BEFORE THE

ARIZONA CORPORATION COMMISSION

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 Schedules Designed to Develop Such Return.	**Docket E-01345A-25-0105**

EXHIBIT _____

DIRECT TESTIMONY

of

PAUL J. ALVAREZ

on behalf of

AARP

Wired Group
PO Box 620756
Littleton, CO 80162

March 2, 2026

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BEFORE THE
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DIRECT TESTIMONY OF PAUL J. ALVAREZ

I. INTRODUCTION

Q. Mr. Alvarez, please state your name, occupation, and business address.

A. My name is Paul J. Alvarez. I lead the Wired Group, a small consulting practice focused on utility infrastructure planning, investment, operations, performance, and regulation. My business address is Wired Group, PO Box 620756, Littleton, CO 80162.

Q. For which party are you testifying?

A. I am testifying on behalf of AARP. AARP advocates on behalf of 125 million Americans age 50 and older and their families. A significant proportion of APS customers are AARP members.

Q. Please summarize your professional experience and education.

A. I have led the Wired Group since 2012. The Wired Group and its associates, as former employees of electric, gas, and water utilities, have extensive experience in utility operations, planning, investment, and performance. Wired Group associates serve as experts to consumer, business, and environmental advocates in utility regulatory proceedings.

Prior to forming the Wired Group in 2012, I had been active in the distribution utility industry since 2001, including roles as an employee of a large, for-profit electric and gas

distribution utility (Xcel Energy). I also have fifteen years' experience working in finance and marketing roles of increasing responsibility at Fortune 500 corporations. I was awarded undergraduate and graduate degrees in finance and marketing from Indiana University and Northwestern University, respectively. I am an adjunct professor at the University of Colorado's Global Energy Management program, and I occasionally teach sessions at the Institute of Public Utilities' Advanced Studies program (at Michigan State University). (Relevant to this testimony, this past October I led a session describing the pros and cons of various ratemaking methods from stakeholder and customer perspectives.) I am also the author of Smart Grid Hype and Reality, a book designed to educate regulators, Staff, and stakeholders on how to secure maximum value from distribution grid investments for customers.

Q. Have you testified previously before this Commission?

A. No.

Q. Have you testified before other state utility regulators regarding rate increase requests and ratemaking methods?

A. Yes. I have submitted testimony before state utility regulators in 19 states in dozens of proceedings in the last ten years, including California, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Mayland, Massachusetts, Michigan, New Hampshire, New Jersey, North Carolina, North Dakota, Ohio, Oklahoma, Utah, Virginia, and Washington. I have also served as a consultant to intervenors participating in utility regulatory proceedings in four other states, including Colorado, Florida, Hawaii and South Carolina. A complete list of all testimony I have submitted in state utility

regulatory proceedings, with identifying case numbers and dates, is available in my curricula vitae, attached as Attachment 1. I ask that the Commission accept my qualifications to serve as an expert on utility planning, investment, operations, performance, and regulation in this proceeding.

Q. Are you sponsoring any other Attachments?

A. Yes. I provide confidential information related to this testimony in Attachment 2.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of this testimony is to present the findings of my review of Arizona Public Service Company's ("APS" or "Company") instant application to increase rates, and the Company's proposal to adjust rates periodically without a rate case after this proceeding through a Formula Rate Adjustment Mechanism ("FRAM").

Q. Please provide an executive summary of this testimony.

A. This testimony begins with a review of the Company's formula ratemaking proposal and associated claims from a customer perspective. I find that formula ratemaking shifts risk from shareholders to customers through several deficiencies, and recommend the Commission reject the Company's FRAM proposal. I also recommend the Commission reject recovery from customers of certain costs, including $198 million in capital to purchase additional equity in Palo Verde Unit 2; $51 million in capital to install a redundant water facility at the Redhawk generating station; and a proposed increase of $31.5 million in annual Palo Verde depreciation expense. In addition,

in the event the Commission approves the FRAM despite well-considered arguments against doing so, I provide a number of back-up recommendations for the Commission's consideration.

Q. Before proceeding, do you have any context you wish to share?

A. Yes. The Company claims it must maintain financial stability despite rapidly growing capital expenditure requirements,[1] and that formula ratemaking will provide that stability.[2] This is a shareholder-centric perspective. When considering new ratemaking methodologies such as the FRAM APS has proposed, I respectfully suggest Commission examine such changes from both a shareholder perspective and a customer perspective. As just one example, while regulatory lag is lamented by shareholders, it is in customer interest and has been embraced by regulators for decades as a critical governor on utility spending. Only in recent years have some regulators modified their perspectives on regulatory lag, increasingly perceiving it as something to be avoided. In my experience, most ratemaking "innovations" designed to reduce regulatory lag are associated with unintended consequences that reduce spending governance, shift spending risk from shareholders to customers, and result in avoidable spending and rate increases to customers.[3]

Utility rate increases reduce customers' quality of life and retard economic development,[4] and should be avoided if possible. On the other hand, safe and reliable electric service is in the public interest, and utility spending can increase safety and reliability. The regulator's challenge

[1] Direct Testimony of Chris R. Bauer dated June 13, 2025 (hereinafter "Bauer Direct"). From 7:22 to 8:2.
[2] Ibid, from 22:8 to 22:21.
[3] Alvarez P, Costello K, Ericson S and Stephens D. *Alternative Ratemaking in the US: A prerequisite for grid modernization or an unwarranted shift of risk to customers?* The Electricity Journal Volume 35 (2022), 107200. Section 4.1.
[4] Metcalf, G. The Relationship Between Electricity Prices and Jobs in Missouri. Tufts University. February 27, 2013. Page 3: "Specifically, these studies (a selection of studies examining the relationship between electricity prices and employment) find elasticities between -0.0045 and -0.363 – meaning that a 1 percent increase in the price of electricity is associated with a decline in employment of between 0.0045 percent and 0.363 percent."

is to encourage utility spending required to deliver safe and reliable service without inadvertently encouraging excessive spending. In my experience, the more permissive the ratemaking construct, the less the governance over utility spending, the greater utility spending and rate increases, and the more likely the instances of avoidable spending.

Q. How does one recognize a permissive ratemaking construct?

A. I believe that regulators of for-profit utilities should assume that capital bias[5] is alive and well. In cost-of-service ratemaking, as the Commission is aware, APS revenue requirements include a provision for profits on the Company's rate base; as that rate base grows, profits grow (all else held equal). As the Commission is also aware, once rates are set, APS has an economic incentive to limit capital and O&M spending. Given capital bias, it is critical that utility incentives to limit capital and O&M spending are preserved in any ratemaking construct. Failure to provide such incentives is the sign of a permissive ratemaking construct.

As the Commission is also aware, information asymmetry makes critical evaluation of utility spending challenging. Information asymmetry refers to the fact that it is difficult, if not impossible, for the Commission, Staff, and intervenors to know as much about a utility's business and operations as the utility itself knows. Given the highly technical nature of electric, gas, and water utility businesses, ratemaking constructs that rely on Staff and intervenors to identify imprudent spending are permissive; instead, ratemaking constructs that encourage utilities to self-

[5] Averch H and Johnson L. *Behavior of the Firm Under Regulatory Constraint*. The American Economic Review. Volume 52, No. 5 (December, 1962), pp 1052-1069.

moderate spending under the influence of regulatory lag and the threat of cost disallowances represent a more appropriate balance between shareholder and customer interest.

Unfortunately, in my experience, formula ratemaking virtually eliminates utility incentives to limit capital and O&M spending, which I will cover in more detail later. Further, formula ratemaking dramatically reduces utilities' risk of cost disallowances. Under traditional ratemaking, utilities are responsible for proving the prudence of their spending; under formula ratemaking, intervenors are responsible for identifying imprudent utility spending. Given their relative lack of information, experience, and resources, placing this responsibility on intervenors results in a permissive regulatory structure and a greater likelihood that unnecessary, premature, and cost-ineffective utility spending will occur.

Q. Do you provide any examples of APS spending that is unnecessary, premature, or cost-ineffective in this testimony?

A. Yes, the cost disallowance recommendations will provide such examples, and I note these examples exist before the Commission has authorized formula ratemaking. I can only imagine the imprudent spending that will occur if the Commission approves APS's FRAM proposal. For now, I conclude my perspective by reminding the Commission that when it comes to for-profit monopoly utilities, regulation is a stand-in for competition. As a result, the Commission bears the important responsibility of striking an appropriate balance between customer/public interest and shareholder interest. Determining this balance requires the Commission to fully understand and appreciate both customer and shareholder perspectives as it examines utility ratemaking proposals.

II. FORMULA RATEMAKING IS IN SHAREHOLDER INTEREST, BUT NOT CUSTOMER INTEREST

Q. Please provide a preview of this section's testimony.

A. This section will compare and contrast traditional ratemaking and formula ratemaking. It will examine the justifications APS presents for formula ratemaking, and provide contrary perspectives for Commission consideration.

Q. Please compare and contrast traditional ratemaking and formula ratemaking at a high level.

A. Traditional ratemaking involves examining a utility's costs over a recently completed period known as a test year. Those historical costs are used to calculate the annual revenues a utility would need to collect to earn a rate of return on investment (profits) comparable to what other businesses with a similar risk profile would earn. This revenue requirement is then allocated to various rate classes via rate designs. Once the new rates go into effect, they remain in effect until the utility files another rate case.

The fact that rates remain in effect until the next rate case under traditional ratemaking represents an appropriate balance between customer and shareholder interests. In the short term, the profit motive (a shareholder interest) encourages utilities to reduce or limit spending, as any spending reductions a utility can secure increases profits until the next rate case. In the long term, this arrangement benefits customers, as any spending reductions a utility can secure are also (in theory) reflected in the test year of the utility's next rate case.

In formula ratemaking, revenue requirements and rates are determined in the same manner. But once the new rates take effect, rates are periodically adjusted as a utility's spending (and other rate determinants) change over time, as measured by the rate of return. If changes in utility spending (and other rate determinants) result in a utility's failure to earn the rate of return its regulator has authorized, rates are increased to compensate. This amounts to a guarantee that a utility will earn the rate of return the Commission authorizes regardless of utility spending.

For a utility enjoying formula ratemaking, spending discipline is thus rendered irrelevant. The risk of excessive, unnecessary, premature, or cost-ineffective utility spending is transferred from shareholders to customers. This is clearly a fundamental change in the way for-profit utilities are regulated, and in the way utility spending is governed. Before approving the APS FRAM proposal, I encourage the Commission to weigh any perceived benefits from formula ratemaking against the higher-than-necessary costs that will inevitably result from the irrelevance of utility spending discipline and the lack of utility spending governance inherent in formula ratemaking.

Q. But in the Company's FRAM proposal, rates can come down if the Company exceeds its rate of return, correct?

A. In theory, yes. But in my experience, without economic penalties for excess spending, the likelihood that a utility overspends is much greater than the likelihood that a utility underspends. This is due in largest part to capital bias, though in my experience the irrelevance of spending discipline created by formula ratemaking results in higher than necessary operations and maintenance ("O&M") spending as well.

Q. But if the interest rates the Company pays on debt fall as a result of formula ratemaking, does that not compensate for any higher APS spending that you fear will occur?

A. No, it will not even come close. The savings on APS debt are minor relative to the excess spending that will occur if the Company no longer has any incentive to control spending under formula ratemaking. The Company reports that in 2022, the Company incurred an extra 15 basis points in interest expense on $400 million in debt due to 'regulatory uncertainty', and estimated the incremental cost to customers of the 15 basis points at $600,000 annually.[6] Applying that ratio ($600,000 annually per $400 million in debt) to APS's total long term debt of $7.2 billion (2023),[7] and assuming that 'regulatory uncertainty' represented 100% of the 15 basis point increase (unlikely), I conservatively estimate the 'regulatory uncertainty debt cost premium' at $10.8 million in incremental interest expense that APS customers must cover annually.

In contrast, the Company reports that it placed $2.1 billion in electric plant (capital spending) into service in 2023, and spent $2.8 billion on O&M expenses in 2023.[8] Assume, as a hypothetical example, that excess, unnecessary, premature, and cost-ineffective spending resulting from formula ratemaking will comprise 5% of Company spending if formula ratemaking is implemented. Five percent of $4.9 billion is $245 million annually; even 1% amounts to $49 million annually. Therefore, as a customer, I would be happy to incur $10.8 million in incremental interest expense annually from 'regulatory uncertainty' if it meant retaining utility incentives to self-govern $4.9 billion in annual spending. The value of the spending governance easily exceeds the incremental interest expense on debt from 'regulatory uncertainty'.

[6] Company Response to Sierra Club 1.16 (c), (e), and (g).
[7] Arizona Public Service Company FERC Form 1 for 2023 filed March 27, 2024. Page 112-113, Ln 24.
[8] Arizona Public Service Company FERC Form 1 for 2023 filed March 27, 2024. Capital, page 207, ln 104; O&M, page 320, ln 198.

Q. What perceived benefits from formula ratemaking does APS identify?

A. APS offers several justifications for formula ratemaking, and I will address each in turn. These include:

- It reduces regulatory lag, improving APS credit ratings, thereby "allowing APS to obtain lower interest rates and have greater access to low-cost capital."[9]
- Some other jurisdictions use it to set utility rates, including 12 states and the Federal Energy Regulatory Commission ("FERC").[10]
- It provides "a better customer experience through smaller, more gradual rate changes."[11]
- It can "streamline the regulatory process and create administrative efficiencies by reducing the need for frequent, full scale rate cases."[12]
- It allows customers to share in excess earnings and "see those cost savings within months through formula rates rather than waiting multiple years for the utility's next rate case."[13]

Q. Are you confident that formula ratemaking will reduce the interest rates APC customers must pay on APC debt?

A. I am not at all confident that formula ratemaking will reduce the Company's cost of debt. I agree that formula ratemaking effectively guarantees that the Company will earn the rate of return the

[9] Direct Testimony of Theodore N Geisler dated June 13, 2025 (hereinafter "Geisler Direct"). Page 28, line 13.
[10] Geisler Direct at 27:14.
[11] Geisler Direct at 27:25.
[12] Geisler Direct at 28:6.
[13] Geisler Direct at 28:4.

Commission authorizes. But it is not at all clear that this will translate into lower interest rates on the Company's debt.

Q. Why is that?

A. Credit ratings are company-specific, and many factors determine the risk level inherent in a company's ability to repay its debts. For example, the APS service territory includes large swaths of forested lands in an arid climate. This increases the risk that a catastrophic wildfire could be sparked by Company equipment. In recent years, catastrophic wildfires in California, Colorado, Hawaii, Oregon, and Texas have been blamed on electric utility equipment. Rating agencies' growing recognition of potential wildfire liabilities are certainly a significant reason why APS credit ratings have deteriorated in recent years.[14] I also note that APS is the operator of one of the largest nuclear generating stations in the US. Nuclear plant operation is also associated with higher risk by credit rating agencies.[15] Neither of these, or other issues impacting the Company's credit risk, will change if the Commission grants APS's request for annual FRAM adjustments. Make no mistake, the Company's FRAM proposal is intended to reduce earnings volatility for shareholders, not to reduce Company interest expense that customers must cover.

As an indicator that APS interest rates are unlikely to change much from the adoption of formula ratemaking, I note that neither S&P nor Fitch have improved their APS credit ratings for corporate, senior unsecured, and short term debt since the Commission adopted its Formula Ratemaking Policy Statement on December 31, 2024. Indeed, Moody's has lowered its ratings on

[14] Direct Testimony of James M. Coyne dated June 13, 2025. Pages 45-46
[15] Ibid, pages 46-48.

APS corporate, senior unsecured, and short term debt since the Commission adopted the Policy Statement.[16]

As another indicator, I note that on November 21, 2025, the Arizona Court of Appeals agreed that the Commission must adhere to the State's Administrative Procedures Act when considering rule changes. This placed the Commission's adoption of formula ratemaking in jeopardy. Yet in each of the four stock market trading sessions that immediately followed the Appeals Court decision, Pinnacle West Capital Corporation[17] share prices increased rather than decreased, as might be expected after a court decision that could be considered averse to shareholder interest.

Q. But formula ratemaking does indeed reduce regulatory lag, does it not?

A. Yes it does, and moreover, it essentially guarantees APS will earn the rate of return on equity the Commission authorizes. While these features of formula ratemaking are clearly in shareholder interest, they are not in customer interest.

Q. Why is reducing regulatory lag not in customer interest?

A There are many reasons, but perhaps the largest is that a utility awarded formula ratemaking has little to no incentive to control spending. Under traditional ratemaking, utilities certainly do have an incentive to reduce spending between rate cases. This is because once rates are set in a rate case, those rates remain in effect until the next rate case. A utility that reduces spending from the

[16] EEI investor presentation November 2023, slide 30; Investor presentation September 2025, slide 23.
[17] APS is owned by Pinnacle West Capital Corporation, and APS financial performance drives the financial performance of Pinnacle West Capital Corporation. APS does not maintain equity shares that are traded in the financial markets.

levels in effect when rates were set can earn more than the rate of return a regulator authorizes, all else being equal. This provides a powerful incentive for a utility to reduce spending once rates are set in traditional ratemaking. This is why regulatory lag is in customer interest, and why historic test year ratemaking became the standard in for-profit utility regulation in the 20th century.

Q. How is this different from formula ratemaking?

A. In the FRAM APS has proposed, utility spending increases or decreases are translated into rate increases or decreases annually (assuming the deadband range around the authorized rate of return is exceeded). If APS reduces spending after this rate case, customers, not shareholders, will get almost all the benefits (in the form of rate reductions). This eliminates the incentive APS has under traditional ratemaking to reduce spending once rates are set. Alternatively, if APS increases spending after this rate case, customers, not shareholders, will bear almost all the costs (in the form of rate increases). This eliminates the penalty APS pays for spending increases once rates are set in traditional ratemaking. With no incentives to reduce spending and no penalty for failing to control spending, formula ratemaking essentially eliminates APS's interest in controlling spending.[18] Furthermore, APS earns profits on capital spending, which encourages APS to increase capital spending. Between the lack of interest in controlling costs and capital bias for increased capital spending, formula ratemaking is in shareholder interest, and not at all in customer interest.

[18] Joskow P. Incentive Regulation and Its Application to Electricity Networks. Review of Network Economics. Volume 7, Issue 4 (December, 2008). Pages 551-552.

Q. But the ability to accommodate increases in capital spending constitutes a feature of formula ratemaking, does it not?

A. The answer to this question depends on one's perspective. To shareholders, the fact that APS will earn the rate of return the Commission authorizes irrespective of APS spending is indeed a feature of formula ratemaking. To customers, the fact that formula ratemaking essentially eliminates APS's interest in controlling spending is a detriment, not a feature.

Q. But without formula ratemaking, APS will not be able to make the investments required to accommodate growing loads, right?

A. That is what APS would like the Commission to believe. However, I believe APS will continue to be able to secure capital on reasonable terms as needed. In its Application, APS declared 4.26% to be the Company's weighted average cost of long-term debt.[19] APS also asked the Commission to authorize a return on equity of 10.7%.[20] I find it hard to believe that any company that can borrow at 4.26% interest and secure a return on equity that will likely end up in the range of 8% to 10% has difficulty securing capital. (The Company's Return on Equity averaged 8.66% from 2014 to 2024.)[21]

Furthermore, the regulatory compact compels APS to make the investments required to provide safe and reliable service to all customers requesting such service in APS's defined service area. In exchange, the State (via the authority assigned to the Commission) provides APS with a reasonable opportunity to earn a rate of return equal to that of companies of similar risk. If APS

[19] Bauer Direct, at 14:22.
[20] Direct Testimony of James M. Coyne dated June 13, 2025.
[21] Company response to Staff 2.25(a).

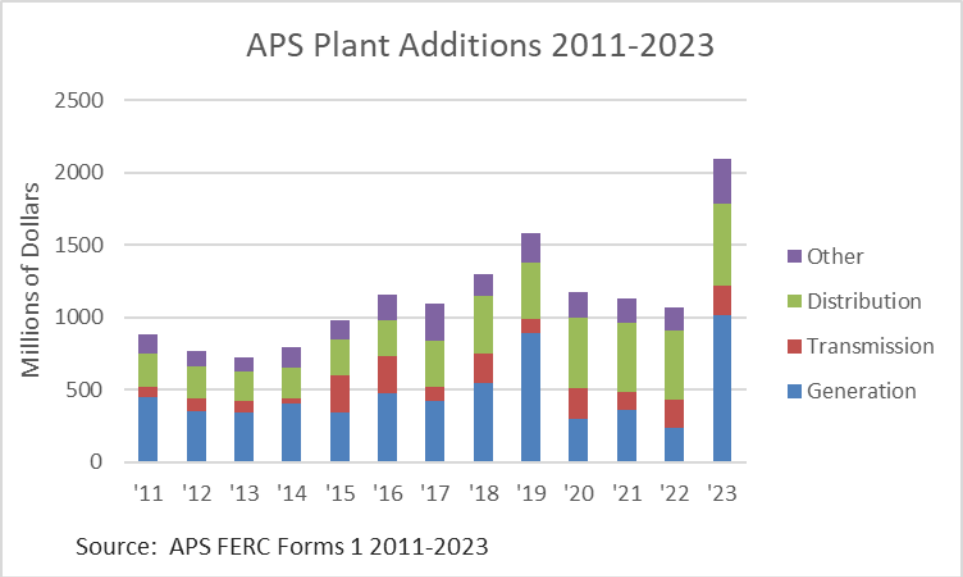
intends to remain the company to which the State offers the regulatory compact in APS's defined service area, APS has no choice but to make the investments required to provide safe and reliable service to all customers requesting it in APS's defined service area. The Company agrees that it maintains an obligation to provide safe and reliable service to all customers in its service territory;[22] and I assume this obligation extends to the investments required to provide safe and reliable service, and to raising the capital required to make such investments.

Q. That is all well and good, but what if APS is unable to raise the capital it needs to accommodate growing loads, or to meet other objectives, such as improved reliability?

A. Figure 1 below shows additions to plant in service over time. It indicates APS has been able to secure capital to fund large increases in electric plant in the past without formula ratemaking. Note, as examples, that significant increases in plant placed into service from 2014 to 2015 ($190 million): 2016 to 2017 ($174 million); 2017 to 2018 ($211 million); 2018 to 2019 ($278 million); and 2022 to 2023 ($1.027 billion) were accommodated by APS without formula ratemaking.

[22] Company response to AARP 1.3(a).

Figure 1: APS Plant Additions 2011-2023



Further, I note that from a customer's perspective, reasonable governance over utility capital spending levels is a good thing. Indeed, businesses operating in competitive markets maintain an ongoing incentive to keep spending low. Given this ongoing incentive, these businesses rigorously scrutinize capital projects for their ability to maximize operating risk reductions per dollar, or to deliver benefits in excess of costs. This rigorous scrutiny ensures these businesses deploy capital to its highest and best use, with non-critical projects deferred to future years. It is precisely this type of internal challenge process that utility ratemaking processes should be designed to encourage through some amount of spending governance. As monopoly regulation is intended as a substitute for competition, and given information asymmetry, it is important for regulators to encourage utility spending self-governance through careful selection of ratemaking methods. As formula ratemaking eliminates utility incentives to control costs, formula ratemaking does not appear to represent a substitute for competition, nor does it encourage spending discipline by for-profit utilities.

Q. APS claims that 12 states and the FERC employ formula ratemaking. If your critiques of formula ratemaking are valid, why do several jurisdictions use it to set rates?

A. Of course I can only speculate as to why these jurisdictions' regulators choose to set rates through formula ratemaking. It could be that these regulators wanted to encourage capital spending above all other objectives (such as affordability). These regulators may believe that formula ratemaking is more administratively efficient (though I will argue below that it is not). Perhaps these regulators simply have not considered the unintended consequences of formula ratemaking and associated customer detriment, as I do in this testimony. Perhaps these regulators believe that the balance of interest between shareholders and customers simply needed revising in shareholders' favor. But in summary, after 20 years of experience, it appears formula ratemaking is increasingly associated with a lack of spending control.

Regarding the FERC specifically, I note the FERC neither maintains nor funds any designated consumer advocate to represent customer interests in electric transmission rate cases. A lack of credible opposition could be responsible for FERC's initial adoption of formula ratemaking. Moreover, there are indications that formula ratemaking's days at the FERC may be numbered. Noted electricity law expert Ari Pescoe, head of the Electricity Law Initiative at Harvard Law School, states "Formula rates are a vehicle for avoiding burdens of proof and limiting protests. The Commission's default presumption that all transmission expenditures are prudent allows utility costs to flow through to consumers' bills without scrutiny. For asset replacement or end-of-life projects, the Commission's policies provide utilities with what amounts to a blank

check that may be worth hundreds of billions of dollars over the next few decades. Customers and ratepayer advocates are pleading for reforms."[23]

In a FERC complaint, the Ohio Office of Consumers' Counsel ("OCC") identifies review of these 'supplemental' projects Mr. Pescoe identifies as a gaping hole in transmission spending oversight.[24] The Ohio OCC estimates that $6 billion in transmission spending, representing 85% of amounts charged to Ohio electric customers from 2018-2022, escaped oversight through formula ratemaking at the FERC.[25] The Ohio OCC's complaint was endorsed by designated state utility consumer advocates in Maryland and New Jersey.[26]

Dozens of state utility consumer advocates and regulatory commissions from across the US are participating in another FERC proceeding to address insufficient transmission spending oversight. Among other deficiencies, the Complaint that prompted the proceeding states that formula ratemaking practices amount to a presumption of spending prudence, thus shifting the burden of proving capital spending prudence – a utility responsibility under historical ratemaking practice – to customers, who bear the burden of proving capital spending imprudence under formula ratemaking.[27]

I further note that Commission peers, including the New England Conference of Public Utility Commissioners[28] and the Ohio Public Utilities Commission,[29] generally endorse the FERC Complaint. In short, formula ratemaking is coming under increasing pressure at the FERC, and I

[23] FERC Docket No. AD22-8 (Transmission Planning and Cost Management). Pre-technical conference statement of Mr. Ari Peskoe dated September 16, 2022.
[24] 'Supplemental' projects are those proposed by utilities rather than solicited by a regional transmission operator such as PJM. Such projects generally replace existing infrastructure and rarely result in transmission capacity increases.
[25] FERC Docket No. EL23-0105. Complaint of the Ohio Office of Consumers Counsel dated September 28, 2023. Page 25.
[26] Ibid. Letter dated November 17, 2023.
[27] FERC Docket No. EL25-44-000. Complaint by multiple parties dated December 19, 2024. Page 34.
[28] Ibid. Comments by the New England Conference of Public Utility Commissioners dated March 20, 2025.
[29] Ibid. Comments by the Public Utilities Commission of Ohio dated March 20, 2025.

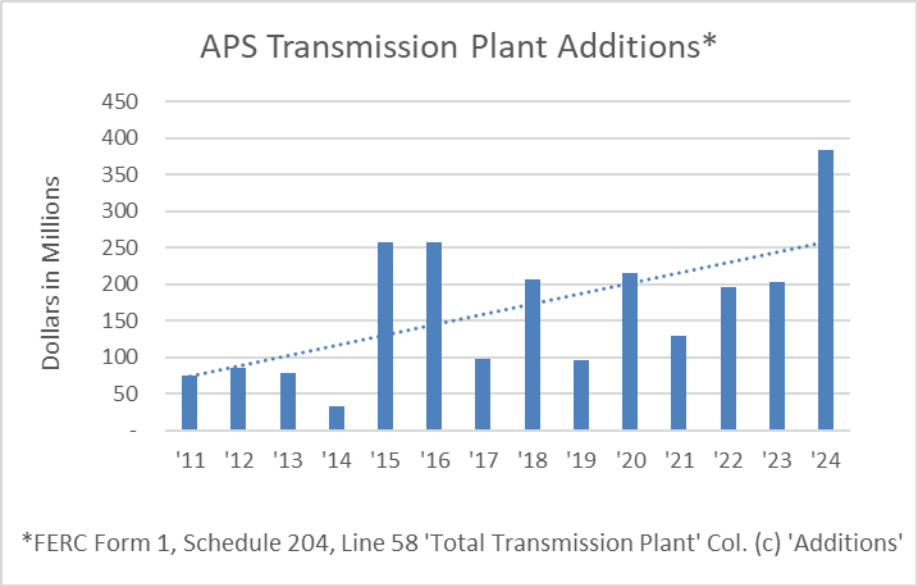
encourage the Commission to avoid the perception that FERC's use of formula ratemaking validates the practice as an appropriate balance of shareholder and customer interests. The Commission may also be interested to know that the FERC does not use formula ratemaking for interstate gas pipelines. If formula ratemaking is superior, I ask why the FERC has not adopted it for interstate gas pipelines in the same way it has for interstate electric transmission lines.

Q. But APS represents that Transmission Cost Adjustments ("TCA") have had minimal bill impacts in recent years,[30] implying that the formula ratemaking practices the FERC has employed to calculate APS Transmission rates do not lead to uncontrolled spending.

A. While TCA adjustments may have been minimal in recent years, the implication stems from the timeframe APS cherry-picked (2019-2024). APS notes that the FERC has employed Formula Ratemaking to calculate APS Transmission rates since 2008.[31] Employing a longer time horizon, APS Transmission spending has increased exponentially since formula ratemaking began, representing an astonishing 13.4% compound annual growth rate from 2011 through 2024, as presented in Figure 2 below.

[30] Direct Testimony of Jessica E. Hobbick dated June13, 2025. Figure 4, page 12.
[31] Geisler Direct at 27:17.

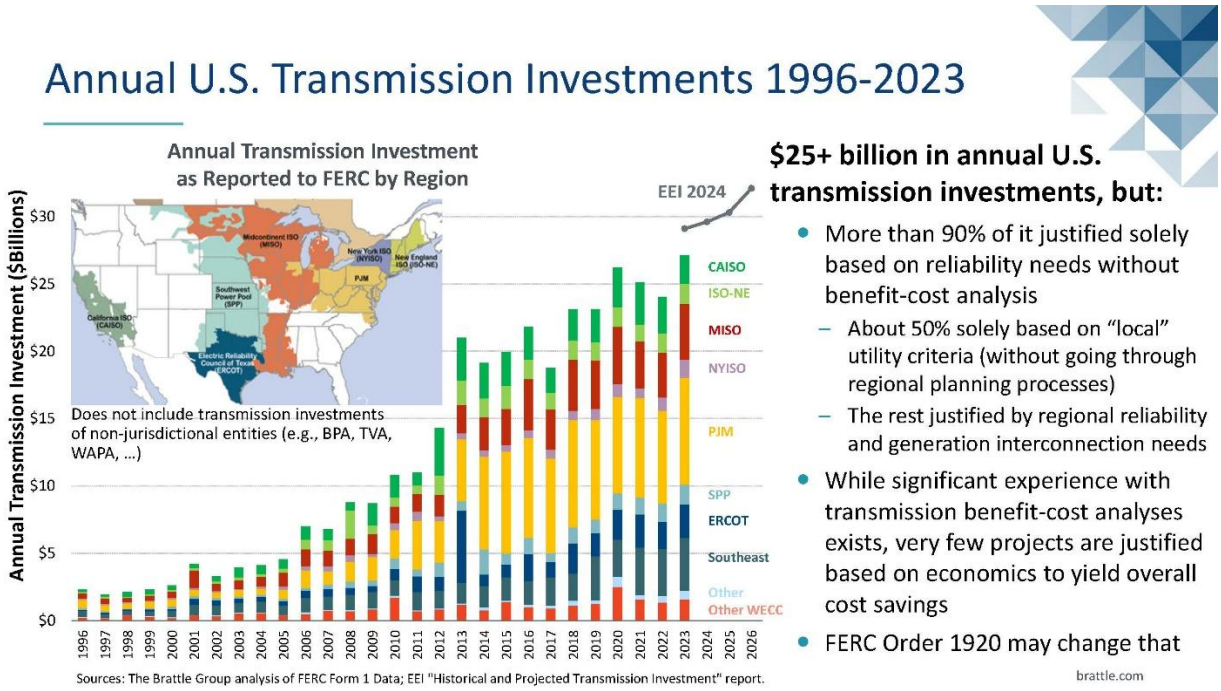
Figure 2: APS Transmission Plant Additions 2011-2024



Further, there is nationwide evidence that FERC's use of formula rates have encouraged an explosion in transmission spending, and that such spending did not accommodate increases in capacity or renewable generation. The Brattle Group estimates that 50% of US transmission investment in recent decades has been justified by utility-claimed reliability requirements that did not result from capacity planning violations and have not been examined for cost-effectiveness.[32]

[32] Brattle Group. Available at https://www.brattle.com/wp-content/uploads/2023/07/Annual-US-Transmission-Investments-1996%E2%80%932023.pdf.

Figure 3: Brattle Group assessment of US transmission investments since FERC introduced formula ratemaking.



Q. But certainly, APS customers have received a lot of value from these increases in transmission spending, have they not?

A. They have certainly received some value, but the Commission should not assume APS customers received as much value as the $1 billion in transmission spending increases the Company has incurred over the level it spent in 2011. On its 2011 FERC Form 1 report, APS reported operating 5,892 miles of transmission lines; on its 2024 FERC Form 1 report, APS reported operating 5,906 miles of transmission lines.[33] Should APS customers have received more for $1 billion in transmission spending increases from 2011 to 2024 than 14 miles of additional transmission line? I think so.

[33] FERC Form 1. Schedule 422, Length in miles [Col. (f) + Col. (g)], line 36 'Total'. APS submissions for 2011 and 2024.

Q. Where did all that investment go if not into new transmission lines?

A. Some was probably appropriately spent on increasing the capacity of existing transmission lines and substations. But as the Brattle Group found nationally, much could have been spent replacing existing equipment, with such replacements offering little in the way of improved reliability or increased capacity. Some spending could have resulted from project cost overruns. An audit or study would be needed for a full, objective assessment of the value APS customers have received for increases in transmission investment since FERC began calculating APS transmission rates through formula ratemaking. But in summary, the extreme growth in APS transmission spending under FERC formula ratemaking illustrates why ratemaking constructs that encourage utilities to self-moderate spending are critical to maintain.

Q. What about the states that have adopted formula ratemaking?

A. Again, I can only speculate as to the rationale employed by regulators in those states to employ formula ratemaking. But I note that many of these state regulatory commissions, including Alabama, Arkansas, Georgia, Mississippi, and Tennessee,[34] all appear near the top of S+P Global's rating of state commissions by the level of "constructive" regulation exhibited[35] (meaning, to my way of thinking, regulation that favors shareholder interest over customer interest). Based on all the above observations, formula ratemaking clearly favors shareholder interest over customer interest. One would hope the Commission would be reluctant to join the ranks of state regulators exhibiting the lowest levels of customer interest by approving APS's FRAM request.

[34] JMC_WP01DR_Attachments JMC-2DR through JMC-12DR (tab 'JMC-10 Alt Rate Plans'); also Staff 2.29_APS25RC01492_Formula Rate Tariffs and Decisions - Combined File.
[35] RRA 101 – Tracking Emergency Issues in Utility Rate Cases. S&P Global Market Intelligence webcast October 30, 2025. Slide 16.

Q. But the FRAM APS proposes is symmetrical, and can result in rate decreases as well as rate increases, can it not?

A, In theory, the annual FRAM adjustment can result in rate decreases as well as a rate increases. However, I would not describe the FRAM adjustment APS proposes as symmetrical. With no incentive to reduce spending, no penalty for failing to control spending, and capital bias to drive capital spending increases, annual rate increases are dramatically more likely than annual rate decreases under formula ratemaking. In fact, if the Commission approves the FRAM APS proposes, I would not expect any annual FRAM adjustments that reduce rates.

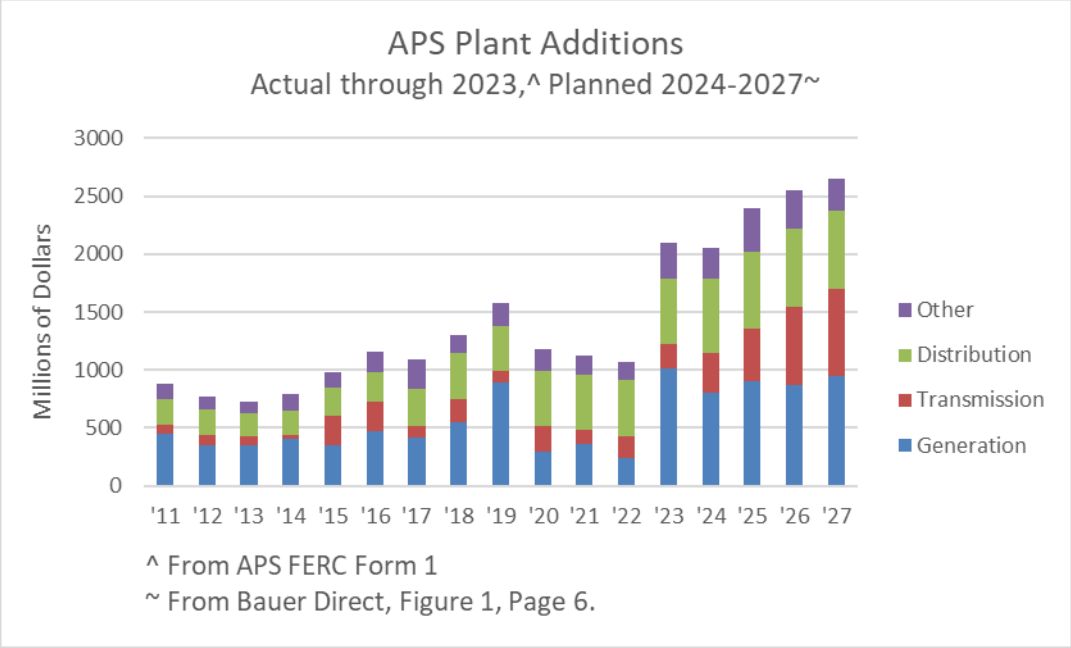
My experience with formula ratemaking in Maryland can serve as a proof point. Through multi-year ratemaking pilots authorized by the Maryland Public Service Commission, utilities were permitted to petition for rate increases annually in the event costs were higher than forecast, as well as rate decreases annually in the event costs were lower than forecast. This annual "reconciliation" of utility costs to utility rates is the same as formula ratemaking in all material respects, with cost increases translating into rate increases upon utility request after a prudence review, just as APS proposes for its FRAM.

Three utilities participated in the ratemaking pilots 2020-2024, making 15 years' experience with annual cost reconciliations. Out of those 15 years, no utility filed any petitions for a rate decrease. But multiple petitions were filed for rate increases, resulting in tens of millions of dollars in rate increases on top of the annual rate increases the Maryland PSC had already authorized in the utilities' multi-year rate cases (using multiple, forecasted future test years). Based on these experiences, and correctly recognizing that annual cost reconciliations eliminated utility incentives to control costs, the Maryland General Assembly passed a bill in its 2025 session

that prohibited the Maryland Public Service Commission from completing annual reconciliations of utility costs to utility rates,[36] essentially prohibiting formula ratemaking in Maryland.

Another proof point is APS's capital spending plans. Note from Figure 3 below that APS forecasts capital spending to increase significantly in 2025, 2026, and 2027. Spending increases of this magnitude are almost certain to result in APS earnings below the deadband, triggering rate increases every year. Indeed, to trigger a rate increase, APS need only ensure it spends enough to underearn the rate of return the Commission authorizes by the amount of the deadband. Such an incentive is in shareholder interest, not customer interest.

Figure 4: APS Plant Additions 2011-2024, Plant Additions Forecast 2025-2027



[36] Maryland General Assembly 2025. House Bill 1035 (SB 937). As Chaptered, Section 4-213, subparts (B)(2) and (C). Page 18. Available at https://legiscan.com/MD/bill/HB1035/2025.

Q. What are your thoughts about the Company's claim that formula ratemaking improves the customer experience by replacing large rate increases with a series of small rate increases?

A. I have two thoughts on that, and neither indicates that the FRAM as proposed is in customer interest. First, while annual rate increases under formula ratemaking may be smaller, they are also sooner. Formula ratemaking advances rate increases, whereas traditional ratemaking defers rate increases. As an APS customer, I would prefer to keep my hard-earned dollars in the bank, earning interest – or, alternatively, paying down high-interest credit card debt – and wait to pay a larger increase in the future, rather than incur smaller, sooner rate increases in the years following a rate case.

Second, rate increase percentages are informational. Public outcry would undoubtedly be greater for a single 20% rate increase than it would be for a series of 4% rate increases over five years. As a commissioner facing re-election, I would much rather preside over a utility's requests for five 4% rate increases than a single request for a 20% rate increase. Thus, while APS positions smaller, sooner rate increases as a customer benefit, I believe smaller, sooner rate increases are in shareholder interest. In addition to reducing regulatory lag, this is because the likelihood that the Company can successfully secure five 4% rate increases is greater than the likelihood that the Company can successfully secure a single rate increase of 20%.

Q. What are your thoughts on the Company's claim that formula ratemaking creates administrative efficiencies by reducing the need for frequent, full scale rate cases?

A. My experiences with ratemaking innovations and annual cost reconciliations in Illinois, Maryland, and Massachusetts – all states with annual reconciliations of utility costs to rates -- tell a different

story, and I believe Staff and intervenors in these states would agree. In my experience, annual reconciliations of costs to rates are characterized by a perfunctory, rubber stamp quality to approving utility costs incurred. This is likely due to the compressed timeframe of annual spending reviews under formula ratemaking, adding to the "presumption of prudence" claim the petitioners in the FERC docket referenced earlier assert. Further, in line with the presumption of prudence claim, my own experience as a consulting to customer advocates is that the burden of prudence does indeed pass from utilities to intervenors under formula ratemaking, just as the petitioners claim in the FERC complaint. Under traditional ratemaking, utilities bear the burden of proving that spending is prudent. But under formula ratemaking, intervenors must prove that spending presented for cost recovery is imprudent.

In essence, annual spending reconciliations become mini rate cases, with at least the same level of effort for discovery and testimony, but in a compressed timeframe. Resources must also be spent validating return on equity deadband violations. In some states, and perhaps one day in Arizona, utility performance must also be compared to targets as part of the new rate determination process. Overall, I have found that alternative ratemaking processes require more Staff and intervenor resources than traditional rate cases, not fewer resources, and I believe a survey of Staff and intervenors in Illinois, Maryland, and Massachusetts would demonstrate agreement.

Q. How do you respond to the Company's claim that formula ratemaking allows customers to share in excess earnings without having to wait for a utility's next rate case?

A. As established earlier, formula ratemaking's annual adjustments remove a utility's incentives to reduce or maintain spending. This, combined with the capital spending increases APS plans as

discussed earlier, make the likelihood that excess Company earnings will be available to share with customers is extremely low. Instead, as I indicated earlier, cost and rate increases will dominate annual FRAM adjustments.

Q. Do you perceive any redeeming qualities of formula ratemaking?

A. Not for customers, no. But for shareholders, yes. In fact, of all the alternative ratemaking methods of which I am familiar, including future test years, multiple future test years, capital trackers, and performance-based/revenue cap ratemaking, formula ratemaking is the most advantageous for shareholders and the least protective of customer interest, for all the reasons presented above.

Q. Are there any additional reasons why the Commission should reject the Company's proposed FRAM?

A. Yes, I can think of at least two reasons, and both are very significant. First, the FRAM the Company proposes essentially guarantees that the Company will earn its authorized rate of return, with variation in the rate of return earned limited to the size of the deadband the Company recommends (just 20 basis points, or between 9.0 and 9.4% for a 9.2% authorized rate of return). If the lower bound of the return on equity deadband is violated, rates will increase by the amount required for the Company to earn the rate of return the Commission authorized. I can think of no ratemaking or regulatory principle indicating that a utility should be guaranteed to earn the rate of return a regulator authorizes. While regulators must determine the rate of return used to calculate rates, this does not mean customers must make up any shortfall come what may.

Earnings volatility results from any number of issues, including weather variation or natural disasters, as well as utility management errors and inadequate spending discipline. Any ratemaking method that puts customers at risk for rate increases in such instances constitutes a shift in risk from shareholders to customers. After all, regulators allow utilities to earn a rate of return in part as compensation for placing capital at risk, and earnings volatility is certainly one of the risks utility shareholders assume in exchange for an opportunity to earn the rate of return the Commission authorizes. In fact, if the Commission approves the Company's FRAM despite my recommendation against doing so, the reduction in earnings volatility arising from formula ratemaking indicates that a lower authorized rate of return is warranted.

Second, the Company's proposed FRAM does not provide for adjustments to the authorized rate of return between rate cases. Under the Company's proposal, the authorized rate of return from the Company's most recent rate case will be used to determine annual rate increases until the Company's next rate case.[37] Under the Company's proposal, the Company will file a rate case after five annual rate adjustments.[38] Assuming a rate adjustment is required every year, a minimum of five years will pass while the authorized rate of return determined in the Company's most recent rate case (the instant case) is utilized to calculate FRAM adjustments. Assuming rate adjustments are required only every other year, ten years (or possibly even more) might pass while the rate of return authorized in the Company's last rate case are utilized to calculate FRAM adjustments.

[37] Attachment JEH-02DR (FRAM Tariff). Page 4.
[38] Direct Testimony of Jessica E. Hobbick dated June 13, 2025. At 17:13.

In the financial markets, ten years, or even five years, is an eternity. If the Company's cost of capital falls between rate cases, for example due to changes in financial markets, customers will still be stuck paying FRAM adjustments calculated using the rate of return the Commission authorized in the Company's most recent rate case, creating a windfall for shareholders. In such a scenario, customers would be covering costs of capital that the Company is not actually incurring. This is a clear violation of ratemaking principles, and in fact, I believe the FRAM violates at least two of Bonbright's well-known Principles of Ratemaking:[39]

1. Effectiveness at yielding total revenue requirements under the fair return standard (FRAM revenue requirements calculated at a rate of return that may be higher than levels experienced by businesses of similar risk is a violation of the fair return standard);
2. Rate stability and predictability, with a minimum of unexpected changes seriously adverse to ratepayers (making customers responsible for covering earnings variation regardless of cause, such as storms, natural disasters, management error, or lack of spending discipline, is a violation of this principle).

Q. But in support for APS's Application, which includes the Company's FRAM proposal, APS Witness and Chief Executive Officer Geisler states "As one of the few remaining single-state, vertically integrated electric utilities in the country, we have the ability to concentrate solely on doing what's right for our customers and the prosperity of Arizona."[40] What is your reaction to this statement?

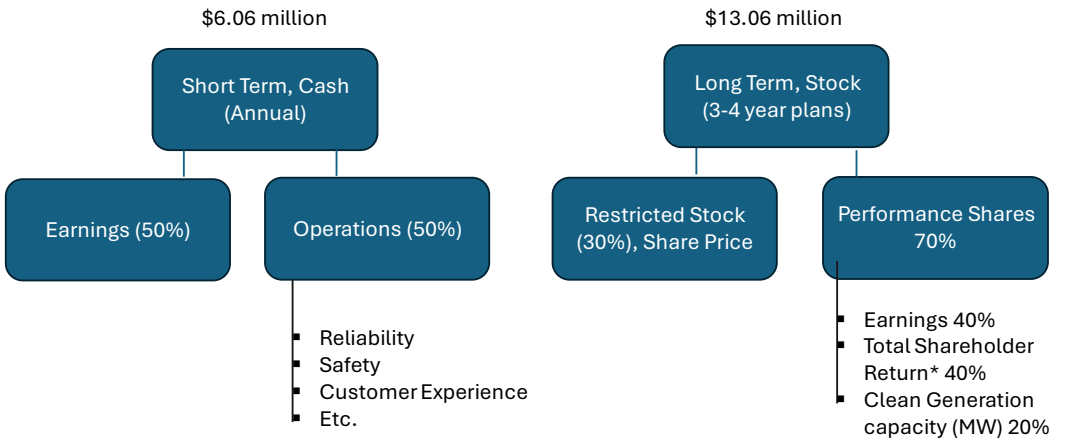
[39] Bonbright J. Principles of Public Utility Rates. Public Utilities Reports, Inc. ISBN 978-0910325233. 1988. Page 383.
[40] Geisler Direct at 29:20.

A. While APS may indeed be one of the few remaining single-state, vertically integrated electric utilities, Mr. Geisler and his executive team are not able to concentrate solely, or even primarily, on doing what is right for customers or the prosperity of Arizona. Instead, the top priority for Mr. Geisler and his team is to advance shareholder interest. They serve in their roles at the pleasure of shareholders. To the extent shareholders perceive Mr. Geisler and his team's failure to adequately advance shareholder interest, shareholders could terminate the executives' employment.

APS executives' incentive compensation is lucrative, and determined primarily by executives' performance on behalf of shareholders, not customers. For example in 2024, Mr. Geisler and five other executives split a total of $6.06 million in short-term incentive awards (cash) and $13.06 million in long-term incentive awards (Pinnacle West Capital Corporation shares).[41] By examining the determinants of incentive awards, and the weights assigned to each,[42] it is a relatively simple matter to calculate APS executive priorities. Using the dollar values, determinants, and weights presented in the figure below, I calculate that in 2024, 16% of APS executive incentives were determined by operational performance of value to customers, while 75% of executive incentives were determined by performance on behalf of shareholders. (The remaining 9% of incentives were determined by clean generation capacity additions, though I note this objective can be secured simply by spending money customers will cover through rates.)

[41] Pinnacle West Capital Corporation. 2025 Proxy Statement (Schedule 14A) filed with the US Securities and Exchange Commission in advance of the annual shareholder meeting held Wednesday, May 21, 2025. Page 86.
[42] Ibid. Page 19.

Pinnacle West Capital Corporation 2024 Executive Compensation Determinants



* Dividends plus Share Price Appreciation relative to peer utilities

I also note that 28% of APS executive long-term incentive awards (40% of the 70% paid in performance shares) are determined by total shareholder return[43] (dividends plus share price appreciation). Very importantly, upon further examination of this particular incentive, I observe that it is calculated *relative to the total shareholder return of peer utilities*. One way to outperform peer utilities on dividends and share price appreciation is to secure a ratemaking method that is superior (from a shareholder perspective) to the methods enjoyed by peer utilities. I bring these observations to the Commission's attention to challenge Mr. Geisler's assertion that APS proposes formula ratemaking out of the Company's interest in customers and Arizona's prosperity.[44] If formula ratemaking were not in shareholder interest, APS would not be proposing it.

[43] Performance Shares awarded, 70% of long-term incentives, multiplied by 40% determined by total shareholder return.
[44] Geisler Direct at 29:20.

Q. Are there any other reasons why the Commission should reject the Company's FRAM proposal?

A. Yes. My review of materials from ACC Case No. AU-00000A-23-0012 indicates that the Commission's adoption of a Formula Ratemaking Policy Statement was rushed, and did not incorporate a rulemaking as required by the Arizona Administrative Procedures Act.[45] I understand the Residential Utility Consumer's Office ("RUCO") appealed the Commission's adoption of the Formula Ratemaking Policy Statement on the basis that no rulemaking was held, and that the Arizona Court of Appeals upheld RUCO's appeal, nullifying the Commission's adoption of the Formula Ratemaking Policy Statement.[46] In such a situation, it seems to me that the Commission should reject the Company's FRAM proposal.

Q. Do you have any other concerns about the Commission's adoption of Formula Ratemaking?

A. Yes. Most significantly, natural gas and water utilities are likely to utilize the precedents established by any Commission approval of formula ratemaking for electric utilities. The need to increase spending by natural gas and water utilities may not be as extensive as that of electric utilities, yet for-profit utilities of all stripes are likely to propose formula ratemaking out of shareholder interest. A consumer or business unlucky enough to be served by for-profit distributors of all three commodities is likely to experience untenable increases in the cost of living or the cost of doing business.

[45] AU-00000A-23-012. Decision 79647 dated December 31, 2024 at 8:21; Also Commissioner Tovar's dissent dated December 24, 2024.
[46] Arizona Court of Appeals No. 1 CA-SA 25-0209. Decision dated November 21, 2025.

Second, while I perceive regulatory lag to be in customer interest, there are ways other than formula ratemaking to reduce regulatory lag. For example, the Commission could establish a policy of completing rate cases within twelve months, and establish procedural schedules consistent with that limit. In my experience, most Commissions complete rate cases in about twelve months. Further, I note that methods other than formula ratemaking are available to reduce regulatory lag. A full rulemaking (consistent with the Arizona Court of Appeals Order) would likely result in a ratemaking method that reduces regulatory lag but more closely balances customer and shareholder interest.

Q. Please summarize your arguments against Commission approval of the Company's FRAM as proposed.

A. The chart below summarizes my arguments against the FRAM as proposed, organized by the Company's justifications for Formula Ratemaking.

APS Justifications	**AARP Challenges**
It reduces regulatory lag, improving APS credit ratings, thereby "allowing APS to obtain lower interest rates and have greater access to low-cost capital."	• APS credit ratings are determined more by inherent risks (wildfire, nuclear generation) than by ratemaking permissiveness, as demonstrated by rating agencies since the Commission adopted its Formula Ratemaking Policy Statement. • APS credit ratings have not improved since the Commission adopted its formula ratemaking policy statement. • APS has been able to secure capital at attractive rates during periods of capital spending growth in the past despite a lack of formula ratemaking. • Given that formula ratemaking eliminates utility incentives to control costs, the impact of regulatory lag on the interest rates APC customers must pay on the Company's debt (estimated at $10.8 million annually) should be compared to the cost to

	customers that will result from the lack of utility spending discipline encouraged by formula ratemaking. • Formula ratemaking amounts to a guarantee that a utility will earn its authorized rate of return. This favors investors. • The rate of return deemed appropriate in the most recent rate case will remain constant until the next rate case, likely 5 to 10 years away, though underlying determinants such as the cost of capital may fall in this timeframe. Paying a utility for a cost (of capital) it does not incur cannot result in equitable rates. • While the Commission adopted the formula ratemaking policy statement out of a concern for growing capital needs in electric distribution, natural gas and water utilities will seize the precedent established to advance their shareholders' interests. • Other means for reducing regulatory lag that are less onerous for customers are available.
Some other jurisdictions use it to set utility rates, including 12 states and the Federal Energy Regulatory Commission ("FERC").	This does not constitute evidence that formula ratemaking is in customer interest, and the practice has been highlighted for examination in an open FERC docket. Further, there is substantial evidence that FERC's use of formula ratemaking for interstate transmission has failed to control spending. For example, APS transmission plant placed into service annually grew at an astonishing 13.4% compound annual growth rate from 2011-2024.
It provides "a better customer experience through smaller, more gradual rate changes."	Formula Ratemaking does indeed spread out rate increases over several years, but advances rate increases rather than deferring them (as with traditional ratemaking). Speeding up rate increases is not in customer interest. Further, a utility is much more likely to secure five 4% rate increases than a single 20% rate increase, which is also in shareholder rather than customer interest.
It can "streamline the regulatory process and create administrative efficiencies by reducing the need for frequent, full scale rate cases."	In the witnesses' experience in three states that have begun to reconcile costs to rates annually in recent years, the consensus among Staff and intervenors is that formula ratemaking increases, rather than decreases, Staff and intervenor resource requirements.
It allows customers to share in excess earnings	Based on the witnesses' experience, the lack of utility spending discipline inherent in formula ratemaking, and based on APS

and "see those cost savings within months through formula rates rather than waiting multiple years for the utility's next rate case."	forecasts of increased capital spending in the next several years, the likelihood of rate increases from the FRAM is dramatically higher than the likelihood of rate decreases.
The Commission has adopted a policy statement indicating it would consider formula ratemaking proposals from Arizona utilities.	The status of the Commission's adoption of the Formula Ratemaking Policy Statement, which did not involve a formal rulemaking, is unclear. The Arizona Court of Appeals has ruled that the Commission is not exempt from the requirements of Arizona's Administrative Procedure Act, and that the Commission failed to comply with the Act's rulemaking provisions when the Commission adopted the Policy Statement.

III. APS REQUESTS COST RECOVERY FOR IMPRUDENT SPENDING

Q. Please provide a preview of this section of testimony.

A. This section of testimony identifies two APS projects and one accounting change that are imprudent, and I recommend the Commission disallow recovery of associated costs from customers. They include 1) APS's purchase of additional equity in Palo Verde Unit 2 ($198.7 million); 2) APS's addition of a redundant makeup water surge pond at the Redhawk Station ($51.6 million); and 3) APS's proposed increase in Palo Verde station depreciation expense ($31.5 million).

APS's purchase of additional equity in Palo Verde Unit 2 ($198.7 million)

Q. Please provide an overview of APS's proposed acquisition of additional equity in Palo Verde Unit 2.

A. Unit 2 is rated at 1,314 MW of capacity. Currently, APS owns 17% of Unit 2 capacity and leases an additional 12.1% of Unit 2 capacity. The leases expire in 2033. At that point, APS can exercise one of three options, including 1) purchase the leased interests at the fair market value of the associated capacity at that time; 2) extend the leases for two additional years; or 3) allow the leases to expire.[47] Of additional interest, in 1986, the Commission authorized APS "to exercise its options to renew the Leases and to repurchase all or any portion of the Unit 2 Facilities in accordance with the terms of the leases."[48]

APS states it will enter into a purchase agreement to purchase an additional 7% of the leased interest in Unit 2, amounting to 92 MW of capacity,[49] at a cost of $198.7 million. APS expects the transaction to close in the fourth quarter of this year, and has therefore proposed a number of post-test year adjustments to reflect the transaction, such as adding $198.7 million to rate base and reducing operating expenses by $11.9 million in annual lease payments that will be avoided by the purchase of the leased interest.[50]

Q. Why do you believe the purchase of additional equity in Palo Verde Unit 2 to be imprudent?

A. Because the transaction will cost customers significantly more than if APS continued to lease the capacity through the end of the lease period (2033).

[47] Direct Testimony of Jacob Tetlow dated June 13, 2025 (hereinafter "Tetlow Direct"). At 30:16 to26.
[48] Docket No. E-1345-86-105. Decision 55120 dated July 24, 1986. At 10:18-20.
[49] Tetlow Direct at 30:16-26.
[50] Direct Testimony of Elizabeth A. Blankenship dated June 13, 2025. At 48:6-10.

Q. Why is APS pursuing the transaction at this time?

A. APS Witness Tetlow testifies that Unit 2 capacity will likely be less costly to purchase now than it will be in 2033, owing to anticipated growth in electric loads. He categorizes the purchase as a hedge against potentially increased cost to purchase the 7% of Unit 2 capacity in 2033. He also claims the purchase price per kW is much lower than current estimates of new nuclear resource costs, and states the purchase of the 7% leased interest is cost-effective for APS customers on this basis.[51]

Q. Do you believe the purchase of Unit 2 capacity to be cost-effective for APS customers?

A. No, for four reasons. First, APS bases its claim that the purchase will cost customers less than continuing to lease on a depreciation schedule of the $198.7 million purchase price through 2065.[52] Currently, Unit 2's license to operate expires in 2046.[53] By rights, the purchase price should be depreciated through 2046, dramatically increasing the cost to customers of the purchase price relative to the cost to customers of continuing to lease. There is certainly no guarantee that the Palo Verde generating station will be awarded a 20-year extension of a license to operate by 2046, which is a full 20 years away. The world will likely look far different in 2046 than it does today.

Second, the Company assumes that the value of baseload resources (and thus the potential purchase price of 7% of Unit 2 capacity upon lease expiration) will be greater in 2033 than it is today. The Company bases this assumption on anticipated load growth from high load factor customers,[54] such as data centers. However, the value of any resource is based not only on demand

[51] Company response to AARP 1.12.
[52] Company's response to AARP 1.14(d).
[53] Ibid.
[54] Company's response to AARP 1.12.

for the resource (in this case capacity and energy), but also on the available supply of the resource. As the cost of solar energy and energy storage continue to fall, it cannot be assumed that supply of capacity and energy from such resources will not increase. As a result, the Company's expectation of growing load cannot, on its own, justify any assumptions about the value of a particular resource eight years from now. Supply and demand, not just demand, will determine the value of capacity in 2033.

Third, APS supports its claim by comparing the cost of its Unit 2 capacity purchase to the cost of new advanced nuclear generation capacity,[55] and to the fixed O&M cost of new advanced nuclear generation capacity.[56] Such a comparison assumes that the only alternative to the 92 MW of capacity offered by the purchase of 7% of Unit 2's capacity is a new advanced nuclear generating station. Such an assumption is not credible, and is inconsistent with modern integrated resource planning concepts that challenge the concept of baseload generation,[57] not to mention the concept of all source solicitations for electric generating capacity.

Table 1 below shows estimated capacity prices and fixed and variable O&M costs for various forms of generation today. These are more appropriate bases for comparisons to the cost of the Company's plan to purchase 7% of Unit 2 capacity. As the reader can observe, three common types of generation are cheaper to build and operate than the Company's proposed purchase of 7% of Unit 2 capacity. Further, prices for PV solar panels and energy storage are falling, and are likely to be even lower when the Company's Unit 2 leases expire in 2033.

[55] Company's response to AARP 1.12,
[56] AARP 1.14_ExcelAPS25RC01763_NetBenefitAnalysis PV2_CONF.
[57] Chang JW et al. *Advancing Past 'Baseload' to a Flexible Grid*. Paper prepared by the Brattle Group for the Natural Resources Defense Council. June 26, 2017. Available at https://www.brattle.com/wp-content/uploads/2022/09/Advancing-Past-Baseload-to-a-Flexible-Grid.pdf

Table 1: Comparison of initial and ongoing costs for various types of generation resources

Generation Type	$/kW, Capacity, 2024 (EIA)[58]	$/kW, Fixed O&M, 2024	$/kWh, Variable O&M. 2024 (EIA)
7% Unit 2 capacity purchase	$2,159[59]	$XX.XX[60]	$0.00254
Advanced New Nuclear	8,467	165.00	0.00254
NG Combined Cycle CT	791	6.97	0.00405
Solar PV with Storage	1,990	39.84	0.00
Wind	1,626	33.55	0.00

Fourth, APS may be able to purchase the capacity from the owners of 7% of Unit 2 capacity upon lease expiration through 2046. The market rate for capacity in 2033 is unknown and, as mentioned above, will be a function of both demand and supply. APS cannot simply assume that the market price for capacity in 2033 will be untenably high. Further, if APS cannot purchase the capacity from the owners of 7% of Unit 2 capacity at a reasonable cost, Table 1 indicates APS could build and operate a natural gas-fired combined cycle combustion turbine at a cost far lower than the cost to purchase and operate 92MW of Unit 2 capacity.

Q. But what about that data center load growth? Isn't that a reason for the Commission to approve the proposed purchase of additional capacity from Palo Verde Unit 2?

A. I think all utilities' data center load growth projections are overstated for several reasons. First, not every data center discussion a utility has with a prospective developer is going to result in new load. If I were a data center developer, I would pursue discussions with four or five utilities, and

[58] Unless otherwise noted, all data from Assumption to the Annual Energy Outlook 2025 (Electricity Market Module). US Energy Information Administration. April, 2025. Available at https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf
[59] Tetlow Direct, page 32. $198.7 million purchase price divided by 92,000 kW.
[60] *See* CONFIDENTIAL AARP Exhibit 2; data from AARP 1.14_ExcelAPS25RC01763_NetBenefitAnalysis PV2_CONF.

perhaps even consider self-generation options. If every utility considers all such discussions in their load growth forecasts as firm commitments, this means collective data center load growth forecasts are probably overstated by a factor of four or five, and the Company's historical experience confirms that only a portion of such discussions result in new loads.[61]

Second, data centers rarely demand as much capacity as they ask utilities to deliver. This can also be observed in the Company's historical experience.[62] In summary, while load growth from data centers can be expected, the amount of load growth relative to the Company's current coincident summer peak appears to me to be within the Company's ability to manage. I do not believe the load growth from data centers the Company will eventually need to accommodate should prompt any extreme measures or capital spending decisions, or for that matter, changes in ratemaking methodology that shift risks from shareholders to customers, as the Company's FRAM proposal would do.

Third, data center load forecasts do not account for technological progress. Quantum computing is likely to increase data processed per unit of energy; semiconductor chip designs are evolving at a rapid pace; and artificial intelligence programs are getting more efficient. The developers of DeepSeek, and artificial intelligence program from China, claim their model uses 10 to 40 times less energy than similar US programs.[63] Though likely exaggerated, there is little doubt that over time, improving technology will reduce data processing's energy needs.

[61] *See* CONFIDENTIAL AARP Exhibit 2 for more information and citations as to the Company's historical experience.
[62] *See* CONFIDENTIAL AARP Exhibit 2 for more information and citations as to the Company's historical experience.
[63] Marshal C. *Game Changer? What DeepSeek AI Means for Electricity*. Energy Wire blog post dated January 9, 2025. Available at https://www.eenews.net/articles/game-changer-what-deepseek-ai-means-for-electricity/#:~:text=DeepSeek%20says%20its%20model%20uses%20roughly%2010,resources%20than%20a%20similar%20one%20from%20Meta.

Finally, for-profit utilities like APS have at least two reasons for exaggerating load growth forecasts. First, growing loads are attractive to potential shareholders, which can increase utility share prices. Second, claims of growing loads help sell regulators on increased generation, transmission, and distribution capital spending, which increases utility profits and share prices (all else held equal).

Q. Have you completed your own analysis comparing current leasing costs to the cost to customers of purchasing a 7% interest in the Unit 2 capacity that is currently being leased?

A. Yes. Using the model the Company's witness herself developed to estimate revenue requirements on the purchase,[64] and assuming a useful life of Unit 2 through 2046 rather than 2065, I estimate that a corrected customer revenue requirement for the proposed Unit 2 7% capacity purchase will be $204 million 2026 through 2033. In contrast, the avoided lease payments over this time frame amount to $95.2 million ($11.9 million per year).[65] Indeed, even the Company's own revenue requirement estimates 2026-2033 of the Unit 2 purchase using a 2065 retirement date are dramatically higher than the lease payments over these years.[66]

So the question before the Commission is, are higher rates now associated with the capacity purchase worth an uncertain benefit eight years from now? As a customer, I'd prefer lower rates now over higher rates now with an uncertain likelihood of lower costs in eight years.

Given that APS will have many options available to replace the 92MW of Unit 2 capacity by 2033 that are likely to be of equivalent cost or lower, and given that the purchase of Unit 2

[64] AARP 3.02_ExcelAPS25RC01859_PV2_RepurchaseRR_HIGHLY CONF
[65] Blankenship Direct at 48:6.
[66] *See* CONFIDENTIAL AARP Exhibit 2 for the Company's estimate of revenue requirements 2026-2033.

capacity will cost customers more than double the lease payments 2026-2033 ($204 million vs. $95 million), the Company's proposed purchase of 92MW of Unit 2 capacity at a cost of $198.7 million is not prudent. I recommend the Commission reject all post-test year adjustments associated with this transaction.

Q. But as you noted earlier, the Commission authorized APS to repurchase the leased amounts of Unit 2 capacity when it first authorized the sale/leaseback transaction in 1986. Is it appropriate for the Commission to reconsider that decision today?

A. Yes, I believe it is. Many things have changed since the Commission's 1986 order. Arizona's population has more than doubled since 1986, from 3.3 million to 7.6 million today. Electric generation capacity has tripled, from an estimated 8-10 GW in 1986 to almost 30 GW today.[67] Adjusting for inflation, natural gas is cheaper today than it was in 1986.[68] Wind and solar generated almost no power in 1986; today, they generate 15% of Arizona's electricity.[69] Given these considerable changes, it would be inappropriate for the Commission to fail to evaluate a current Company proposal because of a decision the Commission made 40 years ago.

Further, in 1986 the Commission did not know what conditions might exist in 2026. It did not know the repurchase price, the available alternatives to such repurchase, or energy and capacity market conditions in 2026. Indeed, the Commission could not have imagined the Energy Policy Act passed by the US Congress in 1992, or the Southwest Power Pool's evolution into a regional

[67] Wikipedia. *List of Power Stations in Arizona*. Available at https://en.wikipedia.org/wiki/List_of_power_stations_in_Arizona#:~:text=In%202023%2C%20Arizona%20had%20a%20net%20summer,4.6%25%20hydroelectric%2C%202.2%25%20wind%2C%20and%200.2%25%20biomass.
[68] Natural Gas Citygate Price in Arizona (1.73% CAGR 1986-2023). Available from the US Energy Information Administration at https://www.eia.gov/dnav/ng/hist/n3050az3a.htm
[69] US Energy Information Administration. Available at https://www.eia.gov/state/?sid=AZ

transmission organization, and further into an independent system operator, and further into the Integrated Marketplace in which APS participates today.

In fulfilling the Commission's mission to ensure safe, reliable, and affordable utility services, I believe the Commission has a responsibility to balance customer and shareholder interest when reviewing any regulated utility proposal. Notwithstanding the Commission's 1986 Order, I further believe the Commission's failure to critically evaluate the Company's repurchase proposal would represent an abdication of this responsibility. I strongly encourage the Commission to consider whether the proposed purchase of 92 MW of Unit 2 capacity at a cost of $198.7 million appropriately balances customer and shareholder interest despite the 1986 Order. Based on this testimony, I believe the Commission will conclude that the Company's proposed purchase is not in customer interest, and therefore imprudent.

APS's addition of a redundant makeup water surge pond at the Redhawk Station ($51.6 million)

Q. Please explain the Company's addition of a makeup water surge pond at the Redhawk Station.

A. The Redhawk Station is a Combined Cycle Gas Turbine (CCGT) generation plant with a capacity of 1,100 MW from multiple generating units. Makeup water surge ponds (MWSP) store water for plant cooling, fire protection, and other plant water system needs.[70] The Redhawk Station already had an MWSP capable of meeting Redhawk Station needs, but the liner of the MWSP required a

[70] Tetlow Direct at 28:6.

six-month maintenance project.[71] To avoid shutting down the Redhawk Station for six months, the Company built a second MWSP at a cost of $51.6 million.

Q. What are your concerns with the Company's decision to install a redundant MWSP?

A. The Company's winter peak demand is typically less than half its summer peak demand. For example, in 2023 the winter peak demand was 4,096 MW while the summer peak demand was 8,159 MW.[72] This means that APS could have easily completed the six-month liner maintenance project from October to March, or from November to April, when the Station's 1,100 MW of generation capacity was not needed to meet APS customer demands. Through such scheduling, no redundant MWSP would have been necessary.

Further, the entire southwestern US region has plenty of spare capacity in the winter months. The North American Electric Reliability Corporation ("NERC") projected that the reserve margin for the Western Electric Coordinating Council's Southwest Region offered a prospective 90% reserve margin (generating capacity in excess of expected load) for the 2024-2025 winter. This amounts to 15.2 GW excess generation capacity under normal conditions, and is well in excess of the 20% reserve margin NERC recommends. Even under the most extreme conditions, NERC estimated 9.4 GW excess generation capacity for the 2024-2025 winter.[73] If the Company was concerned that the capacity provided by the Redhawk Station would not be available for its customers for six months that were not in peak season, it could have easily secured capacity resources or energy from other generators expected to be idle during those months via power

[71] Company response to AARP 1.10 (c).
[72] US Energy Information Administration Form 861 submitted by Arizona Public Service Company for 2023.
[73] 2024-2025 Winter Reliability Assessment. North American Reliability Council. November, 2024. Page 34.

purchase agreements at a cost that would likely have been much lower than $51.6 million. Further, the Company did not even analyze the cost of this alternative to the cost of building a second MWSP.[74] Finally, I note the project will end up costing much more than originally estimated when the project was approved by Company management.[75]

Q. Have you completed a comparison of the cost to contract generation capacity to the cost of constructing a redundant MWSP?

A. Yes. In the Southwest Power Pool in which APS participates, Resource Adequacy prices have hovered around $2,000 to $3,000 per MW-month.[76] So even if APS did need to secure a replacement for Redhawk station capacity, it could do so at a much lower cost than the $51.6 million cost to construct a redundant MWSP. Worst case, I estimate a cost of $13.2 to $19.8 million.[77] I further note that of all APS's generating resources, only one (Sundance) has a redundant MWSP.[78] If APS were to adopt a policy that all generating resources should maintain a redundant MWSP, the cost of such a decision would likely be in the billions of dollars. I encourage the Commission to discourage such profligate capital project spending decisions.

Q. What is your recommendation regarding the Company's request to recover the cost of the second MWSP at the Redhawk Station?

[74] Response to AARP 2.3(q).
[75] *See* CONFIDENTIAL AARP Exhibit 2 for more information on the size of the cost overrun.
[76] Available at https://modoenergy.com/research/en/spp-resource-adequacy-guide-capacity-market-explainer-battery-energy-storage
[77] $2,000-$3,000 per MW-month x 6 months x 1,100 MW.
[78] Company response to AARP 2.2 (j).

A. The Company is proposing a post-test year adjustment of $51.6 million for the Redhawk Station's second MWSP consistent with the second MWSP's in service date of second quarter, 2025.[79] I recommend the Commission disallow the entire $51.6 million cost of the redundant MWSP as imprudent, because the redundant MWSP was not required for safe and reliable service, and because APS did evaluate the cost of reasonable alternatives to the construction project.

APS's proposed increase in Palo Verde station depreciation expense ($31.5 million)

Q. Please explain your concern regarding the Company's proposal to increase Nuclear Plant depreciation.

A. In its Application APS proposes a $31.5 million (290%) increase in Nuclear Plant depreciation, from $10.9 million annually to $42.4 million annually.[80] In discovery, I presented the Company with an opportunity to support this proposed increase with workpapers. The Company provided no support for the increase in its response, other than to say that "Changes in depreciation expense are impacted by many factors" and "the most notable impact is the change in the amortization period applied to Palo Verde excess reserves."[81] No additional explanation or workpapers were provided.

Q. Do you consider this an adequate response to a $31.5 million/290% increase in the depreciation expense of the Company's nuclear assets?

[79] Tetlow Direct, JT-05DR, page 3, line 60.
[80] Direct Testimony of Ronald E. White PhD dated June 13, 2025. At 10:17.
[81] Company response to AARP 2.5 (bb).

A. No, I do not believe the Company has come remotely close to supporting such a large increase in nuclear asset depreciation expense.

Q. What is your recommendation to the Commission regarding the Company's request to increase nuclear asset depreciation expense by $31.5 million annually?

A. I recommend the Commission reject this requested expense increase in its entirety due to a lack of support for the increase provided by the Company.

IV. PRIMARY RECOMMENDATIONS

Q. Please summarize your primary recommendations to the Commission.

A. My primary recommendation is for the Commission to reject the Company's FRAM proposal. My testimony is that 1) Formula ratemaking favors shareholder interest over customer interest by a wide margin, for all the reasons described in this testimony; and 2) the Commission's adoption of a Policy Statement that authorized utilities like APS to propose formula ratemaking is of uncertain status due to legal review. Instead, I recommend the Commission approve a rate increase for APS only to the extent the Commission deems warranted after its review of evidence presented by the Company and the parties.

Other primary recommendations include 1) removing the Company's additional equity purchase in Palo Verde Unit 2 ($198.7 million) from the rate base used to calculate rates, as it is not in customer interest, and therefore imprudent; 2) removing the cost of the Company's redundant water pond at the Redhawk Station ($51.6 million) from the rate base used to

calculate rates, as the redundant water pond is not required for safe and reliable service, and is imprudent; and 3) disallow $31.5 million in increased Palo Verde depreciation expense as unsupported.

V. BACK-UP RECOMMENDATIONS

Q. Please summarize your back-up recommendations.

A. In the event the Commission adopts APS's FRAM proposal despite my primary recommendation to reject it, I provide two sets of back-up recommendations for Commission consideration. One set of back-up recommendations is designed to help reduce the detrimental impacts to customers of the Company's FRAM proposal. These back-up recommendations do not rectify the most egregious deficiencies in formula ratemaking, and I ask the Commission to avoid assuming that they do. Indeed, no amount of adjustments to formula ratemaking change the fact that it favors shareholder interest over customer interest by a wide margin. Notwithstanding this caveat, recommendations to improve formula ratemaking include: 1) Expanding the size of the Return on Equity deadband from 20 basis points on either side of the rate authorized to 248 basis points; 2) re-examining the authorized Return on Equity as part of each FRAM adjustment; 3) reducing the authorized Return on Equity below the amount the Commission might otherwise find appropriate to reflect the reduction in earnings volatility offered by formula ratemaking adjustments; and 4) making adjustments to the FRAM process that the Company recommends be completed when rate of return deadbands are exceeded.

The second set of recommendations in this section of testimony rejects timing and accounting adjustments APS proposes that are no longer appropriate if the Commission approves the Company's FRAM proposal. Instead, timing and accounting adjustments will be addressed by the FRAM adjustment. If the Commission approves the Company's FRAM proposal, I recommend the Commission deny the timing and accounting adjustments APS proposes, including 1) Post test year cost adjustments recommended by Mr. Tetlow ($1.1 billion gross rate base impact, $306 million net); 2) Normalizing, Annualizing, Out-of-period/Miscellaneous, and Revenue accounting adjustments recommended by Ms. Blankenship, Ms. Hobbick, and Mr. Moe ($222.3 million).

Finally, this section of testimony will indicate that the cost disallowances described in my primary recommendations stand regardless of the Commission's decision on the Company's FRAM proposal.

Recommendations to Improve (But Not Fix) Formula Ratemaking for Customers.

Q. Please explain the concept of a deadband.

A. The idea behind the FRAM adjustments the Company proposes is that customers will incur rate increases when APS rates of return are below the amount the Commission authorizes, and that customers will earn refunds when APS rates of return are above the amount the Commission authorizes. The size of the deadband identifies how significant the variances from the authorized rate of return must be before customers are charged or refunded. The larger the deadband, the greater shareholder responsibility for rate of return variation; the smaller the deadband, the greater the customer responsibility for rate of return variation.

As indicated earlier, I do not believe it is likely APS will over-earn the rate of return the Commission authorizes. Nor do I believe customers should be charged for rate of return deficiencies, as customers have almost zero control over the Company's earnings. These are the foundations for my opposition to formula ratemaking. However, if the Commission approves the Company's FRAM proposal despite my concerns, the size of the deadband becomes a critical factor in the frequency and size of FRAM-related rate increases customers will be asked to pay. As a result, the size of the rate of return deadband deserves very careful consideration.

Q. If the Commission approves the Company's FRAM proposal in general, what do you believe are the primary considerations in establishing an appropriately-sized deadband?

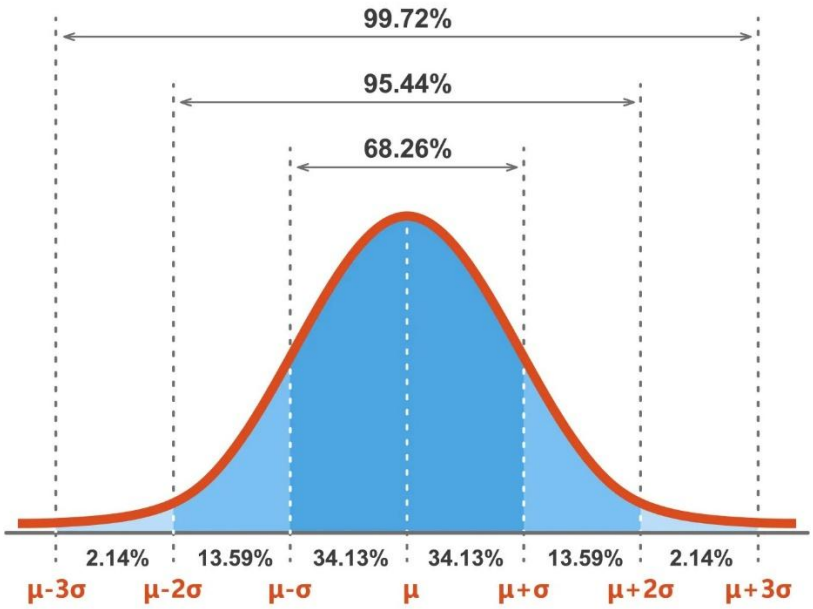
A. My experience with the use of deadbands in utility performance measurement and incentive/penalty calculations is relevant to the use of deadbands in rate of return on equity rate increase/rate decrease determination. In utility performance measurement, deadbands are employed to avoid awarding a utility (or in this instance, a utility's customers) for routine upside performance outside a utility's control, and likewise, to avoid penalizing a utility (or in this instance, a utility's customers) for routine downside performance variation outside a utility's control. In my estimation, if the Commission approves formula ratemaking despite the reasons I've offered to reject it, deadbands should be employed in exactly this manner for determining whether a customer rate increase or decrease is warranted as APS's rate of return on equity varies.

In return on equity variation, an example of a downside variation outside a utility's control would be more severe than expected storms and storm damage repair costs. An unexpected increase in storm damage repair costs would likely reduce a utility's rate of return. An example of an upside variation outside a utility's control would be weather that is more extreme (hotter or colder) than expected in the forecasts used to calculate utility rates. More extreme weather than expected would increase sales volume beyond the amounts forecasted and, more likely than not (all else held equal), increase a utility's rate of return on equity.

Standard deviation is a measure of the variation in a set of data points. In this instance, the set of data points would be APS's historical rate of return on equity. Assuming a standard normal distribution (the familiar 'bell-shaped curve' of data points),[82] a single standard deviation encompasses about two-thirds (68%) of the variation exhibited by a data set. Two standard deviations encompass about 95% of the variation exhibited by a data set, and three standard deviations encompass about 99.7% of the variation exhibited by a data set. This is known as the Empirical Rule for datasets exhibiting a standard normal distribution, and is shown in Figure 5 below.[83]

[82] In a standard normal distribution, the likelihood that a data point (a "result") will be above the average is equal to the likelihood that a data point will be below the average. If the Company's claim that its FRAM is symmetrical is accurate, then such symmetry assumes the Company's rate of return on equity will be represented by a standard normal distribution.
[83] Available at https://www.simplypsychology.org/normal-distribution.html

Figure 5: Diagram of variation covered by 1, 2, and 3 standard deviations from the mean (average) in a data set characterized by a standard normal distribution.



Q. How can the standard deviation of APS's historical rate of return on equity be used to establish an appropriate deadband?

A. I recommend the size of the deadband be determined by calculating the standard deviation in APS's rate of return on equity historically. Then, through careful consideration of the balance of responsibility in rate of return variation it is appropriate for customers versus shareholders to cover, an appropriate number of standard deviations to be represented by the deadband should be selected. As the number of standard deviations represented by the deadband increases, the greater the shareholder responsibility for covering rate of return variation; as the number of standard deviations represented by the deadband decreases, the greater the customer responsibility for covering rate of return variation.

Q. How did the Company determine the number of standard deviations to include in its rate of return on equity deadband?

A. It is unclear whether the Company gave any consideration at all to the concept of standard deviation in its recommended 20 basis-point deadband.[84] The deadband the Company selected is consistent with the amount specified in the Formula Rate Policy Statement the Commission adopted. However, the policy statement provides no basis for the 20 basis-point deadband. Upon examining historical variation in APS's rate of return on equity, it is clear the 20 basis-point deadline is far too small, and assigns far too much responsibility for covering variation in APS's rate of return on equity to customers, and far too little responsibility for covering variation in APS's rate of return on equity to shareholders.

Q. How has the split of responsibility for covering variation in APS's rate of return on equity been split between customers and shareholders historically?

A. Historically, shareholders have shouldered responsibility for 100% of the variation in APS's rate of return on equity, and Customers have shouldered 0%. In my estimation, this is exactly as it should be, as Company managers have far greater control over APS's return on equity than customers, who have little if any control over APS's return on equity. Further, the Commission authorizes the Company to include a rate of return on equity in rates in part to compensate for variation on shareholders' return on equity. This is one more illustration of why I recommend the Commission reject the Company's request for a FRAM.

[84] Company response to AARP 4.1 and the referred Company response to AZLCG 5.1.

Q. Have you calculated the historical variation in APS's rate of return on equity?

A. Yes. I have calculated the standard deviation of APS earnings from 2014 to 2025 (with 2025 represented by the Company's ROE estimate).[85] The mean (average) ROE over that time was 8.66%, and a single standard deviation around that mean is 1.24%, or 124 basis points.

Q. Given that a single standard deviation in the Company's earnings has been 124 basis points historically, what does that mean for the size of the deadband you recommend?

A. Given that shareholders have historically covered 100% of the variation in APS's rate of return, and given that customers have little if any control over APS's rate of return, I think an increase in customer responsibility of no more than 5% of the variation in APS's rate of return is appropriate. As two standard deviations cover 95% percent of the variation in APS's rate of return historically, I recommend two standard deviations, or 248 basis points, as the most appropriate deadband above and below the rate of return the Commission authorizes. If the Commission were to establish a 248-basis point deadband, and assuming the Commission authorizes a 9.5% rate of return on equity, customers would experience rate increases once the Company's rate of return falls below 7.02%, and customers would receive rate reductions once the Company's rate of return exceeded 11.98%.

[85] Company response to Staff 2.25 (a).

Q. Had a 248 basis-point deadband and FRAM been in place over the last 12 years, and had the Commission authorized a 9.5% return on equity over the last 12 years, how often would customers have experienced rate increases, and how often would customers have experienced rate decreases?

A. In the last twelve years, APS's rate of return has been less than 7.02% three times, in 2025 (Company estimate, 6.3%); in 2023 (6.7%); and in 2022 (6.8%).[86] In these years, customers would have experienced rate increases had a FRAM been in place. In no instance in the past twelve years has APS's rate of return exceeded 11.9%, meaning that customers would have never received a rate decrease. (The highest rate of return earned in the last 12 years, 9.7%, was earned twice, once in 2014 and once in 2016.)[87] Based on historical experience and the historical split of customer (0%) and shareholder (100%) responsibilities for covering rate of return variation, I believe 248 basis points above and below the rate of return the Commission authorizes constitutes an appropriate upper and lower bound for the return on equity deadband.

Q. Please explain your recommendation that if the Commission approves the Company's FRAM generally, the authorized Return on Equity should be re-examined as part of each FRAM adjustment.

A. As the Commission is aware, utility costs serve as the basis of utility rates under cost-of-service ratemaking. As mentioned earlier, it is certainly possible that the Company's cost of equity could fall once the Commission determines an appropriate rate of return in this rate case.

[86] Ibid.
[87] Ibid.

(Indeed, given that inflation and interest rates are currently high relative to the average levels over the past two decades, it is likely that the Company's cost of equity will fall in the future.) If the Company's cost of equity falls in the future, and if FRAM adjustments are determined based on the rate of return authorized in this rate case, the rates calculated under the FRAM would reflect costs of equity that the Company is no longer incurring. This is a gross violation of cost-of-service ratemaking principles. Re-examining the appropriate cost of equity to authorize at each FRAM adjustment would address this gross violation.

Q. Please explain your recommendation that if the Commission approves the Company's FRAM proposal, the Commission should set the authorized Return on Equity below the amount the Commission might otherwise find appropriate.

A The reason for this recommendation is simple. Formula ratemaking reduces if not eliminates variation from the rate of return on equity the Commission authorizes. Variation in actual earnings from the rate of return on equity authorized is one of the justifications for authorizing a rate of return on equity in the first place. If the Commission removes (or dramatically reduces) variation in the rate of return earned through formula ratemaking mechanisms such as the FRAM, a reduced rate of return that reflects reduced or eliminated earnings volatility is undoubtedly appropriate.

Q. In the event the Commission approves the Company's FRAM proposal generally despite your recommendation to reject it, what reduction in the authorized rate of return from the amount the Commission otherwise deems appropriate would you recommend?

A. This is a question better directed to cost of capital experts. My recommendation is that to the extent formula ratemaking reduces or eliminates earnings volatility, associated reductions in the rate of return that the Commission would otherwise authorize are necessary and appropriate.

Q. Please explain your recommendation that if the Commission approves the Company's FRAM proposal generally, adjustments to the FRAM process as proposed by the Company are required.

A. If the Commission approves the Company's FRAM proposal generally despite my recommendation to reject it, I recommend several adjustments to the FRAM process the Company proposes to complete when rate of return deadbands are exceeded. These include 1) Providing at least 90 days for intervenors to review spending prudence and all FRAM calculations and adjustments; and 2) Establishing a minimum 180-day litigation schedule as part of each FRAM process.

Q. Please explain your recommendation to provide more time for intervenors to review spending prudence.

A. As noted earlier, I agree with the allegations of multiple FERC complainants that formula ratemaking shifts prudence responsibilities, from utilities having to demonstrate prudence to

intervenors having to demonstrate imprudence. In the annual FRAM adjustment determination process recommended by the Company, intervenors will have just twelve calendar days to review APS spending for prudence.[88] In those twelve calendar days, intervenors will need to review the prudence of O&M spending in the historical test year, as well as plant placed into service since the Company's most recent rate case or FRAM process, as well as any adjustments to these the Company may propose.

I note that in the current rate case, the Company's historical test year O&M spending (not including recommended adjustments) amounted to over $3.7 billion.[89] I also note that in a single year (using 2023 as an example), it is not uncommon for the Company to place over $2 billion in electric plant into service.[90] This means that every FRAM process will require intervenors to evaluate many billions of dollars in O&M and capital spending for prudence. There is simply no way for intervenors to complete such reviews in just 12 calendar days, not to mention reviews of myriad other FRAM calculations, from rate of return deadband exceedance to Company-proposed adjustments. I further note that in the current rate case, the Commission provided intervenors with 8.5 months to complete such reviews (from the date of the Company's filing on June 13, 2025 to the date intervenor testimony was due on March 2, 2026).[91]

[88] Hobbick Direct, Figure 5, page 14.
[89] Attachment JRM-02DR, page 1
[90] Arizona Public Service FERC Form 1, Q4 2023. Page 207, line 104. $2.1 billion in Total Electric Plant additions.
[91] Procedural Order dated July 22, 2025. Pages 1-2.

Q. APS Witness Ms. Hobbick claims intervenors will have two months to challenge the Company's proposed FRAM adjustments.[92] Why do you claim just twelve days?

A. While the Company's proposal provides for a two-month challenge process from start to finish, the Company's proposal also limits formal FRAM adjustment challenges to those identified during the informal challenge process.[93] Under the Company's proposal, informal challenges must be submitted within twelve calendar days of a Company FRAM filing.[94] In effect, this means any imprudent spending or irregular adjustment an intervenor does not identify within twelve days of a Company FRAM filing cannot be challenged. Given billions of dollars in O&M and capital spending to review for prudence, the number and complexity of adjustments the Company is likely to propose (using the instant application as an example), and a typical need for intervenors to complete multiple rounds of data requests to get to the bottom of contentious issues as identified, twelve days is a ludicrously insufficient amount of time for FRAM adjustment issue identification.

Q. What FRAM adjustment process schedule would you recommend?

A. I recommend that intervenors get at least 90 days from the date of a FRAM filing to complete discovery and prepare written testimony, with no more than five days permitted for the Company to respond to data requests. The Company would then have 30 days to complete its discovery and prepare rebuttal testimony. Witnesses could then appear in hearings for cross-examination, with such hearings to be completed within 30 days of Company rebuttal. Written

[92] Hobbick Direct at 13:24.
[93] Attachment JEH-02DR, page 6.
[94] Ibid, page 8.

briefs would be due within 15 days of the conclusion of hearings, and the Commission's decision could be due within 15 days of briefs. With such a schedule, a Commission decision and rate effective date within 180 days of a FRAM filing would be possible while permitting due process.

Recommendations to reject timing and accounting adjustments if the FRAM is approved.

Q. What types of timing and accounting adjustments does the Company propose?

A. Several state utility regulators, including this Commission, consider timing and accounting adjustments reflecting cost or revenue changes which a utility knows (or can reasonably expect) will be needed to more accurately reflect the cost of providing service. In my experience, state utility regulators agree to consider such adjustments only to the extent that they are known and measurable. The Company is proposing multiple timing and accounting adjustments be made to determine revenue requirements and rates that more accurately reflect the Company's cost of providing service.

Q. What is the rationale for considering timing and accounting adjustments as part of rate determination?

A. As the Commission is aware, one justification utilities offer for timing and accounting adjustments is to eliminate the regulatory lag associated with measurable changes to costs or revenues that a utility expects to incur (or does incur) after the test year. Without adjustments, these known and measurable changes would not be considered until a utility's next rate case, thus incurring regulatory lag.

Q. Does APS propose timing and accounting adjustments in its Application?

A. Yes, the Company does propose timing and accounting adjustments as part of rate determination. However, if the Commission approves the Company's FRAM proposal, there is no longer a need for these timing-related adjustments. Instead, the annual FRAM process is designed to address the varying and various factors that create the need for timing and accounting adjustments.

Q. What timing and accounting adjustments do you recommend the Commission reject in favor of future consideration in the FRAM process if the Commission approves it?

A. Timing and accounting adjustments I recommend the Commission reject due to FRAM process redundance include 1) Post test year plant addition adjustments ($1.1 billion gross, $306 million net) recommended by Mr. Tetlow; 2) and Normalizing, Annualizing, Out-of-period/Miscellaneous adjustments, and revenue adjustments recommended by Ms. Blankenship, Ms. Hobbick, and Mr. Moe ($222.3 million).

Q. To begin, please explain the concept of post-test year plant addition adjustments.

A. Under cost-of-service ratemaking as traditionally practiced in Arizona, the Commission has permitted adjustments to the rate base for known and measurable plant additions that are placed (or expected to be placed) into service within twelve months of a test year. Presumably, the idea behind this precedent is to reduce regulatory lag. Without such adjustments, utilities like APS would need to wait until the next rate case to recover the cost of plant placed into service post-test year.

Q. Does the need for post-test year plant addition adjustments change if the Commission authorizes formula ratemaking for APS?

A. In my estimation, yes. Formula ratemaking allows utilities to secure rate increases if an annual review indicates the Company is under-earning the rate of return authorized by the Commission by more than the dead band. As described earlier, one reason why the Company would under-earn its rate of return is growth in capital spending, including capital spending on post-test year plant additions. Thus, formula ratemaking already incorporates a means for accommodating post-test year plant additions. To my way of thinking, the need to adjust the Company's rate base, and associated revenue requirements, by the amount of post-test year plant additions is eliminated by the annual rate-of-return review and rate adjustment process that is part of the Company's FRAM proposal.

Q. What does the Company think of your recommendation to eliminate post-test year plant addition adjustments because Formula Ratemaking already provides a mechanism to address them?

A. The Company's perspective is that waiting for the Formula Ratemaking process to adjust for post-test year plant additions requires too much time, increasing regulatory lag for such additions.[95] For example, if the Commission approves the Company's proposed post-test year plant additions in this case, those costs will be reflected in rates effective July 8, 2026. If the Commission rejects the Company's proposed post-test year plant additions, those costs will not be considered for recovery from customers until the first FRAM process, approximately

[95] Company's response to AARP 1.1.

one year later. Thus, the Company is concerned about an incremental one year of regulatory lag if the Commission rejects the post-test year plant addition adjustment the Company proposes in this case.

Q. What is your response to the Company's perspective?

A. As indicated earlier, regulatory lag provides a valuable function in customers' interest, and is designed to balance shareholder interest and utilities' associated capital bias. As such, regulatory lag encourages utilities to moderate capital spending, and to be as efficient as possible with the capital it spends. Given this observation, regulatory lag is something that state utility regulators may wish to reduce, but eliminating regulatory lag entirely is not in customers' interest. Some amount of regulatory lag is appropriate to retain, even in the event the Commission approves the use of formula ratemaking for Arizona utilities. As a result, if the Commission approves formula ratemaking for APS, I recommend the Commission reject the Company's request to adjust rate base by $1.1 billion in post-test year plant additions.

Q. Is that your formal recommendation?

A. It is, but if the Commission agrees with this recommendation, adjustments to the amount used to calculate rates must be made. For example, the net impact on rate base of an adjustment to reflect the $1.1 billion in post-test year plant additions that the Company recommends is $306.7 million.[96] (The difference is the result of depreciation accumulated and tax impacts during the

[96] Tetlow Direct, from 22:20 to 23:2.

post-test year period,[97] which the Company appears to have appropriately imputed to estimate the net impact to rate base of $1.1 billion in post-test year plant additions.) Thus, if the Commission agrees with this recommendation, it should employ the net amount of $306.7 million to reject this adjustment, not the $1.1 billion gross amount.

Further, the project cost disallowances I recommended earlier, including $198.7 million in APS's purchase of additional equity in Palo Verde Unit 2 and $51.6 million in APS's addition of a redundant makeup water surge pond at the Redhawk Station, are both coincidentally part of the $1.1 billion in post-test year plant addition adjustments the Company recommends. Thus, if the Commission disallows these costs, part of the adjustments associated with $1.1 billion in gross test year plant addition adjustments will already have been made. If the Commission disallows these costs as I recommend, the gross amount of post-test year plant addition adjustment remaining to reject is $849.7 million ($1.1 billion less $198.7 million for Palo Verde Unit 2 and $51.6 million for the redundant Redhawk makeup water surge pond). Similarly, the net amount of post-test year plant addition adjustments remaining to reject is something less than $306.7 million. I trust that Staff or the Company can determine the exact amount of plant to reduce, and the associated reduction in the revenue requirement the Company is requesting, based on the Commission's Order on my recommendations in this proceeding.

[97] Ibid.

Q. Turning to accounting adjustments, please explain why you recommend the Commission reject the test year accounting adjustments the Company proposes in the event the Commission approves the Company's FRAM proposal.

A. In this proceeding Ms. Blankenship, Ms. Hobbick, and Mr. Moe propose 62 accounting adjustments that impact revenue requirements calculated on test year costs. While adjustments that both increase and decrease the revenue requirement are proposed, in total the proposed adjustments will increase the revenue requirement by $222.3 million.[98] In my experience, utilities claim that accounting adjustments are necessary to more accurately reflect the cost of providing service, generally to reflect costs that are known and measurable but not reflected in test year books and records.

In my estimation, formula ratemaking eliminates the need for accounting adjustments. The annual FRAM process the Company recommends will compare the Company's earned rate of return to the rate of return authorized by the Commission. When the Company's earned rate of return is less than the deadband from the Commission-authorized amount – for whatever reason – rates will be increased to the level required for the Company to earn its authorized rate of return. Thus, to the extent the reasons for the proposed accounting adjustments persist or apply when the FRAM process is completed annually, as reflected in the Company's books and records used to complete the FRAM process annually, such adjustments will be addressed as a matter of course in the FRAM process the Company proposes to complete annually.

[98] SFR Schedule C-2, page 21, final column "Total Income Statement Adjustments" (ACC jurisdiction).

Q. Please provide some examples of these accounting adjustments, and explain why the FRAM process makes such adjustments unnecessary.

A. As one example, Mr. Moe proposes a fuel cost adjustment of $165.5 million.[99] To the extent that higher fuel costs will be reflected in the Company's books and records when the first FRAM is completed, these costs will reduce the Company's rate of return, and rates will increase as part of the FRAM process to compensate. As another example, Ms. Hobbick proposes a $63.9 million adjustment to normalize revenues for weather.[100] To the extent weather variation reduces the Company's rate of return when the first FRAM is completed, rates will be increased to compensate. As another example, Ms. Blankenship proposes a $27.0 million adjustment to reflect higher employee benefit costs than reflected in test year books.[101] To the extent higher employee benefits costs reduce the Company's rate of return when the first FRAM is completed, rates will be increased to compensate. In summary, because the FRAM process will ensure the Company earns its authorized rate of return come what may, accounting adjustments intended to reflect "come what may" become redundant.

Q. Is your formal recommendation that the Commission reject the Company's proposed accounting adjustments, reducing the revenue requirement by $222.3 million?

A. Not exactly. One of the adjustments Ms. Blankenship proposes is to increase depreciation expense by $51.7 million.[102] Earlier, I recommended that the Commission disallow a $31.5 million in increased depreciation expense on the Palo Verde station the Company did not

[99] SFR Schedule C-2, page 3, Column 7.
[100] SFR Schedule C-2, page 3, Column 9.
[101] SFR Schedule C-2, page 10, Column 28 (ACC jurisdiction).
[102] SFR Schedule C-2, page 9, Column 26 (ACC jurisdiction).

support. As this amount is included in Ms. Blankenship's proposed $51.7 million depreciation expense adjustment, if the Commission endorses my Palo Verde depreciation recommendation, part of my recommended rejection of accounting adjustments will have already been made. Thus, if the Commission adopts my recommendation to reject $31.5 million in depreciation expense, my recommended accounting adjustment rejection is $190.8 million ($222.3 million less $31.5 million).

Q. You recommend these adjustments be rejected only in the event the Commission approves formula ratemaking generally, correct?

A. Yes, that is correct. However, the disallowances I recommended in Section III regarding imprudent spending and inappropriate nuclear plant depreciation are unaffected by the Commission's decisions regarding the Company's FRAM proposals. As a result, those disallowance recommendations stand irrespective of the Commission's FRAM-related decisions.

VI. REVIEW AND CONCLUSION

Q. Please review your testimony.

A. After introductions, Section 1 concluded with perspective on electric rate increases. That is, rate increases harm consumers' quality of life and retard Arizona's economic development, and as a result, unnecessary, premature, or cost-ineffective spending and rate increases are to

be avoided. (It is my position that formula ratemaking encourages such spending and rate increases.)

Section II explained the deficiencies in the Company's FRAM proposal, and described how it would lead to unnecessary, premature, and cost-ineffective spending and rate increases. Formula ratemaking deficiencies included:

1. Formula ratemaking may not improve the Company's credit rating or reduce the interest rate customers pay on APS debt. I noted that credit ratings are based on multiple factors, including wildfire risk and nuclear plant operations risk, and I observed that the three credit rating agencies have either maintained or reduced their ratings on APS debt since the Commission adopted its formula ratemaking policy.
2. Formula ratemaking essentially eliminates utility incentives to control spending, and I estimate the impact of this on rates to be far greater than any interest expense savings customers might secure through formula ratemaking.
3. APS has been able to obtain credit at reasonable terms during times of growing capital spending in the past without formula ratemaking.
4. Formula ratemaking at the FERC has resulted in out-of-control transmission spending across the US, including an astonishing 13.4% compound annual growth rate in annual APS transmission plant additions since 2011. Further, a case currently before the FERC examines the role of formula rates in encouraging excess transmission spending (EL25-44-000). Still further, many of the states APS identifies as users of formula ratemaking are ranked by S+P Global as the most permissive regulators of for-profit monopoly utilities.

5. While described by the Company as symmetrical, annual FRAM adjustments resulting in rate increases are dramatically more likely than FRAM adjustments resulting in rate decreases. This has been my experience in other jurisdictions that adjust rates to utility spending annually. Further, capital spending increases forecast by the Company 2025-2027 virtually guarantee that the Company will not earn its rate of return, prompting FRAM adjustments that will increase rates in 2026-2028 at a minimum.
6. While rate increases under formula ratemaking may indeed be smaller, they are also sooner. While smaller rate increases are a potential customer advantage of formula ratemaking, sooner rate increases are not in customer interest. Further, as approval for five 4% rate increases are easier for the Company to secure than approval for a single 20% rate increase, annual rate increases are in shareholder interest.
7. In my experience, formula ratemaking is more resource intensive for regulators, Staff, and intervenors that traditional ratemaking, as periodic proceedings to evaluate utility-proposed adjustments constitute mini rate cases.
8. Formula ratemaking essentially guarantees that APS will earn the rate of return on equity the Commission authorizes. This is not in customer interest, as it transfers operations cost and capital spending risks from shareholders to customers.
9. The FRAM as proposed does not adjust the rate of return used to calculate rate adjustments for business conditions as they change over time. In times of falling interest rates, customers will be paying a cost of capital higher than that the Company is incurring, resulting in a shareholder windfall. Not only is this not in customer

interest, it violates a critical cost-of-service ratemaking principle (that customer rates are determined by utility costs, including capital costs).

I closed Section II by observing that the executive incentive compensation plans for APS Witness and CEO Geisler and his team weigh shareholder interests over customer interests by a factor of almost five to one, and I tied this observation to the Company's support for formula ratemaking.

Section III of this testimony provides support for my recommendation that the Commission disallow the cost of two discretionary APS spending decisions and one unsupported increase in depreciation expense. These include:

1. Remove the $198.7 million in cost for APS to acquire additional equity in Palo Verde Unit 2 from rate base;
2. Remove the $51.6 million cost of the redundant makeup water surge pond at the Redhawk generating station from rate base;
3. Remove the $31.5 million increase in depreciation expense for the Company's nuclear assets.

Section IV summarizes my primary recommendations to the Commission. These include:

1. Reject the Company's FRAM proposal as supported by Section II;
2. Disallow the costs described in Section III for the reasons indicated.

Section V summarizes back-up recommendations in the event the Commission approves the Company's FRAM proposal despite my primary recommendation to reject it. First, I clarify that the improvements I recommend to the Company's FRAM proposal do not

rectify the most egregious deficiencies of formula ratemaking, and if adopted will still result in a ratemaking process that favors shareholder interest over customer interest by a wide margin. Notwithstanding this caveat, recommendations to improve the Company's FRAM proposal if the Commission fails to reject it include:

1. Expand the size of the Return on Equity deadband from 20 basis points on either side of the rate authorized to 248 basis points, or two standard deviations, as based on historical APS return on equity variation and historical shareholder responsibility;
2. Modify the authorized Return on Equity to reflect then-current business conditions as part of each formula ratemaking adjustment;
3. Reduce the authorized Return on Equity below the amount the Commission might otherwise find appropriate to reflect the reduction in earnings volatility offered by formula ratemaking adjustments; and
4. Modify and extend the process for FRAM adjustment review and approval to preserve due process while retaining a measure of expediency.

Section V also recommended that the Commission reject several timing and accounting adjustments that will become redundant if the Commission approves the Company's FRAM proposal. Instead, I maintain that the need for any such adjustments will be addressed as part of annual FRAM petitions, in which the Company's failure to earn the rate of return the Commission authorizes will be addressed through rate increases 'come what may', including such timing and accounting adjustments. These included: 1) Post test year cost adjustments recommended by Mr. Tetlow ($1.1 billion gross, $306 million net, less any of my disallowance recommendations the Commission might adopt); and 2) Normalizing, Annualizing, Out-of-

period/Miscellaneous, and revenue adjustments recommended by Ms. Blankenship, Ms. Hobbick, and Mr. Moe ($222.3 million less $31.5 million in depreciation expense I recommend be disallowed as the Commission might adopt). Section V concluded by indicating the cost disallowances recommended and supported in Section III stand regardless of the Commission's decision on the Company's FRAM proposal.

Q. Does this conclude your testimony?

A. Yes, it does.

Curriculum Vitae of Paul J. Alvarez

Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement for Xcel Energy in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed conflicts between ratemaking and benefit maximization. Since 2012 Mr. Alvarez has led the Wired Group, a boutique consultancy serving consumer, business, and environmental advocates, and regulators in matters of distribution planning, investment, and performance measurement.

Appearances and Research Projects in Regulatory Proceedings

Review Dominion Transportation Electrification Plan. Testimony on behalf of a group of environmental and consumer advocates in Virginia SCC PUR-2025-00022. September 9, 2025.

Review DTE spending justification models and alternative ratemaking practices. Testimony on behalf of a group of environmental and consumer advocates in Michigan PSC U-21860. August 22, 2025.

Review Performance Metrics, Targets, Incentives and Penalties for Multi-Year Rate Plans. Testimony on behalf of the Illinois Attorney General in ICC Case Nos. 25-0574 and 25-0514 (Ameren Illinois and Commonwealth Edison, respectively). July 22, 2025 and July 28, 2025 respectively.

Review the Prudence of Commonwealth Edison's Investments in a Telecommunications Network in Annual MYRP Rate Reconciliation. Testimony on behalf of the Illinois Attorney General in ICC Case No. 25-0383. July 15, 2025.

Review of Distribution Investments and Performance Criteria for Additions to Rate Base as Requested by NStar Gas Company. Joint testimony with Nicholas Onysczcak on behalf of the Attorney General in Massachusetts DPU Case No. 24-134. June 20, 2025.

Context and Perspective on Rocky Mountain Power's 2023 Wildland Fire Protection Plan. Testimony on behalf of the Office of Consumer Services in Utah 24-035-04. February 14, 2025.

Evaluate Cost Containment, Recovery, and Prudence Review Processes Associated with Utilities' Electric Sector Modernization Plans. Joint Direct Testimony with Dennis Stephens on behalf of the Attorney General in Massachusetts DPU Case Nos. 24-10, 24-11, and 24-12. January 30, 2025.

Evaluate the Prudence of Pepco Spending in Annual MYRP Rate Reconciliation. Panel Testimony with Dennis Stephens on behalf of the Office of People's Counsel in Maryland PSC Case No. 9655. November 15, 2024.

Examine Duke Energy's Request to Continue, Expand, or Initiate Various Riders in its Electric Security Plan. Testimony on behalf of the Office of Consumer Counsel in Ohio OUC Case No. 24-278-EL-SSO. October 23, 2024.

Recommendations for Commonwealth Edison Beneficial Electrification Plan. Panel testimony with C. Andre Gouin on behalf of the Attorney General in Illinois Commerce Commission Case No. 24-0484. September 27, 2024.

Recommendations for Ameren Illinois Beneficial Electrification Plan. Panel testimony with C. Andre Gouin on behalf of the Attorney General in Illinois Commerce Commission Case No. 24-0494. September 27, 2024.

Evaluate Public Service Oklahoma Application for Rate Increase & Changes in Cost Recovery for Some Expense Types. Testimony on behalf of Commission Staff in PUD 2023-000086. July 29, 2024.

Evaluate DTE Energy's Request for Rate Increase, and to Extend and Expand Rider IRM. Testimony on behalf of a group of environmental and consumer advocates in Michigan PSC U-21534. July 26, 2024.

Determine If Customer Interest Is Served by Smart Meter Stipulation. Testimony before the Ohio PUC on behalf of the Office of Consumer Counsel. Ohio PUC 22-0704-EL-UNC. June 11, 2024.

Evaluate Commonwealth Edison Company's Refiled Grid Plan. Panel Testimony with Dennis Stephens on behalf of the Attorney General in Illinois Commerce Commission Case No. 23-0055. May 23, 2024.

Evaluate Ameren Illinois Company's Refiled Grid Plan. Panel Testimony with Dennis Stephens on behalf of the Attorney General in Illinois Commerce Commission Case No. 23-0082. May 13, 2024.

Evaluate Oklahoma Gas & Electric's historical spending. Testimony on behalf of Oklahoma Corporation Commission Staff in PUD-2023-000087. April 26, 2024.

Evaluate National Grid's historical and proposed distribution spending. Panel testimony with Dennis Stephens on behalf of the Attorney General in Massachusetts DPU Case 23-150. March 29, 2024.

Evaluate Pepco's Second Multi-Year Rate Plan. Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel in Maryland PSC Case No. 9702. December 15, 2023.

Evaluate First Energy's Application to Continue Grid Mod I Program Spending in Grid Mod II. Testimony on behalf of the Ohio Consumers' Counsel in Ohio PUC Case No. 22-0704. October 23, 2023

Evaluate BGE's Second Multi-Year Rate Plan (Electric Distribution Components 2024-2027) and Electric Distribution Spending 2021-2022. Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel in Maryland PSC Case No. 9692. June 20, 2023.

Evaluate DTE Energy's Request for Strategic Capital Plan Cost Recovery and Infrastructure Recovery Mechanism Rider on behalf of the Attorney General and a group of environmental and consumer advocates in Michigan PSC U-21297. June 13, 2023.

Evaluate Commonwealth Edison's Multi-year Grid Plan. Panel testimony with Dennis Stephens on behalf of the Attorney General in Illinois Commerce Commission 22-0486. May 22, 2023.

Evaluate Ameren Illinois Corporation's Multi-year Grid Plan. Panel testimony with Dennis Stephens on behalf of the Attorney General in Illinois Commerce Commission 22-0487. May 11, 2023.

Evaluate Public Service Oklahoma's $450 million Grid Enhancement and Resilience Plan and Request for Rider Cost Recovery from a Policy Perspective. Testimony on behalf of the Attorney General in PUD-2022-000093. March 7, 2023.

Evaluate Duke Energy's Peak-time Rebate Pilot Results. Testimony on behalf of the Attorney General in 2022-00251. November 9, 2022.

Evaluate Georgia Power's Transmission & Distribution Spending Proposals. Panel testimony with Dennis Stephens on behalf of Public Interest Advocacy Staff. Georgia PSC 44280. October 20, 2022.

Evaluate Pacific Gas & Electric's 2023-2026 Multi-year Rate Plan. Panel testimony with Dennis Stephens on behalf of AARP. California PUC A.21-06-021. June 10, 2022.

Evaluate the Distribution Business Components of Georgia Power Company's Integrated Resource Plan. Panel testimony with Dennis Stephens on behalf of Public Interest Advocacy Staff. Georgia PSC 44160. May 6, 2022.

Evaluate Policy Issues and Precedents Associated with Oklahoma Gas & Electric Company's Grid Modernization Factor. Testimony on behalf of the Office of Attorney General in PUD 2021000164. April 27, 2022.

Evaluate Grid Modernization and Advanced Metering Proposals by Massachusetts Utilities. Panel testimonies with Dennis Stephens on behalf of the Office of Attorney General in D.P.U. 21-80, 21-81, and 21-82. January 19, 2022.

Evaluate Dominion's Grid Transformation Plan. Testimony on behalf of Appalachian Voices/Southern Environmental Law Center. Virginia SCC PUR-2021-00127. September 13, 2021.

Investigate Avista Utilities' Electric Distribution and Wildfire Spending, Plans, and Processes. Panel testimony with Dennis Stephens on behalf of Public Counsel. WUTC 200900. April 29, 2021.

Evaluate Kentucky Utilities/Louisville Gas & Electric's CPCN to Install Advanced Meters. Testimony on behalf of the Attorney General. Kentucky PSC 2020-00349/00350. March 5, 2021.

Examine Potomac Electric Power Company's Electric Distribution Spending and Plan. Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel. MD PSC 9655. March 3, 2021.

Determine If Customer Interest Is Served by Smart Meter Stipulation. Testimony before the Ohio PUC on behalf of the Office of Consumer Counsel. Ohio PUC 18-1875-EL-GRD. December 17, 2020.

Critique Public Service Electric & Gas Company's Smart Meter Deployment Plan. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Rate Counsel. NJ BPU EO18101115. Aug. 31, 2020.

Examine Oklahoma Gas and Electric's $800 million Grid Enhancement Plan. Testimony before the Oklahoma Corporations Commission on behalf of AARP. PUD 202000021. August 25, 2020.

Examine Baltimore Gas and Electric's 2021-2023 Grid Investment and Operations Plan. Panel **t**estimony before the Maryland Public Service Commission with Dennis Stephens on behalf of the Office of People's Counsel. MDPSC 9645. August 14, 2020.

Critique of Duke Energy Carolinas/Duke Energy Progress $2.3 billion Grid Improvement Plan. Testimony before the North Carolina Utilities Commission on behalf of a coalition of consumer and environmental advocates. NCUC E-7, Sub 1214 February 18, 2020, and E-2, Sub 1219 March 25, 2020.

Critique of Investment in Traditional Meters (Equipped with AMR). Testimony before the New Hampshire Public Utilities Commission recommending rejection of cost recovery. DE 19-057. December 20, 2019.

Critique of Smart Meter Benefits Claimed by Puget Sound Energy. Testimony before the Washington Utility and Telecom Commission recommending rejection of cost recovery pending demonstration of benefits in excess of costs. UE-190529 and UG-190530. November 22, 2019.

Critique of Smart Meter Benefits Claimed by Rockland Electric Company. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Consumer Advocate recommending rejection of cost recovery pending demonstration of benefits in excess of costs. ER19050552. October 11, 2019.

Critique of Grid Improvement Plan Proposed by Indianapolis Power and Light. Testimony before the Indiana Utility Regulatory Commission recommending reductions in the size of the plan ($1.2 billion) based on benefit-cost analyses of plan components. Cause 45264. October 7, 2019.

Investigation into Distribution Planning Processes. Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

Investigation into Grid Modernization. Comments to the New Hampshire Public Utilities Commission recommending a transparent, stakeholder-engaged distribution planning process. IR 15-296. September 6, 2019.

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Utility Regulation Through Legislation: A Cautionary Tale for Legislators, Regulators, Stakeholders, and Utilities. With Sean Ericson and Dennis Stephens. Electricity Journal. Volume 34 (August, 2021).

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Challenging Utility Grid Modernization Proposals. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. Part 1, August, 2020, pages 59-62; Part 2 September, 2020.

The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. July 8, 2019. Pages 116+

Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. Whitepaper co-authored with Dennis Stephens for GridLab. January 31, 2019

Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Dennis Stephens for GridLab. October 5, 2018.

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Busting Myths: Investor-Owned Utility Performance Can be Credibly Benchmarked. With Joel Leonard. Electricity Journal. Volume 30 (October, 2017), pages 45-48.

Price Cap Electric Ratemaking: Does it Merit Consideration? With Bill Steele. Electricity Journal. Volume 30, (October, 2017), pages 1-7.

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Notable Presentations

NASUCA Annual Meeting. *Reinventing Distribution Planning in New Hampshire.* With D. Maurice Kreis, Executive Director, Office of Consumer Advocate. San Antonio, TX. November 19, 2019.

National Council on Electricity Policy Annual Meeting. Trainer on the economics of distribution grid interoperability and standard compliance; Presentation on communication network economics. Austin, TX. Sept 10-12, 2019.

NASUCA Annual Meeting. *Grid Modernization: Basic Technical Challenges Advocates Should Assert*. Orlando, FL. November 13, 2018.

Illinois Commerce Commission, NextGrid Working Group 7. *Using Peer Comparisons in Distributor Performance Evaluation.* Workshop 3 Presentation. Chicago, IL. July 30, 2018.

NARUC Committee on Electricity. *Using Peer Comparisons in Distributor Performance Evaluation.* Smart Money in Grid Modernization Panel Presentation. Scottsdale, AZ. July 16, 2018.

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NASUCA 2013 Annual Conference. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando, FL. November 18, 2013.

NARUC Subcommittee on Energy Resources and the Environment. *The Distributed Generation (R)Evolution.* Orlando, FL. November 17, 2013.

IEEE Power and Energy Society, ISGT 2013. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

Great Lakes Smart Grid Symposium. *What Smart Grid Deployment Evaluations are Telling Us*. Chicago. September 26, 2012.

Mid-Atlantic Distributed Resource Initiative. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012

DistribuTECH 2012. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25.

DistribuTECH 2012. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23.

NARUC Subcommittee on Electricity. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators*. St. Louis, MO. November 13, 2011.

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Toronto, Canada. January 23, 2011.

Teaching

Post-graduate Adjunct Professor. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

Guest Lecturer. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization; Pros and Cons of Alternative Ratemaking Methods.

Education

Master's Degree in Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Finance, Accounting, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Finance, Marketing.

Certifications

New Product Development Professional. Product Development and Management Association. 2007.