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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

KRISTIN K. MAYES, Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

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

Docket No. E-01345A-08-0172

NOTICE OF FILING DIRECT TESTIMONY (RATE DESIGN/COST OF SERVICE) AND ATTACHMENTS OF KEVIN C. HIGGINS ON BEHALF OF FREEPORT-MCMORAN COPPER & GOLD INC. AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION

Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition (collectively "AECC"), hereby submit the Direct Testimony (Rate Design/Cost of Service) and Attachments of Kevin C. Higgins on behalf of AECC in the above captioned Docket.

RESPECTFULLY SUBMITTED this 9th day of January 2009.

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By: Mary Bollington

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, to Approve Rate) Schedules Designed to Develop Such Return)	**Docket No. E-01345A-08-0172**

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport-McMoRan Copper & Gold Inc. and

Arizonans for Electric Choice & Competition

Rate Design / Cost of Service

January 9, 2009

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DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1]

Q. Are you the same Kevin C. Higgins who previously testified on behalf of AECC in the interim and revenue requirement phases of this proceeding?

A. Yes, I am. My qualifications were presented in my direct testimony filed in the revenue requirement phase of this case, with additional detail in Attachment KCH-1, attached to that testimony.

[1] Henceforth in this testimony, Freeport-McMoRan Copper & Gold Inc. and AECC collectively will be referred to as "AECC."

Overview and Conclusions

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

A. My testimony addresses APS's proposed rate spread, rate design, and cost of service analysis.

Q. What are the primary conclusions and recommendations presented in your testimony?

A. (1) I recommend that APS's cost of service study be adopted by the Commission. The Average and Excess Demand method employed by APS to allocate production plant costs fully meets the Commission's stated objective in Decision No. 69663 with respect to allocating a portion of production plant based on energy. Further, APS's allocation of energy costs based on customer class hourly load shapes and their relationship to hourly energy prices is a significant improvement over the method that APS had used for allocating energy costs in previous cases. The updated approach better aligns cost responsibility with cost causation, improves fairness, and encourages efficiency in resource utilization through better price signals.

(2) In my opinion, APS's proposed rate spread does not move far enough in the direction of cost of service. I propose a rate spread approach that moves further in the direction of aligning rates with cost, while adhering to the principle of gradualism and providing continued rate mitigation for the Residential class. My proposal is summarized in the following five steps:

(a) Set Residential rates midway between system average percentage base rate increase and the percentage increase necessary to bring Residential base rates to cost-of-service.

(b) Move rates for Rate 20 and Street Lighting closer to cost, but cap the base rate increase for these classes at 5 percentage points above the system average base rate increase.

(c) Set Rates E-34 and E-35 (collectively) equal to cost-of-service, with Rate E-34 receiving a percentage increase that is 1.0 percentage point lower than Rate E-35.

(d) Set the percentage increase for the new E-32-XS class equal to cost of service.

(e) Set the percentage increase for all remaining rate schedules (e.g., remaining Rate E-32 schedules, E-32-TOU, Water Pumping, and Dusk-to-Dawn) equal to the respective cost-of-service for each, plus the same percentage point increase necessary to fund the mitigation for Residential customers and the customer classes subject to the 5 percent cap.

(3) If the Company's requested rate increase is reduced by the Commission, I recommend that the revenue apportionment produced by the rate spread shown in Table KCH-4 in my testimony should be used as the basis for spreading the smaller revenue change.

(4) APS is proposing a 188 percent increase in the Delivery Charge for transmission voltage service for Rate E-35. This would result in a much higher Delivery Charge to a transmission voltage customer on Rate E-35 – where the customer pays energy charges that vary with time-of-day – compared to Rate E-34 – where the customer would pay a flat energy charge. I see no merit in introducing such a discrepancy, and recommend that the dramatic increase proposed by APS for the Delivery Charge for Rate E-35 transmission voltage service be rejected. Instead, the Delivery Charge differential between primary and transmission voltage for Rate E-35 should be set at $3.764 per kW. This will

retain consistency between Rates E-34 and Rate E-35, as well with the current structure of E-35 rates.

(5) APS is proposing a change in the terms of Rates E-34 and E-35 that would require a customer to compensate the Company for the costs of additional third-party transmission service that is "required solely to provide service to a specific customer or customers." I recommend that this proposed change to the tariff be rejected. APS's retail transmission charges are simply a straight pass-through of rates in the Company's Open Access Transmission Tariff, which are approved by FERC. APS's attempt to introduce additional retail transmission charges outside the purview of its FERC-approved transmission rates would create an ad hoc pricing regime with limited oversight and the potential for double recovery. It would also create undue utility leverage in its dealings with its customers.

(6) I support the adoption of the CIAC "tax asset" portion of APS's proposed Impact Fee, as these costs are associated with the direct cost of providing facilities to serve the new customers' premises, which is a reasonable assignment of cost to cost causers. However, I recommend against adoption of the portion of the proposed Impact Fee that is intended to recover incremental system costs, as this takes on the character of "vintage pricing," which can result in unintended consequences, including the undue stifling of economic development.

(7) I recommend against APS's proposed changes to cost recovery for its Demand-Side Management ("DSM") programs. The proposed changes would divert DSM dollars <u>away</u> from DSM projects and instead direct them to the

Company's shareholders. In my view, this would not be the best use of revenue from customer-funded programs.

(8) APS is proposing to modify the Environmental Improvement Surcharge ("EIS"). Rather than treating the EIS funds used for eligible projects as Contributions in Aid of Construction ("CIAC"), as is required by the Commission, APS is proposing that the EIS provide a return on investment and recovery of expenses based on the projected cost of approved environmental expenditures. I recommend against adoption of the changes proposed by APS. With customers providing the up-front capital for the EIS projects, the Commission's previous determination that these funds should be booked as CIAC is reasonable. To the extent that this issue is considered anew, I recommend that the Commission consider eliminating the EIS in its entirety, as it is an application of single-issue ratemaking that is not necessary to ensure just and reasonable rates.

<u>**Cost of Service**</u>

Q. What is the purpose of cost-of-service analysis?

A. Cost-of-service analysis is conducted to assist in determining appropriate rates for each customer class. It involves the assignment of revenues, expenses, and rate base to each customer class, and includes the following steps:

- Separating the utility's costs in accordance with the various *functions* of its system (e.g., generation [or production], transmission, distribution);

- *Classifying* the utility's costs with respect to the manner in which they are incurred by customers (e.g., customer-related costs, demand-related costs, and energy-related costs); and
- *Allocating* responsibility for the utility's costs to the various customer classes based on principles of cost causation.

Q. What is the role of cost-of-service analysis in setting rates?

A. Each of the three steps above has an important role in the ratemaking process. If rates are unbundled by function, as they are in Arizona, then separating the utility's costs by function is important in determining which costs are generation-related, transmission-related, and distribution-related.

The classification of costs is critical to the rate design process, i.e., in determining the proper customer charge, demand charge, and energy charge for each rate schedule.

Finally, the allocation of costs to customer classes is important for determining revenue apportionment across customer classes, also called "rate spread." In determining rate spread, it is important to align rates with cost causation to the greatest extent practicable. Properly aligning rates with the costs caused by each customer class is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization. For these reasons, the results of the class cost-of-service analysis should be given very strong weighting in guiding the proper revenue apportionment.

Q. What approach has APS used for allocating generation plant costs between APS retail customers and FERC-jurisdictional customers?

A. As explained in the direct testimony of APS witness David Rumolo, APS uses the 4-Coincident Peaks ("4-CP") method for allocating generation plant costs between its state and federal jurisdictional loads. The 4-CP method allocates fixed production costs based on the average of system peak demands in the four summer months, which is when APS's production capacity requirements are determined.

Q. In your opinion, is the 4-CP method appropriate for allocating APS's jurisdictional generation plant costs?

A. Yes. APS's maximum system demands are driven by summer usage. Given the characteristics of APS's system, the 4-CP method properly aligns the allocation of the Company's fixed costs with cost causation. As noted by Mr. Rumolo, the 4-CP method is used by APS in its cases before FERC.

Q. Does APS also use the 4-CP method for allocating generation plant costs across its retail customer classes in this case?

A. No. Even though in past proceedings APS has used the 4-CP method for allocating generation plant costs across its retail customer classes, in this case the Company uses the Average and Excess Demand method for that purpose.

Q. Does APS explain the basis for the change?

A. Yes. Mr. Rumolo explains that the Company utilized the Average and Excess Demand method in response to a directive from the Commission to propose an energy-weighting method for allocating fixed production plant in this case. This directive was issued on page 71 in Decision No. 69633 in Docket No. E-01345A-05-0816:

> We will order APS, in its next rate application, to propose an energy-weighting method that addresses the concerns raised in this case, and that will also consider the likely cost shifting that will be necessary as we determine the appropriate rate design in this case.

The Commission, in its discussion of this issue, had commented favorably on the use of the Average and Excess Demand method for this purpose:

> We agree with Staff that an energy-weighting method for allocating production plant is appropriate for APS. However, we are not convinced that the method recommended by Staff is the method that should be adopted. AECC's recommended Average and Excess Demand method would eliminate the criticism that the average demand is being counted twice. [Decision No. 69663, p. 70, line 27 – p. 71, line 2.]

Q. Do you agree that the Average and Excess Demand method allocates a portion of production plant cost on the basis of energy usage?

A. Yes, I do. The Average and Excess Demand method is described in the NARUC Manual in its section entitled "Energy Weighting Methods" and fully meets the Commission's stated objective in Decision No. 69663 with respect to allocating a portion of production plant based on energy. As stated in the NARUC Manual, this method "effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor."[2]

Q. How does the Average and Excess Demand method apportion responsibility for incremental production plant that is required to meet loads that are above average demand?

[2] NARUC Electric Utility Cost Allocation Manual, January 1992, p. 49.

A. The Average and Excess Demand method allocates the cost of capacity above average demand in proportion to each class's <u>excess</u> demand, where excess demand is measured as the difference between each class's individual peak demand[3] and its average demand. In this manner, the incremental amount of production plant that is required to meet loads that are above average demand is properly assigned to the users who create the need for the additional capacity.

Q. Is the Average and Excess Demand method used in any neighboring jurisdictions?

A. Yes. This approach is utilized by the Salt River Project as well as by Public Service Company of Colorado.

Q. How does APS allocate energy costs across customer classes?

A. APS allocates energy costs based on customer class hourly load shapes and their relationship to hourly energy prices, which produces a weighted energy cost for each class. This approach is a great improvement over the method that had been used for allocating energy costs in previous cases, in which it made no difference whether a class's kilowatt-hours were concentrated in high-cost, summer on-peak periods, or lower-cost, off-peak periods: each kilowatt-hour was assigned exactly the same cost.

Q. Do you support APS's use of a weighted energy cost for each customer class based on the class's hourly load shape?

A. Yes. The use of a weighted energy cost for each class is consistent with a recommendation I made to the Commission in Docket No. E-01345A-05-0816.

[3] A class's individual peak demand is often referred to as "Class Non-Coincident Peak Demand" or "Class NCP."

This approach better aligns cost responsibility with cost causation, improves fairness, and encourages efficiency in resource utilization through better price signals.

Q. What is your overall recommendation concerning APS's cost-of-service methodology in this proceeding?

A. For the reasons discussed above, I recommend that APS's approach be adopted.

Q. Did you conduct any cost-of-service analysis in addition to what APS has presented?

A. Yes. APS's cost-of-service analysis presents the revenue deficiency for each customer class at an equalized rate of return for <u>base</u> rates. While this is an important piece of information, the focus on base rates necessarily ignores each rate schedule's contribution to APS revenue recovery through the Power Supply Adjustment ("PSA") charge. That is, the APS analysis calculates each customer class's revenue deficiency by assuming the PSA charge is zero and, by extension, that APS fuel costs in excess of the base fuel rate are going un-recovered. While, strictly speaking, this assumption is correct insofar as <u>base</u> rates are concerned, I believe it is also useful to indentify each customer class's revenue deficiency after taking account of class contributions to revenue recovery through the PSA charge. Such an analysis does not undo the APS study, but simply provides more information to present a more complete picture.

In Attachment KCH-10, I present class returns and revenue deficiencies after taking account of PSA revenues. I present this information using (a) current PSA rates, as well as (b) the implied PSA rates in APS's cost-of-service analysis. The results of this analysis are summarized in Table KCH-2, below[4].

Table KCH-2

APS Cost-of-Service Results
Percentage rate change required to bring each class to cost-of-service at APS's proposed revenue requirement

Class	Base Rate Change	Rate Change Net of Current PSA Revenues	Rate Change Net of APS Projected PSA Revenues
Residential	21.74%	17.03%	14.93%
General Service	11.60%	6.52%	4.27%
E-20	54.32%	48.08%	45.29%
GS TOU	7.76%	2.15%	(0.29)%
E-32 (total)	10.64%	5.90%	3.80%
E-32XS	21.57%	17.67%	15.91%
E-32S	10.87%	6.61%	4.70%
E-32M	8.86%	3.93%	1.75%
E-32L	5.93%	0.60%	(1.74)%
E-34	13.19%	6.76%	3.97%
E-35	20.47%	12.62%	9.25%
Water Pumping	3.82%	(1.43)%	(3.73)%
Street Lighting	54.31%	49.86%	47.86%
Dusk-to-Dawn	14.15%	12.58%	11.85%
Total	16.99%	12.09%	9.91%

Q. Please explain the "Base Rate Change" column in Table KCH-2.

A. This column shows the percentage change in base rates that each customer class would need to experience in order to pay rates equal to each class's cost of service at APS's proposed revenue requirement in this proceeding. The percentages in this column focus exclusively on changes in <u>base</u> rates; thus, the information in this column ignores the fact that customers currently make a substantial contribution to fuel cost recovery through the PSA charge. In other words, part of the change in base rates being shown is the shifting of cost recovery out of the PSA charge into base rates.

Q. Please explain the "Rate Change Net of Current PSA Revenues" column in Table KCH-2.

A. This column shows the percentage change in rates that each customer class would need to experience in order to pay rates equal to each class's cost of service at APS's proposed revenue requirement in this proceeding – after taking into consideration that customers are currently paying a PSA charge equal to 0.4 cents/kWh. That is, this column shows the required net increase in rates over and above what customers are currently paying in base rates and the PSA Adjustor.

Q. Please explain the "Rate Change Net of APS Projected PSA Revenues" column in Table KCH-2.

A. This column is similar to the previous column, except that instead of current PSA revenues, it is based on APS's projected PSA revenues that would otherwise prevail in 2010. I present this column to be consistent with information presented in APS's filing. For example, it is comparable to the "Net of PSA Impacts" column shown in APS Schedule H-2.

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[4] This table is enumerated KCH-2 as Table KCH-1 is incorporated in my revenue requirement testimony.

Rate Spread

Q. What general guidelines should be employed in spreading any change in rates?

A. In determining rate spread, or revenue apportionment, it is important to align rates with cost causation, to the greatest extent practicable. Properly aligning rates with the costs caused by each customer group is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

At the same time, it can be appropriate to mitigate the impact of moving immediately to cost-based rates for customer groups that would experience significant rate increases from doing so. This principle of ratemaking is known as "gradualism." When employing this principle, it is important to adopt a long-term strategy of moving in the direction of cost causation, and to avoid schemes that result in permanent cross-subsidies from other customers.

Q. What has APS proposed with respect to rate spread?

A. APS's proposed rate spread is presented in APS Schedule H-2 and is restated in Table KCH-3, below, along with APS's cost-of-service results.

Table KCH-3

Comparison of APS Cost-of-Service Results to APS Proposed Rate Change

Class	Base Rate Change per APS COS	APS Proposed Base Rate Change	Difference Between Cost & Proposed Rate
Residential	21.74%	17.27%	(4.47)%
General Service	11.60%	16.74%	5.14%
E-20	54.32%	20.20%	(34.12)%
GS TOU	7.76%	16.71%	8.95%
E-32 (total)	10.64%	16.58%	5.94%
E-32XS	21.57%	18.67%	(2.90)%
E-32S	10.87%	16.58%	5.71%
E-32M	8.86%	16.22%	7.36%
E-32L	5.93%	15.74%	9.81%
E-34	13.19%	16.50%	3.31%
E-35	20.47%	18.69%	(1.78)%
Water Pumping	3.82%	12.30%	8.48%
Street Lighting	54.31%	19.41%	(34.90)%
Dusk-to-Dawn	14.15%	19.36%	5.21%
Total	16.99%	16.99%	0%

As shown in Table KCH-3, APS's cost-of-service analysis shows the Residential class as warranting a base rate increase of 21.74 percent (at the Company's proposed revenue requirement), but receiving a base rate increase of 17.27 percent. At the same time, General Service customers are shown as warranting a base rate increase of 11.6 percent (at the Company's proposed revenue requirement), but receiving a base rate increase of 16.74 percent. Whereas the rate increase warranted by these two major groupings of customers is separated by more than 10 percentage points, the base rate increased proposed by APS is within a single percentage point for the two groups.

Q. Have you calculated APS's proposed rate increase net of PSA revenues consistent with the information in Attachment KCH-10?

A. Yes. This information is presented in Attachment KCH-11.

Q. What is your assessment of APS's rate spread proposal?

A. It is apparent from APS's proposed rate spread that the Company is proposing a very small step in the direction of cost of service, while perpetuating a very sizable subsidy from General Service customers to Residential customers. I calculate the proposed subsidy to be in excess of $60 million.

In my opinion, the Company's proposed rate spread does not move far enough in the direction of cost of service. While the current economic climate is difficult for all customer classes, the magnitude of the inter-class subsidization in APS's proposal is an especially unreasonable burden to place upon the customers in the General Service class.

Q. Do you have an alternative rate spread recommendation?

A. Yes. I propose an approach that moves further in the direction of cost-of-service, while adhering to the principle of gradualism and providing continued rate mitigation for the Residential class. My proposal is summarized in the following five steps:

(1) Set Residential rates midway between system average percentage base rate increase and the percentage increase necessary to bring Residential base rates to cost-of-service.

(2) Move rates for Rate 20 and Street Lighting closer to cost, but cap the base rate increase for these classes at 5 percentage points above the system average base rate increase.

(3) Set Rates E-34 and E-35 (collectively) equal to cost-of-service, with Rate E-34 receiving a percentage increase that is 1.0 percentage point lower than Rate E-35.

(4) Set the percentage increase for the new E-32-XS class equal to cost of service. (This will place this class right below the 5 percent cap described above.)

(5) Set the percentage increase for all remaining rate schedules (e.g., remaining Rate E-32 schedules, E-32-TOU, Water Pumping, and Dusk-to-Dawn) equal to the respective cost-of-service for each, plus the same percentage point increase necessary to fund the mitigation for Residential customers and the customer classes subject to the 5 percent cap.

Q. What is the rate spread that obtains from your recommended approach at APS's proposed revenue requirement?

A. These results are presented in Attachment KCH-12, and summarized in Table KCH-4, below.

Table KCH-4

Comparison of AECC Rate Spread to APS Rate Spread
At APS's Proposed Revenue Requirement

Class	Base Rate Change per APS COS	APS Proposed Base Rate Change	AECC Proposed Base Rate Change
Residential	21.74%	17.27%	19.37%
General Service	11.60%	16.74%	14.52%
E-20	54.32%	20.20%	21.99%
GS TOU	7.76%	16.71%	11.96%
E-32 (total)	10.64%	16.58%	14.14%
E-32XS	21.57%	18.67%	21.57%
E-32S	10.87%	16.58%	15.07%
E-32M	8.86%	16.22%	13.06%
E-32L	5.93%	15.74%	10.12%
E-34	13.19%	16.50%	16.39%
E-35	20.47%	18.69%	17.39%
Water Pumping	3.82%	12.30%	8.02%
Street Lighting	54.31%	19.41%	21.99%
Dusk-to-Dawn	14.15%	19.36%	18.35%
Total	16.99%	16.99%	16.99%

Q. Please explain the basis for your proposal to move Residential rates halfway to cost of service.

A. In my opinion, moving Residential rates halfway to cost of service strikes a reasonable balance between setting rates based on cost while taking into consideration the principle of gradualism. At APS's proposed revenue requirement, my rate spread proposal would keep the Residential base rate increase within 2.4 percentage points of the system average increase in base rates.

Q. Please explain the basis for your proposed treatment of Rate 20 and Street Lighting.

A. The rates for both of these customer classes are significantly below cost of service. I recommend that rates for these two classes be moved closer to cost; at the same time, in the interest of gradualism, I am recommending capping the base rate increase for these two classes at five percentage points above the system average base rate increase. So, for example, at APS's proposed base rate increase of 16.99 percent, the base rate increase for these two classes would be capped at 21.99 percent.

Q. Please explain the basis for your proposed treatment of Rates 34 and 35.

A. Rates 34 and 35 serve customers with demands greater than 3,000 kilowatts. The difference between the two rate schedules is that the charges for Rate 35 are differentiated on a time-of-use ("TOU") basis, whereas the charges for Rate 34 are not. Because these two rate schedules serve the same set of eligible customers, it is important to maintain a rational relationship between their respective designs. For example, it would make no sense to reduce Rate 34 significantly relative to Rate 35, so as to force Rate 35 customers to abandon TOU pricing and migrate to the flat energy charges of Rate 34. For this reason, I recommend treating the two rate schedules on a collective basis for rate spread purposes. Specifically, I am recommending that rates for these two rate schedules be set, collectively, equal to cost of service, such that there is no subsidy in or out of this group. Further, as the cost of service study indicates that Rate 34 warrants a smaller rate increase than Rate 35, I am recommending that the base rate increase for Rate 34 be set 1.0 percentage point below the base rate increase for Rate 35.

Q. Please explain the basis of your recommended treatment for Rate E-32.

A. As explained by APS witness Gregory A DeLizio, APS is proposing to divide the current Rate E-32 class into four separate rate schedules differentiated by size: E-32-XS, E-32-S, E-32-M, and E-32-L. This change is consistent with the recommendation of Staff as discussed on page 74 of Decision No. 69633 in Docket No. E-01345A-05-0816. APS's cost-of-service analysis demonstrates that the Company's cost recovery from this group of customers increases steadily as customer size increases: the Rate E-32-XS group is under-recovering its costs whereas the E-32-L group is earning some of the highest returns on the system.

In my opinion, the APS rate spread does not adequately reflect this differentiation in cost-of-service results across this group. For example, Rate E-32-XS is slated to receive an increase that is 2.90 percent <u>below</u> cost of service, whereas Rate E-32-L would receive an increase that is 9.81 percent <u>above</u> its cost-of-service. (See Table KCH-3.) The primary reason to split Rate E-32 into distinct rate schedules is to better reflect cost of service. This objective will be better met with my rate spread proposal.

Q. Have you prepared an analysis that compares the AECC rate spread proposal to the APS rate spread proposal net of current PSA revenues?

A. Yes. This information is presented in Table KCH-5, below. It is compiled from information in Attachments KCH-10, KCH-11, and KCH-12. The information in this table reflects the same rate changes shown in Table KCH-4, except the impacts are shown <u>net</u> of the current PSA revenues from each class.

Table KCH-5

Comparison of AECC Rate Spread to APS Rate Spread
Net of Current PSA Revenues
At APS's Proposed Revenue Requirement

Class	Rate Change per APS COS	APS Proposed Rate Change	AECC Proposed Rate Change
Residential	17.03%	12.73%	14.75%
General Service	6.52%	11.42 %	9.30%
E-20	48.08%	15.34%	17.06%
GS TOU	2.15%	10.64%	6.13%
E-32 (total)	5.90%	11.59%	9.25%
E-32XS	17.67%	14.87%	17.67%
E-32S	6.61%	12.09%	10.64%
E-32M	3.93%	10.96%	7.94%
E-32L	0.60%	9.92%	4.58%
E-34	6.76%	9.88%	9.78%
E-35	12.62%	10.96%	9.74%
Water Pumping	(1.43)%	6.62%	2.56%
Street Lighting	49.86%	15.97%	18.48%
Dusk-to-Dawn	12.58%	17.72%	16.72%
Total	12.09%	12.09%	12.09%

Q. What approach to rate spread should be adopted if the Company's requested revenue requirement is reduced by the Commission?

A. If the Company's requested rate increase is reduced by the Commission, I recommend that the revenue apportionment produced by the rate spread shown in Table KCH-4 (p. 17) should be used as the basis for spreading the smaller revenue change.

Q. Please explain your recommendation further.

A. When I refer to the "revenue apportionment produced by the rate spread shown in Table KCH-4" I am referring to each class's percentage share of total revenue requirement that results from that spread. For example, under my proposed spread, Residential customers would pay 52.11 percent of the total revenue requirement (see Attachment KCH-13). If the Commission agrees that this proposed rate spread is reasonable, then by extension, the corresponding revenue apportionment is reasonable as well.

My recommendation is to retain the percentage revenue apportionment that results from my proposed rate spread and to apply this revenue apportionment to whatever final revenue requirement is approved by the Commission. This type of approach (determining a reasonable revenue apportionment first, then applying it to the resulting revenue requirement) is standard in some jurisdictions such as Minnesota, and was recently adopted in Washington. The advantage of this approach is that it balances the application of gradualism with moving toward cost-of-service. If there is a determination that a given revenue apportionment reasonably accomplishes this balance, then this balance should be retained for a range of different revenue requirements. My recommendation accomplishes this objective.

Q. Do you have an example to illustrate how your approach would work?

A. Yes. An example is presented in Attachment KCH-13. In this example, the revenue apportionment associated with my proposed rate spread at APS's proposed revenue requirement is first determined. Next, we assume that the Commission reduces APS's proposed revenue increase by $100 million. The resulting rate spread is then calculated by holding the revenue apportionment constant. The results are summarized in Table KCH-6, below. The percentage changes in this table are shown both for base rates (comparable to Table KCH-4) and for rate changes net of PSA revenues (comparable to Table KCH-5).

Table KCH-6

AECC Recommended Rate Spread Approach
Example Illustrating $100 Million Revenue Reduction to APS Revenue Proposal

Class	AECC Proposed Base Rate Change	AECC Proposed Rate Change Net of Current PSA Revenues
Residential	15.49%	11.02%
General Service	10.80%	5.75%
E-20	18.03%	13.26%
GS TOU	8.32%	2.69%
E-32 (total)	10.43%	5.70%
E-32XS	17.62%	13.85%
E-32S	11.33%	7.05%
E-32M	9.39%	4.43%
E-32L	6.55%	1.19%
E-34	12.61%	6.22%
E-35	13.58%	6.18%
Water Pumping	4.51%	(0.77)%
Street Lighting	18.03%	14.63%
Dusk-to-Dawn	14.50%	12.93%
Total	13.19%	8.45%

Rate Design

Q. Do you have any concerns with respect to APS's proposed rate design?

A. Yes. For Rate E-35, APS is proposing an inordinately large percentage increase in the demand charge for the Delivery Service component for customers taking service at transmission voltage. Specifically, the current demand charge for Delivery Service for E-35 is $0.303 per on-peak kW, plus $0.030 per off-peak kW. In this proceeding, APS is proposing an increase in this charge to $0.874 per on-peak kW plus $0.086 per off-peak kW – an overall increase in excess of 185 percent. This change is dramatically greater than the Company's overall proposed increase in base rates for E-35 of 18.69 percent. This proposal would have an obviously negative impact to customers taking service at transmission voltage on Rate E-35. At the same time, APS is proposing to reduce the Delivery Charge for the other voltage levels on Rate E-35. The net effect is to reduce the differential between the primary voltage delivery charge and the transmission voltage delivery charge from $3.746 per kW-month to $2.845 per kW-month.

Q. By way of background, why do customers taking service at transmission voltage pay a lower Delivery Charge than customers taking service at secondary or primary voltage?

A. The Delivery Charge recovers APS's costs associated with its distribution system. Transmission voltage customers take service directly from the transmission system and do not use the distribution system; thus, the Delivery Charge for these customers should be zero or minimal.

Q. Is APS also proposing an extraordinary increase in the Delivery Service charges for Rate E-34?

A. No. Nor is APS proposing to reduce the Delivery Charges for primary and secondary voltage for Rate E-34 as significantly as for Rate E-35. As a result, APS's changes create a significant divergence in the proposed Delivery Charges between Rates E-34 and E-35. This divergence is shown in Table KCH-7, below.

Table KCH-7

Comparison of Rate E-34 and E-35 Delivery Charges

	Current Unbundled Delivery Charge	**APS Proposed Unbundled Delivery Charge**
Rate Schedule E-34		
Secondary Service	$4.959/kW	$4.577/kW
Primary Service	$4.169/kW	$3.971/kW
Transmission Service	$0.239/kW	$0.207/kW
Voltage Discount between Transmission and Primary	$3.930/kW	$3.764/kW
Rate Schedule E-35		
Secondary Service		
On-Peak	$4.368/kW	$3.700/kW
Off-Peak	$0.437/kW	$0.370/kW
Total	$4.805/kW	$4.070/kW
Primary Service		
On-Peak	$3.708/kW	$3.459/kW
Off-Peak	$0.371/kW	$0.346/kW
Total	$4.079/kW	$3.805/kW
Transmission Service		
On-Peak	$0.303/kW	$0.874/kW
Off-Peak	$0.030/kW	$0.086/kW
Total	$0.333/kW	$0.960/kW
Voltage Discount between Transmission and Primary (Total)	$3.746/kW	$2.845/kW

As shown in Table KCH-7, the proposed Delivery Charge for transmission voltage service for Rate E-35 is much higher than that of Rate E-34, whereas the proposed Delivery Charges for primary and secondary voltage service on Rate E-35 are much lower than that of Rate E-34. This divergence makes little sense, as

Rates E-34 and E-35 serve the same set of eligible customers. As I stated above, the only difference between the two rates is that Rate E-35 is designed on a TOU basis and E-34 is not. I see no merit in charging a much higher Delivery Charge to a transmission voltage customer on Rate E-35 – where the customer pays energy charges that vary with time-of-day – compared to Rate E-34 – where the customer would pay a flat energy charge.

Q. What alternative do you recommend?

A. I recommend that the $3.764 Delivery Charge differential between primary voltage and transmission voltage that APS is proposing for Rate E-34 be applied to Rate E-35.[5] This differential is nearly identical to the differential that exists now for Rate E-35. My alternative would maintain a more rational relationship between Rates E-34 and E-35 and avoid undue negative rate impacts on E-35 customers taking service at transmission voltage, as would occur under the Company's proposal.

Q. Do you have any other rate design recommendations concerning Rates E-34 and E-35?

A. Yes. APS witness Gregory A. DeLizio is recommending a change in the terms of Rates E-34 and E-35 that would "require a customer to compensate the Company for the costs of additional third-party transmission service that is required solely to provide service to a specific customer or customers." Mr. DeLizio states that this provision would apply when APS must enter into transmission arrangements for new or increased transmission service with a third party and those arrangements "can be directly attributable to a specific customer or customers."[6]

I recommend that this proposed change to the tariff be rejected. In my experience, this proposed provision is highly unusual in a retail tariff and would provide the utility with an inordinate amount of leverage in dealing with its customers. Moreover, APS's retail transmission charges are simply a straight pass-through of rates in the Company's Open Access Transmission Tariff, which are approved by FERC. APS's attempt to introduce additional retail transmission charges outside the purview of its FERC-approved transmission rates would create an ad hoc pricing regime with limited oversight and the potential for double recovery. Such a provision is not in the public interest and should be rejected.

<u>Impact Fee</u>

Q. What is APS proposing with respect to charging an Impact Fee for new customers?

A. APS's proposal is explained in Mr. Rumolo's direct testimony. Mr. Rumolo explains that in Decision No. 70185, the Commission approved revisions to Schedule 3 of the Company's tariff that requires new customers to pay for infrastructure investment required to serve them. Proceeds received from customers pursuant to Schedule 3 are booked as Contributions in Aid of Construction ("CIAC").

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[5] For Rate E-35, the differential between primary and transmission voltage would be calculated by comparing the sum of the on-peak and off-peak Delivery Charges for primary voltage to the sum of the on-peak and off-peak Delivery Charges for transmission voltage.
[6] Direct testimony of Gregory A. DeLizio, p. 33, lines 3-12.

As described by Mr. Rumolo, the CIAC proceeds result in an income tax cost to APS that is capitalized and included in rate base. The carrying cost of this "tax asset" is currently charged to all customers. The Impact Fee being proposed by APS would recover this carrying cost from the new customers whose CIAC payment resulted in the creation of the tax asset. Mr. Rumolo estimates that the Impact Fee revenue requirement for this portion of the proposed Impact Fee is $27 million. In addition, APS is proposing to recover certain incremental distribution-related costs through the Impact Fee, which Mr. Rumolo estimates would cost an additional $21 million per year.

Q. What is your assessment of the Company's Impact Fee proposal?

A. I support the adoption of the CIAC "tax asset" portion of the Impact Fee, as these costs are associated with the direct cost of providing facilities to serve the new customers' premises, which is a reasonable assignment of cost to cost causers. However, I am concerned with the portion of the proposed Impact Fee that is intended to recover incremental system costs. Assigning new customers a fee based on incremental system costs begins to take on the character of "vintage pricing," which is a pricing regime that charges customers discriminatory rates based upon the date at which they initiate utility service. This form of price discrimination raises many policy and economic questions and can result in many unintended consequences, including the undue stifling of economic development. My recommendation is to not adopt this portion of the proposed charge.

Q. Do you have any other comments on this proposal?

A. Yes. If the Impact Fee proposal is adopted it is essential that the revenue from the fee is fully credited against any rate increase awarded in this case.

Demand-Side Management Cost Recovery

Q. What changes to the recovery of demand-side management ("DSM") costs are being proposed by APS?

A. APS is proposing several changes to its DSM cost recovery. These proposed changes are presented by Mr. DeLizio. Specifically, APS is proposing to: (1) increase charges to customers to recover "lost revenues" attributable to DSM investments; (2) change the structure of the DSM Adjustor mechanism to recover costs prospectively, and (3) remove the current 10 percent cap on DSM incentive payments to the utility.

Q. What is your recommendation with respect to these proposed changes?

A. I recommend that these proposed changes be rejected by the Commission. In general, these changes would divert DSM dollars away from DSM projects and instead direct them to the Company's shareholders.

Q. What is the basic justification offered by APS for recovery of "lost revenues"?

A. The basic justification is that DSM projects reduce energy consumption, thereby depriving the Company of fixed cost recovery from sales that have been foregone. The gist of the argument is that the loss of margins attributable to DSM programs creates a disincentive for utilities to support DSM, and thus creates a bias in favor of supply-side resources.

Q. What is your response to the "lost revenues" argument?

A. The "lost revenues" argument is widely recited by utilities and is, in part, an unintended consequence of efforts by regulatory commissions to reduce utility risk through the adoption of fuel adjustor mechanisms. Utilities that are at risk for recovery of fuel and purchased power costs have a natural economic incentive to reduce high energy production costs through DSM. This incentive is evidently reduced when utilities are assured recovery of high marginal fuel costs through fuel adjustor mechanisms, such as APS's PSA (although the PSA still provides some incentive through its 90/10 sharing provision). As fuel adjustor mechanisms are an obvious benefit to utilities, the claim that "lost revenue" recovery is necessary to remove the disincentive to undertake DSM is tantamount to demanding a new benefit that is made necessary by virtue of having been awarded a previous benefit. Viewed in this broader context, the argument is not persuasive.

It should also be borne in mind that any "lost revenues" from DSM are short-term in nature. To the extent that DSM reduces sales levels, the utility is able to re-establish its margins in its next rate filing reflecting the newsales volumes. But perhaps more importantly, the argument that without "lost revenue" recovery the utility is biased in favor of supply-side solutions does not square with the jeremiad addressing the problems of regulatory lag filed by APS in this proceeding. One of the reasons to invest in DSM is to avoid incurring new fixed cost. One of the implicit assumptions in the utilities' "lost revenues" argument is that the cost of supply-side alternatives is somehow recovered without regulatory lag – which of course is not the case. The upshot is that a rational utility should have an incentive to invest in DSM – without extra payments for "lost revenues" – if it allows the utility to avoid supply-side investments that are subject to regulatory lag.

Q. What is your response to APS's proposal to change the DSM Adjustor so that it recovers prospective costs rather than incurred costs?

A. I am concerned that setting the adjustor based on prospective costs will create a bias to set DSM charges higher than is necessary, to the detriment of customers. I believe it is sounder to continue to set the charge to recover actually-incurred costs.

Q. What is your response to APS's proposal to remove the cap on its incentive payments from DSM?

A. The current program already allows up to 10 percent of DSM dollars collected from customers to be paid to APS as an incentive, rather than going to fund DSM projects. In my opinion, diverting even more funds away from DSM programs is not a good use of customer money.

<u>Environmental Improvement Surcharge</u>

Q. What changes has APS proposed with respect to the Environmental Improvement Surcharge?

A. As explained by Mr. DeLizio, APS is proposing to modify the Environmental Improvement Surcharge ("EIS") such that it would work as an adjustor mechanism. In addition, rather than treating the EIS funds used for eligible projects as CIAC, as is required by the Commission, APS is proposing that the EIS provide a return on investment and recovery of expenses based on the projected cost of approved environmental expenditures.

Q. What is your assessment of this proposal?

A. This issue was addressed at length by the Commission on pages 82-87 in Decision No. 69633 in Docket No. E-01345A-05-0816. The Commission determined that with customers providing the up-front capital for the EIS projects, these funds should be booked as CIAC when used by APS to finance eligible projects. I agree with this determination.

To the extent that the EIS is considered anew, I recommend that the Commission consider eliminating this surcharge in its entirety, consistent with my recommendation, in Docket No. E-01345A-05-0816, not to adopt this surcharge in the first instance.

Q. Why do you recommend that the Commission consider eliminating this surcharge?

A. Allowing a "stand-alone" rate adjustment for incremental environmental improvement costs is an example of "single-issue ratemaking," in which a single item is permitted to impact rates in isolation from all other rate considerations. In contrast, when regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers, the standard practice is to review and consider all relevant factors, rather than just a single factor. Unless it can be shown to involve a compelling public interest, single-issue ratemaking is generally not sound regulatory policy, as it ignores the multitude of other factors that otherwise influence rates, some of which could, if properly considered, move rates in the opposite direction from the single-issue change. There is no compelling reason to permit single-issue ratemaking in this instance.

Q. Are there circumstances that warrant exceptions to preclusions against single-issue ratemaking?

A. There are certain types of cost increases that regulatory commissions have come to allow without the benefit of conducting a general rate case. Because such exceptions constitute a form of single-issue ratemaking, it is not unusual for regulatory commissions to identify criteria that must be met for such treatment to be allowed, such as whether the costs in question exhibit volatility and/or whether the costs are largely outside the utility's control. In light of such criteria, the single-issue adjustments most commonly adopted are commodity and power cost adjustment mechanisms, such as the PSA mechanism approved by the Commission for APS.

Q. Do environmental improvement costs fit the description of "costs that are outside the utility's control" or "costs that exhibit volatility?"

A. Not really. While APS is subject to current and future provisions governing environmental quality, these provisions are long-term in nature and do not change from month to month the way fuel costs change.

Q. Are you opposed to APS being able to recover prudently-incurred environmental improvement costs?

A. No, I am not. I am opposed to adoption of single-issue adjustment mechanisms absent a compelling public interest. The appropriate forum for establishing rates to recover prudently-incurred utility investment is a general rate proceeding in which all cost and revenue information can be considered.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Summary of APS' Cost of Service Results Excluding PSA Revenue at APS' Proposed $448 Million Base Revenue Increase

Line No.	DESCRIPTION	TOTAL RETAIL	RESIDENTIAL	TOTAL GENERAL SERVICE	E-20 (Church Rate)	General Ser. TOU	E-30, E-32 SUBTOTAL	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)
1	RATE BASE	5,359,964,470	2,954,460,405	2,282,487,853	11,121,512	24,771,860	2,000,716,718	426,820,799	565,107,163	525,979,871	482,808,885
2	SALES REVENUE (PRESENT RATES)	2,637,447,089	1,347,032,966	1,240,168,957	3,267,158	15,428,992	1,046,513,584	173,837,575	273,357,634	292,377,288	306,941,087
3	OPERATING INCOME	203,111,908	84,187,567	114,977,528	(90,787)	1,468,499	109,748,343	15,075,886	32,042,297	30,888,799	31,741,361
4	CURRENT RATE OF RETURN	3.79%	2.85%	5.04%	-0.82%	5.93%	5.49%	3.53%	5.67%	5.87%	6.57%
5	TARGETED RATE OF RETURN	8.86%	8.86%	8.86%	8.86%	8.86%	8.86%	8.86%	8.86%	8.86%	8.86%
6	RETURN REQ FOR TARGETED ROR	474,892,852	261,765,192	202,228,424	985,366	2,194,787	177,263,501	37,816,323	50,068,495	46,601,817	42,776,867
7	SALES REVENUE REQ TARGETED ROR	3,085,640,806	1,639,878,045	1,384,052,449	5,041,823	16,626,709	1,157,851,176	211,338,530	303,084,506	318,289,526	325,138,614
8	REVENUE DEFICIENCY SALES REV	448,193,717	292,845,079	143,883,492	1,774,665	1,197,717	111,337,592	37,500,955	29,726,872	25,912,238	18,197,527
9	PERCENT INCREASE REQUIRED	16.99%	21.74%	11.60%	54.32%	7.76%	10.64%	21.57%	10.87%	8.86%	5.93%

Line No.	DESCRIPTION	E-34	E-35	E-38,221 (Water Pumping)	STREET LIGHTING	DUSK TO DAWN
10	RATE BASE	127,572,106	118,305,657	30,142,093	64,347,024	28,527,095
11	SALES REVENUE (PRESENT RATES)	85,742,120	89,217,103	25,376,187	17,372,977	7,496,002
12	OPERATING INCOME	4,442,684	(591,210)	2,082,640	(20,057)	1,884,230
13	CURRENT RATE OF RETURN	3.48%	-0.50%	6.91%	-0.03%	6.61%
14	TARGETED RATE OF RETURN	8.86%	8.86%	8.86%	8.86%	8.86%
15	RETURN REQ FOR TARGETED ROR	11,302,889	10,481,881	2,670,589	5,701,146	2,527,501
16	SALES REVENUE REQ TARGETED ROR	97,055,192	107,477,548	26,345,775	26,807,718	8,556,819
17	REVENUE DEFICIENCY SALES REV	11,313,072	18,260,445	969,588	9,434,741	1,060,817
18	PERCENT INCREASE REQUIRED	13.19%	20.47%	3.82%	54.31%	14.15%

Data Source: Rumolo_Direct Workpaper DJR_WP01, DJR_WP03_APS08736, APS08738.xls.

Summary of APS' Cost of Service Results Including Current PSA Rate Revenue at APS' Proposed $448 Million Base Revenue Increase ($333 Million Increase Net of Current PSA Revenue)

Line No.	DESCRIPTION	TOTAL RETAIL	RESIDENTIAL	TOTAL GENERAL SERVICE	E-20 (Church Rate)	General Ser. TOU	E-30, E-32 SUBTOTAL	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)
1	RATE BASE	5,359,964,470	2,954,460,405	2,282,487,853	11,121,512	24,771,860	2,000,716,718	426,820,799	565,107,163	525,979,871	482,808,885
2	SALES REVENUE (PRESENT RATES)	2,637,447,089	1,347,032,966	1,240,168,957	3,267,158	15,428,992	1,046,513,584	173,837,575	273,357,634	292,377,288	306,941,087
3	PSA REVENUE (PRESENT RATES)	115,420,488	54,227,260	59,222,740	137,568	847,004	46,854,460	5,764,972	10,946,928	13,874,484	16,268,076
4	OPERATING INCOME WITH PSA	273,102,892	117,070,977	150,890,198	(7,366)	1,982,122	138,160,887	18,571,765	38,680,514	39,302,286	41,606,322
5	CURRENT RATE OF RETURN	5.10%	3.96%	6.61%	-0.07%	8.00%	6.91%	4.35%	6.84%	7.47%	8.62%
6	TARGETED RATE OF RETURN	8.86%	8.86%	8.86%	8.86%	8.86%	0	8.86%	8.86%	8.86%	8.86%
7	RETURN REQ FOR TARGETED ROR	474,892,852	261,765,192	202,228,424	985,366	2,194,787	177,263,501	37,816,323	50,068,495	46,601,817	42,776,867
8	SALES REVENUE REQ TARGETED ROR	3,085,640,806	1,639,878,045	1,384,052,449	5,041,823	16,626,709	1,157,851,176	211,338,530	303,084,506	318,289,526	325,138,614
9	REVENUE DEFICIENCY SALES REV	332,773,229	238,617,819	84,660,752	1,637,097	350,713	64,483,132	31,735,983	18,779,944	12,037,754	1,929,451
10	PERCENT INCREASE REQUIRED	12.09%	17.03%	6.52%	48.08%	2.15%	5.90%	17.67%	6.61%	3.93%	0.60%

Line No.	DESCRIPTION	E-34	E-35	E-38,221 (Water Pumping)	STREET LIGHTING	DUSK TO DAWN
11	RATE BASE	127,572,106	118,305,657	30,142,093	64,347,024	28,527,095
12	SALES REVENUE (PRESENT RATES)	85,742,120	89,217,103	25,376,187	17,372,977	7,496,002
13	PSA REVENUE (PRESENT RATES)	5,164,112	6,219,596	1,351,080	515,000	104,408
14	OPERATING INCOME WITH PSA	7,574,201	3,180,353	2,901,935	292,239	1,947,543
15	CURRENT RATE OF RETURN	5.94%	2.69%	9.63%	0.45%	6.83%
16	TARGETED RATE OF RETURN	8.86%	8.86%	8.86%	8.86%	8.86%
17	RETURN REQ FOR TARGETED ROR	11,302,889	10,481,881	2,670,589	5,701,146	2,527,501
18	SALES REVENUE REQ TARGETED ROR	97,055,192	107,477,548	26,345,775	26,807,718	8,556,819
19	REVENUE DEFICIENCY SALES REV	6,148,960	12,040,849	(381,492)	8,919,741	956,409
20	PERCENT INCREASE REQUIRED	6.76%	12.62%	-1.43%	49.86%	12.58%

Data Source: Rumolo_Direct Workpaper DJR_WP01, DJR_WP03_APS08736, APS08738.xls

Note: PSA revenue at present rates derived by applying 4 mills/kWh to the Schedule H-2 test year energy for each rate schedule. The additional net income impact was derived by applying the operating income factor of 60.64% (see APS Schedule C-3, p. 1 of 1) to the PSA revenue.

Summary of APS' Cost of Service Results Including Projected PSA Rate Revenue at APS' Proposed $448 Million Base Revenue Increase ($278 Million Increase Net of Projected PSA Revenue)

Line No.	DESCRIPTION	TOTAL RETAIL	RESIDENTIAL	TOTAL GENERAL SERVICE	E-20 (Church Rate)	General Ser. TOU	E-30, E-32 SUBTOTAL	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)
1	RATE BASE	5,359,964,470	2,954,460,405	2,282,487,853	11,121,512	24,771,860	2,000,716,718	426,820,799	565,107,163	525,979,871	482,808,885
2	SALES REVENUE (PRESENT RATES)	2,637,447,089	1,347,032,966	1,240,168,957	3,267,158	15,428,992	1,046,513,584	173,837,575	273,357,634	292,377,288	306,941,087
3	PSA REVENUE (PROJECTED RATES)	169,977,000	79,859,000	87,217,000	203,000	1,246,000	69,003,000	8,490,000	16,122,000	20,433,000	23,958,000
4	OPERATING INCOME WITH PSA	306,185,961	132,614,064	167,865,917	32,312	2,224,073	151,591,762	20,224,222	41,818,678	43,279,370	46,269,492
5	CURRENT RATE OF RETURN	5.71%	4.49%	7.35%	0.29%	8.98%	7.58%	4.74%	7.40%	8.23%	9.58%
6	TARGETED RATE OF RETURN	8.86%	8.86%	8.86%	8.86%	8.86%	0	8.86%	8.86%	8.86%	8.86%
7	RETURN REQ FOR TARGETED ROR	474,892,852	261,765,192	202,228,424	985,366	2,194,787	177,263,501	37,816,323	50,068,495	46,601,817	42,776,867
8	SALES REVENUE REQ TARGETED ROR	3,085,640,806	1,639,878,045	1,384,052,449	5,041,823	16,626,709	1,157,851,176	211,338,530	303,084,506	318,289,526	325,138,614
9	REVENUE DEFICIENCY SALES REV	278,216,717	212,986,079	56,666,492	1,571,665	(48,283)	42,334,592	29,010,955	13,604,872	5,479,238	(5,760,473)
10	PERCENT INCREASE REQUIRED	9.91%	14.93%	4.27%	45.29%	-0.29%	3.80%	15.91%	4.70%	1.75%	-1.74%

Line No.	DESCRIPTION	E-34	E-35	E-38,221 (Water Pumping)	STREET LIGHTING	DUSK TO DAWN
11	RATE BASE	127,572,106	118,305,657	30,142,093	64,347,024	28,527,095
12	SALES REVENUE (PRESENT RATES)	85,742,120	89,217,103	25,376,187	17,372,977	7,496,002
13	PSA REVENUE (PROJECTED RATES)	7,605,000	9,160,000	1,989,000	758,000	154,000
14	OPERATING INCOME WITH PSA	9,054,356	4,963,414	3,288,770	439,594	1,977,616
15	CURRENT RATE OF RETURN	7.10%	4.20%	10.91%	0.68%	6.93%
16	TARGETED RATE OF RETURN	8.86%	8.86%	8.86%	8.86%	8.86%
17	RETURN REQ FOR TARGETED ROR	11,302,889	10,481,881	2,670,589	5,701,146	2,527,501
18	SALES REVENUE REQ TARGETED ROR	97,055,192	107,477,548	26,345,775	26,807,718	8,556,819
19	REVENUE DEFICIENCY SALES REV	3,708,072	9,100,445	(1,019,412)	8,676,741	906,817
20	PERCENT INCREASE REQUIRED	3.97%	9.25%	-3.73%	47.86%	11.85%

Data Source: Rumolo_Direct Workpaper DJR_WP01, DJR_WP03_APS08736, APS08738.xls.
Data Source: APS Schedule H-2, Column (I).

Note: The additional net income impact was derived by applying the operating income factor of 60.64% (see APS Schedule C-3, p. 1 of 1) to the PSA revenue.

Summary of APS' Proposed Revenue Spread Excluding PSA Revenue
at APS' Proposed $448 Million Base Revenue Increase

Line No.	DESCRIPTION	TOTAL RETAIL	RESIDENTIAL	TOTAL GENERAL SERVICE	E-20 (Church Rate)	General Ser. TOU	E-30, E-32 SUBTOTAL	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)
1	RATE BASE	5,359,964,470	2,954,460,405	2,282,487,853	11,121,512	24,771,860	2,000,716,718	426,820,799	565,107,163	525,979,871	482,808,885
2	SALES REVENUE (PRESENT RATES)	2,637,447,089	1,347,032,966	1,240,168,957	3,267,158	15,428,992	1,046,513,584	173,837,575	273,357,634	292,377,288	306,941,087
3	OPERATING INCOME	203,111,908	84,187,567	114,977,528	(90,787)	1,468,499	109,748,343	15,075,886	32,042,297	30,888,799	31,741,361
4	CURRENT RATE OF RETURN	3.79%	2.85%	5.04%	-0.82%	5.93%	5.49%	3.53%	5.67%	5.87%	6.57%
5	SALES REVENUE (PROPOSED RATES)	3,085,641,089	1,579,682,966	1,447,768,957	3,927,158	18,006,992	1,220,047,584	206,300,575	318,683,634	339,803,288	355,260,087
6	APS PROPOSED REVENUE INCREASE	448,194,000	232,650,000	207,600,000	660,000	2,578,000	173,534,000	32,463,000	45,326,000	47,426,000	48,319,000
7	PERCENT INCREASE	16.99%	17.27%	16.74%	20.20%	16.71%	16.58%	18.67%	16.58%	16.22%	15.74%
8	OPERATING INCOME WITH INCREASE	474,896,750	225,266,527	240,866,168	309,437	3,031,798	214,979,360	34,761,449	59,527,983	59,647,926	61,042,002
9	PROPOSED RATE OF RETURN	8.86%	7.62%	10.55%	2.78%	12.24%	10.75%	8.14%	10.53%	11.34%	12.64%

Line No.	DESCRIPTION	E-34	E-35	E-38,221 (Water Pumping)	STREET LIGHTING	DUSK TO DAWN
10	RATE BASE	127,572,106	118,305,657	30,142,093	64,347,024	28,527,095
11	SALES REVENUE (PRESENT RATES)	85,742,120	89,217,103	25,376,187	17,372,977	7,496,002
12	OPERATING INCOME	4,442,684	(591,210)	2,082,640	(20,057)	1,884,230
13	CURRENT RATE OF RETURN	3.48%	-0.50%	6.91%	-0.03%	6.61%
14	SALES REVENUE (PROPOSED RATES)	99,891,120	105,896,103	28,497,187	20,744,977	8,947,002
15	APS PROPOSED REVENUE INCREASE	14,149,000	16,679,000	3,121,000	3,372,000	1,451,000
16	PERCENT INCREASE	16.50%	18.69%	12.30%	19.41%	19.36%
17	OPERATING INCOME WITH INCREASE	13,022,637	9,522,936	3,975,215	2,024,724	2,764,117
18	PROPOSED RATE OF RETURN	10.21%	8.05%	13.19%	3.15%	9.69%

Data Source: Rumolo_Direct Workpaper DJR_WP01, DJR_WP03_APS08736, APS08738.xls.
Data Source: APS Schedule H-2

Summary of APS' Proposed Revenue Spread Including Current PSA Revenue
at APS' Proposed $448 Million Base Revenue Increase
($333 Million Increase Net of Current PSA Revenue)

Line No.	DESCRIPTION	TOTAL RETAIL	RESIDENTIAL	TOTAL GENERAL SERVICE	E-20 (Church Rate)	General Ser. TOU	E-30, E-32 SUBTOTAL	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)
1	RATE BASE	5,359,964,470	2,954,460,405	2,282,487,853	11,121,512	24,771,860	2,000,716,718	426,820,799	565,107,163	525,979,871	482,808,885
2	SALES REVENUE (PRESENT RATES)	2,637,447,089	1,347,032,966	1,240,168,957	3,267,158	15,428,992	1,046,513,584	173,837,575	273,357,634	292,377,288	306,941,087
3	PSA REVENUE (PRESENT RATES)	115,420,488	54,227,260	59,222,740	137,568	847,004	46,854,460	5,764,972	10,946,928	13,874,484	16,268,076
4	OPERATING INCOME WITH PSA	273,102,892	117,070,977	150,890,198	(7,366)	1,982,122	138,160,887	18,571,765	38,680,514	39,302,286	41,606,322
5	CURRENT RATE OF RETURN	5.10%	3.96%	6.61%	-0.07%	8.00%	6.91%	4.35%	6.84%	7.47%	8.62%
6	SALES REVENUE (PROPOSED RATES)	3,085,641,085	1,579,682,966	1,447,768,953	3,927,158	18,006,992	1,220,047,580	206,300,571	318,683,634	339,803,288	355,260,087
7	APS PROPOSED REVENUE INCREASE	332,773,508	178,422,740	148,377,256	522,432	1,730,996	126,679,536	26,698,024	34,379,072	33,551,516	32,050,924
8	PERCENT INCREASE	12.09%	12.73%	11.42%	15.34%	10.64%	11.59%	14.87%	12.09%	10.96%	9.92%
9	OPERATING INCOME WITH INCREASE	474,896,748	225,266,527	240,866,166	309,437	3,031,798	214,979,358	34,761,447	59,527,983	59,647,926	61,042,002
10	PROPOSED RATE OF RETURN	8.86%	7.62%	10.55%	2.78%	12.24%	10.75%	8.14%	10.53%	11.34%	12.64%

Line No.	DESCRIPTION	E-34	E-35	E-38,221 (Water Pumping)	STREET LIGHTING	DUSK TO DAWN
11	RATE BASE	127,572,106	118,305,657	30,142,093	64,347,024	28,527,095
12	SALES REVENUE (PRESENT RATES)	85,742,120	89,217,103	25,376,187	17,372,977	7,496,002
13	PSA REVENUE (PRESENT RATES)	5,164,112	6,219,596	1,351,080	515,000	104,408
14	OPERATING INCOME WITH PSA	7,574,201	3,180,353	2,901,935	292,239	1,947,543
15	CURRENT RATE OF RETURN	5.94%	2.69%	9.63%	0.45%	6.83%
16	SALES REVENUE (PROPOSED RATES)	99,891,120	105,896,103	28,497,187	20,744,977	8,947,002
17	APS PROPOSED REVENUE INCREASE	8,984,888	10,459,404	1,769,920	2,857,000	1,346,592
18	PERCENT INCREASE	9.88%	10.96%	6.62%	15.97%	17.72%
19	OPERATING INCOME WITH INCREASE	13,022,637	9,522,936	3,975,215	2,024,724	2,764,117
20	PROPOSED RATE OF RETURN	10.21%	8.05%	13.19%	3.15%	9.69%

Data Source: Rumolo_Direct Workpaper DJR_WP01, DJR_WP03_APS08736, APS08738.xls

Note: PSA revenue at present rates derived by applying *4 mills/kWh to* the Schedule H-2 test year energy for each rate schedule. The additional net income impact was derived by applying the operating income factor of 60.64% (see APS Schedule C-3, p. 1 of 1) to the PSA revenue.

Summary of APS' Proposed Revenue Spread Including Projected PSA Revenue at APS' Proposed $448 Million Base Revenue Increase ($278 Million Increase Net of Projected PSA Revenue)

Line No.	DESCRIPTION	TOTAL RETAIL	RESIDENTIAL	TOTAL GENERAL SERVICE	E-20 (Church Rate)	General Ser. TOU	E-30, E-32 SUBTOTAL	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)
1	RATE BASE	5,359,964,470	2,954,460,405	2,282,487,853	11,121,512	24,771,860	2,000,716,718	426,820,799	565,107,163	525,979,871	482,808,885
2	SALES REVENUE (PRESENT RATES)	2,637,447,089	1,347,032,966	1,240,168,957	3,267,158	15,428,992	1,046,513,584	173,837,575	273,357,634	292,377,288	306,941,087
3	PSA REVENUE (PROJECTED RATES)	169,977,000	79,859,000	87,217,000	203,000	1,246,000	69,003,000	8,490,000	16,122,000	20,433,000	23,958,000
4	OPERATING INCOME WITH PSA	306,185,961	132,614,064	167,865,917	32,312	2,224,073	151,591,762	20,224,222	41,818,678	43,279,370	46,269,492
5	CURRENT RATE OF RETURN	5.71%	4.49%	7.35%	0.29%	8.98%	7.58%	4.74%	7.40%	8.23%	9.58%
6	SALES REVENUE (PROPOSED RATES)	3,085,641,089	1,579,682,966	1,447,768,957	3,927,158	18,006,992	1,220,047,584	206,300,575	318,683,634	339,803,288	355,260,087
7	APS PROPOSED REVENUE INCREASE	278,217,000	152,791,000	120,383,000	457,000	1,332,000	104,531,000	23,973,000	29,204,000	26,993,000	24,361,000
8	PERCENT INCREASE	9.91%	10.71%	9.07%	13.17%	7.99%	9.37%	13.15%	10.09%	8.63%	7.36%
9	OPERATING INCOME WITH INCREASE	474,896,750	225,266,527	240,866,168	309,437	3,031,798	214,979,360	34,761,449	59,527,983	59,647,926	61,042,002
10	PROPOSED RATE OF RETURN	8.86%	7.62%	10.55%	2.78%	12.24%	10.75%	8.14%	10.53%	11.34%	12.64%

Line No.	DESCRIPTION	E-34	E-35	E-38,221 (Water Pumping)	STREET LIGHTING	DUSK TO DAWN
11	RATE BASE	127,572,106	118,305,657	30,142,093	64,347,024	28,527,095
12	SALES REVENUE (PRESENT RATES)	85,742,120	89,217,103	25,376,187	17,372,977	7,496,002
13	PSA REVENUE (PROJECTED RATES)	7,605,000	9,160,000	1,989,000	758,000	154,000
14	OPERATING INCOME WITH PSA	9,054,356	4,963,414	3,288,770	439,594	1,977,616
15	CURRENT RATE OF RETURN	7.10%	4.20%	10.91%	0.68%	6.93%
16	SALES REVENUE (PROPOSED RATES)	99,891,120	105,896,103	28,497,187	20,744,977	8,947,002
17	APS PROPOSED REVENUE INCREASE	6,544,000	7,519,000	1,132,000	2,614,000	1,297,000
18	PERCENT INCREASE	7.01%	7.64%	4.14%	14.42%	16.95%
19	OPERATING INCOME WITH INCREASE	13,022,637	9,522,936	3,975,215	2,024,724	2,764,117
20	PROPOSED RATE OF RETURN	10.21%	8.05%	13.19%	3.15%	9.69%

Data Source: Rumolo_Direct Workpaper DJR_WP01, DJR_WP03_APS08736, APS08738.xls.
Data Source: APS Schedule H-2, Column (I).

Note: The additional net income impact was derived by applying the operating income factor of 60.64% (see APS Schedule C-3, p. 1 of 1) to the PSA revenue.

AECC Recommended Rate Spread at APS' Requested Revenue Increase

AECC Recommended Revenue Increase for each Customer Class based on APS's Cost of Service Study

E-20 & Outdoor/Streetlighting Adder above System Average Increase = 5.00%

Gen. Serv. TOU, E-32 (Greater than 20 kW), Water Pumping & Dusk to Dawn Adder Above Cost = 4.20%

	(a)	(b)	(c)	(d)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
Line No.	Rate Class	Current Retail Base Revenues[1]	Rate Base[1]	Return Req'd Return @ Equal ROR[1]	Required Revenue Increase[1]	Req'd Percent Change	AECC Recommended Base Revenue Increase	AECC Base Percent Change	AECC Recommended Base Revenue Net of Current PSA Revenue	AECC Base Percent Change Net of Current PSA	AECC Recommended Base Revenue Net of Projected PSA Revenue	AECC Base Percent Change Net of Projected PSA
1	Residential	$1,347,032,966	$2,954,460,405	$261,765,192	$292,845,079	21.74%	$260,876,345	19.37%	$206,649,085	14.75%	$181,017,345	12.69%
2	General Service											
3	E-20	$3,267,158	$11,121,512	$985,366	$1,774,665	54.32%	$718,561	21.99%	$580,993	17.06%	$515,561	14.86%
4	General Serv. TOU	$15,428,992	$24,771,860	$2,194,787	$1,197,717	7.76%	$1,845,025	11.96%	$998,021	6.13%	$599,025	3.59%
5	E-30, E-32 (0 - 20 kW)	$173,837,575	$426,820,799	$37,816,323	$37,500,955	21.57%	$37,500,955	21.57%	$31,735,983	17.67%	$29,010,955	15.91%
6	E-32 (21 - 100 kW)	$273,357,634	$565,107,163	$50,068,495	$29,726,872	10.87%	$41,195,313	15.07%	$30,248,385	10.64%	$25,073,313	8.66%
7	E-32 (101 - 400 kW)	$292,377,288	$525,979,871	$46,601,817	$25,912,238	8.86%	$38,178,629	13.06%	$24,304,145	7.94%	$17,745,629	5.67%
8	E-32 (401+ kW)	$306,941,087	$482,808,885	$42,776,867	$18,197,527	5.93%	$31,074,928	10.12%	$14,806,852	4.58%	$7,116,928	2.15%
9	E-30, E-32 Subtotal	$1,046,513,584	$2,000,716,718	$177,263,501	$111,337,592	10.64%	$147,949,825	14.14%	$101,095,365	9.25%	$78,946,825	7.08%
10	E-34	$85,742,120	$127,572,106	$11,302,889	$11,313,072	13.19%	$14,055,843	16.39%	$8,891,731	9.78%	$6,450,843	6.91%
11	E-35	$89,217,103	$118,305,657	$10,481,881	$18,260,445	20.47%	$15,517,674	17.39%	$9,298,078	9.74%	$6,357,674	6.46%
12	General Service Total	$1,240,168,957	$2,282,487,853	$202,228,424	$143,883,492	11.60%	$180,086,928	14.52%	$120,864,188	9.30%	$92,869,928	7.00%
13	Water Pumping (E-38, E-221)	$25,376,187	$30,142,093	$2,670,589	$969,588	3.82%	$2,034,220	8.02%	$683,140	2.56%	$45,220	0.17%
14	Outdoor/Street Lighting	$17,372,977	$64,347,024	$5,701,146	$9,434,741	54.31%	$3,820,920	21.99%	$3,305,920	18.48%	$3,062,920	16.89%
15	Dusk to Dawn	$7,496,002	$28,527,095	$2,527,501	$1,060,817	14.15%	$1,375,304	18.35%	$1,270,896	16.72%	$1,221,304	15.96%
16	ACC Total	$2,637,447,089	$5,359,964,470	$474,892,852	$448,193,717	16.99%	$448,193,717	16.99%	$332,773,229	12.09%	$278,216,717	9.91%

1. Data Source: Rumolo_Direct Workpaper DJR_WP01, DJR_WP03_APS08736, APS08738.xls

AECC Recommended Rate Spread Approach
Example Illustrating a $100 Million Revenue Reduction to APS' Requested Increase

	(a)	(b)	(c)	(d)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
						Revenue Spread at Assumed $348 Million Increase						
Line No.	Rate Class	Current Retail Base Revenues	AECC Recommended Base Revenue Increase at APS' Requested Increase	AECC Recommended Retail Base Revenue at APS' Requested Increase	Revenue Apportionment Percentage	AECC Recommended Retail Base Revenue	AECC Recommended Base Revenue Increase	AECC Base Percent Change	AECC Recommended Base Revenue Increase Net of Current PSA Revenue	AECC Base Percent Change Net of Current PSA	AECC Recommended Base Revenue Increase Net of Projected PSA Revenue	AECC Base Percent Change Net of Projected PSA
1	Residential	$1,347,032,966	$260,876,345	$1,607,909,311	52.11%	$1,555,698,953	$208,665,987	15.49%	$154,438,727	11.02%	$128,806,987	9.03%
2	General Service											
3	E-20	$3,267,158	$718,561	$3,985,719	0.13%	$3,856,299	$589,141	18.03%	$451,573	13.26%	$386,141	11.13%
4	General Serv. TOU	$15,428,992	$1,845,025	$17,274,017	0.56%	$16,713,113	$1,284,121	8.32%	$437,117	2.69%	$38,121	0.23%
5	E-30, E-32 (0 - 20 kW)	$173,837,575	$37,500,955	$211,338,530	6.85%	$204,476,165	$30,638,590	17.62%	$24,873,618	13.85%	$22,148,590	12.15%
6	E-32 (21 - 100 kW)	$273,357,634	$41,195,313	$314,552,947	10.19%	$304,339,111	$30,981,477	11.33%	$20,034,549	7.05%	$14,859,477	5.13%
7	E-32 (101 - 400 kW)	$292,377,288	$38,178,629	$330,555,917	10.71%	$319,822,449	$27,445,161	9.39%	$13,570,677	4.43%	$7,012,161	2.24%
8	E-32 (401+ kW)	$306,941,087	$31,074,928	$338,016,015	10.95%	$327,040,310	$20,099,223	6.55%	$3,831,147	1.19%	($3,858,777)	-1.17%
9	E-30, E-32 Subtotal	$1,046,513,584	$147,949,825	$1,194,463,409	38.71%	$1,155,678,036	$109,164,452	10.43%	$62,309,992	5.70%	$40,161,452	3.60%
10	E-34	$85,742,120	$14,055,843	$99,797,963	3.23%	$96,557,428	$10,815,308	12.61%	$5,651,196	6.22%	$3,210,308	3.44%
11	E-35	$89,217,103	$15,517,674	$104,734,777	3.39%	$101,333,938	$12,116,835	13.58%	$5,897,239	6.18%	$2,956,835	3.01%
12	General Service Total	$1,240,168,957	$180,086,928	$1,420,255,885	46.03%	$1,374,138,814	$133,969,857	10.80%	$74,747,117	5.75%	$46,752,857	3.52%
13	Water Pumping (E-38, E-221)	$25,376,187	$2,034,220	$27,410,407	0.89%	$26,520,365	$1,144,178	4.51%	($206,902)	-0.77%	($844,822)	-3.09%
14	Outdoor/Street Lighting	$17,372,977	$3,820,920	$21,193,897	0.69%	$20,505,711	$3,132,734	18.03%	$2,617,734	14.63%	$2,374,734	13.10%
15	Dusk to Dawn	$7,496,002	$1,375,304	$8,871,306	0.29%	$8,583,246	$1,087,244	14.50%	$982,836	12.93%	$933,244	12.20%
16	ACC Total	$2,637,447,089	$448,193,717	$3,085,640,806	100.00%	$2,985,447,089	$348,000,000	13.19%	$232,579,512	8.45%	$178,023,000	6.34%