DIRECT TESTIMONY OF JAMIE R. MOE

On Behalf of Arizona Public Service Company

Docket No. E-01345A-25-0105

June 13, 2025

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LIST OF ATTACHMENTS

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Jamie R. Moe. My business address is 400 N. 5th Street, Phoenix, Arizona 85004. I am the Manager of Regulatory Affairs for Arizona Public Service Company (APS or Company). I have management responsibility for all aspects relating to rate strategy and specific rates and prices.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I have over 22 years of experience in the utility industry. From 2003 to 2006, I served as a Staff Analyst with the Arizona Corporation Commission (ACC or Commission). From 2007 to 2009, I worked for Global Water Resources, Inc. as a Regulatory Analyst, and from 2015 to 2017, I worked for Arizona Water Company as Manager of Rates and Regulation. I originally joined APS in 2010 as a Senior Rate and Regulatory Analyst and returned in 2017 as Rate Strategy Consultant and later as Rate Strategy Advisor. I now manage the Company's Rate Design and Revenue Requirements teams, which are responsible for analyzing and aligning costs with appropriate pricing structures. I have a Bachelor of Science degree in Accounting from North Dakota State University.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION (COMMISSION)?

A. Yes. I provided testimony in the Company's 2022 Rate Case (including the 2022 Rate Case Rehearing proceeding), and I also testified at the Commission when I worked for Commission Staff and Global Water Resources, Inc.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. My Direct Testimony supports APS's application regarding the following:

- Standard Filing Requirement (SFR) Schedule A-1, ACC jurisdictional portions of SFR Schedules A-2, B-1, B-2, B-3, B-4a, C-1, C-2, F-1, and all SFR G Schedules;
- APS's Cost of Service Study (COSS) in this proceeding; and
- Fair Value Increment (FVI) and Fair Value Rate of Return (FVROR).

II. <u>SUMMARY</u>

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. My Direct Testimony addresses certain SFR schedules including SFR Schedule A-1, which calculates the increase in APS's base rate revenue requirements of $662.44 million and a net base rate increase of $579.52 million — an overall average bill increase of 13.99%. The net increase and bill impact to customers is further discussed in the testimonies of APS witnesses Theodore N. Geisler and Jessica E. Hobbick. This additional revenue will provide APS an opportunity, not a guarantee, of earning a FVROR of 4.84% on a Fair Value Rate Base (FVRB) of $21.6 billion.

My Direct Testimony supports the Company's request to increase its base fuel rate to align with the 12-month period ending December 31, 2024 (Test Year) costs. I also describe the COSS used to support APS's rate design, as well as the jurisdictional allocation of costs. I explain how APS complied with COSS requirements in Decision No. 79293 (March 5, 2024)),[1] which required the Company to evaluate alternative resource requirements and cost impacts to the

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[1] *In re App. of Ariz. Pub. Serv. Co. for a Hr'g to Determine the Fair Value of the Util. Prop. of the Co. for Ratemaking Purposes*, Docket No. E-01345A-22-0144, Decision No. 79293 (Mar. 5, 2024) (Decision No. 79293).

system related to generating capacity, fuel costs, and market purchases if the output from residential distributed generation (DG) resources had not existed during the Test Year. This provides a further demonstration that the current value for solar generation credits in APS's site-load COSS — the approved methodology for assessing the system cost-impacts from residential customer DG — is reasonable and does not need to be adjusted.

I also discuss APS's proposed methodology for allocating costs for new generation resources to the customer classes driving growth on the system. In light of substantial load growth on APS's system that is largely concentrated among a subset of large, high load factor customers, in particular data center customers, new approaches to cost allocation are necessary to mitigate cost shifts. Based on well-established cost causation principles, this growth-focused methodology will help reduce cross-subsidization risks arising from new large-customer growth.

Finally, my Direct Testimony explains the calculation used to determine the FVI derived from the Company's FVRB. The mechanics of the calculation are based on those adopted by the Commission in numerous decisions, including Decision

Nos. 71448 (December 30, 2009),[2] 73183 (May 24, 2012),[3] 76295 (August 18, 2017),[4] and 78317 (November 9, 2021).[5]

III. PROPOSED BASE FUEL AND PURCHASED POWER RATE

Q. IS APS PROPOSING ANY CHANGES TO TEST YEAR FUEL AND PURCHASED POWER EXPENSE?

A. Yes. The Company is proposing an increase to the base fuel rate consistent with the actual fuel and purchased power costs experienced during the Test Year. To effectuate this change, I sponsor the Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals pro forma adjustment. This adjustment captures any fuel and purchased power expenses that occurred during the Test Year beyond what was collected through the base fuel rate and removes the non-cash mark-to-market impacts. These non-cash accounting adjustments are not realized and therefore have no impact on the Company's actual Test Year fuel expense or anticipated future fuel expenses. These two adjustments result in an increase to Test Year expenses of $219.9 million and are shown in the Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals pro forma in SFR Schedule C-2, page 3, Column 7.

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[2] *In re the App. of Ariz. Pub. Serv. Co. for a Hr'g to Determine the Fair Value of the Util. Prop. of the Co. for Ratemaking Purposes*, Docket No. E-01345A-08-0172, Decision No. 71448 (Dec. 30, 2009).

[3] *In re the App. of Ariz. Pub. Serv. Co. for a Hr'g to Determine the Fair Value of the Util. Prop. of the Co. for Ratemaking Purposes*, Docket No. E-01345A-11-0224, Decision No. 73183 (May 24, 2012).

[4] *In re the App. of Ariz. Pub. Serv. Co. for a Hr'g to Determine the Fair Value of the Util. Prop. of the Co. for Ratemaking Purposes*, Docket No. E-01345A-16-0036, Decision No. 76295 (Aug. 18, 2017) (Decision No. 76295).

[5] *In re App. of Ariz. Pub. Serv. Co. for a Hr'g to Determine the Fair Value of the Util. Prop. of the Co. for Ratemaking Purposes*, Docket No. E-01345A-19-0236, Decision No. 78317 (Nov. 9, 2021) (Decision No. 78317).

Q. WHAT IS APS'S PROPOSAL FOR ITS BASE FUEL AND PURCHASED POWER RATE IN THIS PROCEEDING?

A. APS proposes to adjust its base fuel rate based on actual costs from the Test Year. The Company's proposal increases the current base fuel and purchased power rate from 3.8321¢/kWh (as authorized by the Commission in Decision No. 79293) to 4.3881¢/kWh, an increase of 0.5560¢/kWh. APS witness Jacob Tetlow discusses the need to add large amounts of diverse generation resources to fulfill the anticipated capacity requirements and ensure customers are reliably served.

Q. HOW DOES THIS NEW BASE FUEL RATE AFFECT TEST YEAR EXPENSE?

A. Because the Test Year cost of fuel and purchased power expense actually incurred results in a Test Year fuel rate of 4.3881¢/kWh, the Base Fuel and Purchased Power Cost pro forma adjustment reflects no additional impact to Test Year operations, as the increase in costs is fully accounted for by the Deferred Fuel Expense discussed above. The Base Fuel and Purchased Power Costs pro forma adjustment calculations are provided in SFR Schedule C-2, page 2, Column 6.

Q. IS APS PROPOSING ANY CHANGE TO HOW THE BASE FUEL RATE IS APPLIED TO CUSTOMERS?

A. Yes. The Company is proposing to allocate growth-related generation costs to the classes based on their share of growth.

Q. WHAT CHANGE IN THE BASE RATES FOR PRODUCTION-RELATED CHEMICAL COSTS AND SALES OF EMISSIONS ALLOWANCES IS APS PROPOSING?

A. APS proposes that the current base production-related chemical cost of 0.0744¢/kWh accepted in Decision No. 79293 be maintained. The amount and costs of lime, ammonia, and sulfur associated with power plant emission controls vary with the amount of fuel burned at generating plants, and these costs were authorized for recovery through the Power Supply Adjustment (PSA) by the Commission in Decision No. 76295. The impact of this adjustment is shown in the Chemical Operations and Maintenance (O&M) pro forma in SFR Schedule C-2, page 3, Column 8.

APS does not propose to change the current PSA base rate of 0.000001¢/kWh for net margins from emission allowance sales.

IV. STANDARD FILING REQUIREMENT SCHEDULES

Q. PLEASE DESCRIBE THE SFRS THAT YOU SPONSOR.

A. I sponsor SFR Schedule A-1, which presents the requested overall increase in retail revenue requirements. SFR Schedule A-1 demonstrates that the adjusted Test Year rate of return for ACC jurisdictional operations was 2.54% on a FVRB of $21.6 billion. The rate of return on FVRB resulting from the requested increase of $662.4 million is 4.84%.

I also sponsor the ACC jurisdictional portions of SFR Schedules A-2, B-1, B-2, B-3, B-4a, C-1, C-2, F-1, as well as the calculations of rate base for Total Company and ACC jurisdictional operations developed through a COSS on SFR Schedules B-1 and B-2. These schedules contain numerous adjustments sponsored by other APS witnesses as shown in the SFR index (Attachment JRM-01DR), which lists the APS witnesses responsible for preparation of the various SFRs or elements of the SFRs.

I sponsor SFR Schedules G-1 through G-7, which provide detailed information regarding the Company's COSS. The schedules show pro forma adjusted amounts of Original Cost Rate Base (OCRB) and operating expenses allocated to ACC jurisdictional customers and list the allocation factors used in preparing the COSS.

- SFR Schedule G-1 shows percentages of the cost of service and the original cost rate of return at existing rates by customer class, based on the adjusted Test Year COSS;
- SFR Schedule G-2 is similar to SFR Schedule G-1, except it reflects percentages of the cost of service and returns by customer class that would result under APS's proposed rates;
- SFR Schedule G-3 shows the functionalized dollar amount and percentage of adjusted rate base allocated to each retail customer class;
- SFR Schedule G-4 shows the functionalized amount of operating expenses allocated to each retail customer class;
- SFR Schedule G-5 shows the amount of functionalized adjusted rate base allocated to ACC jurisdictional customers;
- SFR Schedule G-6 shows the amount of functionalized adjusted operating expenses allocated to ACC jurisdictional customers; and
- SFR Schedule G-7 lists the allocation factors used in preparing the Test Year COSS.

Q. PLEASE SUMMARIZE THE RESULTS OF THE COSS.

A. The COSS summary attached to my testimony as Attachment JRM-02DR is used to determine the cost associated with serving each customer and rate class based on Test Year level expenses and investments allocated using customer and usage attributes. Based on the Test Year level of revenue that current rates are designed to recover, the study then calculates the class level of revenue deficiency. This study is an important tool used in rate design as it determines:

- The jurisdictional separation of rate base costs, revenues, and operating expenses between ACC and all other jurisdictions; and
- The allocation of ACC costs across rate classes and the percentage of cost to serve paid by each major customer class.

V. COST OF SERVICE STUDY

Q. PLEASE DESCRIBE A COSS GENERALLY.

A. A COSS is a detailed assessment of utility costs and revenues that supports a requested rate adjustment, both in total and for separate rate classes. The study compiles and evaluates the utility's costs for the Test Year period and makes certain normalizing pro forma adjustments to reflect an appropriate test of the adequacy of the utility's rates. The COSS separates the cost and revenue information to reflect those that are jurisdictional to the Commission. Lastly, the study allocates the costs and revenues to various customer rate classes based on cost drivers and cost causation principles. This allocation sets the cost responsibility and revenue deficiency for each class.

Q. WHAT IS THE TEST YEAR FOR APS'S COSS IN THIS RATE CASE?

A. APS conducted an embedded COSS using data from the 12-month period ending December 31, 2024. The results of the COSS are summarized in Attachment JRM-02DR.

Q. PLEASE DISCUSS THE DEVELOPMENT OF THE COSS.

A. In the COSS, the total expense and rate base items that comprise APS's costs are grouped into major categories, such as Plant in Service or O&M expense. Each category is first functionalized into production, transmission, distribution, or customer-related costs, then classified as demand, energy, or customer-related. Allocation factors based on kW (i.e., demand), kWh (i.e., energy), and number of customers are then developed. This process is intended to functionalize and classify costs so that the costs may be allocated to the ACC retail jurisdiction and to the various retail customer classes and sub-classes to determine the class level revenue requirement. An embedded COSS then takes the total revenue requirement and allocates it among customer classes.

Q. WHAT IS FUNCTIONALIZATION?

A. Functionalization is the process of attributing each rate base or expense item to a particular function — namely production (generation of electricity), transmission, distribution, or customer service (e.g., metering and billing) — in the provision of electric service. An example of functionalization is assigning the costs of building and operating the Company's generation power plants to the production function.

Q. WHAT IS CLASSIFICATION?

A. Classification is the process of determining the factor or factors that drive the magnitude of the cost. For example:

- If a cost to serve is driven by the amount of kWh energy consumed, such as fuel cost, it is classified as energy.
- If a cost is driven by the rate at which energy is consumed, or kW capacity, it is classified as demand.
- If a cost is driven by the number of customers taking service on the APS system, irrespective of either the kW demand or kWh energy, it is classified as customer.

Q. WHAT IS ALLOCATION?

A. Allocation occurs after a cost has been functionalized and classified. Allocation factors are applied to allocate costs to other jurisdictions, customer classes and sub-classes, and rate schedules. These factors include approaches such as class coincident peak (CP) — demand contribution at the time of system peak — and non-coincident class peak (NCP) — the sum of individual peaks, energy, or number of customers. A simple example is the allocation of energy-related costs by kWh consumption to different customer classes.

Q. HOW DID YOU ALLOCATE FUNCTIONALIZED COSTS BETWEEN JURISDICTIONS?

A. Production-related assets are generally designed and built to enable the Company to meet its system peak load. Therefore, the costs associated with these investments are allocated between jurisdictions based on the average of the system peak demands occurring in the months of June, July, August, and September (collectively referred to as 4-CP, with the months being core summer months) to determine jurisdictional cost responsibility. This is consistent with the allocation method that APS is required to use in its rate cases before the Federal Energy Regulatory Commission (FERC) and creates jurisdictional alignment to ensure the right proportion of cost is being allocated to each jurisdiction. It also eliminates the potential that costs are not recovered from either jurisdiction due to differences in allocation methods. It has been accepted as the jurisdictional allocation methodology by the Commission for many years.

Q. HOW ARE THE COSTS ALLOCATED ACROSS RATE CLASSES?

A. Within the ACC jurisdictional customer classes, production costs were allocated based on the Average and Peak Demand (A&P) method. This method was adopted by the Commission in Decision Nos. 78317 and 79293.[6] The A&P method uses the sum of an energy, or average demand, allocator as well as a peak demand allocator:

- Energy (Average Demand) allocator — each class's Test Year energy usage divided by 8,760 hours to calculate average energy demand.
- Peak Demand allocator — the average of each rate class's 4-CP during the months of June, July, August, and September.

In addition, APS analyzed the AG-X customer group as a separate customer class in the allocation of production-related costs to reflect the unique nature of their

[6] Decision Nos. 78317 at 234 and 79293 at 249.

load attributes and procurement of generation from a third party. Later in testimony, I discuss a proposed modification to the Company's production cost allocation to ensure fair cost apportionment.

Transmission plant was directly assigned to the non-ACC jurisdictional portion of the COSS. However, a portion of transmission costs are brought back into the ACC jurisdictional cost of service to offset the existing Open Access Transmission Tariff (OATT) revenues from jurisdictional customers. Such an offset ensures that there is no double counting of transmission costs between the ACC and non-ACC jurisdictions and effectively assumes that each customer class pays the cost of transmission service.

Distribution plant, unlike production and transmission plant, is generally designed to meet a customer class's peak load, which may or may not coincide with the system peak load. Thus, costs related to distribution substations and primary distribution lines are typically allocated based on NCP loads. However, a portion of these costs are allocated on a customer basis. Allocation of costs related to distribution transformers and secondary distribution lines are based on the summation of the individual peak loads or demands of all customers within a particular customer class — Sum of Individual Max (SIM). Each of these allocation methods has been used by APS and accepted by the Commission for many years.

Q. PLEASE EXPLAIN THE USE OF REVENUE CREDITS IN THE COSS.

A. APS sells electric service to parties that are not traditional APS retail customers, such as sales to customers on the E-36 XL rate schedule for station service power at large generation plants owned by others. These transactions produce net benefits because their rates more than cover their incremental costs. Therefore, these revenues are allocated, or credited, to all customer classes. In other words, the entire margin that APS realizes from these non-retail transactions is attributed to each class through the revenue credit, benefiting all customers by lowering the amount of their overall revenue requirements.

APS also treats non-firm, short-term transactions, and other small items as revenue credits. These include items such as rent from electric property, forfeited discounts, miscellaneous service revenues, and other electric revenues.

Q. ARE THERE ANY COST ELEMENTS THAT RECEIVE RECOVERY TREATMENT OUTSIDE OF THE BASE RATE SCHEDULES DEVELOPED BY THE COSS?

A. The COSS only addresses the base rate portion of the cost to serve. Additional revenues and expenses from adjustors are removed from the COSS to get a base rate revenue requirement. Various adjustors, surcharges, regulatory assessments, sales/transaction privilege taxes, and franchise fees are charged outside of base rates.

Q. DOES APS'S COSS METHODOLOGY COMPLY WITH THE MOST RECENT RATE CASE DECISION?

A. Yes. APS included the following requirements in its COSS to comply with Decision No. 79293:

- Allocated production demand costs using the A&P methodology;
- Allocated production costs that reflect AG-X customers reliance on APS for resource adequacy to cover their entire site loads, as all AG-X customers were procuring resource adequacy from APS during the Test Year;
- Allocated distribution costs in FERC accounts 360, 361, and 364 through 368 as both demand-related and customer-related, using the minimum-load method (MLM);

- Allocated secondary distribution costs using the sum of individual max (SIM) methodology;
- Maintained Residential DG customers in a separate class;
- Allocated costs of service to residential DG customers based on their site loads, with credits informed by the analysis of what the system would have looked like without residential DG, which is discussed later in my testimony; and
- Calculated Indexed Rate of Returns (IRRs) based on jurisdictional returns rather than on total Company returns.

As ordered in Decision No. 78317 and subsequently approved in Decision No. 79293, the allocation of primary distribution costs for residential solar and non-solar classes used the load coincident with the time of the total residential NCP (combining both solar and non-solar customers).[7]

Q. DID APS ADJUST THE ALLOCATION OF INCOME TAXES?

A. Yes. The Company adjusted the allocation of income taxes to more clearly reflect the level of income tax expense each customer and rate class is responsible for based on their share of rate base. The Company's income taxes are based on the return approved in the revenue requirement. The COSS required return for each cost of service class is based on its share of rate base. Previously, income taxes were allocated based on test year revenues and expenses, which only includes the portion of income tax reflected in current rates, not in total costs allocated. While this method can be effective in apportioning income taxes, there are instances where the rate base allocation is beneficial. For example, if a class had Test Year revenues that exceeded its cost of service, it would be allocated a larger portion of income tax expense than supported by the cost necessary to serve them when based

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[7] Decision Nos. 78317 at 234 and 79293 at 249.

on revenues and expenses. On the reverse side, if a class had Test Year revenues below its cost of service, the allocated income taxes would be lower due to the revenues not being sufficient to meet its allocated costs. By adjusting the allocation of income taxes on rate base, each class's income tax expense will reflect the calculation of rates needed to recover its cost of service.

Q. IS APS PROPOSING ANY OTHER CHANGES TO ITS COSS METHODOLOGY?

A. Yes. The Company seeks to avoid cost shifts to residential and small business customers related to costs associated with serving growth on the system predominantly driven by large general service customers. As such, the Company is proposing a methodology to directly assign costs associated with new generation resources to each cost of service class based on the amount of generation procured to serve their corresponding load growth. In the next section of my testimony, I discuss the importance of modifying this approach to mitigate other classes subsidizing significant investment in the system necessary to serve unprecedented levels of load being requested by high load factor customers and impacts to existing customers that would stem from the A&P methodology.

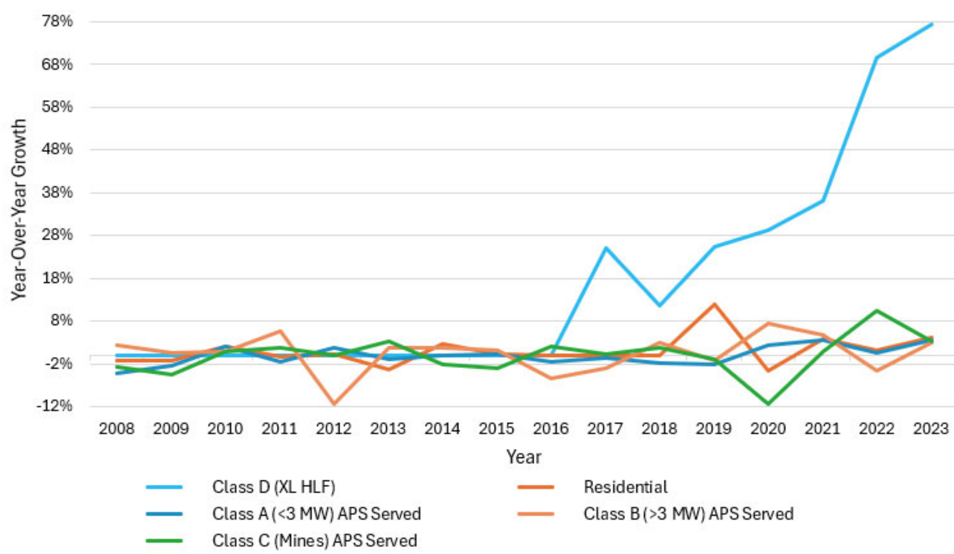
VI. <u>GROWTH-BASED ALLOCATION OF NEW GENERATION RESOURCES</u>

Q. WHY IS APS PROPOSING TO DIRECTLY ASSIGN THE COST OF NEW GENERATION?

A. Historically, expected load growth has been relatively consistent among customer classes (see Figure 1). However, current load forecasts project a significant portion of growth in the future to be driven by large high load factor customers. At the same time, given this high demand for energy resources coupled with a relative lack of available generation supply to serve the full demands of these large high load factor customers, new generation resources must be developed and constructed to serve this concentrated segment of growth on APS's system.

Because new generation resources are inherently more costly than existing resources already embedded in APS customer rates, it is increasingly more expensive for APS to serve new load growth that today is concentrated among large high load factor customers, in particular new data center customers.

Figure 1. *Historic Year-Over-Year Sales Growth by Class*



Coupled with the increased cost of new generation as compared to generation costs already embedded in rates, this change in the concentration of growth rates among customer classes creates a significant risk that the costs associated with procuring new generation resources needed to serve this growth will be borne among all customers, rather than be more appropriately assigned to those customer classes causing these costs. As such, the objective of APS's proposed growth-focused cost methodology is to avoid cost shifts related to new generation resources brought online to serve growth on the system. This methodology will also establish a fair method for allocating these costs in the future to support new large high load factor customers who are the predominant customers driving the need for significant investment in the system.

Q. IN GENERAL, HOW IS APS PROPOSING TO DETERMINE THE FAIR SHARE OF GROWTH-RELATED GENERATION COSTS THAT WOULD BE ASSIGNED TO DIFFERENT CUSTOMER CLASSES?

A. To determine their fair share, APS first determines the resource procurement driven by each class by evaluating which cost of service classes accounted for growth during the Test Year. APS then apportions the costs of the new generation accordingly. At this time, this approach is appropriate given that the resources needed to serve growth among large high load factor customers moving to APS's system are predominantly comprised of newly developed resources that are inherently more expensive than already existing resources. In the future, as the cost of generation needed to serve the next increment of growth becomes more stable and in line with existing system costs, these growth-based adjustments may no longer be needed, and traditional allocation should be sufficient. Currently, however, a new approach is needed to avoid significant cross-subsidization associated with load growth on APS's system, and the Company's proposed methodology is intended to mitigate those impacts.

Q. HOW DOES APS PROPOSE TO PERFORM THIS ANALYSIS?

A. Existing generation resources will continue to be allocated to each class based on the appropriate methodology consistent with past Commission directives. All resources will continue to be split into two categories: 1) those with production costs that are allocated using the A&P methodology, such as APS-owned generation resources and gas tolling agreements; and 2) other resources procured through power purchase agreements (PPAs) that are currently recovered through the base fuel rate or APS's PSA mechanism. For the cost of new resources placed into service during the Test Year or after, APS will follow the same approach.

However, once the new generation resources are grouped into the two categories, the Company will make an adjustment to differentiate between the new generation needed to serve growth and the generation required to serve APS's existing customer base. Because the Company plans on retiring certain resources that are already being recovered in embedded rates within the next several years, new generation procured to serve existing customers would be replacing older, legacy generation that is being taken out of service. In other words, new generation placed into service to replace retiring generation is presumed to serve existing load, while any remaining new generation is presumed to be serving growth.

Q. HOW DOES APS PROPOSE TO DETERMINE WHICH PORTIONS OF NEW GENERATION ARE REPLACING RETIRING GENERATION VERSUS SERVING NEW GROWTH?

A. This will be achieved by calculating the Effective Load Carrying Capability (ELCC) of any retiring resources and removing a corresponding weighted equivalent portion from the total ELCC of the new generation resources (*see* Figure 2). The costs for this weighted portion, which represents the generation required to replace retiring resources, will be allocated to customer classes using the same methodology for existing generation resources. The remaining portion represents costs attributed to the new generation procured because it is necessary to serve growth and will be allocated to cost of service classes using one of the two methodologies described below — one for new, growth-related generation allocated through the A&P methodology, and one for the same new generation procured through PPAs.

Figure 2. *ELCC Reduction Factor Calculation Related to Retirements*[8]

Line No.	ELCC Reduction Calculation		
1	Total ELCC for 2025 New Incremental Generation (MW)		1,601
2	Nameplate Capacity - Cholla (MW)		380
3	New Incremental Generation Retirement Reduction Factor	(Ln 2 / Ln 1)	23.7%
4	Agave Battery Energy Storage System	Total Cost	$ 264,345,414
5	ELCC Reduction	(Ln 4 * Ln 3)	$ 62,749,607
6	Test Year Generation Plant Additions	(Ln 4 - Ln 5)	$ 201,595,807

Q. PLEASE EXPLAIN APS'S PROPOSED ADJUSTMENTS FOR DIRECTLY ASSIGNING THE COSTS OF NEW GENERATION RESOURCES ALLOCATED THROUGH THE A&P METHODOLOGY.

A. The growth in sales and 4-CP —grossed up to account for line losses at the various service levels — will be used to determine each cost of service class's share of the costs for new, growth-related generation resources allocated using the A&P methodology (*see* Figure 3). If necessary, such as when ramping is behind schedule, adjustments to large high load factor customers' load data may be made to align with contract minimums to align cost allocation with resource procurement. In these situations, generation resources have already been procured in accordance with the load projections of large high load factor customers. To the extent the actual load needed by customers is less than their projections, contract minimum quantities shall be used for cost allocation in lieu of actual load data.

[8] The actual total cost of the Agave Battery Energy Storage System will be updated once the project is placed into service.

Figure 3. *Growth A&P Results for the Agave Battery Energy Storage System*

Line No.	Rate Class	A&P Allocation for New Incremental	Test Year Generation Plant Additions	Allocated Generation Plant Additions
1			$ 201,595,807	
2	Residential	32.76%		$ 66,033,899
3	Other Gen Ser	17.20%		$ 34,683,672
4	E-34/E-35	31.55%		$ 63,600,619
5	XHLF	18.49%		$ 37,277,617
6	Total	100.00%		$ 201,595,807

Each class's share of the new, growth-related generation costs will then be added to the A&P method that was calculated for the existing resources, resulting in a modified A&P that will also be used to allocate rate base and rate base-related costs, such as depreciation expense. Figure 4 shows the results of the modified A&P methodology for the Test Year. In this figure, the results are limited to the four groups for display purposes.[9]

Figure 4. Modified A&P Impact

Line No.	Rate Class	Retail A&P Allocation	Retail Modified A&P Allocation	Growth Related Difference
1	Residential	56.15%	55.76%	-0.39%
2	Other Gen Ser	32.87%	32.61%	-0.26%
3	E-34/E-35	6.62%	7.04%	0.42%
4	XHLF	4.26%	4.50%	0.24%
5	Total	99.91%	99.91%	0.00%

For the new plant costs serving growth that would be recovered through the System Reliability Benefit (SRB) adjustor, the Company is proposing to modify the SRB rate design to be based on the same modified A&P calculation allocated to four rate groups for the applicable period.

[9] All General Service and Classified customers not specifically identified are included in the "Other General Service" (Other Gen Ser) group.

Q. HOW WILL APS DETERMINE EACH CLASS'S SHARE OF COSTS FOR NEW, GROWTH-RELATED GENERATION RESOURCES PROCURED THROUGH PPAS?

A. APS separated the various rate classes into the four specific groups shown in Figure 5 below. Using these four groups, APS will use growth in sales to determine each class's share of the costs associated with new, growth-related generation resources procured through PPAs, as demonstrated in Figure 5.

Figure 5. *Growth in Sales by Cost of Service Class*

Line No.	2024 Usage	Residential	Other Gen Ser	E-34/E-35	XHLF	Total
1	2024 Growth (MWh)	671,955	251,935	738,738	476,450	2,139,078
2	Share of 2024 growth	31.41%	11.78%	34.54%	22.27%	100.00%
3	2024 Energy (MWh)	15,579,131	12,302,422	2,998,825	2,014,787	32,895,166

Based on this growth for each cost of service class, the new resources for each cost of service class would be allocated based on their growth. Figure 6 shows the cost allocation to each class for new generation PPA's procured during the Test Year.

Figure 6. *Growth Allocation of New Resources Procured During the Test Year*

Line No.	Allocation of 2024 Costs		Residential	Other Gen Ser	E-34/E-35	XHLF	Total
1	New Incremental Generation Costs						$ 106,490,816
2	Share of 2024 growth	Fig. X Ln 2	31.41%	11.78%	34.54%	22.27%	100.00%
3	Growth-Based Allocation of New Inc. Gen. Costs	Ln 1(e) * Ln 2	$ 33,452,277	$ 12,542,211	$ 36,776,951	$ 23,719,376	$ 106,490,816

Q. PLEASE EXPLAIN APS'S PROPOSED METHODOLOGY FOR DIRECTLY ASSIGNING THE BASE FUEL COSTS OF NEW GENERATION RESOURCES PROCURED THROUGH PPAS.

A. Once each class's share of costs are calculated, the Company will follow the following methodology to determine each class's fair share of base fuel rate allocation:

1. First, the Company will calculate what the base fuel rate would be without the new generation resources by removing the growth-related costs and megawatt hours (MWh) of production. The base fuel rate with growth-related costs and MWh of production removed is shown in Figure 7, Line 8.

Figure 7. *Base Fuel Rate with Growth-related Costs Removed*

Line No.	Base Fuel Calculation		
1	Total Retail Fuel Costs		$ 1,443,457,974
2	Total Usage (MWh)		32,895,166
3	Total Base Fuel ($/kWh)	Ln 1 / Ln 2	$ 0.043881
4	New Incremental Generation Costs		$ 106,490,816
5	New Incremental Generation (MWh)		1,486,134
6	Total Base Fuel less New Incremental Generation Costs	Ln 1 - Ln 4	$ 1,336,967,158
7	Total Usage less New Incremental Generation (MWh)	Ln 2 - Ln 5	31,409,032
8	Total Base Fuel less New Incremental Generation ($/kWh)	Ln 6 / Ln 7	$ 0.042566

2. Then, APS will determine each class's portion of the growth-related costs and MWh of production (Lines 4 and 5 in Figure 7) using the growth in sales shown in Figure 5 — this is reflected in Lines 1 and 2 in Figure 8 below. Next, the Company uses the base fuel rate with growth-related costs and megawatt hours (MWh) of production removed (Line 8 in Figure 7) to calculate the portion of growth-related costs and MWh of production each class paid. APS would then use the remaining balance of the growth-related costs and MWh of production (Line 6 of Figure 8) and total billed sales to calculate a direct allocation component for each class. This direct allocation component is then combined with the base fuel rate with growth-related costs and MWh of production removed (Line 8 in Figure 7) to determine each class's growth-adjusted base fuel rate (Line 9 in Figure 8).

Figure 8. *Calculation of Base Fuel Direct Assignment Rates*

Line No.	Recovery of 2024 Costs		Residential	Other Gen Ser	E-34/E-35	XHLF	Total
			(a)	(b)	(c)	(d)	(e)
1	New Incremental Generation Costs	Fig. 5 Ln 2 x Fig. 7 Ln 4	$ 33,452,277	$ 12,542,211	$ 36,776,951	$ 23,719,376	$ 106,490,816
2	New Incremental Generation (MWh)	Fig. 5 Ln 2 x Fig. 7 Ln 5	466,844	175,033	513,241	331,016	1,486,134
3	Estimated $/kWh	Ln 1 / Ln 2	$ 0.07166	$ 0.07166	$ 0.07166	$ 0.07166	$ 0.07166
4	Total Base Fuel less New Incremental Generation ($/kWh)	Fig. 7 Ln 8	$ 0.042566	$ 0.042566	$ 0.042566	$ 0.042566	$ 0.042566
5	Recovery through Total Base Fuel less New Incr. Gen.	Ln 2 * Ln 4	$ 19,871,669	$ 7,450,455	$ 21,846,626	$ 14,090,030	$ 63,258,780
6	2024 Remainder	Ln 1 - Ln 5	$ 13,580,608	$ 5,091,757	$ 14,930,325	$ 9,629,346	$ 43,232,036
7	Total 2024 Energy (kWh)		15,579,131,415	12,302,422,121	2,998,825,220	2,014,787,457	32,895,166,212
8	Base Fuel Direct Assignment	Ln 6 / Ln 7	$ 0.00087	$ 0.00041	$ 0.00498	$ 0.00478	$ 0.00131
9	Total Base Fuel less New Incr. Gen. + Direct Assignment	Ln 4 + Ln 8	$ 0.043438	$ 0.042980	$ 0.047545	$ 0.047345	$ 0.043881
10	Total Base Fuel ($/kWh)	Fig. 7 Ln 3	$ 0.043881	$ 0.043881	$ 0.043881	$ 0.043881	$ 0.043881
11	Over/(Under) Total Base Fuel Comparison	Ln 9 - Ln 10	$ (0.000443)	$ (0.000901)	$ 0.003664	$ 0.003465	$ (0.000000)

3. Next, the Company will use the base fuel rate with growth-related costs and MWh of production removed (Line 8 in Figure 7) to calculate the portion of growth-related costs and MWh of production each class paid. This is shown in Figure 8, Line 5.

4. Then, APS will use the remaining balance of the growth-related costs and MWh of production (Line 6 of Figure 8) and total billed sales (Line 7 of Figure 8) to calculate a direct allocation component for each class. The Base Fuel Direct Assignment component is shown in Figure 8, Line 8.

5. Finally, APS will combine the Base Fuel Direct Assignment component (Line 8 in Figure 8) with the base fuel rate with growth-related costs and MWh of production removed (Line 8 in Figure 7) to determine each class's growth-adjusted base fuel rate. Each class's growth-adjusted base fuel rate is shown in Figure 8, Line 9.

The Company is proposing to update the Base Fuel Direct Assignment rates each year and reflect the changes in the PSA annual filing.

Q. HOW DOES THE BASE FUEL DIRECT ASSIGNMENT MINIMIZE COST SHIFTS?

A. The amounts collected through the Base Fuel Direct Assignment will be an offset to fuel costs. Because the costs directly assigned to classes are the remainder portion not recovered through the adjusted base fuel rate itself, the direct assignment will offset these costs so that they do not flow into the PSA, which spreads the recovery equally to all customers based on usage. As shown in Figure 8, Column (e), Line 9, the Base Fuel less Increment Generation rates (Line 4) plus the Base Fuel Direct Assignment rates (Line 8) collectively total the Total Base Fuel Rate of 4.3881¢/kWh.

Q. DOES APS'S PROPOSAL ALIGN WITH OTHER ELECTRIC UTILITIES IN THE INDUSTRY RESPONDING TO LARGE HIGH LOAD FACTOR CUSTOMER GROWTH?

A. Yes. Utilities across the country are working to address potential cost shifts related to the growth needs of large high load factor customers. For example, Duke Energy is taking steps to protect customers by seeking take-or-pay minimum demand charges for data centers, as well as up-front infrastructure charges.[10] Additionally, Wisconsin Electric Power Company is proposing that data center customers be obligated to pay their share of the cost of resources dedicated to serve them to protect other customers from cross subsidies.[11]

ACC Chairman Kevin Thompson opened a docket on this topic and expressed the importance of ensuring customers are not burdened with the costs to serve data centers.[12] APS's growth-related generation cost allocation proposal is one way the Company intends to address this concern.

VII. <u>SOLAR COST OF SERVICE STUDY.</u>

Q. WHAT IS THE PURPOSE OF A SOLAR COSS?

A. The purpose of the solar COSS is to determine whether solar customers are paying rates that appropriately cover their costs. The adoption of residential rooftop solar

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[10] Liala Kearney, *Duke Energy seeks take-or-pay power contracts for data centers*, Reuters (May 7, 2024); Zachary Skidmore, *Duke Energy to include take-or-pay provisions in US data center agreements,* Data Center Dynamics (Nov. 9, 2004).

[11] *See App. of Wisconsin Electric Power Company for Approval of its Very Large Customer and Bespoke Resources Tariffs, Wisconsin Public Service Commission (PSC) Docket No. 6630-TE-113, PSC Reference Numbers 539747-539752, Application and Attachments A-F (Mar. 31, 2025).*

[12] *In the Matter of the Comm's Inquiry and Review of the Existing Rate Classifications and other Potential Issues relating to Data Centers,* Docket No. E-00000A-25-0069.

systems has grown significantly over the last ten years. In addition, these systems are designed to last 20 years or more. This class of customers is substantial and growing. These customers have unique energy usage and on-site generation, with related impacts on the cost to serve them and important ramifications for recovery of their cost of service in rates.

The Commission held hearings on the Cost and Value of Solar to explore and address these issues.[13] One key question was whether residential solar customers were paying a fair share of their cost of service in rates, or whether these costs were being under-recovered, shifting recovery to non-solar customers.

The Commission, among other things, ultimately determined that residential customers with solar DG were partial requirements customers and the question of whether solar customers are paying their fair share of their cost of service would be best answered in a solar COSS in a rate case.[14] These findings were affirmed by the Commission in APS's 2022 Rate Case.[15]

Q. DID APS PERFORM A SOLAR COSS IN THIS RATE CASE?

A. Yes. Consistent with every rate case since the Cost and Value of Solar Decision, the Company evaluated residential DG in its own class. As ordered in Decision No. 79293,[16] APS allocated costs to residential DG customers based on their site loads.

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[13] *See In the Matter of the Comm's Investigation of Value and Cost of DG, Docket No. E-00000J-14-0023.*

[14] *Id.,* Decision No. 75859 (Jan. 3, 2017) (Cost and Value of Solar Decision).

[15] Decision No. 79293 at 285.

[16] *Id.* at 448.

Q. PLEASE EXPLAIN THE SITE LOAD COSS APPROACH.

A. The site load approach calculates the cost of service for the site load and then evaluates cost credits for the self-supply.[17] This allocates grid and power plant costs according to the total electricity consumption in the home, including through self-supply via DG — not just the quantity of the electricity delivered to the home by APS, the so-called delivered load. Next, the savings in the utility's grid and power plant costs that occur because of the solar generation self-supply are estimated and credited back against the site load cost of service. Finally, the net value of the solar generation that is exported to the grid is calculated by comparing the fuel cost savings that the utility incurs to the price the utility pays for this power, either through the net metering program or the Resource Comparison Proxy (RCP) program. The site load approach calculates the net impact on utility costs from a solar customer, which is the cost responsibility that should be recovered in rates.

Q. HOW WERE THE SITE LOAD COSTS DETERMINED?

A. The hourly site load for the Test Year was developed by adding the hourly delivered load and the portion of the hourly solar generation that was used for self-supply. The resulting site load reflects the total consumption in the home. The cost of service was then determined for the site load based on the standard cost of service allocation methods used for the other customer classes, as described above.

Q. PLEASE DESCRIBE HOW APS HAS CALCULATED THE VALUE OF THE SOLAR CREDIT.

A. Historically, APS has credited residential DG customers the utility cost savings from residential DG. The value of these cost savings was derived by computing the percentage difference between the relevant credit factor for the site load versus the

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[17] Part of the solar generation in any instance directly serves the load in the home, which is referred to as "self-supply" and the remaining excess portion is exported to the grid.
[18] *Decision No. 79293 at 448.*

delivered load. This percentage difference was then applied to the site load gross revenue requirement. The credit factors for each cost type are as follows:

- Production Demand Credit — based on 4-CP and summer average NCP;
- Transmission Credit — based on 4-CP;
- Distribution Substation Credit — based on summer average NCP;
- Distribution Primary Credit — based on summer average NCP; and
- Distribution Secondary Credit — based on the average SIM peaks for the summer months.

Attachment JRM-03DR summarizes the calculation of the solar credit.

Q. HOW WAS THE NET VALUE OF THE SOLAR ENERGY PRODUCTION DETERMINED?

A. Residential DG customers' solar energy production reduces the overall cost of fuel for the utility, which was valued at the new base fuel cost proposed in this rate case. This fuel cost reduction was then netted against the price paid to the solar customers for this export energy, either through the net metering or RCP programs.

VIII. ANALYSIS OF SYSTEM WITHOUT RESIDENTIAL DG

Q. DID APS CONSIDER ALTERNATIVE SCENARIOS TO CALCULATE THE SOLAR CREDITS IN THE SITE-LOAD COSS?

A. Yes. APS was ordered in Decision No. 79293 to provide a hypothetical comparative analysis of what the Company's system would have looked like without residential DG. This analysis shows how much the Company would have spent on replacement power, including generating capacity, fuel costs, and market purchases, to backfill the residential DG resources as compared to APS's actual Test Year costs.[18] Additionally, APS was ordered to ensure that the solar credits mentioned above are informed by the analysis of what APS's system would have

[18] *Decision No. 79293 at 448.*

looked like in the Test Year without residential DG, even if that means that the credit factors are calculated differently than in prior rate cases.[19]

Q. PLEASE DESCRIBE THE SCENARIOS EVALUATED FOR THE DG REPLACEMENT COST ANALYSIS THAT WAS REQUIRED IN DECISION NO. 79293.

A. The Company evaluated scenarios in which the residential DG was replaced on its system with alternative forms of generation. To perform this analysis using resources comparable to DG, APS examined replacement generation costs that comprise market energy purchases (Scenario 1) and utility-scale solar (Scenario 2).

For Scenario 1, APS analyzed the comparison to market energy purchases because this reflects a feasible near-term means to replace residential DG if it was no longer available for the year. This scenario evaluated the use of market energy purchases to replace the roughly 2.4 million MWh of residential DG produced during the Test Year.

For Scenario 2, APS analyzed utility-scale solar because these resources possess characteristics most similar to residential DG. Nonetheless, it is important to recognize that utility scale solar resources typically have increased value over residential DG due to solar-tracking capabilities as well as economies of scale with utility scale solar facilities. APS used the peak DG production of 1,094 MW reached in May of the Test Year to determine the amount of utility-scale solar nameplate capacity required to replace the current output provided by residential DG production. The utility-scale solar nameplate capacity required would be 1,182 MW when grossed up to account for line losses. Costs were calculated based on the cost of solar from PPAs that went into service during the Test Year.

[19] *Id.*

Q. PLEASE EXPLAIN THE RESULTS OF THE DG REPLACEMENT COST ANALYSES THAT WAS REQUIRED IN DECISION NO. 79293.

A. The results of these analyses demonstrate that the cost to the Company of replacing residential solar DG would range from $54.9 million (0.0231¢/kWh) for equivalent market-energy purchases to $71.6 million (0.0302¢/kWh) for equivalent utility-scale solar generation. This range reflects the solar credit value that could be applied to residential DG customers based on comparable generation using replacement costs alone. These costs are notably lower than the total value of the credit applied to residential DG customers utilizing the Company's site-load COSS, which provides a higher solar credit value totaling $123.4 million. A summary of the results is provided in Attachment JRM-04DR.

Q. WHICH SCENARIOS DOES APS PROPOSE TO INCORPORATE INTO ITS FURTHER EVALUATION OF SOLAR CREDIT CALCULATIONS?

A. APS believes both scenarios have merit in the evaluation of solar credit calculations. The utility-scale solar scenario provides a level for evaluating reasonableness as it provides similar resource attributes. The market energy purchase scenario provides an understanding of the total costs that would be imposed on APS's system in the event the Company was required to procure near-term resources to replace residential solar DG capacity based on available market energy.

During the Test Year, APS's residential DG customers benefited from solar generation credits in the site-load COSS of $123.4 million for the value of load served by their behind-the-meter generation. As such, under either replacement cost scenario, had residential solar DG not been available to serve APS's customers, lower cost resources would have been available or could have been developed to serve the same load (i.e., equivalent generation from utility-scale solar, \$71.6 million, or market energy purchases, \$54.9 million). Even though both replacement cost scenarios support a lower solar credit for residential DG customers, APS is not proposing to change its solar credit calculation methodology in this rate case.

Q. WHY ISN'T APS PROPOSING TO INCORPORATE ITS ANALYSES INTO ITS CALCULATION OF THE SOLAR CREDIT?

A. APS calculated a solar credit of \$123.4 million using the site load solar cost of service methodology approved in its last rate case. Although APS considered the results of its replacement cost scenarios, APS continues to recommend that its site-load solar cost of service methodology guide the solar credit calculation in this case because it is consistent with the methodology approved in the Company's last rate case. APS believes that the results of the replacement cost scenarios provide an important benchmark and underscores the reasonableness of the Company's solar credit calculation.

In addition, the mode of analysis required in Decision No. 79293 is limited to the Test Year for this rate proceeding.[20] As such, the methodology involves an evaluation that only presents a snapshot in time for the resource scenarios evaluated. This results in inherent limitations that should be considered as part of whether to use these scenarios as a basis for adjusting the solar generation credit value in APS's site-load COSS. Nonetheless, the analysis ordered in Decision No. 79293 still provides significant value as a benchmark comparison against present-day resource values and strongly suggests that the solar generation credit value in APS's site-load COSS should not be increased.

[20] Decision No. 79293, at 448.

Finally, APS is proposing to increase revenue allocations from residential customers with DG in order to bring them closer to their cost of service, either in the form of an increased grid access charge for customers on current rates for service or increased rate components for customers on legacy rates. Through both of these mechanisms, APS's residential solar customers are coming closer to their cost of service, as described in more detail by Ms. Jessica Hobbick. For these reasons, APS does not believe that additional measures, such as refinement of the solar generation credit value in the site-load COSS, are necessary at this time.

IX. FAIR VALUE INCREMENT

Q. WHAT IS APS'S FVRB AND RATE OF RETURN FOR THE ADJUSTED TEST YEAR?

A. As shown on SFR Schedule A-1, APS's FVRB is $21.6 billion and the current FVROR is 2.54% as reflected on SFR Schedule A-1, Line 3.

Q. HOW WAS THE FVRB DETERMINED?

A. The FVRB is based on the average of the OCRB and the Reconstructed Cost New less Depreciation (RCND) rate base. The Commission has historically accepted this calculation as an appropriate way of determining the FVRB. APS witness Elizabeth A. Blankenship describes this calculation in more detail.

Q. DID APS PERFORM A CALCULATION TO ADDRESS THE APPROPRIATE LEVEL OF RETURN ON FVRB?

A. Yes. APS witness James M. Coyne describes the methodologies he used to determine the real-risk free rate, which the Company used to calculate the after-tax return on the FVI shown on SFR Schedule A-1, Line 9. The details of the calculation are shown in Attachment JRM-05DR.

Q. IS THE TREATMENT CONSISTENT WITH THE METHOD USED IN APS'S LAST RATE CASE?

A. Yes.

Q. HOW DID APS CALCULATE THE FVROR?

A. FVRB is divided into three components:

- The FVRB Increment is calculated by subtracting the OCRB from the FVRB to determine the portion of FVRB in excess of the OCRB;
- The debt component of OCRB is calculated by multiplying the Company's adjusted Test Year debt percentage (47.65%) by the OCRB; and
- The equity component of OCRB is calculated by multiplying the Company's adjusted Test Year equity percentage (52.35%) by the OCRB.

Next, a return component of 1.0%, as supported by Mr. Coyne's real-risk free rate analyses, is applied to the FVRB Increment. Using the 1.0% return for the FVRB Increment, 4.26% return on the debt component, and 10.7% on the equity component, a new fair value weighted average cost of capital is calculated.

The fair value weighted average cost of capital is applied to the FVRB and the result is compared to the original cost increase in revenue requirement of $540.7 million reflected on SFR Schedule A-1, Line 8. The difference between those two values indicates that the after-tax return, or FVI, is $121.8 million, as reflected on SFR Schedule A-1, Line 9. Further detail is provided in Attachment JRM-05DR.

X. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Index for Sponsorship of Standard Filing Requirements	
SFR Number	**Witness**
A-1	Mr. Moe
A-2*, A-3, A-4, A-5	Ms. Blankenship
B-1*, B-2*[1], B-3*, B-4, B-4a*, B-5	Ms. Blankenship
C-1*	Ms. Blankenship
C-2*[1] (Columns 1-5, 11-13, 17, 21-23, 25-35, 37-52, 54-62)	Ms. Blankenship
C-2 (Columns 6-8)	Mr. Moe
C-2*(Columns 9-10, 20, 24, 36, 53)	Ms. Hobbick
C-2* (Columns 14-16, 18-19) [2]	Ms. Hobbick/Ms. Blankenship
C-3	Ms. Blankenship
D-1, D-2, D-3, D-4	Mr. Bauer
E-1, E-2, E-3, E-4, E-5, E-6, E-7, E-8, E-9	Ms. Blankenship
F-1*, F-2, F-3, F-4	Ms. Blankenship
G-1, G-2, G-3, G-4, G-5, G-6, G-7	Mr. Moe
H-1, H-2, H-3, H-4, H-5	Ms. Hobbick

*Mr. Moe sponsors the ACC jurisdictional amounts that are computed based on the Cost-of-Service Study.

[1]Mr. Tetlow discusses the details of post-Test Year plant projects included in the pro formas.

[2]Ms. Hobbick addresses the rate impacts of the proposed adjustment mechanism pro formas.

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2024 Test Year Adjusted Cost of Service Study

SUMMARY OF RESULTS	ELECTRIC TOTAL	ALL OTHER	ACC JURISDICTION	RETAIL					
				RESIDENTIAL	GENERAL SERVICE	E-221 NonAG	E-221 AG	Street Lighting	Dusk to Dawn
DEVELOPMENT OF RATE BASE									
PRODUCTION PLANT IN SERVICE	$ 11,407,456,735	$ 9,881,014	$ 11,397,575,721	$ 6,333,101,312	$ 4,962,999,350	$ 79,625,492	$ 120,812	$ 18,746,325	$ 2,982,430
TRANSMISSION PLANT IN SERVICE	3,986,340,920	3,986,340,920	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	9,019,398,608	36,142	9,019,362,465	6,695,015,469	2,060,422,133	42,980,195	125,567	115,440,212	105,378,890
GENERAL & INTANGIBLE PLANT	3,123,456,800	278,055,156	2,845,401,644	1,877,745,697	942,260,897	15,888,107	44,281	5,471,047	3,991,614
LESS: RESERVE FOR DEPRECIATION	(10,037,959,209)	(1,264,790,898)	(8,773,168,311)	(5,517,332,393)	(3,128,236,016)	(53,081,970)	(107,371)	(42,056,187)	(32,354,374)
MATERIALS, SUPPLIES & PREPAYMENTS	659,665,129	75,448,049	584,217,080	352,127,995	223,194,107	3,908,300	8,317	2,926,268	2,052,093
MISCELLANEOUS DEFERRED DEBITS	27,471,000	1,667,893	25,803,107	15,335,497	10,202,909	178,354	451	60,603	25,294
OTHER DEFERRED CREDITS	(1,717,699,266)	(21,484,063)	(1,696,215,203)	(949,200,797)	(731,075,572)	(11,916,278)	(19,894)	(3,206,145)	(796,517)
OPEB	335,458,444	30,988,471	304,469,973	198,488,485	103,244,988	1,750,310	4,830	596,571	384,789
WORKING CASH	(175,589,220)	(33,380,934)	(142,208,286)	(93,714,600)	(45,804,398)	(790,549)	(1,495)	(1,025,513)	(871,730)
REGULATORY ASSETS	(294,943,411)	77,308,647	(372,252,058)	(240,002,011)	(123,167,732)	(1,914,508)	123	(3,801,979)	(3,365,951)
ACCUM. DEFERRED TAXES	(2,445,464,847)	(416,681,676)	(2,028,783,171)	(1,315,663,992)	(677,646,137)	(11,792,129)	(24,508)	(12,987,281)	(10,669,124)
OPERATING LEASES	(15,587,914)	5,945,068	(21,532,982)	(1,081,020)	(19,959,937)	(389,543)	(747)	(135,284)	33,549
DECOMMISSIONING FUND	1,657,000,038	1,491,300	1,655,508,738	923,986,650	717,026,013	11,433,954	16,885	2,628,416	416,821
CUSTOMER ADVANCES	(569,343,441)	(38,254,375)	(531,089,066)	(50,621,741)	(479,054,941)	(130,554)	(294)	(1,281,229)	(307)
CUSTOMER DEPOSITS	(42,198,184)	-	(42,198,184)	(9,118,941)	(31,961,976)	(608,124)	(1,401)	(351,644)	(156,098)
PROFORMA ADJUSTMENTS	373,658,684	83,429,305	290,229,379	147,658,146	140,006,361	2,259,668	2,567	409,424	(106,787)
TOTAL RATE BASE	**15,291,120,867**	**2,776,000,020**	**12,515,120,846**	**8,366,723,755**	**3,922,450,049**	**77,400,724**	**168,123**	**81,433,604**	**66,944,591**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	4,232,605,779	78,057,643	4,154,548,136	2,201,721,531	1,886,868,982	35,900,474	82,699	20,759,219	9,215,231
PRO FORMA TO BASE REVENUES FROM RATES	(11,353,503)	-	(11,353,503)	(49,494,072)	38,022,913	380,371	(176)	(342,002)	79,463
SURCHARGE & OTHER ELECTRIC REVENUES	910,744,221	49,917,692	860,826,530	428,410,748	419,610,921	9,904,082	25,154	2,302,525	573,099
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(729,683,904)	(734,708)	(728,949,196)	(360,586,606)	(357,249,563)	(8,742,782)	(22,231)	(1,867,294)	(480,720)
TOTAL OPERATING REVENUES	**4,402,312,593**	**127,240,626**	**4,275,071,966**	**2,220,051,602**	**1,987,253,253**	**37,442,145**	**85,447**	**20,852,448**	**9,387,072**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	2,709,315,376	(211,167,442)	2,920,482,819	1,522,524,700	1,363,377,674	25,480,535	66,345	6,916,718	2,116,847
ADMINISTRATIVE & GENERAL	225,590,531	25,902,597	199,687,934	129,496,207	68,353,329	1,156,684	3,110	412,257	266,348
DEPRECIATION & AMORT EXPENSE	850,735,052	102,065,600	748,669,452	478,277,960	259,262,016	4,451,863	9,690	3,737,569	2,930,354
OTHER EXPENSE ITEMS	43,154,099	54,614	43,099,485	21,770,386	20,813,074	373,041	816	122,027	20,142
TAXES OTHER THAN INCOME	258,912,678	41,746,984	217,165,694	145,830,027	67,200,992	1,206,307	2,851	1,579,018	1,346,499
PROFORMA ADJUSTMENTS	(395,123,815)	8,615,454	(403,739,268)	(201,069,307)	(197,842,501)	(4,769,568)	(12,113)	(424,992)	379,212
INCOME TAX	136,678,000	22,856,367	113,821,633	76,524,808	35,216,993	699,612	1,541	754,387	624,292
PROFORMA INCOME TAX ADJUSTMENTS	(116,724,651)	(2,446,032)	(114,278,620)	(58,140,803)	(55,127,891)	(889,750)	(1,011)	(161,212)	42,048
TOTAL OPERATING EXPENSES	**3,712,537,271**	**(12,371,859)**	**3,724,909,130**	**2,115,213,978**	**1,561,253,686**	**27,708,723**	**71,229**	**12,935,773**	**7,725,741**
OPERATING INCOME	**689,775,322**	**139,612,485**	**550,162,837**	**104,837,624**	**425,999,567**	**9,733,422**	**14,218**	**7,916,676**	**1,661,330**
RATE OF RETURN (PRESENT)	**4.51%**	**5.03%**	**4.40%**	**1.25%**	**10.86%**	**12.58%**	**8.46%**	**9.72%**	**2.48%**
INDEX RATE OF RETURN (PRESENT)	**-**	**-**	**1.0**	**0.3**	**2.5**	**2.9**	**1.9**	**2.2**	**0.6**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**4,980,132,094**	**174,497,748**	**4,805,634,347**	**2,947,588,267**	**1,792,520,677**	**31,901,036**	**82,250**	**18,958,213**	**14,583,903**
% OF TOTAL COST OF SERVICE (PRESENT)	**87.23%**	**44.78%**	**88.78%**	**75.06%**	**110.71%**	**122.38%**	**108.19%**	**108.82%**	**64.01%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**98.06%**	**44.73%**	**100.00%**	**85.02%**	**124.01%**	**131.67%**	**180.35%**	**124.87%**	**73.90%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2024 Test Year Adjusted Cost of Service Study

	RESIDENTIAL								
SUMMARY OF RESULTS	**Legacy Solar (Energy)**	**Legacy Solar (Demand)**	**R-Solar TOU**	**R-Solar (Demand)**	**R-Basic (0-600kW)**	**R-Basic (601-999 kW)**	**R-Basic (1000+ kW)**	**R-TOU**	**R-Demand**
DEVELOPMENT OF RATE BASE									
PRODUCTION PLANT IN SERVICE	$ 506,115,619	$ 13,849,264	$ 453,910,068	$ 172,831,913	$ 605,902,157	$ 536,068,939	$ 407,059,786	$ 1,318,465,464	$ 2,318,898,102
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	461,286,582	11,137,620	460,733,639	166,845,588	1,043,588,348	645,467,557	369,860,670	1,354,833,001	2,181,262,465
GENERAL & INTANGIBLE PLANT	129,118,193	3,204,534	124,653,646	45,352,624	289,771,979	180,225,476	106,835,381	377,934,067	620,649,797
LESS: RESERVE FOR DEPRECIATION	(408,778,190)	(10,577,833)	(384,534,852)	(142,701,561)	(702,227,978)	(501,230,711)	(330,058,875)	(1,130,637,357)	(1,906,585,037)
MATERIALS, SUPPLIES & PREPAYMENTS	26,316,309	695,099	24,642,417	9,282,362	42,841,461	31,410,005	21,317,754	72,200,217	123,422,369
MISCELLANEOUS DEFERRED DEBITS	1,105,789	29,069	1,041,595	392,134	2,042,982	1,396,368	913,731	3,112,217	5,301,613
OTHER DEFERRED CREDITS	(74,810,480)	(2,039,279)	(67,558,696)	(25,718,273)	(95,634,221)	(81,102,602)	(60,390,515)	(196,885,626)	(345,061,103)
OPEB	13,766,715	344,299	13,228,831	4,830,458	29,927,716	18,913,113	11,380,845	40,040,241	66,056,267
WORKING CASH	(6,941,922)	(177,013)	(6,588,849)	(2,425,730)	(12,094,497)	(8,576,484)	(5,548,521)	(19,243,481)	(32,118,103)
REGULATORY ASSETS	(19,949,158)	(525,668)	(18,174,688)	(6,732,750)	(21,058,892)	(20,359,608)	(15,290,665)	(50,872,237)	(87,038,345)
ACCUM. DEFERRED TAXES	(96,691,278)	(2,474,855)	(91,825,722)	(33,926,069)	(172,255,075)	(120,547,965)	(77,780,040)	(269,402,017)	(450,760,971)
OPERATING LEASES	(424,802)	(22,877)	(233,599)	(188,990)	2,110,485	453,108	(353,019)	(367,241)	(2,054,086)
DECOMMISSIONING FUND	73,898,759	2,018,247	66,255,871	25,180,276	88,456,451	78,315,640	59,378,232	192,448,346	338,034,829
CUSTOMER ADVANCES	(1,727,967)	(79,146)	(2,829,702)	(1,051,001)	(5,475,137)	(4,783,758)	(3,983,620)	(11,992,648)	(18,698,761)
CUSTOMER DEPOSITS	(305,577)	(14,180)	(507,775)	(188,520)	(987,829)	(862,951)	(719,398)	(2,163,899)	(3,368,813)
PROFORMA ADJUSTMENTS	12,732,015	364,107	11,016,757	4,299,634	9,170,042	11,519,560	10,120,958	31,295,701	57,139,370
TOTAL RATE BASE	**614,710,607**	**15,731,387**	**583,228,941**	**216,082,096**	**1,104,077,992**	**766,305,686**	**492,742,703**	**1,708,764,748**	**2,865,079,594**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	73,780,020	3,423,733	122,599,623	45,517,080	238,506,176	208,355,117	173,694,963	522,462,294	813,382,525
PRO FORMA TO BASE REVENUES FROM RATES	(3,755,615)	(63,964)	(234,635)	3,872,507	(4,502,029)	(2,570,293)	1,822,754	(43,277,083)	(785,715)
SURCHARGE & OTHER ELECTRIC REVENUES	17,893,377	662,487	23,018,953	9,196,439	47,372,308	38,783,632	29,438,883	94,231,187	167,813,484
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(12,582,676)	(510,271)	(18,205,269)	(7,267,504)	(40,986,100)	(33,251,277)	(25,106,199)	(80,264,419)	(142,412,889)
TOTAL OPERATING REVENUES	**75,335,105**	**3,511,985**	**127,178,671**	**51,318,522**	**240,390,354**	**211,317,179**	**179,850,400**	**493,151,979**	**837,997,406**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	68,134,460	2,182,803	119,057,540	40,997,326	175,024,343	134,256,830	97,173,605	318,565,766	567,132,027
ADMINISTRATIVE & GENERAL	9,036,901	226,881	8,661,009	3,167,830	19,242,966	12,285,411	7,458,068	26,158,419	43,258,721
DEPRECIATION & AMORT EXPENSE	34,953,125	896,724	33,113,776	12,245,175	63,328,917	43,915,327	28,295,405	97,724,951	163,804,559
OTHER EXPENSE ITEMS	1,708,796	48,865	1,543,462	613,283	2,052,337	1,786,561	1,405,202	4,485,451	8,126,429
TAXES OTHER THAN INCOME	10,448,526	262,691	10,071,691	3,695,599	20,494,233	13,626,520	8,431,842	29,700,889	49,098,036
PROFORMA ADJUSTMENTS	(1,112,292)	(179,103)	(6,340,325)	(1,456,281)	(23,008,885)	(18,571,728)	(13,529,791)	(54,371,623)	(82,499,278)
INCOME TAX	5,604,809	143,079	5,327,665	1,971,831	10,194,300	7,027,546	4,493,520	15,618,320	26,143,737
PROFORMA INCOME TAX ADJUSTMENTS	(5,013,266)	(143,368)	(4,337,879)	(1,692,993)	(3,610,729)	(4,535,859)	(3,985,155)	(12,322,769)	(22,498,785)
TOTAL OPERATING EXPENSES	**123,761,060**	**3,438,572**	**167,096,939**	**59,541,771**	**263,717,482**	**189,790,608**	**129,742,696**	**425,559,404**	**752,565,446**
OPERATING INCOME	**(48,425,954)**	**73,413**	**(39,918,268)**	**(8,223,249)**	**(23,327,128)**	**21,526,571**	**50,107,704**	**67,592,575**	**85,431,960**
RATE OF RETURN (PRESENT)	**-7.88%**	**0.47%**	**-6.84%**	**-3.81%**	**-2.11%**	**2.81%**	**10.17%**	**3.96%**	**2.98%**
INDEX RATE OF RETURN (PRESENT)	**(1.8)**	**0.1**	**(1.6)**	**(0.9)**	**(0.5)**	**0.6**	**2.3**	**0.9**	**0.7**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**203,420,884**	**5,019,170**	**240,889,819**	**84,523,405**	**388,732,272**	**262,738,095**	**163,652,758**	**579,931,210**	**1,018,680,653**
% OF TOTAL COST OF SERVICE (PRESENT)	**35.39%**	**69.03%**	**52.02%**	**60.00%**	**61.81%**	**80.35%**	**109.88%**	**84.93%**	**82.20%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**41.30%**	**80.29%**	**60.13%**	**69.18%**	**71.27%**	**91.17%**	**122.17%**	**95.83%**	**92.53%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2024 Test Year Adjusted Cost of Service Study

	GENERAL SERVICE								
SUMMARY OF RESULTS	**E-20 (Church Rate)**	**E-32 TOU (0-20 kW)**	**E-32 TOU (21-100 kW)**	**E-32 TOU (101-400 kW)**	**E-32 TOU (401+ kW)**	**School TOU**	**E-30, E-32 (0-20 kW)**	**E-32 (21-100 kW)**	**E-32 (101-400 kW)**
DEVELOPMENT OF RATE BASE									
PRODUCTION PLANT IN SERVICE	$ 12,338,128	$ 7,288,416	$ 8,533,779	$ 33,598,265	$ 98,923,878	$ 81,044,085	$ 532,377,348	$ 833,357,436	$ 1,008,564,807
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	11,239,680	4,963,749	4,133,493	12,249,934	36,334,999	44,541,508	584,884,644	428,193,207	404,829,708
GENERAL & INTANGIBLE PLANT	2,794,592	1,665,610	1,698,658	5,788,110	16,834,198	14,400,823	163,754,374	172,610,307	175,343,220
LESS: RESERVE FOR DEPRECIATION	(9,716,836)	(5,281,659)	(5,579,738)	(20,372,026)	(59,852,698)	(53,580,729)	(471,850,931)	(556,441,314)	(622,561,886)
MATERIALS, SUPPLIES & PREPAYMENTS	644,265	370,269	396,106	1,467,036	4,366,650	3,702,653	31,155,574	38,523,239	44,621,801
MISCELLANEOUS DEFERRED DEBITS	26,039	16,675	18,052	65,748	195,807	153,378	1,395,911	1,748,541	1,975,502
OTHER DEFERRED CREDITS	(1,821,305)	(1,090,847)	(1,261,885)	(4,921,259)	(14,528,104)	(11,812,745)	(81,086,229)	(122,830,104)	(147,767,967)
OPEB	306,858	179,348	186,956	639,699	1,862,273	1,591,333	17,276,620	18,971,353	19,373,678
WORKING CASH	(168,174)	(82,140)	(83,422)	(297,627)	(870,517)	(859,562)	(7,860,727)	(8,465,823)	(9,253,886)
REGULATORY ASSETS	(512,878)	(203,162)	(218,775)	(868,029)	(2,500,482)	(2,801,044)	(17,870,390)	(22,694,130)	(27,375,137)
ACCUM. DEFERRED TAXES	(2,330,799)	(1,198,840)	(1,228,555)	(4,385,266)	(12,887,730)	(12,141,853)	(112,334,212)	(123,379,637)	(135,416,554)
OPERATING LEASES	(21,585)	(25,805)	(32,526)	(145,255)	(462,326)	(270,125)	(658,584)	(2,559,531)	(4,260,903)
DECOMMISSIONING FUND	1,797,051	1,051,455	1,232,871	4,855,263	14,271,123	11,768,047	77,128,072	120,774,650	145,799,576
CUSTOMER ADVANCES	(704,157)	(627,112)	(659,286)	(2,191,461)	(5,907,437)	(4,454,852)	(45,869,370)	(58,981,333)	(63,930,168)
CUSTOMER DEPOSITS	(74,839)	(66,693)	(70,105)	(232,969)	(627,913)	(473,436)	(4,878,187)	(6,270,944)	(6,795,940)
PROFORMA ADJUSTMENTS	325,895	195,547	241,003	978,428	2,891,897	2,258,996	12,305,731	23,025,888	29,387,532
TOTAL RATE BASE	**14,121,935**	**7,154,811**	**7,306,625**	**26,228,590**	**78,043,616**	**73,066,476**	**677,869,644**	**735,581,807**	**812,533,383**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	4,418,087	3,937,224	4,138,637	13,753,285	37,068,722	27,949,200	287,982,783	370,203,932	401,196,979
PRO FORMA TO BASE REVENUES FROM RATES	(60,341)	(228,981)	363,144	656,168	3,733,074	1,131,755	3,770,891	4,455,324	3,271,111
SURCHARGE & OTHER ELECTRIC REVENUES	1,102,679	833,324	863,520	2,990,191	7,666,392	6,511,423	58,050,767	83,701,084	90,603,132
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(962,634)	(738,862)	(754,820)	(2,570,509)	(6,399,130)	(5,569,709)	(51,532,890)	(73,689,579)	(78,044,009)
TOTAL OPERATING REVENUES	**4,497,790**	**3,802,704**	**4,610,480**	**14,829,135**	**42,069,058**	**30,022,669**	**298,271,551**	**384,670,762**	**417,027,213**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	3,305,956	2,159,786	2,314,131	8,446,995	24,998,404	20,678,100	157,948,570	224,950,242	257,153,224
ADMINISTRATIVE & GENERAL	202,528	117,974	123,500	425,742	1,240,358	1,060,842	11,253,159	12,509,641	12,895,229
DEPRECIATION & AMORT EXPENSE	828,680	447,254	466,393	1,671,939	4,909,372	4,435,901	41,087,714	46,697,452	51,207,883
OTHER EXPENSE ITEMS	44,126	31,480	35,965	140,413	426,404	306,291	2,124,858	3,303,966	4,190,786
TAXES OTHER THAN INCOME	249,877	126,196	124,120	425,480	1,250,639	1,219,695	12,568,659	12,559,172	13,251,112
PROFORMA ADJUSTMENTS	(509,447)	(564,908)	(446,170)	(1,166,718)	(2,392,556)	(2,309,303)	(30,008,977)	(44,990,907)	(43,550,003)
INCOME TAX	128,450	64,795	65,786	235,095	699,711	659,263	6,196,830	6,634,356	7,291,594
PROFORMA INCOME TAX ADJUSTMENTS	(128,322)	(76,997)	(94,896)	(385,259)	(1,138,692)	(889,486)	(4,845,416)	(9,066,507)	(11,571,422)
TOTAL OPERATING EXPENSES	**4,121,848**	**2,305,582**	**2,588,830**	**9,793,688**	**29,993,639**	**25,161,304**	**196,325,396**	**252,597,415**	**290,868,402**
OPERATING INCOME	**375,943**	**1,497,123**	**2,021,651**	**5,035,447**	**12,075,418**	**4,861,364**	**101,946,154**	**132,073,347**	**126,158,811**
RATE OF RETURN (PRESENT)	**2.66%**	**20.92%**	**27.67%**	**19.20%**	**15.47%**	**6.65%**	**15.04%**	**17.95%**	**15.53%**
INDEX RATE OF RETURN (PRESENT)	**0.6**	**4.8**	**6.3**	**4.4**	**3.5**	**1.5**	**3.4**	**4.1**	**3.5**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**5,433,170**	**2,505,982**	**2,615,181**	**10,602,914**	**33,357,507**	**30,735,896**	**231,290,253**	**280,235,169**	**326,425,979**
% OF TOTAL COST OF SERVICE (PRESENT)	**85.60%**	**151.56%**	**177.25%**	**140.92%**	**124.74%**	**100.32%**	**130.18%**	**139.14%**	**128.94%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**93.03%**	**161.76%**	**176.96%**	**151.33%**	**141.82%**	**108.19%**	**137.88%**	**145.51%**	**136.01%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2024 Test Year Adjusted Cost of Service Study

	GENERAL SERVICE					
SUMMARY OF RESULTS	**E-32 (401+ kW)**	**E-34**	**E-35**	**XHLF**	**AG-X GSP RA**	**AG-X APS RA**
DEVELOPMENT OF RATE BASE						
PRODUCTION PLANT IN SERVICE	$ 829,404,119	$ 287,212,447	$ 520,216,620	$ 517,650,284	$ -	$ 192,489,738
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	287,208,874	73,088,267	88,061,680	62,462,101	-	18,230,289
GENERAL & INTANGIBLE PLANT	140,835,517	47,151,605	84,386,215	83,840,794	-	31,156,875
LESS: RESERVE FOR DEPRECIATION	(496,645,346)	(164,237,365)	(284,814,482)	(276,105,125)	-	(101,195,880)
MATERIALS, SUPPLIES & PREPAYMENTS	36,522,871	11,945,113	20,997,703	20,758,823	-	7,722,004
MISCELLANEOUS DEFERRED DEBITS	1,655,968	549,297	1,000,492	1,016,955	-	384,544
OTHER DEFERRED CREDITS	(121,979,225)	(41,919,983)	(75,954,871)	(75,826,670)	-	(28,274,379)
OPEB	15,579,923	5,217,108	9,336,456	9,276,392	-	3,446,994
WORKING CASH	(7,116,032)	(2,287,509)	(3,752,537)	(3,472,439)	-	(1,234,003)
REGULATORY ASSETS	(19,902,305)	(6,622,483)	(10,192,521)	(8,585,491)	-	(2,820,906)
ACCUM. DEFERRED TAXES	(106,176,380)	(34,254,237)	(57,560,928)	(54,601,074)	-	(19,750,072)
OPERATING LEASES	(4,028,998)	(1,296,989)	(2,476,786)	(2,668,523)	-	(1,052,001)
DECOMMISSIONING FUND	119,536,459	41,500,053	75,083,371	74,552,615	-	27,675,408
CUSTOMER ADVANCES	(48,166,069)	(22,423,424)	(106,620,037)	(108,578,159)	-	(9,942,076)
CUSTOMER DEPOSITS	(5,119,416)	(1,517,989)	(2,546,042)	(2,231,028)	-	(1,056,476)
PROFORMA ADJUSTMENTS	24,622,978	8,241,094	14,791,547	14,924,741	-	5,815,086
TOTAL RATE BASE	**646,232,936**	**200,345,005**	**269,955,879**	**252,414,196**	**-**	**121,595,145**
DEVELOPMENT OF RETURN						
BASE REVENUES FROM RATES	302,223,726	89,614,192	150,305,068	131,708,306	-	62,368,841
PRO FORMA TO BASE REVENUES FROM RATES	(2,256,280)	7,522,639	11,329,107	3,437,022	-	898,280
SURCHARGE & OTHER ELECTRIC REVENUES	64,946,959	19,949,924	39,850,237	38,355,765	-	4,185,526
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(54,061,386)	(16,360,151)	(33,273,145)	(31,679,245)	-	(1,613,495)
TOTAL OPERATING REVENUES	**310,853,018**	**100,726,605**	**168,211,267**	**141,821,848**	**-**	**65,839,153**
OPERATING EXPENSES						
OPERATION & MAINTENANCE	212,464,740	84,982,964	158,147,067	153,448,413	-	52,379,084
ADMINISTRATIVE & GENERAL	10,373,548	3,476,324	6,215,124	6,168,591	-	2,290,768
DEPRECIATION & AMORT EXPENSE	40,701,977	13,349,739	23,028,617	22,274,322	-	8,154,774
OTHER EXPENSE ITEMS	3,648,819	1,194,517	2,201,219	2,281,838	-	882,391
TAXES OTHER THAN INCOME	10,259,839	3,216,328	5,265,660	4,919,650	-	1,764,565
PROFORMA ADJUSTMENTS	(34,493,912)	(5,312,642)	(14,579,097)	(16,943,953)	-	(573,908)
INCOME TAX	5,787,590	1,788,611	2,375,745	2,211,180	-	1,077,987
PROFORMA INCOME TAX ADJUSTMENTS	(9,695,366)	(3,244,953)	(5,824,212)	(5,876,658)	-	(2,289,706)
TOTAL OPERATING EXPENSES	**239,047,236**	**99,450,887**	**176,830,122**	**168,483,383**	**-**	**63,685,954**
OPERATING INCOME	**71,805,783**	**1,275,717**	**(8,618,856)**	**(26,661,535)**	**0**	**2,153,199**
RATE OF RETURN (PRESENT)	**11.11%**	**0.64%**	**-3.19%**	**-10.56%**	**0.00%**	**1.77%**
INDEX RATE OF RETURN (PRESENT)	**2.5**	**0.1**	**(0.7)**	**(2.4)**	**-**	**0.4**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**275,953,441**	**117,713,842**	**203,068,160**	**198,696,859**	**0**	**73,886,323**
% OF TOTAL COST OF SERVICE (PRESENT)	**111.08%**	**84.14%**	**81.20%**	**69.48%**	**0.00%**	**86.20%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**126.07%**	**100.00%**	**100.00%**	**100.00%**		**100.90%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Solar Credits
Site Load - Solar Table

SUMMARY OF RESULTS	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
COS - Site Load	243,825,505	5,902,419	226,324,191	84,216,759
Solar Credits with Export Payment Offset	40,404,621	883,250	(14,565,627)	(306,646)
Net COS	203,420,884	5,019,170	240,889,819	84,523,405
Revenue Deficiency	131,428,478	1,554,556	115,576,683	33,807,635
% COS Recovered	**35.4%**	**69.0%**	**52.0%**	**60.0%**

ARIZONA PUBLIC SERVICE COMPANY
Summary of Residential DG Replacement Study

System costs without residential DG					
Studies:		**Total Cost ($)**	**Energy Replaced (MWh)**	**Cost/MWh ($)**	**Cost/KWh ($)**
Replace residential DG with market energy purchases	**Alt2**	54,870,244	2,373,322	23.12	0.0231
Replace residential DG with utility-scale solar based on nameplate same as peak of residential DG generation	**Alt3**	71,593,416	2,373,322	30.17	0.0302

Notes:
1) Energy replaced is based on actual metered residential DG energy for 2024.

2) Grossed up for line losses (8%).

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Fair Value Increment
(Thousands of Dollars)

	Adjusted Test Year Capital Structure	Amount	%	Cost Rate	Weighted Avg
1.	Long-Term Debt	$ 7,543,975	47.65%	4.26%	2.03%
2.	Preferred Stock	-	0.00%	0.00%	0.00%
3.	Common Equity	8,287,281	52.35%	10.70%	5.60%
4.	Short-Term Debt	-	0.00%	0.00%	0.00%
5.	Total	$ 15,831,256	100.00%		7.63%

	Capital Structure with 1.00% FV Increment	Amount	%	Cost Rate	Weighted Avg
6.	Long-Term Debt	$ 5,963,757	27.57%	4.26%	1.17%
7.	Preferred Stock	-	0.00%	0.00%	0.00%
8.	Common Equity	6,551,364	30.29%	10.70%	3.24%
9.	Short-Term Debt	-	0.00%	0.00%	0.00%
10.	FVRB Increment	9,117,010	42.15%	1.00%	0.42%
11.	Total	$ 21,632,131	100.00%		4.84%

	Fair Value Increment Calculation	Fair Value	Original Cost
12.	Rate Base	$ 21,632,131	$ 12,515,121
13.	Rate of Return	4.84%	7.63%
14.	Required Operating Income	$ 1,046,222	$ 955,052
15.	Adjusted Operating Income	550,163	$ 550,163
16.	Adjusted Operating Income Deficiency (line 14 - line 15)	$ 496,059	$ 404,889
17.	Revenue Conversion Factor	1.3358	1.3358
18.	Increase in Base Revenue Requirements (line 16 * line 17)	$ 662,638	$ 540,852
19.	Fair Value Increment	$ 121,785.352	
	RCND Rate Base	$ 30,749,140	