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BEFORE THE ARIZONA CORPORATION COMMISSION

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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, AND TO AMEND DECISION NO. 67744	DOCKET NO. E-01345A-05-0816 **NOTICE OF FILING OF DIRECT TESTIMONY, ATTACHMENTS, AND SUMMARY OF KEVIN C. HIGGINS ON COST OF SERVICE/RATE SPREAD/RATE DESIGN ON BEHALF OF PHELPS DODGE MINING COMPANY AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION**

Phelps Dodge Mining Company and Arizonans for Electric Choice and Competition, through undersigned counsel, hereby provide notice of filing the Direct Testimony, Attachments, and Summary on Cost of Service/Rate Spread/Rate Design of their witness, Kevin C. Higgins, in the above captioned docket.

RESPECTFULLY SUBMITTED this 1st day of September 2006.

Arizona Corporation Commission
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SEP - 1 2006
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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 FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	**Docket No. E-01345A-05-0816**

Summary of

Direct Testimony of Kevin C. Higgins

on behalf of

Phelps Dodge Mining Company and

Arizonans for Electric Choice and Competition

Cost-of-Service / Rate Spread / Rate Design

September 1, 2006

SUMMARY

DIRECT TESTIMONY OF KEVIN C. HIGGINS

Cost-of-Service / Rate Spread / Rate Design

With respect to cost-of-service, rate spread, and rate design issues, I offer the following conclusions and recommendations:

- APS's use of the 4-CP method for allocating fixed production cost is appropriate given the Company's system load characteristics and should be accepted by the Commission.

- APS's proposed rate spread continues the current practice of requiring General Service customers to subsidize Residential rates. According to APS's cost-of-service study, General Service rates would have to increase 14.88 percent and Residential rates would have to increase 27.05 percent for the Company to recover its requested revenue requirement (excluding the proposed Environmental Improvement Charge). Instead, APS has proposed a 21.6 percent increase for General Service rates and a 21.14 percent increase for Residential rates.

- APS's fuel and purchased power costs vary considerably throughout the year as well as during the course of each day. Generally, these costs are higher in summer, and for any given day, higher during the peak hours of the afternoon and evening. Yet, the Company's allocation of its energy costs across customer classes does not take into consideration the variation in class usage across seasons or time-of-day. The Company's approach simply allocates fuel and purchased power cost based on the system average cost throughout the year. Such an approach understates the energy cost responsibility for those customer classes whose usage is more heavily weighted toward the more expensive summer and daily on-peak periods. In turn, this practice overstates the cost responsibility for the remaining classes. To better align the allocation of APS's energy cost with cost causation, I have added a step to APS's cost-of-service analysis in which the Company's hourly fuel and purchased power costs are allocated based on each class's actual usage for each of the 8,760 hours of the test year. I recommend that rate spread be guided by the results of this modified version of the APS cost-of-service study, to reflect the hourly allocation of fuel and purchased power costs.

- With respect to rate spread, I recommend the following approach:

(1) Set Residential rates midway between system average percentage increase and Residential cost-of-service, as modified to include an hourly energy allocation.
(2) Set the percentage increase for Street Lighting equal to Residential.
(3) Set Rates E-34 and E-35 equal to cost-of-service, as modified to include an hourly energy allocation.
(4) Set the percentage increase for Rate E-32, Water Pumping, and Dusk-to-Dawn equal to the respective cost-of-service for each, as modified to include an hourly energy allocation, plus the same percentage point increase necessary to fund the Residential rate mitigation.

- For all customers with demand meters (e.g., Rates E-32 [> 20 kW], E-34, E-35), except partial requirements customers, the transmission revenue requirement should be recovered exclusively through a demand charge instead of an energy charge.

- The generation rate increases that APS has proposed for Rates E-32, E-34, and E-35 are heavily weighted on the energy charge, with a much smaller increase falling on the demand-related charges. As a result, APS's proposed generation demand-related charges for these rate schedules under-collect generation-related demand costs, while the Company's proposed generation energy charges over-collect energy-related costs. This bias unfairly impacts higher-load-factor customers and is unreasonable. Instead, any APS generation rate increase for these rate schedules should be implemented by increasing demand-related revenues and energy-related revenues by an equal percentage.

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 FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	**Docket No. E-01345A-05-0816**

Direct Testimony of Kevin C. Higgins

on behalf of

Phelps Dodge Mining Company and

Arizonans for Electric Choice and Competition

Cost-of-Service / Rate Spread / Rate Design

September 1, 2006

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DIRECT TESTIMONY OF KEVIN C. HIGGINS

I. 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 Phelps Dodge Mining Company ("Phelps Dodge") and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.

Q. Are you the same Kevin C. Higgins who submitted direct testimony on behalf of Phelps Dodge and AECC with respect to Revenue Requirements?

A. Yes, I am.

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

A. My testimony addresses cost-of-service, rate spread, and rate design issues pertaining to the general rate case filed by Arizona Public Service Company ("APS").

Q. What are your conclusions and recommendations with respect to these topics?

A. I offer the following conclusions and recommendations:

- APS's use of the 4-CP method for allocating fixed production cost is appropriate given the Company's system load characteristics and should be accepted by the Commission.

- APS's proposed rate spread continues the current practice of requiring General Service customers to subsidize Residential rates. According to APS's cost-of-service study, General Service rates would have to increase 14.88 percent and Residential rates would have to increase 27.05 percent for the Company to recover its requested revenue requirement (excluding the proposed Environmental Improvement Charge). Instead, APS has proposed a 21.6 percent increase for General Service rates and a 21.14 percent increase for Residential rates.

- APS's fuel and purchased power costs vary considerably throughout the year, as well as during the course of each day. Generally, these costs are higher in summer, and for any given day, higher during the peak hours of the afternoon and evening. Yet, the Company's allocation of its energy costs across customer classes does not take into consideration the variation in class usage across seasons or time-of-day. The Company's approach simply allocates fuel and purchased power cost based on the system average cost throughout the year. Such an approach understates the energy cost responsibility for those customer classes whose usage is more heavily weighted toward the more expensive summer and daily on-peak periods. In turn, this practice overstates the cost responsibility for the remaining classes. To better align the allocation of APS's energy cost with cost causation, I have added a step to APS's cost-of-service analysis in which the Company's hourly fuel and purchased power costs are allocated based on each class's actual usage for each of the 8,760 hours of the test year. I recommend that rate spread be guided by the results of this modified version of the APS cost-of-service study, to reflect the hourly allocation of fuel and purchased power costs.

- With respect to rate spread, I recommend the following approach:

  (1) Set Residential rates midway between system average percentage increase and Residential cost-of-service, as modified to include an hourly energy allocation.
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- For all customers with demand meters (e.g., Rates E-32 [> 20 kW], E-34, E-35), except partial requirements customers, the transmission revenue requirement should be recovered exclusively through a demand charge instead of an energy charge.

- The generation rate increases that APS has proposed for Rates E-32, E-34, and E-35 are heavily weighted on the energy charge, with much smaller increases falling on the demand-related charges. As a result, APS's proposed generation demand-related charges for these rate schedules under-collect generation-related demand costs, while the Company's proposed generation energy charges over-collect energy-related costs. This bias unfairly impacts higher-load-factor customers and is unreasonable. Instead, any APS generation rate increase for these rate schedules should be implemented by increasing demand-related revenues and energy-related revenues by an equal percentage.

II. Use of the 4-CP Method for Allocating Fixed Production and Transmission Costs

Q. Do you agree with the Company's use of the 4-CP method for allocating fixed production and transmission costs?

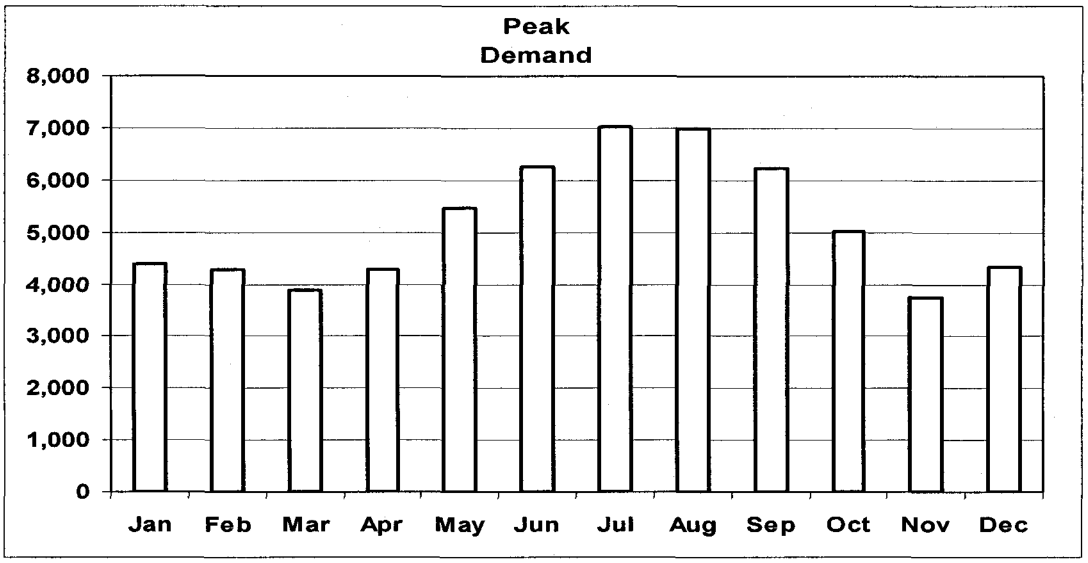
A. Yes, I do.

Q. Please explain the basis for your agreement with APS on this point.

A. APS's retail demands are driven by summer usage, as shown in Figure KCH-1, below. As indicated by that graph, APS's summer peak requirements are quite pronounced. In fact, the Company's average peak of 6,629 MW in the four summer months is 50 percent greater than its average peak of 4,423 MW in the non-summer months.

Figure KCH-1[1]

APS Monthly Peak Demands



The 4-CP method allocates fixed production and transmission costs based on the average of system peak demands in the four summer months, which is when APS's production and transmission capacity requirements are determined. Such an approach properly aligns the allocation of the Company's fixed costs with cost causation. Both this Commission and the FERC have previously recognized the merit of applying the 4-CP method to APS, given the Company's system load characteristics. I recommend approval of APS's continued use of this method in this proceeding.

III. APS proposed rate spread

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

[1] Source: APS Workpaper PWE WP-11.

A. 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.

At the same time, it can be appropriate to mitigate the impact of moving immediately to cost-based rates for classes 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 rate spread does APS propose and how does it relate to APS's cost-of-service results?

A. Table KCH-1 provides a comparison of APS's proposed rate spread, at APS's proposed revenue requirement, and the rate increases that would apply if each customer class were charged cost-based rates, as determined by APS's cost-of-service study. A more detailed summary of APS's cost-of-service results is shown in Attachment KCH-4.

Note that all proposed rate increases in my testimony are expressed in terms of changes in base rates, exclusive of PSA-related charges. That is, the rate changes are *not* expressed as incremental to the 7-mill-per-kWh Interim PSA Adjustor that was approved in Decision No. 68685, but refer to total changes in rates relative to base rate levels prior to the adoption of the Interim PSA Adjustor.

This approach is necessary in order to maintain consistency between my analysis and APS's filing. (Upon adoption of new base rates pursuant to this proceeding, the Interim PSA Adjustor will be terminated. Thus, as experienced by customers, the incremental rate change resulting from this rate case proceeding will be less than the total rate changes presented here, by the amount of 7-mills-per-kWh.)

Table KCH-1[2]

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

Class	Rate Change Based on APS COS	APS Proposed Rate Change	Relative Rates of Return Current	Relative Rates of Return APS Proposal
Residential	27.05%	21.14%	0.58	0.82
General Service	14.88%	21.60%	1.51	1.25
E-32	13.40%	21.19%	1.37	1.28
E-34	24.61%	24.61%	0.03	1.00
E-35	24.85%	24.85%	(1.07)	1.00
Water Pumping	(1.15)%	0.14%	3.59	1.07
Street Lighting	42.10%	24.11%	0.79	0.67
Dusk-to-Dawn	17.78%	10.50%	2.23	0.86
Total	21.14%	21.14%	1.00	1.00

As Table KCH-1 shows, APS's cost-of-service study indicates that Residential rates would have to increase 27.05 percent to fund that class's share of the Company's requested $450 million base rate increase, if rates were set at Residential cost-of-service (as calculated by APS). Instead, however, APS proposes that Residential rates increase 21.14 percent, which is exactly the system average.

[2] Source: Attachment KCH-4.

To fund the resulting revenue shortfall, APS proposes that General Service rates increase to a level significantly higher than the cost to serve that customer class. Specifically, the APS cost-of-service study indicates that General Service rates would have to increase 14.88 percent to be priced at cost, but instead APS proposes an increase for this class of 21.60 percent, which is even slightly higher than the Residential class. Within the General Service class, the industrial customer rates of E-34 and E-35 are proposed to be increased by nearly 25 percent, placing these rate schedules exactly on cost-of-service, as calculated by APS.

Under APS's proposal, the bulk of the subsidization burden falls to Rate E-32, which warrants a cost-based increase of 13.4 percent, but is proposed to receive an increase of 21.19 percent.

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

A. In my view, APS's proposal to set the Residential increase at the system average – and to set E-32 rates almost 8 percent above cost in order to make this possible – is not equitable. Gradualism provides for mitigation of rate impacts – but rate increases for classes that are below cost-of-service should generally be set above the system average in order to move them more reasonably toward cost-based rates.

I note here that APS makes no attempt to mitigate the rate impact of its proposed 25 percent increase for the industrial Rates E-34 and E-35, making it difficult to justify on principled grounds that another customer class warranting a 27 percent increase needs somehow to be limited to 21 percent.

Q. What rate spread do you recommend?

A. I present my rate spread recommendation in a later section of my testimony following my discussion of the allocation of energy costs. To properly determine cost-of-service used for rate spread, APS's cost-of-service results should be adjusted to reflect an allocation of the Company's fuel and purchased power costs based on hourly costs. I recommend that the final approved rate spread be guided by the results of this modified version of the APS cost-of-service study reflecting such an hourly cost allocation. I discuss this proposal in the next section of my testimony.

IV. Allocation of Hourly Energy Costs

Q. How are fuel and purchased power costs allocated to customer classes in APS's cost-of-service study?

A. Currently, in APS's cost-of-service study, fuel and purchased power costs ("energy costs") are allocated based on the number of kilowatt-hours each customer class consumes. It makes no difference whether those kilowatt-hours are concentrated in high-cost, summer on-peak periods, or lower-cost, off-peak periods: each kilowatt-hour is assigned exactly the same weight.

Q. But aren't APS's rates characterized by seasonal and time-of-use pricing features?

A. Yes. That is how the costs that are allocated to the classes are *collected* from customers. That is a matter of rate design, but rate design should not be confused with cost allocation. Under present practice, the amounts *to be collected* from each respective class are determined without regard to energy price differences during the course of the year or time of day. Put another way, APS's seasonal and time-of-use rates are designed based on class revenue requirements that are determined based on system average kWh costs throughout the year. These average kWh costs are then "shaped" into seasonal and time-of-use rates as part of the design of each class's rate schedule(s). But no seasonal or time-of-use information is used in determining the allocation of APS energy costs to the customer classes in the first instance.

Q. In your opinion, should seasonal and time-of-use information be used in determining the allocation of energy costs to customer classes?

A. Yes, definitely. Such a step would better align cost responsibility with cost causation, improving fairness and encouraging efficiency in resource utilization through better price signals. While these objectives are often addressed in ratemaking with respect to fixed costs, they are frequently overlooked with respect to energy-related costs. But with the increasing sensitivity of energy costs to seasonality and time-of-use, and with the widespread availability of powerful software packages that can be applied to large data bases to perform the necessary calculations, the time has come to start using seasonal and time-of-use information in determining the allocation of energy costs to customer classes.

Q. Is the need to include seasonal and time-of-use information in determining the class allocation of energy costs particularly important in Arizona?

A. Yes, in Arizona the need is acute. The Commission is well aware that the rapid load growth in the APS service territory is causing great pressure on APS's costs, with much of the new load requirements occurring in summer when energy costs are most expensive. As the strong summer growth pushes up the system average cost of energy, all customers are negatively impacted – but the greatest percentage rate increases are occurring in the industrial sector.

As part of the record of the Interim proceeding, APS indicated that if its rate increase proposal in this proceeding was approved, the Company's industrial customer rates would rise cumulatively in excess of 40 percent between mid-2003 and early 2007. In my view, this is a matter of very serious concern for Arizona economic development and sustainability. APS's industrial rates are already 52 percent higher than in neighboring Utah, 28 higher than in Colorado, and 5 percent higher than in New Mexico.[3]

The pressure on industrial customer rates in Arizona is exacerbated by the lack of an hourly energy cost allocation in APS's cost-of-service study. While it is fair for industrial customers to pay their share of summer energy costs based on industrial summer usage, it is not fair for the cost of expensive summer usage of other customers to be transferred to industrial customers via the averaging of annual energy costs in the cost-of-service study. And currently, that is what happens. As I explain below, the use of annual average energy cost in assigning class energy cost responsibility is causing the rates for E-34 customers to be inflated by 3 percent, and is causing the rates for E-35 customers to be inflated by over 6 percent.

[3] All comparisons are for a 10 MW, 75% load factor customer. APS rates are for Rate E-34. Utah rates are calculated for PacifiCorp Rate 9, Colorado rates are calculated for Public Service of Colorado Rate Schedule PG, and New Mexico rates are calculated for Public Service Company of New Mexico Large Primary Voltage Rate.

Q. Can you provide a simple example of how this transfer of cost responsibility occurs?

A. Yes, let's assume we have two customer classes, Cooling and Manufacturing. Assume further that we have two pricing periods, Winter and Summer, and that the price of energy is $20/MW in Winter and $50/MWh in Summer. Further, assume that the load for Cooling is 10 MWH in Winter and 40 MWH in Summer, whereas for Manufacturing it is 20 MWH in each period. These assumptions are listed in Table KCH-2, below.

Table KCH-2

Average Energy Cost Allocation – Simple Example

Class	Winter P = $20	Summer P = $50	Annual Totals
Cooling Manufacturing System MWH	10 MWH 20 MWH 30 MWH	40 MWH 20 MWH 60 MWH	50 MWH 40 MWH 90 MWH
System Cost Average Energy Cost	$600 $20	$3,000 $50	$3,600 $40
Cost caused by Cooling Cost allocated to Cooling	$200	$2,000	$2,200 $2,000
Cost caused by Manuf. Cost allocated to Manuf.	$400	$1000	$1,400 $1,600

As shown in Table KCH-2, the Winter cost attributable to the Cooling class is $200 ($20 x 10 MWH) and the Summer cost attributable to this class is $2,000 ($50 x 40 MWH) for a total of $2,200. However, the use of average annual energy cost for cost allocation assigns only $2,000 of cost to this class

($40/MWH x 50 MWH). The difference, of course, is picked up by Manufacturing, which causes $1,400 in energy costs, but is allocated $1,600. Essentially, the higher system costs driven by Cooling's strong summer usage is being transferred, in part, to Manufacturing's Winter usage. This simple example illustrates the transfer of cost responsibility that occurs if seasonal and time-of-use considerations are not incorporated into the allocation of energy costs across classes.

Q. Using this simple example, how would your recommended method allocate energy cost responsibility?

A. My approach would identify that the Cooling class is responsible for causing $200 in energy costs in Winter and $2,000 in Summer, and allocate $2,200 in energy costs to this class. Similarly, it would identify that the Manufacturing class is responsible for $400 in energy costs in Winter and $1,000 in Summer, and allocate $1,400 to that class.

A convenient means to implement these adjustments is to apply an energy cost multiplier of 1.10 to Cooling's average annual cost of $2,000 and to apply an energy cost multiplier of 0.875 to Manufacturing's average annual cost of $1,600.

Q. How do you apply this principle to the APS system?

A. Instead of two classes, there are several, and instead of two periods, there are 8,760 hours, corresponding to each hour in the test period.

Q. How did you calculate the hourly energy cost allocator for the APS system?

A. In response to data requests, APS provided me with its average hourly energy cost for the test period. The Company also provided its load research data and formulas for computing hourly loads by customer class. I used this information to compute each customer class's energy cost responsibility for each hour of the test period, and then aggregated these results for the test year. I then translated this information into scalars (or energy cost multipliers) which I applied to the energy costs that APS had allocated to each customer class in its cost-of-service study.

A summary of the scalars, or energy cost multipliers, calculated for each class is presented in Table KCH-3, below.

Table KCH-3

Energy Cost Multipliers Applied to APS Energy Cost Allocations to Reflect Hourly Energy Cost Differences between Classes

Class	Energy Cost Multiplier
Residential	1.0323
General Service	
E-32	0.9780
E-34	0.9625
E-35	0.9339
Water Pumping	0.9762
Street Lighting	0.8278
Dusk-to-Dawn	0.8353
Total	1.0000

Q. After you re-calculated each class's energy cost allocation, what step did you take next?

A. I used this new information to recalculate APS's cost-of-service results, changing only the allocation of fuel and purchased power costs to each class. This calculation is presented in Attachment KCH-5 and is summarized in Table KCH-4, below.

Table KCH-4

Comparison of APS and AECC Cost-of-Service Results
Impact of Using Hourly Energy Allocator

Class	Rate Change Based on APS COS	Rate Change Based on AECC COS
Residential	27.05%	28.74%
General Service	14.88%	13.19%
E-32	13.40%	12.14%
E-34	24.61%	21.60%
E-35	24.85%	18.72%
Water Pumping	(1.15)%	(2.82)%
Street Lighting	42.10%	35.16%
Dusk-to-Dawn	17.78%	14.53%
Total	21.14%	21.14%

Q. What do the results of the re-calculated cost-of-service study show?

A. The net impact on the Residential class of including an hourly energy allocator is relatively modest: the overall cost responsibility for Residential customers increases by 1.69 percent. When rate spread mitigation is taken into account, the net impact on Residential rates is even less. However, the beneficial impact on industrial rate schedules more significant: the cost responsibility for Rate E-34 declines 3.01 percent and that of Rate E-35 declines by 6.13 percent.

This is an important result. It demonstrates that increasing the accuracy of energy cost allocation has a significant beneficial impact for Arizona industry, while having a modest impact on Residential customers. This result is especially important in light of the fact that APS is proposing to set rates for industrial customers exactly at cost-of-service. It is essential, then, that these costs are calculated as accurately as possible.

Q. Other than modifying the allocation of energy costs, did you make any other changes to APS's cost-of-service study?

A. No. Modifying the allocation of fuel and purchased power to reflect hourly cost and class usage was the only change I made to the study.

Q. Cost-of-service studies frequently apply energy allocators to cost items other than fuel and purchased power. Does your modification change any energy allocators that are applied to cost items other than fuel and purchased power?

A. No. The logical basis for the modification I made is tied to the variation in the cost of fuel and purchased power over the course of the year. There was no reason to modify the energy allocators applied to other cost items in the study.

Q. What is your recommendation to the Commission on this issue?

A. I strongly recommend that the Commission approve the utilization of an hourly energy cost allocator in APS's cost-of-service study. I have made this single modification to APS's cost-of-service study, and urge the adoption of that study, as modified.

V. AECC Proposed Rate Spread

Q. What is your recommended rate spread?

A. As a first step, I recommend setting Residential rates midway between system average percentage increase and Residential cost-of-service. The basis for determining cost-of-service for this purpose should be the re-calculated APS cost-of-service study that incorporates my recommended hourly energy cost allocation, as shown in Attachment KCH-5. Further, within the General Service customer class, Rates E-34 and E-35 should be set exactly at cost-of-service. These results are presented in Attachment KCH-6 and summarized in Table KCH-5, below.

Table KCH-5

Comparison of APS and AECC Recommended Rate Spread
Calculated at APS's Requested Revenue Requirement

Class	APS Proposed Rate Change	AECC Proposed Rate Change
Residential	21.14%	24.94%
General Service	21.60%	17.34%
E-32	21.19%	16.97%
E-34	24.61%	21.60%
E-35	24.85%	18.72%
Water Pumping	0.14%	2.01%
Street Lighting	24.11%	24.94%
Dusk-to-Dawn	10.50%	19.36%
Total	21.14%	21.14%

Q. What are you recommending for the Water Pumping and Dusk-to-Dawn classes?

A. The cost-of-service results indicate that these two relatively-small rate classes warrant rate increases that are less than system average. APS proposes a miniscule increase of 0.14 percent for Water Pumping and an increase of about half the system average for Dusk-to-Dawn of 10.50 percent.

In my opinion, assigning less-than-average increases for these two rate classes is appropriate. But at the same time, Rate E-32 should not be expected to shoulder the full cost burden of mitigating the Residential rate increase. It would be more equitable for Rate E-32, Water Pumping, and Dusk-to-Dawn to each pay the same percentage above their respective costs-of-service to mitigate the Residential rate increase. My proposed rate spread for the Water Pumping and Dusk-to-Dawn customer classes reflects this principle.

Q. What are you recommending for the Street Lighting class?

A. The cost-of-service study indicates that Street Lighting is below cost-of-service. APS had recommended the system average increase for this class. I recommend basing the Street Lighting rate increase on its cost-of-service, but capping the increase at the same level assigned to Residential. My proposed rate spread for Street Lighting reflects this result.

Q. Do you have any other rate spread recommendations for specific rate schedules?

A. Yes. In the last rate proceeding, Rate E-32-TOU was created as an option for E-32 customers to move to time-of-use rates. In this proceeding, APS's proposed rate increase for Rate E-32-TOU is 34.72 percent – more than 50 percent higher than the Company's recommended increase for Rate E-32. I believe this dramatic differential would strongly discourage E-32 customers from switching to time-of-use rates. Instead, the rate increase for Rate E-32-TOU should be set equal to the rate increase for Rate E-32, to retain the same relationship between these two rate schedules that was established in the last proceeding.

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, then the rate increase necessary for each customer class to have its rates set at cost-of-service will be reduced. In this case, these new cost-based rate changes should be re-calculated or estimated by APS in a compliance filing, using the energy cost multipliers developed in my analysis to reflect hourly energy cost responsibility. Then, the same basic formulation I recommended above should be applied:

(1) Set Residential rates midway between system average percentage increase and Residential cost-of-service.

(2) Set the percentage increase for Street Lighting equal to Residential.

(3) Set Rates E-34 and E-35 equal to cost-of-service.

(4) Set the percentage increase for Rate E-32, 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 Residential mitigation.

VI. Rate Design

A. Transmission Rate Design

Q. What has APS proposed with respect to transmission rate design?

A. APS has proposed to levy a flat 4.76 mills-per-kWh unbundled transmission charge for all customers. This is the same rate design that was adopted in the previous general rate case.

Q. Do you agree with this rate design?

A. No. This rate design was acceptable as part of a settlement package in the prior rate case, but as transmission charges are 100 percent demand-related, these charges should be billed to customers who have demand meters through a demand charge. The one exception to this rule should be customers with distributed generation who take partial requirements service, as the service needs for these customers are unique.

Q. What rate design do you recommend instead?

A. I am not recommending any change in the transmission rate design for Residential customers, partial requirements customers, or non-residential customers without demand meters. But for all other customers with demand meters (e.g., Rates E-32 [> 20 kW], E-34, E-35), I am recommending that the transmission revenue requirement be recovered exclusively through a demand charge instead of an energy charge.

Q. Have you determined what this charge should be?

A. Yes. For E-32 customers with billings demands greater than 20 kW, APS's proposed 4.76 mills-per-kWh charge can be replaced with a demand charge of $1.826 per kW-month. For E-34 customers, the equivalent transmission demand charge is $2.474 per kW-month, and for E-35 customers, it is $2.853 per kW-month. These calculations are shown in Attachment KCH-7.

Alternatively, a single transmission demand charge for all demand-billed General Service customers could be implemented.

B. Generation Rate Design

Q. What are your observations regarding APS's proposed generation rate design for Rates E-32, E-34, and E-35?

A. The generation rate increases that APS has proposed for Rates E-32, E-34, and E-35 are heavily weighted on the energy charge, with a much smaller increase falling on the demand-related charges, as summarized in Table KCH-6, below.[4] The net effect of APS's proposed generation rate design is that higher-load-factor customers would experience a much greater rate increase than lower-load-factor customers. This impact is demonstrated in the Company's Schedule H-4, which shows the customer bill impacts resulting from the Company's proposed rate changes.

Table KCH-6

APS Proposed Generation Rate Increases by Rate Component

Rate Schedule	APS Proposed Rev. Increase from Demand-Related Charges	APS Proposed Rev. Increase from Energy Charges
E-32 >20 kW	2%	53%
E-34	11%	53%
E-35	12%	48%

Q. In your opinion, is it appropriate for APS to recover such a large proportion of its proposed generation rate increase on the energy charge of these rate schedules?

A. No. Attachment KCH-8 compares the Company's proposed unbundled generation *revenues* to the Company's energy and demand *costs* in its cost-of-

[4] Note that for Rate E-32, APS's generation-related demand costs are not collected through a demand charge, but are collected as part of the first energy block, which is collected on a "first 200 kWh per kW basis."

service study. For each of these rate schedules, APS's proposed generation demand charge (or demand-related charge) under-collects the rate schedule's generation-related demand costs. At the same time, the Company's proposed generation energy charge over-collects the rate schedule's energy-related costs. This information demonstrates that the strong bias in APS's proposed rate increase toward increasing the generation energy charge is unwarranted. This bias unfairly impacts higher-load-factor customers and is unreasonable.

Q. From a customer's perspective, why should it matter if APS proposes a demand charge that does not fully recover its demand-related costs?

A. If a utility proposes a demand charge that is below the cost of demand, then the utility is going to seek to recover the revenue requirement for that rate schedule by over-recovering its costs in another area, most typically through levying an energy charge that is above unit energy costs, which is the case here. For a given rate schedule, when demand charges are set below cost, and energy charges are set above cost, those customers with relatively higher load factors end up subsidizing the costs of the lower-load-factor customers within the rate class.

Q. Why is it important for rate design to be representative of underlying cost causation?

A. Aligning rate design with underlying cost causation improves efficiency because it sends proper price signals. For example, setting a demand charge below the cost of demand understates the economic cost of demand-related assets, which in turn distorts consumption decisions, and calls forth a greater level of investment in fixed assets than is economically desirable.

At the same time, aligning rate design with underlying cost causation is important for ensuring equity among customers, because properly aligning with costs minimizes cross-subsidies among customers. As I stated above, if demand costs are understated in utility rates, the costs are made up elsewhere – typically in energy rates. When this happens, higher-load-factor customers (who use fixed assets relatively efficiently through relatively constant energy usage) are forced to pay the demand-related costs of lower-load-factor customers. This amounts to a cross-subsidy that is fundamentally inequitable.

Q. What generation rate design approach do you recommend?

A. For Rate E-34, any generation rate increase should be implemented as an equal percentage increase on both the demand and the energy charge. This approach will produce a better alignment of demand charges with demand costs, and energy charges with energy costs, relative to the Company's approach. It will have the additional advantage of removing any load-factor bias in the generation rate increase. That is, the generation rate increase would impact high- and low-load-factor customers on a proportionate basis.

For Rate E-32 customers with billing demands greater than 20 kW, any generation rate increase should be implemented as an equal percentage increase on the first energy block (i.e., the first 200 kWh/kW block) and the second energy block. As is the case for Rates E-34, this approach will produce a better alignment of demand charges with demand costs, and energy charges with energy costs, relative to the Company's approach. It will also have the additional advantage of removing any load-factor bias in the generation rate increase. That is, the generation rate increase would impact high- and low-load-factor customers on a proportionate basis.

For Rate E-35, any generation rate increase should be implemented as an equal percentage increase on the energy charges and on "demand charge revenues in the aggregate." For Rate E-35, demand charge revenues need to be treated on an aggregate basis due to APS's proposed change in the definition of the off-peak demand charge for this rate schedule. As is the case for Rates E-32 and E-34, this approach will produce a better alignment of demand charges with demand costs, and energy charges with energy costs, relative to the Company's approach. It will also have the additional advantage of removing any load-factor bias in the generation rate increase.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Summary of APS's Cost of Service Results

Revenue Increase Required to Move each Customer Class to Cost of Service using APS' Cost of Service Results

Line No.	(a) Rate Class	(b) Current Retail Revenues	(c) Rate Base	(d) Current Return	(e) APS Current Rate of Return	(f) APS Current Relative Rate of Return	(g) APS Required Return @ Equal ROR of 8.73%	(h) Req'd Rev. Increase w/o EIC @ Conversion Factor of 1.6407	(i) Percent Change @ Equal ROR
1	Residential	$1,089,551,030	$2,489,739,663	$37,745,444	1.52%	0.58	$217,354,273	$294,684,796	27.05%
2	General Service								
3	E-20	$3,586,700	$7,360,472	$623,406	8.47%	3.26	$642,569	$31,441	0.88%
4	E-32	$859,172,589	$1,664,603,376	$75,138,666	4.51%	1.74	$145,319,875	$115,146,540	13.40%
5	E-34	$66,719,281	$115,618,777	$86,584	0.07%	0.03	$10,093,519	$16,418,412	24.61%
6	E35	$67,661,237	$88,981,169	($2,480,075)	-2.79%	(1.07)	$7,768,056	$16,814,142	24.85%
7	General Service Total	$997,139,807	$1,876,563,794	$73,368,581	3.91%	1.51	$163,824,019	$148,410,535	14.88%
8	Water Pumping (E-38, E-221)	$20,864,101	$25,474,477	$2,370,299	9.30%	3.59	$2,223,922	($240,161)	-1.15%
9	Street Lighting	$13,344,265	$51,298,120	$1,053,936	2.05%	0.79	$4,478,326	$5,618,408	42.10%
10	Dusk to Dawn	$6,422,696	$23,620,450	$1,366,217	5.78%	2.23	$2,062,065	$1,141,681	17.78%
11	ACC Total	$2,127,321,899	$4,466,696,504	$115,904,477	2.59%	1.00	$389,942,605	$449,615,257	21.14%

Data Source: APS Workpaper DJR_WP1

APS Proposed Revenue Increase without EIC for each Customer Class using APS' Cost of Service Results

Line No.	(a) Rate Class	(b) Current Retail Revenues	(c) Rate Base	(d) Proposed Return	(e) APS Proposed Rate of Return	(f) APS Proposed Relative Rate of Return	(g) Change from Current Return	(h) Rev. Increase w/o EIC @ Conversion Factor 1.6407	(i) APS Proposed Percent Change
12	Residential	$1,089,551,030	$2,489,739,663	$178,138,344	7.15%	0.82	$140,392,900	$230,343,093	21.14%
13	General Service								
14	E-20	$3,586,700	$7,360,472	$642,641	8.73%	1.00	$19,235	$31,558	0.88%
15	E-32	$859,172,589	$1,664,603,376	$186,118,703	11.18%	1.28	$110,980,037	$182,085,312	21.19%
16	E-34	$66,719,281	$115,618,777	$10,094,296	8.73%	1.00	$10,007,712	$16,419,686	24.61%
17	E35	$67,661,237	$88,981,169	$7,767,902	8.73%	1.00	$10,247,977	$16,813,890	24.85%
18	General Service Total	$997,139,807	$1,876,563,794	$204,623,542	10.90%	1.25	$131,254,961	$215,350,445	21.60%
19	Water Pumping (E-38, E-221)	$20,864,101	$25,474,477	$2,388,379	9.38%	1.07	$18,080	$29,663	0.14%
20	Street Lighting	$13,344,265	$51,298,120	$3,014,967	5.88%	0.67	$1,961,031	$3,217,471	24.11%
21	Dusk to Dawn	$6,422,696	$23,620,450	$1,777,373	7.52%	0.86	$411,156	$674,584	10.50%
22	ACC Total	$2,127,321,899	$4,466,696,504	$389,942,605	8.73%	1.00	$274,038,128	$449,615,257	21.14%

APS's Cost of Service Results Adjusted to Reflect Hourly Fuel and Purchased Power Costs

Revenue Increase Required to Move each Customer Class to Cost of Service using AECC's Proposed Hourly Energy Cost Allocation Method

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Rate Class	Current Retail Revenues	Rate Base	Return Req'd Return @ Equal ROR	Equalized Rate of Return	Equalized Relative Rate of Return	Required Revenue Increase w/o EIC	Required Revenue Increase	Req'd Percent Change
1	Residential	$1,089,551,030	$2,489,739,663	$217,354,273	8.73%	1.00	$1,402,634,119	$313,083,089	28.74%
2	General Service								
3	E-20	$3,586,700	$7,360,472	$642,569	8.73%	1.00	$3,685,034	$98,334	2.74%
4	E-32	$859,172,589	$1,664,603,376	$145,319,875	8.73%	1.00	$963,502,314	$104,329,725	12.14%
5	E-34	$66,719,281	$115,618,777	$10,093,519	8.73%	1.00	$81,129,877	$14,410,596	21.60%
6	E35	$67,661,237	$88,981,169	$7,768,056	8.73%	1.00	$80,329,232	$12,667,995	18.72%
7	General Service Total	$997,139,807	$1,876,563,794	$163,824,019	8.73%	1.00	$1,128,646,457	$131,506,650	13.19%
8	Water Pumping (E-38, E-221)	$20,864,101	$25,474,477	$2,223,922	8.73%	1.00	$20,276,356	($587,745)	-2.82%
9	Street Lighting	$13,344,265	$51,298,120	$4,478,326	8.73%	1.00	$18,036,625	$4,692,360	35.16%
10	Dusk to Dawn	$6,422,696	$23,620,450	$2,062,065	8.73%	1.00	$7,356,001	$933,305	14.53%
11	ACC Total	$2,127,321,899	$4,466,696,504	$389,942,605	8.73%	1.00	$2,576,949,558	$449,627,659	21.14%

Summary of Energy Cost Multipliers (Relecting Hourly Energy Cost Differences)

	Residential					
	E-10	E-12	EC-1	ET-1	ECT-1R	Residential Total
Overall Retail Energy Cost (¢/kWh)	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904
Class Cost Ratio (Step 3)	1.0179	1.0275	1.0244	1.0398	1.0241	1.0323
Class Energy Rate (¢/kWh)	3.2475	3.2781	3.2684	3.3175	3.2674	3.2936
Energy Use @ Generation (MWh)	852,812	4,001,457	504,571	6,373,509	1,478,487	13,210,836
Energy Use @ Meter (MWh)	793,929	3,725,172	469,732	5,933,443	1,376,403	12,298,679
Energy Revenue ($)	$25,783,227	$122,115,055	$15,352,556	$196,840,323	$44,972,271	$405,063,432

	General Service								
	Church Rate E-20	0 - 20 kW E-21, E-23, E-30 E-32 & E-32 TOU	21 - 100 kW E-22, E-32 & E-32 TOU	101-400 kW E-32 & E-32 TOU	401-999 kW E-24, E-32 & E-32 TOU	1000 + kW E-32 & E-32 TOU	E-32 Total	E-34	E-35
Overall Retail Energy Cost (¢/kWh)	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904
Class Cost Ratio (Step 3)	1.0402	0.9805	0.9818	0.9813	0.9744	0.9685	0.9780	0.9625	0.9339
Class Energy Rate (¢/kWh)	3.3186	3.1282	3.1324	3.1308	3.1088	3.0898	3.1203	3.0707	2.9796
Energy Use @ Generation (MWh)	38,650	1,404,282	2,696,965	3,314,293	2,310,169	1,714,920	11,440,629	1,242,014	1,455,999
Energy Use @ Meter (MWh)	36,618	1,307,541	2,511,175	3,140,255	2,188,928	1,626,501	10,774,400	1,178,438	1,397,289
Energy Revenue ($)	$1,215,190	$40,901,867	$78,661,029	$98,314,070	$68,049,629	$50,255,946	$336,190,235	$36,186,552	$41,633,187

	Water Pumping E-38/E-221	Streetlights	Dusk to Dawn	ACC Total
Overall Retail Energy Cost (¢/kWh)	3.1904	3.1904	3.1904	3.1904
Class Cost Ratio (Step 3)	0.9762	0.8278	0.8353	1.0000
Class Energy Rate (¢/kWh)	3.1146	2.6410	2.6651	3.1904
Energy Use @ Generation (MWh)	339,389	124,808	29,370	27,881,695
Energy Use @ Meter (MWh)	321,550	114,924	27,044	36,923,342
Energy Revenue ($)	$10,014,931	$3,035,197	$720,749	$1,178,002,303

(Note: Hourly load data based on 12 months ending Sept. 30, 2005)
(Note: Overall energy cost of 3.1904 ¢/kWh based on 12 months ending Dec. 31, 2006)

AECC's Adjusted Cost of Service Study Using Energy Scalars
for Fuel and Purchased Power Costs
for the 12 Months ending Sep. 30, 2005
($)

	1	2	3	4	5	6	7	8	9	10	11	12	13
Line No.	Description	Allocation Factor	Electric Total	ACC Jurisdiction	All Other	Total Residential	E-10 Residential	E-12 Residential	EC-1 Residential	ET-1 Residential	ECT-1 Residential	Total General Service	E-20 Church Rate
	SUMMARY OF RESULTS												
16	TOTAL RATE BASE		$5,327,833,192	$4,466,696,504	$861,136,688	$2,489,739,663	$148,234,534	$795,627,566	$79,691,088	$1,227,004,375	$239,182,100	$1,876,563,794	$7,360,472
17													
18	DEVELOPMENT OF RETURN												
19	Revenues from Rates		$2,103,857,729	$2,066,144,726	$37,713,003	$1,058,729,739	$70,337,587	$360,585,198	$36,686,029	$490,471,664	$100,649,261	$967,398,538	$3,344,799
20	Proforma to Revenues from Rates		$60,953,295	$61,177,173	($223,878)	$30,821,291	($2,224,915)	$11,853,176	($1,254,829)	$20,328,518	$2,119,341	$29,741,269	$241,901
21	Other Electric Revenues		$1,344,909,372	$1,313,268,573	$31,640,799	$624,903,158	$40,280,141	$189,690,778	$23,754,957	$301,576,795	$69,600,487	$662,981,780	$1,836,772
22	TOTAL OPERATING REVENUES		$3,509,720,396	$3,440,590,472	$69,129,924	$1,714,454,188	$108,392,813	$562,129,152	$59,186,157	$812,376,977	$172,369,089	$1,660,121,587	$5,423,472
23	Revenue Increase Required to Achieve Equalized ROR		$449,627,659	$449,627,659	$0	$313,083,089	$18,438,156	$77,192,927	$11,369,627	$170,049,197	$36,033,182	$131,506,650	$98,334
24	TOTAL OPERATING REVENUES WITH REVENUE INCREASE		$3,959,348,055	$3,890,218,131	$69,129,924	$2,027,537,277	$126,830,969	$639,322,079	$70,555,784	$982,426,174	$208,402,271	$1,791,628,237	$5,521,806
25	Percent Increase		20.77%	21.14%	0.00%	28.74%	27.07%	20.73%	32.09%	33.29%	35.06%	13.19%	2.74%
24													
25	OPERATING EXPENSES												
26													
27	O&M Energy Related												
28	Energy Production	Energy1	$74,369,000	$73,170,843	$1,198,157	$34,692,327	$2,239,528	$10,508,029	$1,325,029	$16,737,158	$3,882,582	$37,182,385	$101,497
29	Energy Production - Related Fuel (M&T)	Energy2	$842,735,000	$829,157,722	$13,577,278	$393,126,677	$25,377,890	$119,074,939	$15,014,971	$189,662,215	$43,996,662	$421,343,530	$1,150,143
30	Energy Production - Related Fuel	Energy100	$885,397,911	$871,149,260	$14,248,651	$426,382,540	$27,140,225	$128,542,154	$16,160,595	$207,200,327	$47,339,237	$430,410,906	$1,256,908
31	Total Energy Related		$1,802,501,911	$1,773,477,826	$29,024,085	$854,201,543	$54,757,643	$258,125,123	$32,500,595	$413,599,700	$95,218,481	$888,936,821	$2,508,548
32	O&M Non-Energy Related		$443,510,785	$528,986,908	($85,476,123)	$301,820,410	$19,684,036	$102,391,452	$9,791,173	$142,143,302	$27,810,447	$216,936,518	$643,832
33	Operation & Maintenance		$2,246,012,696	$2,302,464,734	($56,452,038)	$1,156,021,953	$74,441,680	$360,516,575	$42,291,768	$555,743,002	$123,028,928	$1,105,873,339	$3,152,380
34	Administrative & General		$141,768,184	$132,687,129	$9,081,055	$81,444,413	$5,435,590	$28,926,720	$2,483,640	$37,721,841	$6,876,622	$48,487,581	$168,558
35	Depreciation & Amortization Expense		$321,526,002	$285,758,992	$35,767,010	$159,732,184	$9,911,645	$51,449,950	$5,249,433	$77,904,622	$15,216,534	$119,779,815	$441,855
36	Amortization on Gain		($6,613,637)	($6,528,054)	($85,583)	($3,299,367)	($196,177)	($991,655)	($116,349)	($1,640,307)	($354,879)	($3,172,586)	($7,702)
37	Regulatory Assets		($2,203,511)	($2,203,511)	$0	($1,144,246)	($65,676)	($342,833)	($38,994)	($575,685)	($121,058)	($1,049,237)	($2,397)
38	Pro-Forma Energy Related - Jurisdictional	Energy100'	$61,052,503	$60,070,266	$982,237	$29,401,291	$1,871,459	$8,863,649	$1,114,357	$14,287,539	$3,264,286	$29,679,067	$86,670
39	Pro-Forma Energy Related - ACC	Energy100'	$269,376,144	$269,376,144	$0	$131,845,700	$8,392,281	$39,747,712	$4,997,168	$64,070,335	$14,638,205	$133,091,349	$388,660
40	Pro-Forma Energy Related - ACC(Weather & Cust)	Assigned	$18,114,000	$18,114,000	$0	$9,044,540	($677,719)	$3,428,524	($350,866)	$5,867,427	$777,174	$9,157,238	$56,452
41	Pro-Forma Non-Energy Related		$485,465,130	$477,680,531	$7,784,599	$80,661,617	$4,686,627	$26,134,252	$2,515,995	$39,350,626	$7,974,117	$66,749,536	$154,603
42	Proforma Adjustments		$504,561,367	$495,794,531	$8,766,836	$250,953,148	$14,272,648	$78,174,137	$8,276,654	$123,575,927	$26,653,782	$238,677,190	$686,386
43	Taxes Other than Income		$139,970,769	$116,332,656	$23,638,113	$65,666,582	$4,071,767	$21,173,025	$2,145,953	$32,090,164	$6,185,673	$47,839,519	$190,638
44	Income Tax		$185,532,148	$175,969,050	$9,563,098	$100,808,337	$6,018,617	$30,957,874	$3,306,647	$50,489,128	$10,036,071	$71,368,597	$249,519
45	TOTAL OPERATING EXPENSES		$3,530,554,018	$3,500,275,527	$30,278,491	$1,810,183,004	$113,890,094	$569,863,793	$63,598,752	$875,308,692	$187,521,673	$1,627,804,218	$4,879,237
46													
47	OPERATING INCOME		$428,794,038	$389,942,605	$38,851,433	$217,354,273	$12,940,875	$69,458,287	$6,957,032	$107,117,482	$20,880,597	$163,824,019	$642,569
48													
49	RETURN		$428,794,038	$389,942,605	$38,851,433	$217,354,273	$12,940,875	$69,458,287	$6,957,032	$107,117,482	$20,880,597	$163,824,019	$642,569
50													
51	RATE OF RETURN (EQUALIZED)		8.05%	8.73%	4.51%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%
52													
53	INDEX RATE OF RETURN		1.00	1.08	0.56	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08
54													
55	ACC JURISDICTION INDEX RATE OF RETURN			1.00		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
			843593										
	Tax Calculation:		815224	28369	27511	858							
	Operating Revenues		$3,959,348,055	$3,890,218,131	$69,129,924	$2,027,537,277	$126,830,969	$639,322,079	$70,555,784	$982,426,174	$208,402,271	$1,791,628,237	$5,521,806
	Operating Expenses Before Income Taxes		$3,345,021,870	$3,324,306,477	$20,715,393	$1,709,374,667	$107,871,477	$538,905,919	$60,292,105	$824,819,564	$177,485,603	$1,556,435,621	$4,629,717
	Operating Income Before Interest and Income Taxes		$614,326,185	$565,911,654	$48,414,531	$318,162,609	$18,959,491	$100,416,160	$10,263,679	$157,606,610	$30,916,668	$235,192,616	$892,089
	Interest Expense:												
	Rate Base		$5,327,833,192	$4,466,696,504	$861,136,688	$2,489,739,663	$148,234,534	$795,627,566	$79,691,088	$1,227,004,375	$239,182,100	$1,876,563,794	$7,360,472
	Long Term Debt Rate		2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%
	Interest Expense (RB x LTD)		$131,147,279	$109,949,968	$21,197,310	$61,286,187	$3,648,867	$19,584,770	$1,961,636	$30,203,326	$5,887,587	$46,192,556	$181,182
	State Taxable Income		$483,178,907	$455,961,686	$27,217,221	$256,876,422	$15,310,624	$80,831,390	$8,302,043	$127,403,284	$25,029,081	$189,000,060	$710,907
	State Income Tax Rate		6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%
	State Income Taxes		$30,106,048	$28,410,190	$1,695,858	$16,005,529	$953,979	$5,036,465	$517,286	$7,938,280	$1,559,519	$11,776,269	$44,295
	Federal Taxable Income		$453,072,858	$427,551,496	$25,521,362	$240,870,893	$14,356,646	$75,794,925	$7,784,757	$119,465,004	$23,469,562	$177,223,791	$666,612
	Federal Income Tax Rate		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
	Federal Income Taxes		$158,575,500	$149,643,024	$8,932,477	$84,304,813	$5,024,826	$26,528,224	$2,724,665	$41,812,751	$8,214,347	$62,028,327	$233,314
	Total State and Federal Income Taxes		$188,681,549	$178,053,214	$10,628,335	$100,310,342	$5,978,805	$31,564,689	$3,241,951	$49,751,031	$9,773,866	$73,804,596	$277,609
	Proforma Production Income Tax Adjustment - Demand		($1,784,029)	($1,763,462)	($20,567)	($915,736)	($52,560)	($274,368)	($31,207)	($460,719)	($96,882)	($839,701)	($1,918)
	Proforma Production Income Tax Adjustment - Energy		($78,374)	($77,111)	($1,263)	($36,561)	($2,360)	($11,074)	($1,396)	($17,639)	($4,092)	($39,185)	($107)
	Proforma Production Income Tax Adjustment		($1,286,998)	($243,591)	($1,043,407)	$1,450,292	$94,732	($321,373)	$97,299	$1,216,455	$363,179	($1,557,113)	($26,065)
	Total Income Taxes		$185,532,148	$175,969,050	$9,563,098	$100,808,337	$6,018,617	$30,957,874	$3,306,647	$50,489,128	$10,036,071	$71,368,597	$249,519

AECC's Adjusted Cost of Service Study Using Energy Scalars
for Fuel and Purchased Power Costs
for the 12 Months ending Sep. 30, 2005
($)

	1	2		14	15	16	17	18	19	20	21	22	23
Line No.	Description	Allocation Factor	E-30, E-32 Total	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401 - 999 kW)	E-32 (1,000 + kW)	E-34	E-35	E-38, 221 Water Pumping	Street Lighting	Dusk to Dawn
	SUMMARY OF RESULTS												
16	TOTAL RATE BASE		$1,664,603,376	$378,234,736	$469,359,372	$410,940,132	$228,078,549	$177,990,587	$115,618,777	$88,981,169	$25,474,477	$51,298,120	$23,620,450
17													
18	DEVELOPMENT OF RETURN												
19	Revenues from Rates		$830,331,951	$142,275,889	$218,138,380	$229,640,445	$146,123,538	$94,153,699	$66,695,622	$67,026,166	$20,966,540	$12,913,053	$6,136,856
20	Proforma to Revenues from Rates		$28,840,638	$9,060,700	$3,862,319	$13,851,012	$1,053,159	$1,013,448	$23,659	$635,071	($102,439)	$431,212	$285,840
21	Other Electric Revenues		$535,912,322	$67,075,107	$127,027,116	$155,000,606	$107,242,574	$79,566,919	$57,813,897	$67,418,789	$15,739,104	$8,074,267	$1,570,264
22	TOTAL OPERATING REVENUES		$1,395,084,911	$218,411,696	$349,027,815	$398,492,063	$254,419,271	$174,734,066	$124,533,178	$135,080,026	$36,603,205	$21,418,532	$7,992,960
23	Revenue Increase Required to Achieve Equalized ROR		$104,329,725	$30,894,780	$27,549,990	$14,900,922	$7,219,198	$23,764,834	$14,410,596	$12,667,995	($587,744.7)	$4,692,360	$933,305
24	TOTAL OPERATING REVENUES WITH REVENUE INCREASE		$1,499,414,636	$249,306,476	$376,577,805	$413,392,985	$261,638,469	$198,498,900	$138,943,774	$147,748,021	$36,015,460	$26,110,892	$8,926,265
25	Percent Increase		12.14%	20.41%	12.41%	6.12%	4.91%	24.97%	21.60%	18.72%	-2.82%	35.16%	14.53%
24													
25	OPERATING EXPENSES												
26													
27	O&M Energy Related												
28	Energy Production	Energy1	$29,995,769	$3,687,388	$7,082,367	$8,703,502	$6,038,893	$4,483,619	$3,261,592	$3,823,527	$891,253	$327,752	$77,127
29	Energy Production - Related Fuel (M&T)	Energy2	$339,906,198	$41,784,757	$80,256,003	$98,626,385	$68,431,554	$50,807,500	$36,959,723	$43,327,466	$10,099,502	$3,714,023	$873,989
30	Energy Production - Related Fuel	Energy100	$349,267,098	$43,043,545	$82,787,067	$101,682,496	$70,057,238	$51,696,753	$37,374,165	$42,512,734	$10,358,616	$3,230,153	$767,046
31	Total Energy Related		$719,169,065	$88,515,690	$170,125,436	$209,012,382	$144,527,685	$106,987,872	$77,595,480	$89,663,727	$21,349,371	$7,271,928	$1,718,163
32	O&M Non-Energy Related		$186,519,760	$39,935,977	$49,240,450	$47,241,310	$28,103,553	$21,998,470	$15,082,655	$14,690,272	$3,635,216	$5,209,795	$1,384,969
33	Operation & Maintenance		$905,688,826	$128,451,666	$219,365,886	$256,253,693	$172,631,238	$128,986,343	$92,678,134	$104,353,999	$24,984,587	$12,481,723	$3,103,132
34	Administrative & General		$42,560,789	$10,453,288	$11,676,787	$10,128,362	$5,827,742	$4,474,610	$3,006,658	$2,751,576	$880,883	$1,303,165	$571,087
35	Depreciation & Amortization Expense		$105,486,858	$23,085,668	$29,369,824	$26,524,854	$15,018,891	$11,487,621	$7,583,550	$6,267,552	$1,842,301	$3,034,821	$1,369,871
36	Amortization on Gain		($2,680,293)	($476,581)	($702,487)	($718,845)	($430,995)	($351,385)	($241,284)	($243,307)	($45,007)	($8,981)	($2,113)
37	Regulatory Assets		($905,344)	($182,950)	($247,693)	($234,016)	($129,353)	($111,332)	($74,006)	($67,490)	($10,028)	$0	$0
38	Pro-Forma Energy Related - Jurisdictional	Energy100'	$24,083,780	$2,968,076	$5,708,598	$7,011,536	$4,830,810	$3,564,760	$2,577,143	$2,931,474	$714,280	$222,736	$52,892
39	Pro-Forma Energy Related - ACC	Energy100'	$108,000,119	$13,309,894	$25,599,357	$31,442,188	$21,663,048	$15,985,633	$11,556,812	$13,145,757	$3,203,084	$998,825	$237,186
40	Pro-Forma Energy Related - ACC(Weather & Cust)	Assigned	$9,679,725	$2,669,378	$500,908	$6,436,947	$40,808	$31,684	($578,939)	$0	($125,097)	$37,319	$0
41	Pro-Forma Non-Energy Related		$57,260,104	$11,831,089	$14,879,773	$15,349,113	$8,207,116	$6,993,013	$4,637,795	$4,697,034	$767,202	$50,580	$5,186
42	Proforma Adjustments		$199,023,729	$30,778,437	$46,688,636	$60,239,784	$34,741,783	$26,575,089	$18,192,811	$20,774,265	$4,559,469	$1,309,460	$295,263
43	Taxes Other than Income		$42,553,612	$9,622,639	$12,021,204	$10,585,525	$5,888,989	$4,435,255	$2,889,635	$2,205,634	$739,434	$1,432,424	$654,697
44	Income Tax		$62,366,584	$14,554,417	$17,430,575	$14,738,555	$8,178,917	$7,464,121	$4,814,757	$3,937,736	$839,900	$2,079,954	$872,263
45	TOTAL OPERATING EXPENSES		$1,354,094,761	$216,286,584	$335,602,732	$377,517,912	$241,727,212	$182,960,322	$128,850,255	$139,979,965	$33,791,538	$21,632,566	$6,864,200
46													
47	OPERATING INCOME		$145,319,875	$33,019,892	$40,975,073	$35,875,074	$19,911,257	$15,538,578	$10,093,519	$7,768,056	$2,223,922	$4,478,326	$2,062,065
48													
49	RETURN		$145,319,875	$33,019,892	$40,975,073	$35,875,074	$19,911,257	$15,538,578	$10,093,519	$7,768,056	$2,223,922	$4,478,326	$2,062,065
50													
51	RATE OF RETURN (EQUALIZED)		8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%
52													
53	INDEX RATE OF RETURN		1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08
54													
55	ACC JURISDICTION INDEX RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Tax Calculation:												
	Operating Revenues		$1,499,414,636	$249,306,476	$376,577,805	$413,392,985	$261,638,469	$198,498,900	$138,943,774	$147,748,021	$36,015,460	$26,110,892	$8,926,265
	Operating Expenses Before Income Taxes		$1,291,728,177	$201,732,167	$318,172,157	$362,779,357	$233,548,295	$175,496,201	$124,035,498	$136,042,229	$32,951,639	$19,552,612	$5,991,937
	Operating Income Before Interest and Income Taxes		$207,686,459	$47,574,309	$58,405,648	$50,613,628	$28,090,175	$23,002,699	$14,908,276	$11,705,792	$3,063,821	$6,558,279	$2,934,328
	Interest Expense:												
	Rate Base		$1,664,603,376	$378,234,736	$469,359,372	$410,940,132	$228,078,549	$177,990,587	$115,618,777	$88,981,169	$25,474,477	$51,298,120	$23,620,450
	Long Term Debt Rate		2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%
	Interest Expense (RB x LTD)		$40,975,045	$9,310,437	$11,553,516	$10,115,497	$5,614,268	$4,381,327	$2,846,014	$2,190,316	$627,067	$1,262,729	$581,429
	State Taxable Income		$166,711,415	$38,263,872	$46,852,132	$40,498,132	$22,475,907	$18,621,372	$12,062,262	$9,515,476	$2,436,754	$5,295,551	$2,352,899
	State Income Tax Rate		6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%
	State Income Taxes		$10,387,502	$2,384,156	$2,919,276	$2,523,369	$1,400,435	$1,160,266	$751,579	$592,893	$151,830	$329,957	$146,605
	Federal Taxable Income		$156,323,912	$35,879,716	$43,932,856	$37,974,763	$21,075,472	$17,461,106	$11,310,683	$8,922,583	$2,284,924	$4,965,594	$2,206,294
	Federal Income Tax Rate		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
	Federal Income Taxes		$54,713,369	$12,557,901	$15,376,500	$13,291,167	$7,376,415	$6,111,387	$3,958,739	$3,122,904	$799,724	$1,737,958	$772,203
	Total State and Federal Income Taxes		$65,100,871	$14,942,057	$18,295,776	$15,814,536	$8,776,850	$7,271,653	$4,710,318	$3,715,797	$951,554	$2,067,915	$918,808
	Proforma Production Income Tax Adjustment - Demand		($724,544)	($146,415)	($198,228)	($187,282)	($103,521)	($89,098)	($59,227)	($54,012)	($8,025)	$0	$0
	Proforma Production Income Tax Adjustment - Energy		($31,611)	($3,886)	($7,464)	($9,172)	($6,364)	($4,725)	($3,437)	($4,030)	($939)	($345)	($81)
	Proforma Production Income Tax Adjustment		($1,978,132)	($237,339)	($659,509)	($879,527)	($488,048)	$286,291	$167,103	$279,981	($102,690)	$12,384	($46,464)
	Total Income Taxes		$62,366,584	$14,554,417	$17,430,575	$14,738,555	$8,178,917	$7,464,121	$4,814,757	$3,937,736	$839,900	$2,079,954	$872,263

**AECC Development of
Energy Related
Allocation Factors**

Allocation Factor Name	Electric Total	ACC Jurisdiction	All Other	Total Residential	E-10 Residential	E-12 Residential	EC-1 Residential	ET-1 Residential	ECT-1 Residential
Energy1	100.00%	98.39%	1.61%	46.65%	3.01%	14.13%	1.78%	22.51%	5.22%
Energy2	100.00%	98.39%	1.61%	46.65%	3.01%	14.13%	1.78%	22.51%	5.22%
Energy2'		100.00%		47.41%	3.06%	14.36%	1.81%	22.87%	5.31%
Energy100	100.00%	98.39%	1.61%	48.16%	3.07%	14.52%	1.83%	23.40%	5.35%
Energy100'		100.00%		48.94%	3.12%	14.76%	1.86%	23.78%	5.43%

Energy Data Input:

	Electric Total	ACC Jurisdiction	All Other	Total Residential	E-10 Residential	E-12 Residential	EC-1 Residential	ET-1 Residential	ECT-1 Residential
DJR_WP5 Totals	28,319,711	27,863,453	456,258	13,210,836	852,812	4,001,457	504,571	6,373,509	1,478,487

Data Source: DJR WP5.

AECC Energy Wtg					1.0179	1.0275	1.0244	1.0398	1.0241
Wtd. Energy	28,319,711	27,863,964	455,747	13,637,970	868,088	4,111,458	516,901	6,627,363	1,514,159

**AECC Development of
Energy Related
Allocation Factors**

Allocation Factor Name	Total General Service	E-20 Church Rate	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401 - 999 kW)	E-32 (1,000 + kW)	E-34	E-35	E-38, 221 Water Pumping	Street Lighting	Dusk to Dawn
Energy1	50.00%	0.14%	4.96%	9.52%	11.70%	8.12%	6.03%	4.39%	5.14%	1.20%	0.44%	0.10%
Energy2	50.00%	0.14%	4.96%	9.52%	11.70%	8.12%	6.03%	4.39%	5.14%	1.20%	0.44%	0.10%
Energy2'	50.82%	0.14%	5.04%	9.68%	11.89%	8.25%	6.13%	4.46%	5.23%	1.22%	0.45%	0.11%
Energy100	48.61%	0.14%	4.86%	9.35%	11.48%	7.91%	5.84%	4.22%	4.80%	1.17%	0.36%	0.09%
Energy100'	49.41%	0.14%	4.94%	9.50%	11.67%	8.04%	5.93%	4.29%	4.88%	1.19%	0.37%	0.09%

Energy Data Input:

	Total General Service	General Service								E-38, 221 Water Pumping	Street Lighting	Dusk to Dawn
		E-20 Church Rate	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401 - 999 kW)	E-32 (1,000 + kW)	E-34	E-35			
DJR_WP5 Totals	14,159,050	38,650	1,404,157	2,696,965	3,314,293	2,299,610	1,707,362	1,242,014	1,455,999	339,389	124,808	29,370

Data Source: DJR WP5.

AECC Energy Wtg		1.0402	0.9805	0.9818	0.9813	0.9744	0.9685	0.9625	0.9339	0.9762	0.8278	0.8353
Wtd. Energy	13,766,819	40,203	1,376,760	2,647,969	3,252,344	2,240,801	1,653,536	1,195,424	1,359,782	331,323	103,317	24,534

AECC Proposed Rate Spread at APS Requested Revenue Increase

AECC Proposed Revenue Increase for each Customer Class based on AECC's Proposed Hourly Energy Cost Allocation Method

E-32, Water Pumping & Dusk to Dawn Adder Above Cost = 4.824%

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Rate Class	Current Retail Revenues	Rate Base	Return Req'd Return @ Equal ROR	Equalized Rate of Return	Equalized Relative Rate of Return	Required Revenue Increase w/o EIC	Req'd Percent Change	AECC Proposed Revenue Increase w/o EIC	AECC Percent Change
1	Residential	$1,089,551,030	$2,489,739,663	$217,354,273	8.73%	1.00	$313,083,089	28.74%	$271,684,504	24.94%
2	General Service									
3	E-20	$3,586,700	$7,360,472	$642,569	8.73%	1.00	$98,334	2.74%	$98,334	2.74%
4	E-32	$859,172,589	$1,664,603,376	$145,319,875	8.73%	1.00	$104,329,725	12.14%	$145,776,879	16.97%
5	E-34	$66,719,281	$115,618,777	$10,093,519	8.73%	1.00	$14,410,596	21.60%	$14,410,596	21.60%
6	E35	$67,661,237	$88,981,169	$7,768,056	8.73%	1.00	$12,667,995	18.72%	$12,667,995	18.72%
7	General Service Total	$997,139,807	$1,876,563,794	$163,824,019	8.73%	1.00	$131,506,650	13.19%	$172,953,805	17.34%
8	Water Pumping (E-38, E-221)	$20,864,101	$25,474,477	$2,223,922	8.73%	1.00	($587,745)	-2.82%	$418,756	2.01%
9	Street Lighting	$13,344,265	$51,298,120	$4,478,326	8.73%	1.00	$4,692,360	35.16%	$3,327,453	24.94%
10	Dusk to Dawn	$6,422,696	$23,620,450	$2,062,065	8.73%	1.00	$933,305	14.53%	$1,243,141	19.36%
11	ACC Total	$2,127,321,899	$4,466,696,504	$389,942,605	8.73%	1.00	$449,627,659	21.14%	$449,627,659	21.14%

Derivation of Transmission Demand Charges

E-32 General Service	Demand Units (Over 20 kW) [1]	Transmission Revenues (Over 20 kW)[1]	Proposed Transmission Charge
Total	24,696,457	$45,092,740	$1.826

E-34	Demand Units[1]	Transmission Revenues[1]	Proposed Transmission Charge
Total	2,327,022	$5,757,046	$2.474

E-35	Demand Units[1]	Transmission Revenues[1]	Proposed Transmission Charge
Total	2,310,533	$6,592,489	$2.853

1. Source DJR_WP9

Comparison of APS's Generation Cost Components with APS's Proposed Generation Revenue Components

E-32 General Service	Generation Demand Costs (Over 20 kW)[1]	Demand Generation Revenue E-21-24 (Over 20 kW)[2]	Demand Generation Revenue E-32 (1st 200kWh/kW)[3]	Total Demand Generation Revenue
Total	$273,642,337	$3,709,768	$182,147,286	$185,857,054
			Generation Demand Cost Under Collection	($87,785,283)

E-32 General Service	Generation Energy Costs (Over 20 kW)[1]	Energy Generation Revenue E-21-24 (Over 20 kW)[2]	Energy Generation Revenue E-32 (1st 200kWh/kW & All Addt.)[3]	Total Energy Generation Revenue
Total	$315,557,749	$8,086,307	$422,771,992	$430,858,299
			Generation Energy Cost Over Collection	$115,300,550

E-34	Generation Demand Costs[1]		Total Demand Generation Revenue[2]
Total	$28,359,773		$19,923,962
		Generation Demand Cost Under Collection	($8,435,811)

E-34	Generation Energy Costs[1]		Total Energy Generation Revenue[2]
Total	$37,684,591		$46,201,502
		Generation Energy Cost Over Collection	$8,516,911

E-35	Generation Demand Costs[1]		Total Demand Generation Revenue[2]
Total	$26,046,173		$20,968,904
		Generation Demand Cost Under Collection	($5,077,269)

E-35	Generation Energy Costs[1]		Total Energy Generation Revenue[2]
Total	$44,903,360		$47,600,181
		Generation Energy Cost Over Collection	$2,696,821

1. Source DJR_WP3
2. Source DJR_WP9
3. See KCH-8 pg. 2 Line 7

Comparison of APS's Generation Cost Components with APS's Proposed Generation Revenue Components

Derivation of E-32 Demand-Related & Energy-Related Revenues

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Summer	Units	Rate	Line 1 - Line 2	Demand Related Revenue[1]	Energy Related Revenue	Source
1	Gen. - 1st 200kWh/kW	2,642,829,245	$0.09085	$0.03855	$101,881,067	$138,219,970	= Row ((b) x (c)) - (e)
2	Gen. - All Addit. kWh	2,595,455,920	$0.05230			$135,742,345	= Row (b) x (c)
3				Total Summer	$101,881,067	$273,962,314	
	Winter	Units	Rate	Line 4 - Line 5	Demand Related Revenue[1]	Energy Related Revenue[2]	
4	Gen. - 1st 200kWh/kW	2,082,132,784	$0.07555	$0.03855	$80,266,219	$77,038,913	= Row ((b) x (c)) - (e)
5	Gen. - All Addit. kWh	1,939,750,391	$0.0370			$71,770,764	= Row (b) x (c)
6				Total Winter	$80,266,219	$148,809,677	
7				Total Revenue	$182,147,286	$422,771,992	

1. Row (d) x (b)