether credit rating agencies will downgrade or upgrade APS's credit rating. (AZLCG Br. at 102; *see* Tr. at 308-309, 618; *Arizona Corp. Comm'n v. Citizens Utils. Co.*, 120 Ariz. 184, 190 (App. 1978).) AZLCG argues that a lower ROE and potential downgrade would actually save customers money, based on Mr. Cooper's testimony that the higher cost of debt from a lower credit rating would increase APS's borrowing costs on $7.5 billion in capital by $216 million over a period of 20 years, which AZLCG states indicates that ratepayers would pay approximately $11 million more annually. (AZLCG Br. at 102; *see* Ex. APS-5 at 4; Tr. at 596-598, 2684-2685, 3647.) In comparison, AZLCG asserts, APS's requested 10.25% ROE, which is 135 basis points higher than the currently authorized 8.9% ROE, would result in ratepayers paying far more than

[697] This is consistent with Mr. Parcell's testimony, but Mr. Parcell subsequently clarified that APS's Moody's credit rating and S&P credit rating were both the most common rating for electric utilities. (*See* Tr. at 3518-3519.)

$11 million more per year, something APS acknowledged although it did not do the math. (AZLCG Br. at 102-103; *see* Tr. at 602, 604, 2683-2685.) AZLCG points to Mr. Garrett's testimony agreeing that APS's proposed ROE would produce approximately $100 million more annually as compared to Mr. Walters's recommended ROE and approximately $200 million more annually as compared to RUCO's recommended ROE. (AZLCG Br. at 103; *see* Tr. at 3649.) AZLCG argues that APS's proposed ROE, even if it did result in a lower cost of debt, would not save ratepayers money. (AZLCG Br. at 103.)

In its Responsive Brief, AZLCG contradicts APS's assertion that Dr. Morin's ROE is conservative and asserts that utilities' awarded ROEs have consistently decreased since 1990, that the average awarded ROE for electric utilities in 2022 was 9.52%, and that the range for awarded ROEs in 2023 was 9.25% to 10%. (AZLCG RBr. at 5-6; *see* Ex. RUCO-5 at 9; Ex. AZLCG&FEA-1 at 4; Ex. AZLCG&FEA-2 at 3.) Further, AZLCG argues that the "perfect storm" factors, if real, are faced by other electric utilities and thus are reflected in the COE analyses using the proxy group. (AZLCG RBr. at 6.) AZLCG reiterates that APS's customers will not save money through a higher ROE and urges the Commission to award APS an ROE that accurately reflects its COE. (AZLCG RBr. at 6.)

<u>IBEW Locals</u>

The IBEW Locals urge the Commission to approve APS's proposed ROE of 10.25%, which the IBEW Locals state is in the public interest. (IBEW Br. at 3.) The IBEW Locals state that a highly skilled workforce is needed to provide safe and reliable service and that such a workforce comes at a high cost, making it imperative that APS be granted rate relief sufficient to allow it to ramp up hiring to ensure an appropriate number of qualified personnel to replace employees who retire. (IBEW Br. at 3; *see* Ex. IBEW-1 at 7, 12; Tr. at 802-804.) If APS does not have adequate funds, the IBEW Locals state, the existing APS workers will need to work more and will not be able to do as much safety training or to get as much rest, putting the safety of employees and ratepayers at risk. (IBEW Br. at 3-4; *see* Ex. IBEW-1 at 12.)

The IBEW Locals further assert that APS must have sufficient funding to support its transition to clean energy and meet the growing demand for energy, including from Arizona's becoming a hub for data centers, manufacturing, and semiconductors. (IBEW Br. at 4; *see* Ex. APS-2 at 16.) The

IBEW Locals state that APS has been able to meet historic levels of demand due to its planning foresight and ongoing projects. (IBEW Br. at 4; *see* Ex. IBEW-2 at 2-3; Ex. APS-2 at 16.)

The IBEW Locals also agree with APS's assertions that unreasonably low ROEs will ultimately hurt ratepayers by detrimentally impacting APS's credit rating and making it difficult for APS to secure low-interest debt. (IBEW Br. at 4; *see* Ex. APS-34 at 96-97.) The IBEW Locals urge the Commission to approve the 10.25% ROE proposed by APS as fair, reasonable, and sufficient to compensate investors, maintain APS's capital strength, and permit APS to attract capital. (IBEW Br. at 4.)

<u>Ms. Nelson</u>

Ms. Nelson asserts that APS should be awarded an ROE of 8.4% and that this would "allow APS to be more efficient and prudent in their growth and transition to renewable resources in the next 7 years." (KN Br. at 4.)

<u>Sierra Club</u>

The Sierra Club urges the Commission to award APS an ROE within the range recommended by RUCO and AZLCG and FEA. (SC Br. at 3.) Sierra Club notes that the ROE recommendations made by Staff, AZLCG and FEA, and RUCO are all lower than APS's proposed 10.25% ROE and then notes Mr. Cooper's testimony acknowledging that APS may be able to maintain its current credit rating even without an increase to its ROE. (SC Br. at 38-39; *see* Ex. APS-33 at 12; Ex. APS-20 at 14; Ex. S-2 at 16; Ex. S-1 at 3; Ex. AZLCG&FEA-1 at 3, 5, 58; Ex. RUCO-5 at 2-4; Tr. at 618.) Sierra Club argues that a higher ROE will mean higher rates for customers and will result in a transfer of wealth from customers to shareholders. (SC Br. at 39; *see* Tr. at 618-619.[698]) Sierra Club argues that APS has not justified its need for a 10.25% ROE and that the evidence in this matter shows that APS can remain financially healthy with a lower ROE. (SC Br. at 39.) Sierra Club argues that the Commission should protect customers by approving an ROE within the range recommended by RUCO and AZLCG and FEA. (SC Br. at 39; SC RBr. at 25.)

<u>RUCO</u>

If the Commission accepts APS's capital structure, RUCO recommends an ROE of 8.2%.

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[698] Mr. Cooper did not agree with this wealth transfer characterization but did acknowledge that a higher ROE results in a higher return on investments for shareholders. (*See* Tr. at 618-619.)

(RUCO Br. at 27; *see* Ex. RUCO-5 at 3-4, ex. DJG-17.) If the Commission instead adopts RUCO's imputed ratemaking capital structure for APS, RUCO recommends an ROE of 8.7%. (RUCO Br. at 27; *see* Ex. RUCO-5 at 3-4, ex. DJG-17.) RUCO determined its estimates of ROE using the CAPM and DCF. (RUCO Br. at 27; *see* Ex. RUCO-5 at 2-3.) RUCO argues that there is no merit to APS's suggestion that a higher ROE would support its current credit rating, only a guarantee that a higher ROE will result in higher rates. (RUCO Br. at 28.) RUCO quotes at length Mr. Garrett's testimony to the effect that it is APS's business operations, as opposed to the Commission, that controls APS's credit metrics. (RUCO Br. at 28-29; *see* Tr. at 3618-3621.) RUCO further quotes Mr. Garrett's testimony to the effect that ratepayers will pay more in the longer term if a higher ROE is awarded as compared to what would happen if APS again had its credit downgraded. (RUCO Br. at 29; *see* Tr. at 3622-3623.) RUCO asserts that the credit downgrade could cost ratepayers approximately an additional $11 million per year due to increased borrowing costs while APS's ROE would cost ratepayers approximately $200 million more per year as compared to RUCO's ROE. (RUCO Br. at 30; *see* Tr. at 2679, 3648-3649.) RUCO notes Mr. Parcell's testimony that APS's credit rating is already at the same level as or better than that of most electric utilities. (RUCO Br. at 30; *see* Ex. S-1 at 17.) RUCO argues that the Commission is obligated to provide APS the opportunity to earn a fair rate of return on the fair value of its property, not the highest ROE, and that RUCO's 8.70% ROE is more than fair. (RUCO Br.at 30.[699])

RUCO criticizes Dr. Morin's analyses, stating that the Risk Premium analysis should be viewed skeptically because it is less accepted by PUCs, is potentially inaccurate, and tends to produce higher results. (RUCO Br. at 30.[700]) RUCO further argues that the Risk Premium model is unnecessary because the CAPM is a real risk premium model and was also used by Dr. Morin. (RUCO Br. at 30; *see* Ex. RUCO-5 at 43.) RUCO also criticizes Dr. Morin for not adjusting APS's capital structure when calculating ROE to reflect APS's lower debt ratio as compared to the proxy group companies because failure to do so inflates APS's CAPM. (RUCO Br. at 30-31; *see* Ex. RUCO-5 at 3-4, ex. DJG-17.)

[699] RUCO cites *Arizona Corp. Comm'n v. Citizens Utils. Co.*, 120 Ariz. 184, 190 n.5 (App. 1978); *Public Serv. Comm'n of Montana v. Great Northern Utils. Co.*, 289 U.S. 130, 135 (1933); and *Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679, 690, 692-693 (1923).

[700] RUCO cites to a FERC Opinion that is not part of the record in this matter. (*See* RUCO Br. at 30.)

Finally, RUCO criticizes Dr. Morin's use of the DCF in a manner that overstates APS's COE by using analysts' projected growth rates and applying an unwarranted flotation cost adjustment, resulting in unreasonably high DCF results. (RUCO Br. at 31.[701])

In its Responsive Brief, RUCO observes that Dr. Morin has focused much of his argument on the authorized ROEs awarded across the U.S. and has criticized the recommended ROEs of Mr. Walters and Mr. Parcell because their ROEs are not as high as the reported recently awarded average ROE for vertically integrated utilities of 9.71%. (RUCO Br. at 4; *see* Ex. APS-34 at 6.) RUCO argues that if the average ROE is 9.71%, then neither APS's proposed 10.25% nor Dr. Morin's determination of a 10.40% COE can possibly be conservative as claimed by APS. (RUCO Br. at 4.) Additionally, RUCO asserts, APS's 10.25% proposed ROE must be considered in light of APS's requested 0.5% return on the FVI. (RUCO Br. at 4-5.)

<u>Staff</u>

Staff states that its recommended 9.68% ROE is based on the most current data available at the time Staff's direct testimony was filed in early June 2023 and notes that the average authorized ROE for vertically integrated electric utilities, as of the hearing, was 9.73%. (Staff Br. at 22; *see* Tr. at 2715, 3479.) Staff states that although there is "substantial common ground" between Dr. Morin's and Staff's ROE results, they differ on the CAPM models, Staff's use of a Comparable Earnings model that APS did not use, Dr. Morin's inclusion of a flotation cost adjustment, and the appropriate proxy group to use.[702] (Staff Br. at 22-23; *see* Ex. S-2 at 2; Ex. APS-34 at 5, 59; Ex. S-1 at 28.)

Concerning the proxy group, Staff states that it is not only appropriate but necessary to include PNW in the proxy group because it is the entity that most resembles APS, and a proxy group is intended to provide companies with the most similar financial attributes to use as a benchmark for the subject utility. (Staff Br. at 27; *see* Ex. S-2 at 2.) Further, Staff asserts that Dr. Morin referenced investors' assessment of PNW's risk "as the linchpin for determining the proper ROE." (Staff Br. at 28; *see* Tr. at 2676-2677.) Staff defends against APS's criticism that the small size of Staff's proxy group

[701] RUCO also cites to Exhibit RUCO-11, which was not admitted in this matter as such but was admitted as Exhibit S-75 and has no bearing on this statement.

[702] Mr. Parcell testified that Dr. Morin added a 5% adjustment to the DCF dividend yield, a 0.20% adjustment to his CAPM results, and a 0.20% adjustment to his historical risk premium results for flotation costs. (*See* Ex. S-1 at 28, n.32; Ex. APS-33 at 65, 69-74, Att. RAM-03DR, Att. RAM-07DR.)

increases the risk of measurement error and makes it statistically less reliable than a group that includes 20 or more companies by pointing out that Staff's proxy group contains companies with similar size, capital structure, common stock safety, and bond ratings to APS, while APS's larger proxy group contains companies with much more capitalization than APS, much lower common equity ratios, more risky safety ratings, and more risky bond ratings, all of which render APS's proxy group less similar to APS. (Staff Br. at 28-29; *see* Ex. APS-34 at 40; Ex. APS-35 at 10; Ex. S-2 at 3, Sched. 6, ex. DCP-1, ex. DCP-2.) Staff asserts that APS's argument based on the law of large numbers is flawed because the law of large numbers is meaningless if the numbers are not good, and the companies in the proxy group are not all comparable to APS. (Staff Br. at 29; *see* Tr. at 3482.) Staff points out that seven of APS's proxy companies have equity ratios of less than 40%, three of the proxy companies have value and safety data higher or much higher than APS, and one of the proxy companies has a debt rating at junk bond levels. (Staff Br. at 30; *see* Tr. at 3482-3483.) Staff also points out that APS's proxy group in the 2019 rate case started at 14 companies and was then narrowed to 10. (Staff Br. at 30; *see* Tr. at 3483.) Further, Staff argues that APS's claimed inability to "reconcile" Staff's proxy group in this matter with Staff's proxy group in the 2022 TEP rate case is based on APS's failure to recognize that Staff considered market capitalization of the proxy companies in each case and that TEP's parent has a market capitalization of more than $25 billion as compared to PNW's market capitalization of $9 billion. (Staff Br. at 30-31; *see* Ex. S-2 at 3-4.) Staff stands by its proxy group, which it states includes companies with risk comparable to APS's risk. (Staff Br. at 30; *see* Tr. at 3483.)

Staff notes Mr. Parcell's disagreement with several of the inputs Dr. Morin used in his DCF analyses. (Staff Br. at 23.) First, Staff takes issue with Dr. Morin's use of a (1+g) dividend yield adjustment, which added 10 basis points to his DCF COE result, although the (1+.5g) dividend yield adjustment is more common; was used in the 2022 TEP rate case, the 2019 APS rate case, and a number of other rate cases before the Commission; and is endorsed by FERC. (Staff Br. at 23; *see* Ex. APS-34 at 67; Ex. S-2 at 4; Ex. S-64; Tr. at 2717.) Next, Staff takes issue with the flotation cost adjustments made in most of Dr. Morin's COE analyses, which increased Dr. Morin's COE by 20 basis points although PNW has not had a public stock offering since 2010 and does not have one planned, few PUCs approve an upward adjustment to COE for flotation costs unless there is actually a stock issue, and any such costs that did exist would need to be justified as APS's costs because APS itself does not issue stock and would need to be determined reasonable and prudent to be recoverable. (Staff Br. at 24; *see* Ex. S-1 at 28, n.3, n.4; Ex. APS-34 at 66-67; Tr. at 2728-2729, 3594-3595.) Staff asserts that there is no such evidence of record in this matter and, further, that any flotation cost adjustment to be approved should be recovered through cost of service as an expense rather than through an inflated ROE. (Staff Br. at 24; *see* Tr. at 3594-3595.)

Regarding the CAPM, Staff states that the difference between Mr. Parcell's and Dr. Morin's results are based on the market risk premium, as APS and Staff disagree about the use of income returns on bonds versus total returns on bonds and on the use of geometric returns along with arithmetic returns. (Staff Br. at 25; *see* Ex. S-2 at 5-6.) Staff criticizes Dr. Morin for using both capital gains/losses and income (interest and dividends) for stocks while using only income returns for bonds, which Staff states does not provide a consistent basis for comparison of stock returns and bond returns. (Staff Br. at 25; *see* Ex. APS-34 at 52; Ex. S-2 at 6.) Staff also asserts that both arithmetic and geometric growth rates should be used, as this information is the most cited aspect of Stocks, Bonds, Bills, and Inflation ("SBBI") studies used to provide investors comprehensive historical data, and investors presumably rely on both growth rates. (Staff Br. at 25-26; *see* Ex. S-2 at 6-7.)

Staff asserts that although Dr. Morin did not use it, the Comparable Earnings method, which examines realized ROEs for proxy utilities and unregulated companies and evaluates investor acceptance of these ROEs by referring to market-to-book ratios, is an accepted methodology used to evaluate ROEs. (Staff Br. at 26; *see* Ex. S-1 at 34-37; Ex. S-2 at 9.)

Staff states that Mr. Parcell's Risk Premium analysis, which compared average authorized ROEs of electric utilities for 2012 through 2022 is more appropriate than Dr. Morin's Risk Premium analysis that went back to 1986, a period with significant declines in interest rates for which Dr. Morin performed a regression analysis that did not recognize other changes caused by events in the 1990s, such as diversification and deregulation, or changes caused by events in the past decade, such as increased use of regulatory mechanisms for cost recovery. (Staff Br. at 26-27; *see* Ex. S-1 at 41, 45; Ex. S-2 at 11; Ex. APS-34 at 66.) Staff asserts that except for Staff's failure to include a flotation cost adjustment, Dr. Morin agrees with Staff's Risk Premium analysis results. (Staff Br. at 27; *see* Ex. S-2 at 11; Ex. APS-34 at 66.)

Finally, Staff takes issue with APS's arguments about the impacts that an ROE lower than 10.25% would have on APS's credit ratings by asserting that APS's ratings are currently at or above the most common ratings of electric utilities, that APS's Moody's rating is higher than all but one of Staff's proxy companies, and that APS's S&P rating is consistent with most of the proxy companies. (Staff Br. at 31, 33; *see* Ex. S-1 at 16-17, ex. DCP-1, Sched. 6; Ex. S-2 at 13-14, ex. DCP-2, Sched. 17; Ex. APS-6 at 5.) Staff asserts that although APS claimed that its credit ratings were not above those of other electric utilities, APS offered no support for such a claim, and Mr. Cooper actually acknowledged that APS's ratings are at the most common levels for electric utilities. (Staff Br. at 31; *see* Ex. S-2 at 13; Ex. APS-6 at 5.) Staff recounts APS's testimony about the risk of downgrades and asserts that APS ultimately conceded that the credit rating is not within the Commission's control and that even with approval of APS's proposed ROE, there is no guarantee that APS's credit rating would be improved. (Staff Br. at 32-33; *see* Tr. at 593-594, 701-702, 2678, 2680, 2701-2702; Ex. APS-34 at 66.)

In its Responsive Brief, Staff argues that both APS's and RUCO's ROE recommendations should be rejected. (Staff RBr. at 15.) Staff argues that APS's ROE should be rejected because it is inflated with unnecessary costs and ignores information investors rely on when picking their investments and that APS's warnings about the "devastating consequences" to APS and ratepayers from approval of any ROE other than APS's recommended ROE have been refuted by Staff's evidence showing that APS's ratings (A3 with Moody's and BBB+ with S&P) are the most common ratings for electric utilities and better than the ratings for many electric utilities. (Staff RBr. at 16; *see* Ex. S-1 at 16-17, 28; Ex. S-2 at 6; Tr. at 584.) Staff also reiterates its disagreements with Dr. Morin's analyses and proxy group. (Staff RBr. at 16-17; *see* Ex. S-2 at 4-5; Ex. S-1 at 28; Ex. APS-34 at 67; Tr. at 3482.)

Staff also takes issue with RUCO's "inadequate" ROE recommendations, based on an "average capital structure," and RUCO's use of a Hamada CAPM adjustment and notes that TEP was awarded an ROE of 9.55% in its 2022 rate case, which Staff states most reasonably aligns with Staff's recommended ROE of 9.68%.[703] (Staff RBr. at 17; *see* Ex. RUCO-5 at 3-4, ex. DJG-17; Tr. at 3682; Ex. APS-84 at 36.) Staff asserts that a Hamada adjustment was performed by a different RUCO witness in the 2022 TEP rate case, in which RUCO chose not to use an alternative capital structure. (Staff Br. at 17; *see* Tr. at 3677.) Staff argues that "using a hypothetical capital structure and applying the Hamada adjustment are in fact synonymous acts" and that RUCO's witness acknowledged that it would not be fair to a utility to do both. (Staff RBr. at 17; *see* Tr. at 3677-3678.) Staff asserts that the two methods produced different and yet inadequate results and noted that RUCO's witness has made upward adjustments for low ROEs in the past but chose not to do so in this matter. (Staff RBr. at 17-18; *see* Tr. at 3633-3641.) Staff asserts that the Commission must balance the interests of APS to earn a reasonable return on the cost to provide reliable service against ratepayers' interests in affordable and reliable service and that this should result in the Commission's approval of Staff's 9.68% ROE recommendation. (Staff RBr. at 18.)

APS Response

In its Responsive Brief, APS emphasizes the importance of its recommended ROE to improving its financial stability and credit rating, reiterating that APS is on negative watch with the credit rating agencies; reiterating Dr. Morin's calculations about the extra costs to issue bonds as a BBB rated company versus a single A company; and asserting that a credit downgrade would decrease stock prices, reduce APS's ability to obtain equity financing, and require APS to rely more on debt financing at higher borrowing costs to meet its capital needs. (APS RBr. at 9-10; *see* Ex. APS-7 at 3; Ex. APS-6 at 3; Ex. APS-33 at 13-14, 84; Tr. at 2679.) APS accuses AZLCG and RUCO of ignoring these impacts of a credit downgrade. (APS RBr. at 9.) Additionally, APS asserts that a cost-benefit analysis for ROE as performed by AZLCG and RUCO does not capture the long-term impacts on customer affordability and reliability of financial stability, which would allow APS to reduce and maintain low customer costs over the long term even as it makes large capital investments. (APS RBr. at 10; *see* Tr. at 750-752.) If APS's credit ratings were downgraded again, APS argues, it would create serious risks to customer affordability and reliability of service. (APS RBr. at 10; *see* Tr. at 751-752.)

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[703] Staff does not acknowledge AZLCG and FEA's recommended ROE of 9.55%.

APS argues that AZLCG's reliance on APS's ability to reduce its cost of debt following the credit ratings downgrade that resulted from the 2019 rate case is "fundamentally flawed" because interest rates fell dramatically following the last rate case and reduced the cost of debt for everyone. (APS RBr. at 10; *see* Ex. APS-33 at 15.) APS argues that if its credit had not been downgraded, it would have been able to lower its cost of debt even further. (APS RBr. at 11.) APS notes Dr. Morin's testimony that interest rates have "surged" recently and states that if a credit downgrade results from the Commission's awarding APS an ROE lower than that of comparable utilities in this matter, ratepayers may be exposed to much higher borrowing costs. (APS RBr. at 11; *see* Tr. at 2703; Ex. APS-34 at 38.)

APS refutes other parties' assertions that Dr. Morin's proxy group is not comparable to APS because of the difference in equity ratio and argues that the other parties are improperly comparing APS's capital structure to the equity ratio of holding companies rather than the operating utilities that are peers of APS. (APS RBr. at 11; *see* Ex. APS-7 at 4-5.) According to APS, its actual TY capital structure is in line with that of the companies included in Dr. Morin's proxy group and with the average common equity ratio of 53% reported for operating utilities in 2022, meaning that Dr. Morin's proxy group is appropriate. (APS RBr. at 11-12; *see* Ex. APS-34 at 91.) APS criticizes AZLCG's argument about the proxy group companies not having traditional generation capital trackers and states that the proxy company data shows 38 operating utilities have a renewable or traditional generation capital tracker and that 20[704] of them have a traditional capital tracker. (APS RBr. at 12; *see* Ex. APS-102.)

APS takes issue with AZLCG's criticisms of Dr. Morin's DCF analysis, asserting that they "are unfounded and miss the point entirely," and points out Dr. Morin's issues with Mr. Walters's multi-stage DCF analyses—that the investment community does not look to GDP growth over the next several decades when evaluating utility investments, that Mr. Walters erroneously assumed that one factor can change while all others remain constant, and that it is problematic to assume that dividend/earnings growth will eventually track GDP growth because technological advances have increased energy efficiency and reduced electricity consumption relative to GDP. (APS RBr. at 12-13;

[704] Exhibit APS-102 appears to show 19 traditional or combination traditional/renewable trackers, not 20.

see Ex. APS-35 at 6.) Thus, APS argues, it was appropriate for Dr. Morin to use only the constant growth DCF method. (APS RBr. at 13.) Further, APS asserts, Dr. Morin's use of the *Value Line* growth rate, rather than the median value, was appropriate because the median value discards all information in the data series other than one number. (APS RBr. at 13.)

Finally, APS requests that the Commission reject the opinions on ROE of Sierra Club, AARP, and Ms. Nelson because none of them presented any testimony or cost of capital analysis on the record.[705] (APS RBr. at 13-14.)

Resolution

As is usually the case in Class A electric utility rate cases, the Commission has received abundant and conflicting analyses of estimated COE from experts in the field employed by different parties. The Commission is aware that some experts work primarily for utilities and that other experts work primarily for non-utility parties, apparently based on their respective ideologies, and does not believe that either is a reason to disregard an expert's opinion. The Commission does, however, conclude that Dr. Morin's flotation cost adjustments should be rejected outright, as there is no justification on the record for arbitrarily increasing (by approximately 20 basis points) the result of COE analyses based on nonexistent flotation costs for purely speculative stock issuances that may be made at some point in the future by PNW rather than APS. The flotation cost adjustment is unjustified and unjustifiable, and the Commission sincerely hopes that it will not be proposed again in the absence of evidence that an actual stock issuance with reasonable and prudently incurred flotation costs objectively attributable to APS has occurred. The Commission also notes that while Dr. Morin's original COE analyses may have assumed Commission approval of the expanded REAC, which would have been limited to clean energy resources and storage only, they could not have assumed approval of the broader SRB, which the Commission concludes reduces APS's risks as compared to the proxy group utilities that do not have generation resource recovery mechanisms that allow for traditional generation resources.

After consideration of all of the COE analyses provided by the parties, as well as their

[705] We note that the IBEW Locals also provided an opinion on ROE although they did not provide any cost of capital analysis on the record.

arguments regarding their own and other parties' COE analyses, we conclude that APS's COE should be established at 9.55%. This COE is sufficient to maintain (and should improve) APS's financial integrity, will enable APS to attract capital under reasonable terms, and is commensurate with returns that investors could earn by investing in other enterprises of comparable risk.

C. Return on Fair Value Increment ("FVI")

APS Proposal

APS requests a return on the FVI of 0.50%, the same return advocated by Staff, which APS states is well below what would be derived from the expected return on a risk-free investment. (APS Br. at 12, 21; *see* Ex. S-2 at exec. summ.; Ex. APS-6 at 19.) APS asserts that the traditional approach to determine the return on FVI would produce a return on FVI of 1.0% in this matter, consistent with APS's original proposal, but that APS reduced its request to mitigate customer bill impacts and create greater alignment with the positions of Staff and AZLCG and FEA. (APS Br. at 21; *see* Ex. APS-5 at 24; Ex. APS-6 at 19.) APS argues that RUCO's position that APS should be awarded a 0.0% return on FVI represents "an extreme outlier" that should be disregarded because it is inconsistent with Arizona Constitution Article 15, § 14's fair value requirement and "fundamentally at odds with the economic value of opportunity costs associated with utility company investments." (APS Br. at 21-22; *see Arizona Corp. Comm'n v. Arizona Water Co.*, 85 Ariz. 198, 203 (1959).) APS points to Mr. Cooper's testimony that without a return on the FVI, a fair value calculation is just original cost. (APS Br. at 22; *see* Ex. APS-6 at 21.) APS argues that providing a positive return on the FVI reflects the opportunity costs associated with APS's dedication of its rate base property for public use and represents the appreciation in value of the capital investments made by APS. (APS Br. at 22; *see* Ex. APS-6 at 20; Tr. at 718-719.)

AZLCG & FEA[706]

AZLCG argues that public service corporations are not entitled to a positive return on the FVI because "fair value" does not include the determination of the appropriate rate of return, and the FVI does not represent the investment of capital. (AZLCG Br. at 103; *see* Ex. RUCO-7 at 327; *SIB Opinion*

[706] FEA joined the cost of capital section of AZLCG's initial brief, which includes the FVI. (FEA Br. at 8.)

at 112.[707]) AZLCG argues that while Mr. Walters recommended a return on the FVI no higher than 0.35% (as Staff recommended a return on the FVI of no higher than 0.50%), AZLCG and Staff agree that a 0.0% return on the FVI is appropriate from a financial and economic standpoint. (AZLCG Br. at 104; *see* Ex. AZLCG&FEA-2 at 13; Ex. S-1 at 47; Tr. at 3481, 3515, 3578, 3592.) AZLCG notes the Commission's determination in Decision No. 78317 that the "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" exceeding what would be required in an OCRB jurisdiction. (AZLCG Br. at 104; Ex. RUCO-7 at 328.) AZLCG further notes that this reasoning "was recently discussed and left undisturbed by the Arizona Court of Appeals" and that the Commission recently approved a 0.0% return on TEP's FVI.[708] (AZLCG Br. at 104; *see Arizona Pub. Serv. Co. v. Arizona Corp. Comm'n*, 526 P.3d 914, 919 (Ariz. Ct. App. 2023); Ex. APS-84 at 36.) AZLCG asserts that New Mexico is also a fair value jurisdiction and that it does not provide utilities a positive return on their FVI. (AZLCG Br. at 104-105; *see Hobbs Gas Co. v. N.M. Pub. Serv. Comm'n*, 616 P.2d 1116, 1120 (N.M. 1980); *Alto Vill. Servs. Corp. v. N.M. Pub. Serv. Comm'n*, 587 P.2d 1334, 1335 (N.M. 1978).[709])

AZLCG recommends that APS be awarded a 0.0% return on the FVI in this matter but, in the alternative, if the Commission believes that a positive return on the FVI should be awarded, that APS be awarded a return on the FVI no higher than 0.35%[710] and that any positive return be paired with a "commensurate reduction to APS's awarded ROE." (AZLCG Br. at 105.) AZLCG points to APS witness testimony acknowledging that any revenue collected through the FVI "becomes additional pretax revenue . . . that is beyond the revenue . . . associated with the return on [OCRB]" and that a return on the FVI of 1.0% would result in an additional $82.8 million in after-tax revenue. (AZLCG Br. at 105; *see* Tr. at 716, 1701-1702; Ex. APS-24 at 46.) AZLCG asserts that APS's reduced requested

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[707] AZLCG also cited a Texas case.

[708] We note that this was done pursuant to an agreement reached with TEP during Open Meeting. (*See* Ex. APS-84 at 36.)

[709] The Alto Villages case does not clearly support AZLCG's assertion that New Mexico does not provide a positive return on FVI because the paragraph cited by AZLCG shows different awarded returns for OCRB and FVRB that result in different dollar amounts, which is inconsistent with the language of the decision itself.

[710] Mr. Walters determined his recommended return on FVI by calculating a real risk-free rate of 1.4% and then dividing it by one fourth, consistent with the resolution in Decision No. 78317, which approved a return set at half of Staff's recommendation (essentially one-fourth of Staff's calculated real risk-free rate). (*See* Ex. AZLCG&FEA-1 at 59.)

return on FVI of 0.50% would still result in an after-tax return of $40.9 million. (AZLCG Br. at 105; *see* Ex. APS-26 at Att. JRM-01RJ; Tr. at 1703.) AZLCG points to Mr. Geisler's inability to identify any benefit to ratepayers resulting from APS's receiving a positive return on the FVI and asserts that because a positive return on FVI represents a "windfall" to APS paid for by ratepayers, Staff, RUCO, the AZLCG, and APS witness Mr. Cooper all agree that such a positive return reduces APS's risk. (AZLCG Br. at 105; *see* Tr. at 357, 673-674, 3522; Ex. RUCO-5 at 53.) AZLCG asserts that the Commission has previously made a reduction to ROE when a positive return on the FVI is awarded and that the Commission should do so here as well if it awards a positive return on the FVI. (AZLCG Br. at 105-106; *see* Ex. RUCO-5 at 53 (citing Decision No. 77956 (April 15, 2021)[711] at 54).)

RUCO

RUCO argues that there is no basis from a financial perspective to award a positive return on the FVI and that neither APS nor Staff has provided justification for such an award. (RUCO Br. at 25.) To support its argument that applying a return for non-investor supplied capital is not appropriate, RUCO points to Mr. Parcell's testimony that providing a return on investor-supplied capital is appropriate. (RUCO Br. at 25; *see* Ex. S-1 at 47; Ex. RUCO-5 at 53.) RUCO also points to Mr. Parcell's testimony in the 2019 rate case that it is inconsistent with financial theory to provide an opportunity to earn a return on the FVI because the FVI is not financed by investors or at all, making it logical and appropriate to assume that the FVI has no financing costs. (RUCO Br. at 25-26; *see* Ex. RUCO-7 at 326.) RUCO also points out that Mr. Walters cited with approval the language from Decision No. 78317 stating that the FVI does not represent the investment of capital but instead represents inflation recognized in the RCND. (RUCO Br. at 26; *see* Ex. AZLCG&FEA-1 at 58; Ex. RUCO-7 at 327.) A "fundamental tenet of utility regulation," RUCO asserts, is that "profit is allowed for . . . investment . . . – not inflation." (RUCO Br. at 26.) RUCO argues that awarding a positive return on the FVI will simply increase APS's profits, by approximately $39.5 million on day one based on Staff's revenue requirement. (RUCO Br. at 26; *see* Tr. at 5220; Ex. S-24 at 5.) RUCO argues that

[711] Official notice is taken of this decision, issued in a rate case for Arizona Water Company ("AWC"), in which the Commission awarded AWC a return on FVI of 0.20%, determined that this positive return reduced AWC's overall risk, and then lowered AWC's COE by 20 basis points to reflect the reduced risk afforded by the return on FVI. (Decision No. 77956 at 54.)

the Commission has recognized that a positive return on the FVI is a "windfall" and notes that TEP recently agreed to no return on the FVI. (RUCO Br. at 26; *see* Ex. APS-84 at 36.) RUCO argues that no return should be awarded on the FVI but requests that the Commission make a corresponding downward adjustment to the ROE, consistent with past cases,[712] to reflect APS's reduced risk, if the Commission decides to award a positive return on the FVI. (RUCO Br. at 26-27.)

In its Responsive Brief, RUCO argues that APS's argument concerning the return on FVI is "misplaced" and questions how APS can characterize RUCO's position as an "extreme outlier" when APS is proposing to receive an annual revenue increase of more than $40 million in return for non-investor supplied capital, RUCO is the ratepayer advocate, and awarding a return on non-investor supplied capital is "contrary to fundamental regulatory principles." (RUCO RBr. at 5.) RUCO again cites the resolution of the FVI issue in the 2022 TEP rate case, the language in the last APS rate case that awarding a return on the FVI is inconsistent with financial theory, and the language from the 2019 TEP rate case making a downward adjustment to ROE to compensate for the reduced risk from a positive return on FVI. (RUCO RBr. at 5-6; *see* Ex. RUCO-7 at 326; Ex. AZLCG-28 at 69-70.)

RUCO also argues that not approving a positive return on the FVI would not violate the constitutional requirement for the Commission to find fair value because the Arizona Supreme Court has confirmed that the fair value provision refers to the company's rate base, not the return on that rate base. (RUCO RBr. at 6; *see SIB Opinion* at 112.)

<u>Staff</u>

Staff proposes two alternatives for a return on the FVI—the first a 0.0% return and the second a return of 0.50%. (Staff Br. at 34; *see* Tr. at 3480-3481.) Staff notes that APS agrees with Staff's second alternative. (Staff Br. at 34; *see* Tr. at 3481.) Mr. Parcell testified that a 0.0% return on the FVI is appropriate because APS would still receive a return on all investor-supplied capital. (*See* Ex. S-1 at 47.) Mr. Parcell also testified that if the Commission desires to provide a positive return on the FVI, the return should be no higher than the real risk-free rate of return, which he initially calculated

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[712] Specifically, RUCO quotes Decision No. 77856 (admitted herein as Exhibit AZLCG-28), issued in the 2019 TEP rate case, in which the Commission approved a 0.20% return on the FVI and a downward ROE adjustment of 20 basis points to reflect the reduced risk to TEP due to the positive return on FVI. (*See* Ex. AZLCG-28 at 69-70.)

based on historical data to be negative 1.3%, although he stated that it is not appropriate to use a negative real risk-free rate. (*See* Ex. S-1 at 47.) Mr. Parcell subsequently calculated the real risk-free rate using forecasted figures, finding it to be 1.5% in his direct testimony and then to be 1.3% in his surrebuttal testimony. (*See* Ex. S-1 at 49; Ex. S-2 at 17.) Mr. Parcell asserted that an appropriate return on the FVI would be the midpoint between zero and half of the real risk-free rate, first recommending 0.75% and then recommending 0.50% to be consistent with APS's rebuttal proposal because it fell within the range of returns on FVI that he found acceptable. (*See* Ex. S-1 at 49; Ex. S-2 at 17.)

APS Response

In its Responsive Brief, APS states that it and Staff recommend a "fair and reasonable" 0.50% return on the FVI and that other parties' recommendations for a 0.0% return on the FVI are "contrary to Arizona law and sound economics." (APS RBr. at 14.) According to APS, RUCO's argument that no return can be justified on the FVI because it is not investor-supplied capital "is wrong both as a matter of law and economics" because the Arizona Supreme Court has held that a utility is entitled to a fair return on the fair value of its property devoted to public use regardless of whether the property was bought by the utility, was gifted, or was won in a lottery. (APS RBr. at 14; *see Arizona Corp. Comm'n v. Arizona Water Co.*, 85 Ariz. 198, 203 (1959).) APS argues that the Arizona Court of Appeals has reached the same conclusion and that parties who advocate for a 0.0% return on the FVI are arguing for a result that has been repeatedly rejected (and never endorsed) by Arizona courts. (APS RBr. at 14-15; *see Chaparral City Water Co. v. Arizona Corp. Comm'n*, 2007 WL 9710985 at ¶¶ 14, 17 (Ariz. Ct. App. 2007) ("*Chaparral*").[713]) APS argues that no party has presented evidence contesting that the FVI return reflects the opportunity costs associated with APS's dedication of its property to public service. (APS RBr. at 15.) APS also argues that AZLCG's citation to New Mexico case law is inapt as the cases are distinguishable due to the New Mexico State Constitution's not

[713] APS acknowledges that this is a memorandum decision but states that the holding is binding on the Commission under Arizona Supreme Court "Rule 111(A)." As we noted in the last rate case, Arizona Supreme Court 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 the 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).) The court in *Chaparral* held that "the Commission did not comply with the requirements of Article 15, Section 14 of the Arizona Constitution when the Commission determined the operating income of Chaparral City using the original cost rate base instead of the fair value rate base." (*Chaparral* at ¶ 49.)

containing a fair value requirement. (APS RBr. at 15-16.)

APS argues that RUCO and AZLCG's arguments to reduce APS's ROE commensurate with any positive return on the FVI because the FVI reduces APS's risks "is effectively the same thing as finding a 'zero' FVI [and thus] contrary to Arizona law and sound basic economics" and, further, would increase APS's risk related to regulatory certainty. (APS RBr. at 16; *see* Ex. APS-6 at 20-21; Tr. at 672-674.) APS argues that Commission actions that are contrary to legal requirements inherently increase risk, and that neither RUCO nor AZLCG has presented evidence to the contrary. (APS RBr. at 16.[714]) APS argues that a positive return on the FVI would not justify a corresponding reduction to APS's ROE. (APS RBr. at 16.)

Resolution

Based on the expert evidence and the arguments presented herein, the Commission continues to believe that the FVI represents the inflation recognized in the RCND and not a capital investment. The Commission also continues to believe that there is not a legal requirement to authorize a positive return on the FVI and that any positive return on the FVI decreases APS's risk. Further, the Commission continues to believe it "unlikely 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." (Ex. RUCO-7 at 329.)

APS's customers have incurred large rate increases in the past year due to the PSA and the court resolution surcharge and will again incur a significant rate increase as a result of this decision. The Arizona Court of Appeals recently recognized that in fulfilling its duty to set just and reasonable rates that are fair to both consumers and public service corporations, it is appropriate for the Commission to balance the interests of the utility versus those of the ratepayers and, further, that the Commission is best suited to make this judgment call.[715] APS has acknowledged that it is appropriate to reduce its requested return on the FVI based on the impact that the return will have on its ratepayers. The Commission agrees with this assessment but believes that APS's downward adjustment to its requested

[714] To support this, APS cites a quote from Mr. Cooper to the effect that regulatory risk is caused by regulatory actions that "jeopardize the utility's opportunity to recover its costs and earn its allowed rate of return on its shareholders' invested capital due to changes in laws or regulations" or in how they are applied. (APS RBr. at 16; *see* Ex. APS-5 at 7.) This choice is interesting because Mr. Cooper specifically refers to shareholders' invested capital, which is precisely what RUCO and AZLCG assert the FVI is not.

[715] *Arizona Pub. Serv. Co. v. Arizona Corp. Comm'n*, 526 P.3d 914, 919 (Ariz. Ct. App. 2023).

return on the FVI did not go far enough. Based on the evidence and arguments of the parties, the conclusions reached above, the Commission's recognition that any positive return on the FVI decreases APS's risk, and the Commission's decision not to make a commensurate deduction to APS's ROE as a result of awarding a positive return on the FVI, the Commission concludes that it is appropriate to grant APS a return on the FVI of 0.25% (half of the amount recommended by APS and by Staff in the alternative). The Commission determines that this positive return on the FVI, made without a commensurate reduction to the ROE awarded herein, will result in a FVROR that is sufficient to maintain (and should improve) APS's financial integrity, will enable APS to attract capital under reasonable terms, and is commensurate with returns that investors could earn by investing in other enterprises of comparable risk.

D. Fair Value Rate of Return

Based on our resolutions of the cost of capital issues, we find that APS's WACC is the following ($ amounts are in thousands):

Capitalization	$ Amount	% Amount	Cost Rate	Composite Cost
Common Equity	$5,377,565	51.93%	9.55%	4.96%
Long-Term Debt	$4,977,846	48.07%	3.85%	1.85%
			WACC:	**6.81%**

Further, we find that APS's FVROR is the following ($ amounts are in thousands):

	$ Amount	% Amount	Cost Rate	Composite Cost
Common Equity	$5,377,565	32.74%	9.55%	3.13%
Long-Term Debt	$4,977,846	30.31%	3.85%	1.17%
FVI	$6,069,129	36.95%	0.25%	0.09%
			FVROR:	**4.39%**

IX. Revenue Requirement

In light of the determinations reached herein, we conclude that APS's base rate revenues should be increased by $491.678 million or by approximately 14.56%, over TY base rate revenues of $3,377,773,000. The following compares APS's final position with our determinations made herein ($ amounts are in thousands):

	APS Final	**Commission**
OCRB	$10,359,616	$10,355,411
RCND	$22,497,874	$22,493,669
FVRB	$16,428,745	$16,424,540

FVI	$6,069,129	$6,069,129
Current Rate of Return on OCRB	2.48%	3.41%
Required Rate of Return on OCRB/WACC	7.17%	6.81%
Required Operating Income - OCRB	$742,784	$705,203
TY Operating Income	$256,436	$352,610
Operating Income Deficiency on OCRB	$486,348	$352,593
GRCF	1.3345	1.3345
Increase in Base Revenue Requirement Based on OCRB	$649,047	$470,547
FVI Revenue	$41,383	$21,131
Requested/Required Increase in Base Rate Revenue Requirement	$690,430	$491,678

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 through set forth fully here.

3. The description of APS's application, as amended, 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 descriptions of the uncontested proposals and the evidence supporting the approval of the uncontested proposals described in Section V of the Discussion portion of this Decision are accurate and we adopt them in their entirety as though set forth fully here.

5. The background information, descriptions of parties' positions, and evidence described in Sections VI, VII, VIII, and IX of the Discussion portion of this Decision are accurate and we incorporate them as though set forth fully here.

6. The resolutions reached in Section V and in the various subsections within Sections VI, VII, VIII, and IX 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.

7. The rates, charges, and terms and conditions of service resulting from the resolutions described in Findings of Fact No. 6 are just and reasonable and in the public interest.

8. The rates, charges, and terms and conditions of service resulting from the Commission's resolution of the issues 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.

9. 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 15, § 2 of the Arizona Constitution.

2. The Commission has jurisdiction over APS, over the subject matter of APS's application as amended, and over the issues raised and resolved herein (uncontested and contested).

3. Notice of the application and hearing were provided as required by Arizona law.

4. APS's FVRB is $16,424,540,000.

5. A FVROR of 4.39% results in just and reasonable rates and a revenue requirement that is sufficient to maintain (and should improve) APS's financial integrity, will enable APS to attract capital under reasonable terms, and is commensurate with returns that investors could earn by investing in other enterprises of comparable risk.

6. The rates, charges, and terms and conditions of service resulting from the Commission's resolution of the issues 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.

7. 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 shall file with the Commission, on or before February 29, 2024, revised rate plan tariffs and plans of administration conforming to the resolutions reached in this Decision and the following Ordering Paragraphs.

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 March 1, 2024.

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 the Environmental Improvement Surcharge Mechanism ("EIS") is hereby terminated, and the $10.3 million collected in the EIS shall be transferred into base rates.

IT IS FURTHER ORDERED that the Transmission Cost Adjustment Mechanism ("TCA") shall be retained in its current form.

IT IS FURTHER ORDERED that the Tax Expense Adjustment Mechanism ("TEAM") shall be retained in its current form and with its current zero rate.

IT IS FURTHER ORDERED that APS's three main residential rate plan options available to new customers (Fixed-Energy-Charge Plan aka R-Basic or R-1, Time-of-Use 4 pm-7pm Weekdays aka TOU-E, and Time-of-Use 4pm-7pm Weekdays with Demand Charge aka R-3) shall be retained and that seasonality shall not be introduced to the Fixed-Energy-Charge Plan.

IT IS FURTHER ORDERED that APS's Energy Support Program aka E-3 and Medical Care Equipment Support Program aka E-4 rate rider POAs shall be modified to provide two tiers of discounts based on income level, with a 60% discount capped at $165/month provided to those customers with incomes of 0% to 75.99% of the Federal Poverty Level under both E-3 and E-4, with a 25% discount capped at $95/month provided to those customers with incomes of 76% to 200% of the Federal Poverty

Level under E-3, and with a 35% discount capped at $95/month provided to those customers with incomes of 76% to 200% of the Federal Poverty Level under E-4.

IT IS FURTHER ORDERED that APS is authorized to track discounts paid to customers and to defer program costs incurred above or below the level authorized in this Decision on the Energy Support Program (E-3) and the Medical Care Equipment Support Program (E-4) for possible later recovery or refund through rates. Nothing in this Decision shall be construed in any way to limit the Commission's authority to review the entirety of the programs and to make any disallowances thereof due to imprudence, errors, or inappropriate application of the requirements of this Decision.

IT IS FURTHER ORDERED that APS's Crisis Bill Assistance Program shall be retained with an annual budget of $2.5 million.

IT IS FURTHER ORDERED that the following two new off-peak holidays shall be provided to residential customers on Time-of-Use 4 pm-7pm Weekdays (TOU-E), Time-of-Use 4pm-7pm Weekdays with Demand Charge (R-3), and the frozen Saver Choice Plus demand rate (R2): Juneteenth and Indigenous People's Day/Columbus Day.

IT IS FURTHER ORDERED that APS shall work with parties through its RPAC to examine whether and how DSM and EE measures can be evaluated in resource planning to reflect their value for risk reduction and as a hedge.

IT IS FURTHER ORDERED that the following compliance filings and requirements are eliminated or waived:

- The two compliance requirements related to the E-32 L Storage Pilot included in Decision No. 76295, as those have been superseded by Decision No. 78317 and Decision No. 78966 (May 9, 2023);
- The compliance requirement in Decision No. 68741 (June 5, 2006) concerning annual filings relating to Competitive Electric Affiliates;
- The compliance requirement in Decision No. 77270 (June 27, 2019) for tracking and quarterly reporting of gross margins from higher-than-projected revenues; and
- The compliance requirement in Decision No. 76295 concerning APS being required to meet with interested parties once a specified number of customers are signed up for an Optional

R-Tech Pilot Rate Program.

IT IS FURTHER ORDERED that the Palo Verde Generating Station decommissioning costs recommended by APS are adopted as set forth in the decommissioning contribution schedule attached as Exhibit C to this Decision.

IT IS FURTHER ORDERED that APS's proposed modifications to Service Schedules 1 and 9, as included in Exhibit APS-30, Attachments JEH-13RB and Attachment JEH-15RB, and Service Schedule 3, as included in Exhibit APS-29, Attachment JEH-15DR, are approved.

IT IS FURTHER ORDERED that APS shall categorize its plant projects from their inception as growth-related or non-growth-related, with such categorization documented consistently and reflected in APS's budgeting.

IT IS FURTHER ORDERED that APS shall be allowed a return set at the Company's WACC on its net prepaid pension asset and its net other post-employment benefits ("OPEB") liability.

IT IS FURTHER ORDERED that APS's Four Corners Power Plant Effluent Limitation Guidelines Plant Modifications ("ELG Project") shall be included as post-test-year plant in rate base with a cap of $52,596,551 and that APS shall file, as a compliance item in this docket, within 30 days after the effective date of this Decision, a report providing the final as-recorded costs of the ELG Project and the breakdown of those costs among APS and the other owners of the Four Corners Power Plant.

IT IS FURTHER ORDERED that APS shall explore thoroughly and in good faith with the other Four Corners Power Plant owners the issue of retiring the Four Corners Power Plant earlier than 2031 and shall, within six months after the effective date of this Decision, file as a compliance item in this docket and submit to the Commission a report concerning the outcome of those efforts. To the extent that the report includes information APS deems to be confidential, APS shall redact the information before filing the report in this docket. APS shall provide Staff and any other party to this matter the opportunity to review the confidential information from the report subject to a protective agreement previously executed by the party for this matter or a new protective agreement. APS shall provide a hard copy of the confidential report to each Commissioner's office and the Utilities Division Director under seal.

IT IS FURTHER ORDERED that APS shall explore thoroughly and in good faith the extent to which it would be able to obtain the resources identified in the earlier retirement scenarios included in its 2023 IRP and shall, within six months after the effective date of this Decision, file as a compliance item in this docket and submit to the Commission a report that details the following for each early retirement scenario: (1) APS's projected ability to obtain the resources and any needed associated infrastructure, (2) the timeline to obtain the resources and associated infrastructure, (3) whether the pricing would be consistent with the pricing assumed in the 2023 IRP, (4) any reliability issues foreseen by APS as a result of implementing any of the scenarios, (5) factual information supporting APS's assertions as to the first four items, and (6) any additional relevant information of which APS believes the Commission should be aware. To the extent that the report includes information APS deems to be confidential, APS shall redact the information before filing the report in this docket. APS shall provide Staff and any other party to this matter the opportunity to review the confidential information from the report subject to a protective agreement previously executed by the party for this matter or a new protective agreement. APS shall provide a hard copy of the confidential report to each Commissioner's office and to the Utilities Division Director under seal.

IT IS FURTHER ORDERED that APS shall make adjustments to the depreciation expense on all portions of the Four Corners Power Plant Selective Catalytic Reduction plant ("SCRs") (both the allowed and disallowed portions from Decision No. 78317) to reflect a 2038 end of life and shall use a 2038 end of life for depreciation of the SCRs going forward.

IT IS FURTHER ORDERED that APS shall recover the deferred SCRs costs incurred in the period from January 1, 2021, through December 1, 2021, on a levelized basis, over the period from the effective date of this rate case through December 31, 2038, with a carrying charge set at 4.10%, the cost of debt approved in Decision No. 78317.

IT IS FURTHER ORDERED that APS shall adjust the amortization period for the existing SCRs deferral for which recovery was allowed in Decision No. 78317 so that the remaining deferral amount is recovered on a levelized basis over the period from the effective date of this rate case through December 31, 2038, with a carrying charge set at 4.10%, the cost of debt approved in Decision No. 78317.

IT IS FURTHER ORDERED that the Commission strongly encourages APS to use a test year that is a calendar year for its next rate case application.

IT IS FURTHER ORDERED that except as modified by the Resolutions reached and ordering paragraphs included in this Decision, APS's depreciation and amortization rates and methods are approved.

IT IS FURTHER ORDERED that APS shall, in future Fuel and Purchased Power Audits and in future rate cases, provide Staff and Staff's consultants with all available documentation supporting APS's contemporaneous decision-making concerning potentially disputed issues and APS's efforts to mitigate any potentially harmful impacts to ratepayers arising from contract positions.

IT IS FURTHER ORDERED that APS's base fuel rate is 3.8321¢/kWh.

IT IS FURTHER ORDERED that APS's proposed modifications to the Demand Side Management Adjustment Charge ("DSMAC") Plan of Administration ("POA"), as included in Exhibit APS-30 at Attachment JEH-04RB, are approved.

IT IS FURTHER ORDERED that APS is granted a waiver, under A.A.C. R14-2-2419, of the language in A.A.C. R14-2-2404, A.A.C. R14-2-2405, and A.A.C. R14-2-2411 restricting performance incentive provisions to energy efficiency programs and providing a cap on the amount of demand response that can be counted toward achieving cumulative annual energy savings.

IT IS FURTHER ORDERED that APS shall not be authorized to collect $59.4 million annually in DSM investment through base rates.

IT IS FURTHER ORDERED that the Renewable Energy Standard Adjustment Charge ("REAC") shall be retained in its current form.

IT IS FURTHER ORDERED that APS shall not transfer $1.9 million of Solar Communities program costs from the REAC into base rates.

IT IS FURTHER ORDERED that APS may transfer into base rates only the booked $27,149,479 in Lost Fixed Cost Recovery Mechanism ("LFCR") revenues by removing this amount from "Revenues from Surcharges."

IT IS FURTHER ORDERED that APS may keep the remaining $31,360,000 that reflects un-booked lost fixed cost revenues in the LFCR adjustor, to be reviewed and considered for recovery either in its next general rate case or its next annual LFCR reset proceeding.

IT IS FURTHER ORDERED that APS's proposed modification to "clarify" the LFCR POA's earnings test is rejected, and the language of the LFCR POA's earnings test shall be made consistent with the LFCR as approved in Decision No. 78317: "If the Earnings Test Period's rate of return is higher than the Earnings Test Threshold, the LFCR Adjustment for the coming year will be set to zero."

IT IS FURTHER ORDERED that APS shall, in consultation with Staff, AZLCG, and any other interested parties, modify the LFCR POA to achieve at least the following: (1) modify the Balancing Account and all related language to clarify that APS will not be permitted to defer and/or collect any amounts related to a year in which the Earnings Test Threshold is lower than the Earnings Test Period's rate of return; (2) include as numbered pages within the POA each Schedule used for purposes of calculation; (3) explain, clearly and in detail (a) how each component of the lost fixed cost amount is to be calculated and what starting point and billing determinants are to be used, (b) how each component of the calculation of future lost fixed cost amounts are impacted by whether the surcharge revenues were or were not transferred into base rates in the most recent general rate case, and (c) the accounting treatment in a general rate case to transfer lost fixed cost amounts into base rates when the prior general rate case did or did not transfer lost fixed cost amounts into base rates; and (4) identify for each line of each Schedule within the POA the source for the data included or to be included.

IT IS FURTHER ORDERED that APS shall, within 90 days after the effective date of the decision in this matter, file as a compliance item in this docket the proposed revised LFCR POA (both in clean and in redline form from the version included in Exhibit APS-100).

IT IS FURTHER ORDERED that Staff shall, within a reasonable period of time not to exceed 120 days, review the proposed revised LFCR POA and file, for Commission review and approval at an Open Meeting, a Staff Report and Proposed Order addressing whether the LFCR POA complies with the requirements of this Decision and should be approved by the Commission.

IT IS FURTHER ORDERED that APS's Power Supply Adjustor ("PSA") POA shall be modified by increasing the annual PSA increase cap to 6 mill/kWh.

IT IS FURTHER ORDERED that APS's PSA POA shall be modified to require APS, whenever the under-collected or over-collected balance/s of the PSA account/s exceed/s $100 million, to file, in both the docket in which the then-current PSA rate was approved and in the docket for the most recently completed general rate case, a notice that sets forth the current balance/s of the PSA account/s and includes a proposal for how the under-collection or over-collection should be addressed through the transition component of the PSA POA along with the calculations supporting the proposal.

IT IS FURTHER ORDERED that Staff shall, within 60 days after the filing of such a notification and proposal regarding the under- or over-collection in the PSA account/s, review the notification and proposal, contact APS to obtain any supporting data necessary to scrutinize the calculations, and file in the docket in which the then-current PSA rate was approved, with a copy to the docket for the most recently completed general rate case, a Staff Report and Proposed Order analyzing the notification and proposal and recommending whether and in what manner the under-collection or over-collection should be addressed through the transition component of the PSA POA.

IT IS FURTHER ORDERED that the PSA POA under-collection/over-collection notice requirement adopted herein replaces the $500,000 filing requirement imposed by Decision No. 78877, which is hereby nullified.

IT IS FURTHER ORDERED that the PSA POA shall be modified to eliminate the requirement for APS to file third-party storage contracts and have them approved by the Commission in order to include them as Storage Product Costs in the PSA.

IT IS FURTHER ORDERED that the PSA POA shall not be modified to replace "APS's then existing short term borrowing rate" with "APS's deposit interest rate as established in Service Schedule 1."

IT IS FURTHER ORDERED that APS shall ensure that its revised PSA POA, filed to conform to the requirements established herein, provides consistency in the time periods used for calculating the forward component, meaning that the forecasted costs and forecasted kWh consumption shall be for the same 12-month period.

IT IS FURTHER ORDERED that APS's proposed SRB is approved, with the following modifications from APS's SRB proposal included in Exhibit A hereto, all of which shall be reflected in the SRB POA APS files as a compliance item in this docket:

- A coal-fired steam generator may be an SRB Qualifying Resource;
- APS shall not be permitted to defer for future recovery in a subsequent SRB proceeding any

amount that exceeds the 3% year-over-year cap on the SRB surcharge increase;

- If APS exceeds the Earnings Test Threshold, APS shall not be permitted to defer for future recovery in a subsequent SRB proceeding any amount that exceeds the Earnings Test Threshold and shall not be permitted to increase the SRB surcharge to be applied for the following year;
- If APS under-collects through the SRB surcharge, APS shall not be permitted to collect any such under-collection in a subsequent SRB proceeding;
- To the extent that AIAC and/or CIAC has been provided to APS for any Qualifying Resource proposed for recovery through the SRB, the entire AIAC and/or CIAC amount shall be deducted from the costs included in calculating the SRB surcharge;
- APS shall be limited to an initial SRB Application and five Reset Applications, with no more than one filed in each 12-month period, before its next rate case application is filed;
- The prudency of projects proposed for inclusion in the SRB shall be determined by the Commission during an SRB proceeding, not during a rate case, and shall be based upon the definition of "prudently invested" included in A.A.C. R14-2-103(A)(3)(l);
- The possibility of a hearing to determine the prudency of an investment proposed for inclusion in the SRB shall be provided in an SRB proceeding upon party (APS, Staff, or Intervenor) request;
- The deadline for a Motion to Intervene shall be 60 days after APS files an SRB Notice;
- In addition to notifying its customers through posting a link to the SRB Notice on its website, APS shall, with its regularly scheduled billing immediately following the date when the SRB Notice is filed, mail or email to its customers,[716] as a billing insert or a separate communication, an explanation of the SRB Notice that includes at least (1) how to find the SRB Notice and the subsequent SRB Application/Reset Application on the APS website, (2) standard Commission-required information about intervention and instructions to file a Motion to Intervene, (3) the deadline for a Motion to Intervene, and (4) a phone

[716] The delivery method used by APS shall be consistent with the manner in which each customer receives their monthly bill.

number to contact a representative of APS;

- Staff's deadline for completing its review and filing a Staff Report[717] and/or a Request for Hearing ("Staff Report/Request for Hearing") shall be 90 days after the SRB Application/Reset Application is filed;
- An Intervenor's deadline for filing an Objection to an SRB Application/Reset Application and/or a Request for Hearing ("Intervenor Objection/Request for Hearing") shall be 75 days after the SRB Application/Reset Application is filed;
- Each party may file a Response to a Staff Report/Request for Hearing or Intervenor Objection/Request for Hearing within 14 days after it is filed, and APS may include in its Response a Request for Hearing;
- If a Request for Hearing is filed:
  - The Hearing Division shall issue a Procedural Order scheduling the hearing to occur within 60 days after the Request for Hearing is filed, unless the parties agree to a later date or a later date is necessary due to Commission scheduling constraints;
  - The hearing shall be scheduled for one day only, unless good cause exists for additional scheduled hearing days;
  - The scope of the hearing shall be limited to determining the prudency of the capital investments APS proposes in the SRB Application/Reset Application, and the standard to be used shall be the definition of "prudently invested" included in A.A.C. R14-2-103(A)(3)(l); and
  - The Hearing Division shall issue a Recommended Opinion and Order for the Commission's final determination of prudency and approval or disapproval of the SRB Application/Reset Application;
- When each Qualifying Resource for which Capital Carrying Costs are being recovered through the SRB is moved into rate base in a subsequent general rate case, the plant balance

[717] If Staff is not filing a Request for Hearing along with its Staff Report, Staff's Staff Report shall be accompanied by Staff's Proposed Order for Commission determination of prudency for each Qualifying Resource included in the SRB Application/Reset Application and Commission approval or denial of the SRB Application/Reset Application.

for the Qualifying Resource shall reflect all accumulated depreciation since the actual in-service date;

- An AG-X customer who self-supplies Resource Adequacy, as described and resolved in Section (VI)(I)(4) herein, shall be exempt from the SRB surcharge for the duration of the time the customer maintains its status as an AG-X customer who self-supplies Resource Adequacy; and
- APS shall ensure that the modified SRB POA consistently uses the terms that are defined rather than variations on those terms, and shall ensure that the language of the SRB POA and the language used on Tables I, II, and III and the Schedules accompanying the SRB POA is consistent with the directives described above.

IT IS FURTHER ORDERED that Staff shall actively participate in APS's Resource Planning Advisory Committee ("RPAC").

IT IS FURTHER ORDERED that in its next general rate case, APS shall comply with the following in creating its Cost of Service Study ("COSS"):

- Production demand costs shall be allocated using the A&P-4CP method approved herein.
- If AG-X customers are obtaining Resource Adequacy from APS rather than Generation Service Providers ("GSPs"), APS shall allocate to AG-X customers production costs that reflect their reliance on APS for Resource Adequacy to cover their entire site loads.
- If AG-X customers are successfully obtaining Resource Adequacy from GSPs rather than APS, APS shall allocate to AG-X customers production costs that reflect their loads served by APS when GSP deliveries are curtailed.
- If necessary to comply with the two immediately preceding items, APS may separate AG-X customers into separate classes—those AG-X customers who obtain Resource Adequacy from APS and those AG-X customers who obtain Resource Adequacy from GSPs.
- APS shall allocate the distribution costs in FERC accounts 360, 361, and 364 through 368 as both demand-related and customer-related, using the minimum-load method ("MLM") as approved herein.
- APS shall allocate its secondary distribution costs using the sum of individual max ("SIM")

allocator as approved herein.

- APS shall maintain residential Distributed Generation ("DG") customers in a separate class.
- APS shall allocate costs of service to residential DG customers based on their site loads, with credits made based on the difference between the site loads and delivered loads using the credit factors for each cost type as described in Mr. Moe's testimony (production demand credit, transmission credit, distribution substation credit, distribution primary credit, and distribution secondary credit) and the value of the solar export power provided (fuel cost reduction using the current base fuel rate), which may be offset by the actual amounts paid to the DG customers for the exported energy. APS shall ensure that the credits provided are informed by the analysis of what APS's system would have looked like in the test year without residential DG, required below, even if that means that the credit factors must be calculated differently than they were in this case, and that detailed data is provided with the application to support the credits provided.

IT IS FURTHER ORDERED that with the application filing in its next general rate case, APS shall include for the test year used an analysis of what its system would have looked like without residential DG and how much more it would have spent on generating capacity, fuel costs, and market purchases to backfill the residential DG resource, compared to APS's actual TY costs, with sufficient detail for parties to scrutinize the stated differences.

IT IS FURTHER ORDERED that APS shall make the following revenue allocations to ameliorate the worst of the subsidization in APS's current rate design:

- The following subclasses shall receive revenue allocation at the level of approximately 1.15 times[718] the system average increase: Legacy Solar (Energy), Legacy Solar (Demand), TOU-E with Solar, R-3 with Solar, and E-34.
- The following subclasses shall receive revenue allocation at the level of 0.85 times the system average increase: E-32TOU XS and E-32TOU S.
- The remaining subclasses shall receive revenue allocation at the level of the system average

[718] This is to ensure that APS is not required to over-allocate revenue, due to the higher number of subclasses that will receive a higher increase as opposed to the number of subclasses that will receive a lower increase.

increase.

IT IS FURTHER ORDERED that to achieve the additional revenue allocation specific to residential DG solar customers who take service under TOU-E and R-3, APS shall include an additional charge applicable only to DG solar customers on each of these two tariffs, to minimize customer confusion concerning which tariff applies to their situation.

IT IS FURTHER ORDERED that APS shall increase the basic service charge ("BSC") for each residential rate plan, other than Legacy Solar E-12 (Energy), consistent with the system average increase.

IT IS FURTHER ORDERED that APS shall accomplish the increased revenue allocation for the Legacy Solar E-12 (Energy) rate plan in large part by increasing the BSC for this rate plan to $0.40 per day.

IT IS FURTHER ORDERED that APS shall make the following increases to the E-32 M bundled energy charges:

Bundled Rate	Present Rate	Commission Approved Increase
Summer tier 1 kWh	$0.10065	System Average %
Winter tier 1 kWh	$0.08532	System Average %
Summer tier 2 kWh	$0.06210	Half of System Average %
Winter tier 2 kWh	$0.04678	Half of System Average %
Standby Delivery	$0.01230	One-Quarter of System Average %

IT IS FURTHER ORDERED that APS shall make the following increases to the E-32 L bundled energy charges:

Bundled Rate	Present Rate	Commission Approved Increase
Summer kWh	$0.05258	Half of System Average %
Winter kWh	$0.03542	Half of System Average %

IT IS FURTHER ORDERED that APS shall make up the remainder of the system average increase percentage for the E-32 M and E-32 L rate schedules through evenly distributed increases to demand charges.

IT IS FURTHER ORDERED that APS shall, as a compliance item in this docket, file a tariff that implements changes to the E-32 L SP program to include an on-peak period on weekdays only within 60 days of the effective date of this Decision.

IT IS FURTHER ORDERED that APS shall modify the E-32 L SP tariff, as included in the conforming tariffs to be filed herein, to define "monthly peak site load" as "the average kW supplied during the 15-minute period of maximum use during on-peak hours for each respective billing period."

IT IS FURTHER ORDERED that the AG-X program shall be modified as follows, and the AG-X POA that is included in the conforming tariffs and POAs filing shall be modified from the POA included in Exhibit B (as necessary) to reflect the following:

- APS's Resource Adequacy ("RA") options, as provided in Exhibit B hereto, including the notice timing provisions, are approved.
- During the 12 months following the effective date of this Decision, APS shall assess a reserve capacity charge for APS-supplied RA that is equal to its current AG-X reserve capacity charge ($5.248/kW) increased by the system standard revenue increase approved herein.
- The reserve capacity charge for APS-supplied RA after the one-year transition period shall be set at the level of the unbundled generation demand charge from E-34.
- The RA supplied by GSPs to AG-X customers who do not desire to pay for APS-supplied RA shall be required to meet WRAP RA requirements.
- The minimum aggregated peak load threshold to participate in AG-X shall be reduced to 5 MW, and E-32 S and E-32 TOU S customers shall be allowed to participate in AG-X.
- APS must give AG-X customers at least three years' notice, in writing, before filing an application with the Commission that proposes termination of the AG-X program, except in case of an emergency situation that makes termination of the AG-X program imperative to protect non-AG-X customers and the public interest.
- APS shall allow an AG-X customer to increase its load by more than 10% if the customer requests permission for such expansion, and the expansion does not cause the AG-X program to exceed the 200 MW cap.
- AG-X customers moving from APS-supplied RA to self-supplied RA shall be required to provide APS notice six months before the WRAP Forward Showing deadline, and AG-X

customers moving from self-supplied RA to APS-supplied RA shall be required to provide APS notice three years before the move, though this may be shortened at APS's discretion if there will be no shift of cost or risk to non-AG-X customers.

- Demand Response ("DR") may be used to supply at least a portion of self-supplied RA and may originate with the AG-X customer rather than with the GSP.
- APS shall revise the language regarding failure to meet the timing of the Forward Showing Program contained in the "Default of the Third-Party Generation Provider" section of the AG-X POA to read as follows: "Failure on the part of the Generation Service Provider who is providing Resource Adequacy to meet the timing of the Forward Showing Program as outlined in the Program Guidelines may result in penalty charges which will be charged to the offending Generation Service Provider as applicable. A Generation Service Provider's repeated failure to meet the timing of the Forward Showing Program may result in termination from the program." Additionally, the heading for this section shall be corrected to include "Generation Service Provider" rather than "Generation Provider."
- APS shall clarify the new RA language in the "Description of Services and Obligations" section specifically to ensure identification of the correct entity or entities as responsible for providing RA, purchasing RA, demonstrating RA, and paying for RA.
- The $15 million annual PSA POA off-system sales mitigation provision for AG-X shall be eliminated.

IT IS FURTHER ORDERED that APS shall:

- Meet and collaborate with AZLCG, NRG, Staff, and any other interested parties concerning the manner in which the AG-X program DR measures should be structured and described in the AG-X POA to ensure WRAP compliance;
- Include in the meetings discussion of the merits of the DR program provisions proposed by NRG;
- Craft language regarding the DR measures for inclusion in the AG-X POA, with the language to be informed by the stakeholder discussions and created by consensus if possible; and

- File in this docket, within 180 days after the effective date of this Decision, proposed revised AG-X POA language that explains the DR measures in sufficient detail for an AG-X customer, potential AG-X customer, or GSP to understand the applicable requirements and where to find additional information if needed (such as in the WRAP Tariff).

IT IS FURTHER ORDERED that APS shall cancel R-Tech.

IT IS FURTHER ORDERED that APS shall, within 180 days of this Decision, file as a compliance item in this docket a Bring-Your-Own-Device ("BYOD") Pilot POA that includes the BYOD Program features identified by AriSEIA/SEIA in this matter, with the following modifications:

- The BYOD Pilot shall be capped at 5,000 customers;
- The BYOD Pilot shall establish pricing which does not result in a cost shift to non-participating customers;
- EnergyHub shall serve as the aggregator for the BYOD Pilot; and
- The BYOD Pilot shall require battery discharge periods of up to four hours that can be scheduled together or staggered within the period from 4 p.m. to 10 p.m., depending on APS's capacity needs for an event.

IT IS FURTHER ORDERED that APS shall, within 60 days after the effective date of this Decision, meet with AriSEIA/SEIA and any other interested parties to discuss collaboratively and attempt to reach agreement on the language of the BYOD Pilot POA. During these collaborative discussions, the participants shall analyze whether incentive pricing should be based on kWh or kW, whether there should be differences in on-peak vs. off-peak pricing for incentives, and whether any on-peak and off-peak times used for incentive pricing should be different than those established for TOU customers.

IT IS FURTHER ORDERED that Staff shall:

- Within 120 days after the BYOD Pilot POA is filed, review the BYOD Pilot POA; and
- Within 180 days after the BYOD Pilot POA is filed, file in this docket a Staff Report and Proposed Order, for Commission consideration at an Open Meeting, that provides Staff's analysis of the BYOD Pilot POA and the issues prescribed above and recommends whether the BYOD Pilot POA should be approved as written or should be further modified.

IT IS FURTHER ORDERED that APS shall not use ratepayer-derived funds on marketing, advertising, media production, advertising retainers, or advertising research, or for any other marketing- or advertising-related purposes (collectively "marketing/advertising") unless the content of the marketing/advertising is educational and directly related to a specific Commission-approved program, rate plan, or tariff.

IT IS FURTHER ORDERED that APS shall consider taking steps to ensure a proper and thorough accounting of ratepayer-funded advertising/marketing expenses going forward, so that the programs and funds such efforts are associated with are more easily trackable in a future review.

IT IS FURTHER ORDERED that the Solar Communities Program shall not be expanded or extended and therefore APS shall not add any new participants to the Program as of the effective date of this Decision.

IT IS FURTHER ORDERED that APS shall be prohibited from expanding into customer-sited microgrids until further direction from the Commission.

IT IS FURTHER ORDERED that APS shall ensure going forward that all of the documents that affect the operation of or the terms and conditions related to the rates APS charges its customers (such as its POAs and Program Guidelines) are posted on its website so that they may be accessed by the public.

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

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN O'CONNOR	COMMISSIONER MÁRQUEZ PETERSON

DISSENT		
COMMISSIONER TOVAR	COMMISSIONER THOMPSON	COMMISSIONER MYERS

IN WITNESS WHEREOF, I, DOUGLAS R. CLARK, 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 5th day of March 2024.

DOUGLAS R. CLARK
EXECUTIVE DIRECTOR

DISSENT Anna Tovar

DISSENT ______________________

SNH/(gb)

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Consented to Service by Email

System Reliability Benefit Adjustment Mechanism
Plan of Administration

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1. General Description

This document describes the plan for administering Arizona Public Service Company's (APS or the Company) System Reliability Benefit Adjustment Mechanism (SRB) and Adjustment Schedule SRB-1. As authorized for APS by the Arizona Corporation Commission (Commission) in Decision No. XXXXX (XXX X, XXX), the SRB provides for the recovery of approved Capital Carrying Costs for Qualifying Resources not already recovered in base rates or through a separate Commission-approved recovery mechanism. Schedule SRB-1 is applied to Standard Offer or Direct Access customer bills as a monthly kilowatt-hour charge (for Residential customers and General Service customers served in accordance with non-demand billed rate schedules), or a kilowatt demand charge (for General Service customers served in accordance with demand billed rate schedules), unless the customer's current rate has alternate provisions.

The SRB is subject to the following limitations absent the express approval of the Commission: (1) a year-over-year annual increase limit of 3% of the Company's ACC jurisdictional base rate revenue requirement , as determined in APS's most recent rate case; (2) an Earnings Test that allows recovery of costs not to exceed the Earnings Test Threshold authorized in the Company's last rate case, as described in this document; (3) a Qualifying Resource threshold investment cost of at least $50 million; and (4) a limit of one SRB Application annually, and no more than five such Applications between general rate cases.

2. Definitions

<u>Adjusted Weighted Cost of Capital</u> – The Weighted Cost of Capital (WACC) approved by the Commission in the Company's most recent general rate case discounted by 1.00%. This discount is applied only for the purpose of calculating a return to include in Capital Carrying Costs for Qualifying Resources recovered through Adjustment Schedule SRB-1 prior to moving the Qualifying Resource into the Company's rate base in a subsequent rate case. Once included in

rate base, the WACC applied to the Qualifying Resource will be the same as that applied to all other rate base items.

All-Source Request for Proposal (All-Source RFP) – A document issued by APS soliciting proposals from qualified parties in which all types of electric resources or energy storage projects that can meet all or part of APS's needs as described in the RFP will be considered equally.

Allowable Costs – Schedule SRB-1 shall recover Capital Carrying Costs for Qualifying Resources that are in service at the time Schedule SRB-1 rates are approved and are not being recovered in base rates or other recovery mechanism.

Applicable Interest – Interest is applied on Balancing Account funds annually at the following rates: any over-collection existing at the time of the adjustor rate calculation will be credited an amount equal to interest at a rate equal to the Company's authorized return on equity (ROE) or APS's deposit interest rate as established in Service Schedule 1, whichever is greater, and will be refunded to customers over the following 12 months; any under-collection existing at the time of the adjustor rate calculation will be debited an amount equal to interest at a rate equal to the Company's authorized ROE or APS's deposit interest rate as established in Service Schedule 1, whichever is less, and will be recovered from customers over the following 12 months.

Earnings Test – Comparison of the Earnings Test Period rate of return with the Earnings Test Threshold. The Earnings Test Period rate of return will be based on APS's most recently filed FERC Form 1, using Earnings Test Period costs, revenues, and other financial information, with certain pro forma adjustments related to surcharges and explicit items removed in the Company's most recently approved rate case applicable to the evaluation year.

Earnings Test Period – Historical calendar year represented in the Company's most recently filed FERC Form 1.

Earnings Test Threshold – The Return on Equity (ROE) authorized in the Company's most recent rate case, with an updated capital structure and cost of debt adjusted to reflect authorized recovery of the Fair Value Increment (FVI) approved in the most recent rate case.

Integrated Resource Planning Action Plan (IRP Action Plan) - The three-year plan required by the Commission's Integrated Resource Planning (IRP) Rules set forth in A.A.C. R14-2-703(H), which is based on the most recent IRP filed by APS and outlines the actions to be taken by the Company on future resource acquisitions.

Qualifying Resource – An APS-owned generation or energy storage resource with an individual investment cost of $50 million or more acquired through an All-Source RFP process. Coal-fired steam generators are not eligible Qualifying Resources for purposes of the SRB.

Qualifying Resource Capital Carrying Costs – Qualifying Resource Capital Carrying Costs include (1) a return at the Company's Adjusted Weighted Average Cost of Capital as defined herein; (2) depreciation expense calculated using the rate(s) approved in APS's most recent general rate case; (3) income taxes; (4) property taxes; (5) deferred taxes and tax credits associated with Qualifying Resources where appropriate; and (6) associated operations and maintenance expenses.

Resource Planning Advisory Council (RPAC) – A group of diverse stakeholders formed to provide input on resource planning activities and collaborate with the Company in the development of its Integrated Resource Plan (IRP).

SRB Table I - The schedule of All-Source RFPs which have been initiated and are in process. The schedule shall be limited to the details included in any applicable public announcement.

SRB Table II - The schedule of planned Qualifying Resource projects that have gone through the All-Source RFP process and have been publicly announced. The schedule shall include the following:

A. Type (e.g. energy storage, wind, solar, gas, etc.).
B. Size (MW).
C. Location.
D. Estimated in-service month and year.
E. Other project descriptions.

SRB Table III - The schedule of completed Qualifying Resource projects that have gone through the All-Source RFP process. The schedule shall include the following:

A. Project tracking number (if applicable).
B. Type (e.g. energy storage, wind, solar, gas, etc.).
C. Resource Name.
D. Size (MW).
E. Location.
F. Actual in-service month and year.
G. Other project descriptions.
H. Total cost.
I. ACC jurisdictional cost.

Tax Credit Benefit – Any federal or state tax credit benefit available to the Company based upon either (i) energy produced by Qualifying Resource, or (ii) the Company's eligible investment in the Qualifying Resource.

3. Determination of Qualifying Resources

To be eligible for inclusion in the Schedule SRB-1 adjustor rate, a Qualifying Resource must be consistent with APS's IRP Action Plan and must be acquired through an All-Source RFP process. The All-Source RFP process will comply with the Commission's Procurement Rules set forth in A.A.C. R14-2-705 and 706 and will include the use of an Independent Monitor.

Each Qualifying Resource will be classified in one or more of the Federal Energy Regulatory Commission (FERC) Plant in Service accounts listed below, any successor FERC account, or any other specific FERC account approved by the Commission. The FERC Plant in Service accounts shall include the following:

Steam Production[1]

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

Nuclear Production

- 320 – Land and Land Rights
- 321 – Structures and Improvements
- 322 – Reactor Plant Equipment
- 323 – Turbogenerator Units
- 324 – Accessory Electric Equipment
- 325 – Miscellaneous Power Plant Equipment

Hydraulic Production

- 330 – Land and Land Rights
- 331 – Structures and Improvements
- 332 – Reservoirs, Dams, and Waterways
- 333 – Water Wheels, Turbines and Generators
- 334 – Accessory Electric Equipment
- 335 – Miscellaneous Power Plant Equipment
- 336 – Roads, Railroads and Bridges

Other Production[2]

- 340 – Land and Land Rights

[1] Excluding coal-fired steam production.

[2] Includes natural gas, solar, and wind production.

- 341 – Structures and Improvements
- 342 – Fuel Holders, Producers, and Accessories
- 343 – Prime Movers
- 344 – Generators
- 345 – Accessory Electric Equipment
- 346 – Miscellaneous Power Plant Equipment

Energy Storage

- 348 – Energy Storage Equipment - Production
- 351 – Energy Storage Equipment - Transmission
- 363 – Energy Storage Equipment - Distribution Steam Production

If any Qualifying Resource included in Schedule SRB-1 generates a Tax Credit Benefit specific to that resource that is not being accounted for in base rates or another recovery mechanism, such Tax Credit Benefit will be included in the calculation of the Schedule SRB-1 adjustor rate in the year the credit is generated. To the extent that the Company is unable to realize a Tax Credit Benefit in the year generated, any carryforward of the Tax Credit Benefit will be included in the calculation of the Schedule SRB-1 adjustor rate.

4. Balancing Account

The Balancing Account shall accumulate and defer the difference between actual Allowable Costs and the recovery of Allowable Costs through Schedule SRB-1 each month. If the Balancing Account has accrued an over or under collected balance in a given period, any such over or under collection shall be included in the Schedule SRB-1 adjustor rate in a future year, subject to the Earnings Test described in Section 6.

5. Determination of the Schedule SRB-1 Adjustor Rate

The Schedule SRB-1 adjustor rate will recover Qualifying Resource Capital Carrying Costs over a twelve-month period (subsequent to approval by the Commission) and will be developed based on the following formula:

$$\text{SRB-1} = \frac{\text{QRCC} + \text{BA} + \text{I}}{\text{Sales}}$$

Where:

QRCC	=	Qualifying Resource Capital Carrying Cost as defined herein.
BA	=	Any balance in the Balancing Account as defined herein.
I	=	Applicable Interest as defined herein.
Sales	=	Forecast energy (kWh) sales under applicable rate schedules during the period in which Schedule SRB-1 will be effective.

The Schedule SRB-1 adjustor rate for General Service customers that are billed on demand will be calculated as a per kW charge. The Schedule SRB-1 adjustor rate for General Service customers that are not billed on demand will be calculated as a per kWh charge. To calculate the per kW charge, the recoverable costs shall first be allocated to the General Service class based upon the number of kWh consumed by that class. The remainder of the recoverable costs allocated to the General Service class shall then be divided by the kW billing determinants for the demand billed customers in that class to determine the per kW Schedule SRB-1 adjustor rate.

Any annual increase in recovery through Schedule SRB-1 is subject to both an annual Earnings Test as described in Section 6 below and a year-over-year cap of 3% of the base rate revenue requirement approved in the Company's most recent rate case. If the calculation results in an amount in excess of either the Earnings Test Threshold or the 3% year-over-year cap, any amount in excess of the cap will be deferred for recovery in a future year.

6. Earnings Test

Any requested increase in the recovery of costs through Schedule SRB-1 will be subject to an Earnings Test, which will compare the previous year's adjusted rate of return for the Earnings Test Period with an Earnings Test Threshold.

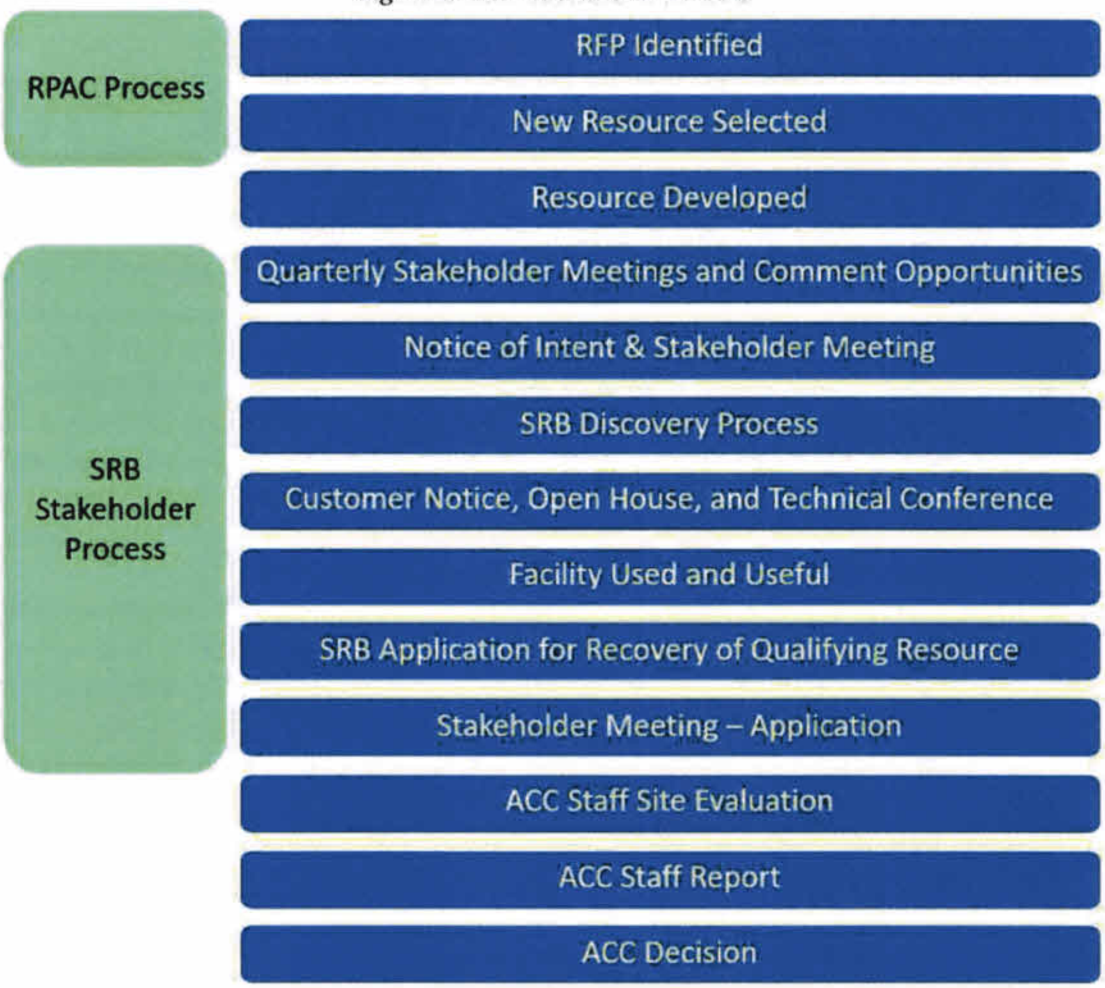
If the results of the Earnings Test are higher than the Earnings Test Threshold, the cost recovered through Schedule SRB-1 will be limited to the amount corresponding to the Earnings Test Threshold. The amount above the Earnings Test Threshold, if any, will be deferred in the Balancing Account for recovery through Schedule SRB-1 in a future year.

7. Stakeholder Process

As part of the existing RPAC process, stakeholders provide feedback on the RFP process. APS will facilitate an additional targeted SRB stakeholder process to provide information to interested parties and incorporate feedback into SRB Applications. In addition to the applicable docket filings detailed in Section 8 herein, APS will host quarterly public stakeholder meetings and will provide updates to the information included in SRB Tables I through Table III. Through the SRB stakeholder process, stakeholders will provide feedback on potential projects eligible for SRB inclusion. APS will facilitate a stakeholder comment period and provide written responses to comments. APS will make good-faith efforts to include stakeholder feedback in the development of SRB Applications. A summary of stakeholder meetings and a description of the included resources with relevant supporting documentation will be included in each SRB Application.

As described in Section 8 herein, for each Notice of Intent to File an Application for Approval of Schedule SRB-1 (Notice), APS will provide notifications on the APS website and in the appropriate ACC docket(s), host a stakeholder meeting, and offer both a technical conference and open house event for each Qualifying Resource. Once a Notice has been submitted, Commission Staff and interested parties may intervene and conduct discovery. As described in Section 9 herein, APS will file an Application and hold at least one stakeholder review meeting. Parties may also file an objection to the Company's Application. Both interested parties and the public will have the opportunity to provide public comment if desired during the Commission's review of the Application. Figure 1 illustrates the SRB stakeholder process flow.

Figure 1: SRB Stakeholder Process



8. Notification of Filing

At least 60 days prior to filing an Application for Approval of Schedule SRB-1 (Application) under the SRB Adjustment Mechanism as described herein, APS will file a Notice with the Commission. APS will request a new docket for purposes of reviewing the Notice and Application, and any subsequent Notice(s) and/or Application(s) will be filed in that docket, until the conclusion of APS's next rate case. The Notice(s) will include SRB Tables I, II, and III and will also be filed in APS's most recently concluded rate case docket in order to provide all interested parties an opportunity to participate in the stakeholder process. In addition, APS will notify its customers that it has filed a Notice by posting a link to a copy of the Notice, and when available, a copy of the Application, on its website (www.aps.com) in a prominent location on the main page, and will maintain the link until the Commission has issued a Decision on the Application.

9. Application

Each Application will include the attachments outlined in Section 10 herein, a description of the Qualifying Resource(s) included in the Application, a discussion of the All-Source RFP that resulted in such Qualifying Resource(s), and additional relevant information to aid in review of the Application, including an updated determination of Jurisdictional Fair Value Rate Base.

Commission Staff will make its best efforts to review and process the Application promptly with the goal of completing its review within 60 days after filing of the Application. Additional discovery may be conducted if necessary. Prudency may be determined in the Application proceeding or alternatively may be deferred until APS's next general rate case. Schedule SRB-1 will not become effective until approved by the Commission.

Once the initial Application is approved by the Commission, APS will file an Application to Reset Schedule SRB-1 (Reset Application) every twelve months. The Reset Application will include calculations for the Earnings Test, calculations for the 3% revenue cap as described herein, and updated SRB Tables I, II, and III. The Reset Application may also include a request to recover additional Qualifying Resources through the Schedule SRB-1 adjustor rate. Any such request will be subject to the Notice requirements outlined in Section 8 herein. However, after the initial Application is approved, APS shall not file a request to include additional Qualifying Resources more often than annually, and shall not file more than five Applications including additional Qualifying Resources prior to filing its next rate case.

Any Qualifying Resource(s) with Capital Carrying Costs being recovered through Schedule SRB-1 will be moved into rate base in the Company's subsequent rate case, and Schedule SRB-1 will be reset upon the issuance of a Commission Decision in that case.

10. Supporting Schedules

The following supporting schedules will be included with each Application and each Reset Application:

SRB Table I – All-Source RFP Public Information
SRB Table II – Schedule of Planned Qualifying Resource Projects
SRB Table III – Schedule of Completed Qualifying Resource Projects
Attachment A - Schedule SRB-1 Adjustor Rate Calculation
Attachment B - Calculation of Revenue Requirement for Qualifying Resource(s) and Determination of Jurisdictional Fair Value Rate Base
Attachment C - List of Qualifying Resource(s) Requested for SRB Recovery
Attachment D - Balancing Account
Attachment E - Earnings Test
Attachment F – Estimated Customer Bill Impact

ARIZONA PUBLIC SERVICE COMPANY
SRB Table I - System Reliability Benefit (SRB) Adjustment Mechanism
INITIATED ALL SOURCE REQUEST FOR PROPOSALS
AS OF *MONTH, DAY, YEAR*

	(A)	(B)	(C)	(D)	(E)
Line No.	**Detail A**	**Detail B**	**Detail C**	**Detail D**	**Detail E**
1.					
2.					
3.					
4.					
5.					

ARIZONA PUBLIC SERVICE COMPANY
SRB Table II - System Reliability Benefit (SRB) Adjustment Mechanism
SCHEDULE OF PLANNED QUALIFYING RESOURCES PROJECTS
AS OF *MONTH, DAY, YEAR*

	(A)	(B)	(C)	(D)	(E)
Line No.	Resource Type	Size (MW)	Location	Estimated In-Service Date	Other Project Descriptions
1.					
2.					
3.					
4.					
5.					
6.					
7.					
8.					
9.					
10.					

ARIZONA PUBLIC SERVICE COMPANY
SRB Table III - System Reliability Benefit (SRB) Adjustment Mechanism
COMPLETED QUALIFY NG RESOURCES PROJECTS
AS OF *MONTH, DAY, YEAR*

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Project Tracking Number	Resource Type	Resource Name	Size (MW)	Location	Actual In-Service Date	Other Project Descriptions	Total Cost	ACC Jurisdictional Cost
1.									
2.									
3.									
4.									
5.									
6.									
7.									
8.									
9.									
10.									

ARIZONA PUBLIC SERVICE COMPANY
Attachment A - System Reliability Benefit (SRB) Adjustment Mechanism
CURRENT TWELVE MONTH PERIOD SRB ADJUSTOR RATE CALCULATION
BILLING PERIOD XXXXXX

Line No.	(A) SRB Adjustor Rate Calculation	(B) Reference	(C) Totals
1.	SRB Balancing Account	Attachment D, Line 14	
2.	Eligible Qualifying Resource(s) Capital Carrying Costs	Attachment B, Line 13	
3.	Total Current Year Eligible Cost	Line 1 + Line 2	$ -
4.	Earnings Test Incremental Threshold	Attachment E, Page 1, Line 47	$ -
	SRB Year Over Year Cap		
5.	Total Retail Revenue Requirement Approved in Decision No. XXXXX		$ -
6.	Annual Year Over Year Percentage		3%
7.	Annual Year over Year Cap Amount (Line 5 x Line 6)		$ -
8.	Prior Year Cap Amount (Prior Year Line 9)		$ -
9.	Current Year Cap Amount (Line 7 + Line 8)		$ -
10.	Amount Recovered through Schedule SRB-1	Lesser of Line 3, Line 4, and Line 9	$ -
11.	Amount Deferred in Balancing Account	Line 3 - Line 10	
12.	Applicable Company Sales (kWh)		
13.	SRB Adjustor Rate Applied to Residential and Non-Demand General Service Bills ($/kWh)	Line 10 / Line 12	$ -
14.	Applicable Company kWh for General Service Billed Demand		
15.	Applicable Revenue Requirement for General Service Billed Demand		
16.	Applicable Company kW for General Service Billed Demand		
17.	SRB Adjustor Rate Applied to General Service Demand Bills ($/kW)	Line 15 / Line 16	$ -

ARIZONA PUBLIC SERVICE COMPANY
Attachment B - System Reliability Benefit (SRB) Adjustment Mechanism
ANNUAL CAPITAL CARRYING COST FOR THE PERIOD(S) XXXXXX
DETERMINATION OF FAIR VALUE RATE BASE
BILLING PERIOD XXXXX

Line No.	(A) Annual SRB Capital Carrying Cost Calculation	(B) Reference	(C) Totals
	Qualifying Resources		
1.	SRB Qualifying Resources (Jurisdictional)	Attachment C, Column G	
2.	Accumulated Depreciation		
3.	Cumulative Deferred Tax/Tax Credits/Excess Deferred Taxes		
4.	Qualifying Resource Net Plant in Service	Line 1 - Line 2 - Line 3	$ -
5.	Pre-tax Weighted Average Cost of Capital for Calendar Year XXX		X.XX%
6.	Cost of Capital Adjustment		-1.00%
7.	Adjusted Weighted Average Cost of Capital	Line 5 + Line 6	X.XX%
	Capital Carrying Cost		
8.	Composite Return on SRB Qualifying Resource Net Plant in Service	Line 4 * Line 7	
9.	Annual Depreciation of Plant In Service		
10.	Applicable Property Tax		
11.	Associated O&M Expense		
12.	Applicable Other Deferred Tax/Tax Credits/Excess Deferred Taxes		
13.	Total SRB Capital Carrying Cost for Qualifying Resources	Line 8 + Line 9 + Line 10 + Line 11 - Line 12	$ -
	Determination of Jurisdictional Fair Value Rate Base		
14.	Jurisdictional Fair Value Rate Base as Determined in Decision No. XXXXX		
15.	Jurisdictional Capital Cost of Qualifying Resource(s)	Attachment C, Column G	
16.	Jurisdictional Fair Value Rate Base with Qualifying Resource(s)		$ -

ARIZONA PUBLIC SERVICE COMPANY
Attachment C - System Reliability Benefit (SRB) Adjustment Mechanism
QUALIFIED RESOURCES
ELECTRIC PLANT IN SERVICE
FOR THE PERIOD XXX

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Resource Tracking Number	Resource Name	Purpose	In-Service Date	Total Cost	ACC Jurisdictional Cost
1.						
2.						
3.						
4.						
5.						
6.						
7.						
8.						
9.						
10.						
11.						
12.						
13.						
14.						
Totals					$ -	$ -

ARIZONA PUBLIC SERVICE COMPANY
Attachment D - System Reliability Benefit (SRB) Adjustment Mechanism
BALANCING ACCOUNT
FOR TWELVE MONTH PERIOD ENDING XXX

Line No.		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
1.	**Balance XXX X, XXX**	$ -												
2.	**SRB Deferral Amount**	$ -												
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
3.	**Beginning Balance**													$ -
4.	Projected Costs													$ -
5.	Actual Costs													$ -
6.	Variance													$ -
7.	Projected Revenue													$ -
8.	Actual Revenue - Billed													$ -
9.	Actual Revenue - Unbilled													$ -
10.	Actual Revenue Total													$ -
11.	Variance													$ -
12.	Applicable Interest													$ -
13.	Change in Balance													$ -
14.	**Ending Balance**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ARIZONA PUBLIC SERVICE COMPANY
Attachment E - System Reliability Benefit (SRB) Adjustment Mechanism
EARNINGS TEST
CALENDAR YEAR XXXX

Line No.	(A)	(B) Reference	(C) Totals
	DEVELOPMENT OF RATE BASE		
1	PRODUCTION PLANT IN SERVICE		
2	TRANSMISSION PLANT IN SERVICE		
3	DISTRIBUTION PLANT IN SERVICE		
4	GENERAL & INTANGIBLE PLANT		
5	LESS: RESERVE FOR DEPRECIATION		
6	MATERIALS, SUPPLIES & PREPAYMENTS		
7	MISCELLANEOUS DEFERRED DEBITS		
8	OTHER DEFERRED CREDITS		
9	OPEB		
10	WORKING CASH		
11	REGULATORY ASSETS		
12	ACCUM. DEFERRED TAXES		
13	OPERATING LEASES		
14	DECOMMISSIONING FUND		
15	CUSTOMER ADVANCES		
16	CUSTOMER DEPOSITS		
17	COMMISSION ORDERED ADJUSTMENTS		
18	**TOTAL RATE BASE**	(Sum Lines 1 to 17)	$ -
19			
20			
21	*DEVELOPMENT OF RETURN*		
22	BASE REVENUES FROM RATES		
23	ADJUSTMENTS TO BASE REVENUES FROM RATES		
24	SURCHARGE & OTHER ELECTRIC REVENUES		
25	ADJUSTED SURCHARGE & OTHER ELECTRIC REVENUES		
26	**TOTAL OPERATING REVENUES**	(Sum Lines 22 to 25)	$ -
27			
28			
29	*OPERATING EXPENSES*		
30	OPERATION & MAINTENANCE		
31	ADMINISTRATIVE & GENERAL		
32	DEPRECIATION & AMORT EXPENSE		
33	OTHER EXPENSE ITEMS		
34	TAXES OTHER THAN INCOME		
35	COMMISSION ORDERED ADJUSTMENTS		
36	INCOME TAX		
37	INCOME TAX ADJUSTMENTS		
38	**TOTAL OPERATING EXPENSES**	(Sum Lines 30 to 37)	$ -
39			
40			
41	**OPERATING INCOME FROM EARNINGS TEST PERIOD**	Line 26 - Line 38	$ -
42			
43	**RATE OF RETURN**	Line 41 / Line 18	0.00%
44			
45	**EARNINGS TEST THRESHOLD**	Attachment E, Line 5, Column H	0.00%
46			
47	**EARNINGS TEST INCREMENTAL THRESHOLD**	Line 18*(Line 45 - Line 43)	$ -

ARIZONA PUBLIC SERVICE COMPANY
Attachment E - System Reliability Benefit (SRB) Adjustment Mechanism
EARNINGS TEST
CALENDAR YEAR XXXX

	Adjusted Test Year Capital Structure	Amount	%	Cost Rate	approved WACC	FVI cost rate[1]	WACC adjusted for FVI
1.	Long-Term Debt						
2.	Preferred Stock						
3.	Common Equity						
4.	Short-Term Debt						
5.	Total	$ -	0.00%		0.00%		0.00%

	Operating Income using FVI adjusted WACC	Original Cost	approved WACC
12.	Rate Base		$ 1,000
13.	Rate of Return (line 5 WACC adjusted for FVI)		0.00%
14.	Required Operating Income using FVI adjusted WACC	$ -	$ -
15.	Required operating income using approved WACC (line 12 * line 4 Approved WACC)		
16.	**Operating income attributed to FVI adjustment**	**$ -**	
17.	FVI increment approved in 2017 rate case		
18.	Difference from approved FVI Increment	$ -	

[1]FVI cost rate is based on amount required to adjust WACC in order to achieve the approved FVI increment on original cost rate base and must be adjusted when the capital structure changes.

ARIZONA PUBLIC SERVICE COMPANY
Attachment F - System Reliability Benefit (SRB) Adjustment Mechanism
MONTHLY BILL IMPACT ESTIMATES
FOR TWELVE MONTH PERIOD ENDING XXX

	AVERAGE MONTHLY BILL IMPACTS				SEASONAL BILL IMPACTS			
	Current	Proposed			Current	Proposed	Current	Proposed
Residential (Avg)	Average Monthly Bill [1]	Average Monthly Bill [1]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -			$ -	$ -	$ -	$ -
REAC	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
CRS-1	$ -	$ -			$ -	$ -	$ -	$ -
TEAM	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -			$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Residential (Avg - Demand Ra	Average Monthly Bill [1]	Average Monthly Bill [1]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-				-	-	-	-
Average kW per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -			$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
CRS-1	$ -	$ -			$ -	$ -	$ -	$ -
TEAM	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -			$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Commercial XS (E-32)	Average Monthly Bill [1]	Average Monthly Bill [1]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -			$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
CRS-1	$ -	$ -			$ -	$ -	$ -	$ -
TEAM	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -			$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ARIZONA PUBLIC SERVICE COMPANY
Attachment F - System Reliability Benefit (SRB) Adjustment Mechanism
MONTHLY BILL IMPACT ESTIMATES
FOR TWELVE MONTH PERIOD ENDING XXX

	AVERAGE MONTHLY BILL IMPACTS				SEASONAL BILL IMPACTS			
	Current	Proposed			Current	Proposed	Current	Proposed
Commercial XS D (E-32)	Average Monthly Bill [1]	Average Monthly Bill [1]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-				-	-	-	-
Averge kW per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -			$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
CRS-1	$ -	$ -			$ -	$ -	$ -	$ -
TEAM	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -			$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Commercial S (E-32)	Average Monthly Bill [1]	Average Monthly Bill [1]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-				-	-	-	-
Averge kW per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -			$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
CRS-1	$ -	$ -			$ -	$ -	$ -	$ -
TEAM	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -			$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Commercial - M (E-32)	Average Monthly Bill [1]	Average Monthly Bill [1]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-	-			-	-	-	-
Averge kW per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -			$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
CRS-1	$ -	$ -			$ -	$ -	$ -	$ -
TEAM	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -			$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ARIZONA PUBLIC SERVICE COMPANY
Attachment F - System Reliability Benefit (SRB) Adjustment Mechanism
MONTHLY BILL IMPACT ESTIMATES
FOR TWELVE MONTH PERIOD ENDING XXX

	AVERAGE MONTHLY BILL IMPACTS				SEASONAL BILL IMPACTS			
	Current	Proposed			Current	Proposed	Current	Proposed
Commercial - L (E-32)	Average Monthly Bill [1]	Average Monthly Bill [1]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-	-			-	-	-	-
Averge kW per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -			$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
CRS-1	$ -	$ -			$ -	$ -	$ -	$ -
TEAM	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -			$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Industrial - XL (E-34,35)	Average Monthly Bill [1]	Average Monthly Bill [1]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-	-						-
Averge kW per Month	-							
Base Rates	$ -	$ -					$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -			$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
CRS-1	$ -	$ -			$ -	$ -	$ -	$ -
TEAM	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -			$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:
Bill excludes regulatory assessment Charge, taxes and fees. All Adjustor levels in effect as of MONTH, DATE, YEAR

RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION

AVAILABILITY

This rate rider schedule is available in all territories served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate rider schedule is available for Standard Offer Customers who have an Aggregated Peak Load of ~~10~~ 5 MW or more and are served under Rate Schedules E-34, E-35, E32-L, ~~or~~ E-32 TOU L, E-32 M, E-32 TOU M, E-32 S, or E-32 TOU S. ~~An aggregated group may also include metered accounts that are served under Rate Schedules E-32 M or E-32 TOU M, if the accounts are located on the same premises and served under the same name as an otherwise eligible Customer.~~

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

All provisions of the Customer's applicable rate schedule will apply in addition to this Schedule AG-X, except as modified herein. Total program participation will be limited to 200 MW of Customer load~~, 100 MW of which will be initially reserved for Customers with single site peak demands of 20 MW or greater and with monthly average load factors above 70%, unless not fully subscribed during the solicitation process~~.

DEFINITIONS

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

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

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

Forward Showing Program: As defined by the Western Resource Adequacy Program ("WRAP") Tariff.

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

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

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

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

Operations Program: As defined by the WRAP Tariff.

Resource Adequacy: To ensure the reliable operation of the grid, each Generation Service Provider will assure they have acquired sufficient resources, which may include demand response, to satisfy forecasted future loads and planning reserve margins by meeting the criteria identified in the applicable Federal Energy Regulatory Commission (FERC) approved WRAP tariff and business practices. Generation Service Providers must provide Forward Showing to APS three weeks prior to APS's obligation to submit its Forward Showing. Failure to submit a timely Forward Showing Program or meet the program guidelines for the Operations Program may result in penalty charges which will be charged to the offending Generation Service Provider as applicable. To the extent options exist within the context of the WRAP Tariff, resources including demand response will meet equivalent standards as APS.

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

Western Resource Adequacy Program (WRAP): Is a Resource Adequacy program operated and administered by the Western Power Pool or its successor.

WRAP Tariff: Shall refer to the currently applicable FERC approved tariff.

CUSTOMER ENROLLMENT

The Company will establish an initial enrollment period during which Customers can apply for service under this rate rider schedule. If the applications for service are greater than the program maximum amount, then Customers will be selected for enrollment through a lottery process as detailed in the program guidelines, which may be revised from time-to-time during the term of this rate rider schedule. Otherwise, Customers may enroll on a first come first serve basis. After the initial lottery, if necessary, Customers who enter the program will not be required to participate in a subsequent lottery to remain in the program.

AGGREGATION

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

DESCRIPTION OF SERVICES AND OBLIGATIONS

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

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

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

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

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

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

The Generation Service Provider must provide Resource Adequacy for their Customer's load by either purchasing from APS or by demonstrating Resource Adequacy seasonally.

1. During the first year after the effective date of this Schedule, AG-X Customers must meet Resource Adequacy as follows:

    a. By purchasing Resource Adequacy from APS and paying a transition reserve capacity charge of $6.453 per kW; or

b. By receiving Resource Adequacy from their Generation Service Provider in compliance with the WRAP Tariff (including eligible demand response provided through the Generation Service Provider) and paying a reserve capacity charge of $0.000 per kW.

2. After the first year following the effective date of this Schedule, AG-X Customers must meet Resource Adequacy as follows:

 a. By receiving Resource Adequacy from their Generation Service Provider in compliance with the WRAP Tariff (including eligible demand response provided through the Generation Service Provider) and paying a reserve capacity charge of $0.000 per kW; or~~.~~

 ~~a.~~b. By purchasing Resource Adequacy from APS and paying a reserve capacity charge equal to the unbundled generation demand charge of E-34.

The Company will settle with the Generation Service Provider for Imbalance Service and other relevant costs ~~on a monthly basis~~monthly according to the AG-X ~~p~~Program ~~g~~Guidelines.

The Generation Service Provider must bill the Company the monthly billed amounts for each C~~c~~ustomer for Generation Service and Imbalance Service according to the program guidelines.

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

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

~~APS will not propose a deferral of unmitigated costs resulting from AG X, if any, and APS will not request recovery of any unmitigated costs resulting from AG X, if any, in its next rate case.~~

DELIVERY OF POWER TO THE COMPANY'S SYSTEM

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

SCHEDULING

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

IMBALANCE SERVICE

The Company will provide Imbalance Service according to the terms and provisions below:

i. Within the range of +/- 15% each hour or +/- 2 MW, whichever is greater, Generation Service Providers would pay based on Schedule 4 of APS's Open Access Transmission Tariff (OATT), which now reflects the terms of the California Independent System Operator (CAISO) imbalance charges.

ii. Greater than 15 % each hour or +/- 2 MW, whichever is greater, in addition to the charges in subsection i above,~~i)~~ Generation Service Providers would pay a penalty of $3 per MWh.

iii. In addition to the imbalance provisions described above, Generation Service Providers with 20% of hourly deviations greater than 20% of the scheduled amount occurring in a calendar month will receive a notice of intent to terminate the Generation Service Provider's eligibility in the program unless remedied. Imbalances of this magnitude and frequency will be deemed "Excessive." Should Excessive imbalances occur again ~~in a subsequent month,~~ within 12 months from the date of the first notice, the Generation Service Provider's eligibility may be terminated. To avoid termination, a Generation Service Provider must demonstrate to APS that it is operating in good faith to match its resources to its load. In the event of the Generation Service Provider's termination, the Customer will be required to secure a replacement Generation Service Provider within 60 days, -and will be subject to the terms listed in "Default of the ~~third-~~Third-~~p~~Party ~~g~~Generation ~~p~~Provider".

DEFAULT OF THE THIRD--PARTY GENERATION PROVIDER

~~In the event that~~If the Generation Service Provider is unable to meet its contractual obligations, the Customer must notify the Company and select another Generation Service Provider within 60 days of such notification. Prior to execution of any new power contract, the Company will provide the required power to the Customer, which will be charged at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus $10 per MWh not to be less than $0 per MWh or at the applicable retail rate at the Company's option. In addition, all other provisions of this rate rider schedule will continue to apply.

Failure on the part of the Generation Service Provider who is providing Resource Adequacy to meet the timing of the Forward Showing Program as outlined in the Program Guidelines will result in termination from the program.

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

~~Failure to meet the timing of Forward Showing as outlined in the Program Guidelines will result in termination from the program.~~

RETURN TO COMPANY'S STANDARD GENERATION SERVICE

Customers may return to the Company's Standard Generation Service under their applicable retail rate schedules if: (1) they provide one ~~or more~~ year~~s~~ notice to the Company and are receiving Company provided Resource Adequacy; (2) they provide three years notice to the Company where they are receiving ~~GSP~~ Generation Service Provider provided Resource Adequacy; or (~~2~~3) if the Commission terminates the program. Absent one of these conditions, the Company will provide generation service to ~~the~~ Customers under the following conditions. The Company may elect to provide a~~the~~ Customer with generation service at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus $10 per MWh for a period of time for the Customer to attain ~~1~~ one year notice if the ~~c~~Customer had previously been receiving Company provided Resource Adequacy or three years notice if the ~~c~~Customer had previously been receiving ~~GSP~~ Generation Service Provider provided Resource Adequacy, at which time the Customer returns to the Company's Standard Generation Service under its~~their~~ applicable retail rate schedule. APS may accommodate shorter timeframes at the discretion of the Company provided the shorter timeframe does not shift cost or risk to non-participating customers. The returning Customer must remain with the Company's Standard Generation Service for at least 1 year.

RATES

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

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

4. The applicable proportionate part of any taxes or governmental impositions, which are or may in the future be assessed based on any of the following will be applied to the Customer's bill ~~on the basis of~~:

    a. The Company's gross revenues ~~of the Company and/or~~,

    b. ~~t~~The price or revenue from the electric energy or service sold ~~and/or~~,

    ~~a.~~c. ~~t~~The volume of energy generated or purchased for sale ~~and/or~~or sold hereunder~~, will be applied to the Customer's bill~~.

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

1. A monthly administrative management fee of ~~$0.00171~~ $0.00164 per kWh applied to the Customer's billed kWh;
2. A monthly reserve capacity charge ~~of $5.248 per kW~~ applied to 100% of the Customer's billed kW (on-peak for Rate Schedules E-35 and E-32 TOU L);
3. Returning Customer charge, where applicable, as described herein;
4. Generation Service Provider Default charge, where applicable, as described herein.

~~These charges and other parameters will be re-evaluated in APS's next rate case, including whether AG-X should be evaluated as a separate customer class in the cost of service study.~~

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

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

    a. When the contract provides for pricing that reflects a specific index price, the minimum price will be the specified index minus 35% and the maximum price will be the specified index plus 35%. The determination that a contract is consistent with this provision will be based on the specified index price applicable on the date the contract is executed.
    b. When the contract provides for a fixed price supply for the term of the contract, the minimum price will be the generation rate of the Customer's applicable retail rate schedule minus 35%, and the maximum price will be the generation rate of the Customers applicable retail schedule plus 35%. If the Customer has more than one otherwise applicable retail rate schedule, the highest applicable retail rate schedule will be used for purposes of the consistency determination. The

determination that a contract is consistent with this provision will be based on the Customer's otherwise applicable retail rate schedule in effect on the date the contract is executed.

c. Losses from the delivery point to the Customer's meters and charges for transmission and distribution will not be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule, while Capacity Reservation Charge, the Management Fee, and Imbalance Service charges will be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule.

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

CONTRACT TERM AND REQUIREMENTS

The term of the contract with the Generation Service Provider must be for not less than one year and must include termination provisions to comply with ~~Section~~ section ~~IV~~ iii under ~~imbalance~~ Imbalance ~~services~~Services, as well as general termination provisions should the program be discontinued at some point in the future.

The Generation Service Provider and Customer will enter into a contract or contracts with the Company, stating the pertinent details of the transaction with the Generation Service Provider, including but not limited to, the scheduling of power, location of delivery and other terms related to the Company's management of the generation resource.

AG-X C~~c~~ustomers that aggregated accounts to meet the ~~10~~5 MW minimum load size eligibility requirements may add new accounts not previously on their application if their load falls below the ~~10~~5 MW threshold because of participation in energy efficiency programs.

AG-X C~~c~~ustomers may grow up to 10% beyond their original allocation in the program.

CREDIT REQUIREMENTS

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

ARIZONA PUBLIC SERVICE COMPANY
PALO VERDE DECOMMISSIONING TRUST
PROPOSED NUCLEAR DECOMMISSIONING TRUST FUNDING SCHEDULES
(Dollars in Thousands)

	Currently Expected Unit Closure Date				
	6/1/2045	4/24/2046	11/25/2047		
YEAR	UNIT 1	UNIT 2	UNIT 3	TOTAL[1]	ACC JURISDICTIONAL AMOUNT[2]
2022	$377	$868	$1,036	$2,281	$2,276
2023	$377	$868	$1,036	$2,281	$2,276
2024	-	$2,281	-	$2,281	$2,276
2025	-	$2,281	-	$2,281	$2,276
2026	-	$2,281	-	$2,281	$2,276
2027	-	$2,281	-	$2,281	$2,276
2028	-	$2,281	-	$2,281	$2,276
2029	-	$2,281	-	$2,281	$2,276
2030	-	$2,281	-	$2,281	$2,276
2031	-	$2,281	-	$2,281	$2,276
2032	-	$2,281	-	$2,281	$2,276
2033	-	$2,281	-	$2,281	$2,276
2034	-	$2,281	-	$2,281	$2,276
2035	-	$2,281	-	$2,281	$2,276
2036	-	$2,281	-	$2,281	$2,276
2037	-	$2,281	-	$2,281	$2,276
2038	-	$2,281	-	$2,281	$2,276
2039	-	$2,281	-	$2,281	$2,276
2040	-	$2,281	-	$2,281	$2,276
2041	-	$2,281	-	$2,281	$2,276
2042	-	$2,281	-	$2,281	$2,276
2043	-	$2,281	-	$2,281	$2,276
2044	-	$2,281	-	$2,281	$2,276
2045	-	$2,281	-	$2,281	$2,276
2046	-	$570	-	$570	$569
2047	-	-	-	-	-
	$ 754	$ 52,488	$ 2,072	$ 55,314	$ 55,193

1. Arizona Public Service Company (APS) is proposing to keep the level of Decommissioning Trust funding constant. Therefore, APS is not proposing any additional funding even though APS anticipates higher amounts than what are reflected in this Schedule. See EAB_WP78DR for the full Decommissioning Trust funding amount.
2. ACC Jurisdictional share is approximately 99.80%.

COMMISSIONERS
Jim O'Connor - Chairman
Lea Márquez Peterson
Anna Tovar
Kevin Thompson
Nick Myers

Anna Tovar
COMISSIONER

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ARIZONA CORPORATION COMMISSION
OFFICE OF COMMISSIONER ANNA TOVAR

March 4, 2024

Docket Control
Arizona Corporation Commission
1200 W. Washington St.
Phoenix, AZ 85007

Re: In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, and to Approve Rate Schedules Designed to Develop Such Return (E-01345A-22-0144).

Dear Commissioners and Parties:

Unfortunately, I was unable to vote in support of this Decision, because it does not adequately balance the interests of the customers of Arizona Public Service Corporation ("APS"). First, the Decision approved the System Reliability Benefits mechanism ("SRB"). This mechanism, although modeled after the System Improvement Benefits ("SIB") mechanism implemented by water and wastewater utilities, is markedly different in several ways. Unlike the SIB, the projects that will be eligible for flowing through the SRB were not approved in this Decision. Also, there is no requirement with the approved SRB that APS file a rate case within a certain number of years. What is most problematic is that even though this mechanism provides substantial benefits to APS, there are no significant demonstrated benefits to its customers, and ultimately APS made no commitment that it would discontinue use of the mechanism if it turned out to be more costly to its customers than seeking recovery using the typical approach. While this type of mechanism may have merit, I cannot support it in its current form.

Second, the Decision approved an additional solar-specific charge to residential rooftop solar customers that no party in the case recommended. This type of charge was previously eliminated by the Commission in APS's 2019 rate case. The public notice provided in this case did not mention consideration of the reimplementation of this charge. I believe this additional charge is overly burdensome and fails to recognize the benefits that rooftop solar provides to all APS customers.

Third, the Decision failed to authorize additional funding for the Community Coal Transition. This funding would help assist those communities that are or will be impacted by the closure of coal generating facilities. These facilities have benefited both APS and its customers for decades. In not authorizing additional funding, the Decision fails to address the benefits these impacted communities have provided to APS and its customers.

I therefore regrettably must dissent.

Sincerely,

Anna Tovar

Anna Tovar
Commissioner