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BEFORE THE ARIZONA CORPORATION COMMISSION

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COMMISSIONERS

JEFF HATCH-MILLER, Chairman  
WILLIAM A. MUNDELL  
MIKE GLEASON  
KRISTIN K. MAYES  
GARY PIERCE

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

IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.

DOCKET NO. E-01345A-05-0826

IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF THE ARIZONA PUBLIC SERVICE COMPANY.

DOCKET NO. E-01345A-05-0827

Arizona Corporation Commission

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STAFF'S POST HEARING BRIEF**

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1 **I. INTRODUCTION**

2 Arizona Corporation Commission Staff (“Staff”) hereby files its opening brief in this matter.  
3 This brief primarily attempts to identify and explain all issues and/or positions adopted by Staff in  
4 this proceeding. Although this brief also attempts to anticipate and respond to other parties’  
5 criticisms of those positions, Staff intends to address the majority of such criticisms in its responsive  
6 brief, currently due on February 5, 2007.

7 **II. THE COMMISSION SHOULD REJECT APS’ PROPOSED “ATTRITION**  
8 **ADJUSTMENTS,” WHICH ARE BOTH MERITLESS AND UNTIMELY RAISED.**

9 APS criticizes Staff for failing to perform an analysis of the likely consequences of its overall  
10 revenue requirement recommendation. (Dittmer Surrebuttal Test., hereinafter referred to as “Dittmer  
11 Surrebuttal,” Ex. S-34 at 4). APS concedes a number of adjustments, but advocates for an “attrition  
12 adjustment” that would make up on a dollar-for-dollar basis the sum of any Staff, RUCO, or  
13 intervener adjustments that the Commission might adopt. (Dittmer Direct Test., hereinafter referred  
14 to as “Dittmer Direct,” Ex. S-34 at 4; Tr. at 4264-65). The basis of this request is APS’ financial  
15 forecasts for 2006, 2007, and 2008, which allegedly indicate that the Company must receive all of its  
16 rate request in order to retain its investment grade credit rating. (Dittmer Surrebuttal at 4-5). Staff  
17 urges the Commission to entirely reject APS’ various requests for so-called “attrition adjustments”  
18 for the reasons discussed below.

19 **A. APS’ Initial Testimony And Exhibits Were Not Developed Based Upon Financial**  
20 **Integrity Issues.**

21 APS’ rate application is based upon an adjusted historic test year ending September 30, 2005.  
22 (Dittmer Surrebuttal at 5). The nature of this filing is consistent with the majority of APS’ prior rate  
23 cases: not since the completion of Palo Verde has APS requested rate relief based upon financial  
24 integrity issues. *Id.* at 5-8. Until the Company filed its rebuttal testimony, there was no reason to  
25 assume that the present case was any different. *Id.* at 5.

1 In Staff's view, this rate case has been driven primarily by rising fuel and purchased power  
2 costs and by issues concerning the mechanics of the Company's existing Power Supply Adjustor  
3 ("PSA"), which imposes restrictions upon the timing and recovery of fuel and purchased power costs.  
4 *Id.* at 6. Staff has therefore devoted extensive resources to evaluating the reasonableness of proposed  
5 fuel and purchased power cost increases and to reviewing the mechanics of the existing PSA. *Id.* at  
6 6-7. Given the nature of the Company's original rate case filing, this resource allocation was  
7 reasonable.

8 During the construction of Palo Verde, APS occasionally sought rate relief based upon  
9 financial integrity issues. *Id.* at 5. Those cases, however, clearly identified the basis for the rate  
10 request within the original filings. *Id.* In the present case, APS has essentially "laid in wait,"  
11 allowing Staff and the other parties to expend considerable time and resources evaluating its  
12 proposed adjusted historic test year cost of service before switching the basis for its request virtually  
13 in mid-stream. (*See* Dittmer Surrebuttal at 7, 13). If the Commission were to adopt APS' specific  
14 "attrition adjustments"—requests that first arose in APS' rebuttal—it will encourage this utility as  
15 well as other Arizona utilities to adopt similar tactics in the future. APS will conclude that it can hold  
16 its "real case" in reserve until rebuttal, when opportunities for discovery and analysis are severely  
17 limited. This practice is unfair, and the Commission should not reward APS for this behavior, but  
18 should instead expressly disregard APS' untimely request for "attrition adjustments."

19 **B. The Commission Should Be Wary Of Relying Upon The Company's Unaudited**  
20 **Forecasts.**

21 The Commission should not rely on the Company's forecasts as a basis for determining rates.  
22 (*Dittmer Surrebuttal* at 8). Arizona is an historic test year jurisdiction. Both Commission regulations  
23 and applicable case law would appear to foreclose APS' attempts to achieve rates based upon a future  
24 test year.

1 APS' forecasts are also not as reliable as they would be if they had been subjected to typical  
2 rate case scrutiny. Staff and the other parties did not know until late in the proceeding that the  
3 Company planned to assert a request for rate relief based upon rationales other than an historic test  
4 year. Therefore, the forecasts presented by the Company have not received the level of review  
5 necessary to determine the extent of their accuracy or reliability. *Id.* at 7-10.

6 For example, APS' forecasts appear to be based on "total company" earnings, including data  
7 related to APS' transmission operations. (Dittmer Supplemental Test., Ex. S-39 at 8-9). Therefore, it  
8 is not clear to what degree any alleged earnings shortfall is related to a potential need for transmission  
9 rate relief. *Id.* at 9.

10 Just as mistakes and oversights occurred in the preparation of APS' original case, it is entirely  
11 possible that mistakes and oversights occurred in the preparation of APS' financial forecasts. *Id.* at  
12 10. Even in the absence of actual errors, forecasts can be prepared with results skewed toward  
13 pessimistic or optimistic results. *Id.* If the Commission were to base APS' rates upon these  
14 forecasts—which were provided late in the proceeding, thereby precluding the parties from  
15 performing a meaningful review—APS will be encouraged to repeat these tactics. The Commission  
16 should not allow APS to benefit by these manipulations of the rate case process.

17 **C. The Commission Should Recognize The Significant Advantages To APS'**  
18 **Shareholders Inherent In The Existing PSA.**

19 The inclusion of demand charges in APS' PSA is a substantial benefit to APS in its efforts to  
20 address attrition. (Dittmer Surrebuttal at 11). Earnings attrition occurs when the increase in the cost  
21 of providing service begins to outpace the increase in margins from growth in sales. *Id.* at 10. APS  
22 is experiencing and probably will continue to experience high growth in retail sales. *Id.* at 11. This  
23 growth creates a need to add transmission and distribution plant and to find new sources of  
24 generation capacity and energy. *Id.* At least until the expiration of the self-build moratorium  
25

1 established in Decision No. 67744, APS will probably meet the need for new generation capacity and  
2 energy through purchased power agreements. *Id.*

3 APS' existing PSA permits APS to pass through not only energy charges but also demand  
4 charges. *Id.* The purchased capacity paid for through the demand charges replaces the need to build  
5 generating capacity that would otherwise be required to meet customer growth. *Id.* It is worthwhile  
6 and significant to note that demand charges are not always included in fuel adjustment clauses. *Id.*  
7 Specifically, demand charges are often excluded from such clauses because growth in retail sales will  
8 often be available to offset or "pay for" the incremental demand costs incurred to serve new load. *Id.*

9 Staff is not suggesting that demand charges should be excluded from APS' PSA; Staff merely  
10 raises this issue to point out that APS' PSA is more beneficial to shareholders than many fuel  
11 adjustment clauses. *Id.* Because any attrition related to production costs is significantly addressed  
12 through the recovery of demand charges in the PSA, growth in retail margins is available to a much  
13 larger extent to meet cost increases related to growth in distribution plant and to recover cost  
14 increases caused by inflation over time. *Id.* at 12. This feature of APS' *existing* PSA significantly  
15 undermines APS' claim that it will suffer "attrition."

16 **D. APS' Request For "Attrition Adjustments" Is Without Merit And Should Be**  
17 **Rejected.**

18 Staff urges the Commission to reject APS' requested "attrition adjustments" at this time.  
19 Although such adjustments were sometimes granted in the timeframe of the late 1970s through early  
20 1990s, the circumstances that supported attrition adjustments in those cases are not present in this  
21 case. (Dittmer Surrebuttal at 18). For example, interest rates and inflation rates are but a fraction of  
22 what they were in the early 1980s. *Id.* Although APS forecasts a need for significant construction  
23 expenditures for transmission and distribution, it does not have plans to construct a new generating  
24 facility. *Id.* Pursuant to Decision No. 67744, APS is foreclosed from constructing new generating  
25 facilities absent Commission approval. *Id.* at 18-19.

1 Furthermore, the need for a base rate increase in this case is entirely driven by increased fuel  
2 and purchased power expenses. *Id.* at 19. Specifically, Staff recommended an overall base rate  
3 increase of \$191.4 million, which includes an increase in fuel and purchased power costs of \$193.5  
4 million. *Id.* Thus, outside of fuel and purchased power costs, APS' cost of service has been—and  
5 continues to be—adequately recovered within existing base rates. *Id.*

6 Finally, Staff is recommending significant modifications to the existing PSA. Staff is  
7 recommending the elimination of the 90/10 sharing mechanism, which contributed to some degree to  
8 APS' cash flow constraints and earnings shortfalls. *Id.* Staff is also recommending a “forward  
9 component” for the PSA, which will serve to set the adjuster rate based upon forecasts that are closer  
10 in time to the period in which fuel and purchased power costs will be incurred. *Id.* at 19-20. If these  
11 and other modifications are adopted, the likelihood of cash flow constraints due to delays in recovery  
12 of fuel and purchased power costs should be significantly diminished. *Id.* at 19.

13 Staff believes that any “attrition” that may have occurred was related to the delay in the  
14 recovery of fuel and purchased power costs. *Id.* at 20. If Staff's PSA recommendations are adopted,  
15 attrition caused by such delay should be virtually eliminated. *Id.* Given current conditions of low  
16 inflation, low interest rates, experience with APS' existing PSA, and Staff's proposed changes to the  
17 PSA, “attrition adjustments” are not necessary at this point in time, and the Commission should reject  
18 them. *Id.*

19 **E. If The Commission Were Inclined To Adopt—Over Staff's Objection—Any Of**  
20 **APS' “Attrition Adjustments,” It Should Adopt Either The CWIP Proposal Or**  
21 **The Accelerated Depreciation Proposal.**

22 If the Commission were inclined to adopt an “attrition adjustment,” it should at least choose  
23 an alternative that will eventually be credited to ratepayers. Both the CWIP proposal and the  
24 accelerated depreciation proposal affect the recovery period for fixed assets. (Dittmer Surrebuttal at  
25 at 16). Each of these two proposals results in accounting changes that will eventually yield  
reductions in rates for future ratepayers. *Id.* at 16-17.

1 The other "attrition adjustments" proposed by APS have no associated accounting changes;  
2 thus, the revenues collected under those proposals would flow to APS' "bottom line," resulting in  
3 increased earnings for shareholders but failing to produce any direct benefit to ratepayers. *Id.* at 17.  
4 At least the CWIP proposal and the accelerated depreciation proposal would eventually provide  
5 benefits to future ratepayers.

6 **F. If APS Wishes To Seek "Attrition Adjustments" In Future Cases, The**  
7 **Commission Should Require APS To Specifically Set Forth The Relief That It**  
8 **Requests In Its Initial Filing.**

9 If, in the future, APS wishes to propose an attrition adjustment or any other unique rate  
10 proposal that is driven by forward-looking financial metrics, it should be required to make such  
11 requests within its initial direct filing so that Staff and other parties are appropriately forewarned and  
12 can efficiently allocate resources. (Dittmer Surrebuttal at 17). The Commission should issue a  
13 specific and express statement to that effect in this case.

14 APS should not be permitted to make significant requests based upon new arguments for the  
15 first time in the rebuttal phase of its case. *Id.* Staff and other parties had less than two weeks to  
16 respond in surrebuttal to APS' rebuttal; accordingly, there was insufficient time to undertake  
17 discovery or perform meaningful analysis of APS' new proposals. *Id.* It is simply unfair to allow  
18 such behavior from APS, and the Commission should ensure that such tactics are not repeated.

19 **III. THE COMMISSION SHOULD ADOPT STAFF'S PROPOSED BASE COST OF FUEL**  
20 **AND PURCHASED POWER**

21 In its direct case, APS used normalized, projected 2006 data to form the basis for its proposed  
22 base cost of fuel and purchased power. (Antonuk Direct Test., hereinafter referred to as "Antonuk  
23 Direct", Ex. S-28 at 4-5, 26). Staff reviewed APS' proposal and concluded that calendar year 2006  
24 serves as an appropriate period from which to establish the fuel and energy portion of APS' base  
25 rates. *Id.* at 26. Staff proposed a number of adjustments to the 2006 data in order to arrive at its  
calculation for net retail fuel costs: \$824.4 million, which results in an average fuel cost of 2.8104

1 cents/kWh. *Id.* at 5-6, 26-32. Based upon this calculation, Staff concluded that APS' proposed base  
2 cost of fuel and purchased power should be reduced by \$111.6 million (with the APS sharing  
3 proposal) or \$111.4 (without the APS sharing proposal). *Id.* at 33. It should also be reduced by a  
4 further \$3,702,501 to reflect 2006 margins for transactions involving non-utility use of an APS  
5 transmission asset. *Id.* at 29-30, 33. Finally, it should be reduced further to account for the removal  
6 of non-fuel and energy costs associated with non-utility marketing and trading activity. (Antonuk  
7 Direct at 33; Dittmer Direct at 59-61).

8         Instead of responding to the adjustments that Staff and others proposed in direct testimony,  
9 APS' rebuttal abandoned its use of a 2006 forecast and instead substituted a 2007 forecast. (Ewen  
10 Rebuttal at 4-6; Antonuk Surrebuttal, hereinafter referred to as "Antonuk Surrebuttal", Ex. S-29 at 2-  
11 3). Staff opposes the use of APS' 2007 forecasts (provided in APS' rebuttal and rejoinder) as the  
12 means for determining the base cost of fuel and purchased power. (Antonuk Surrebuttal at 8-10). As  
13 Staff witness Antonuk's direct testimony describes, Staff thoroughly analyzed APS' originally  
14 proposed base cost of fuel and purchased power, which was based upon calendar year 2006.  
15 (Antonuk Direct at 26-33). By contrast, the 2007 forecasts, which were provided relatively late in the  
16 proceeding, have not undergone the same level of Staff scrutiny as the 2006 forecast presented in  
17 APS' original case. (Antonuk Surrebuttal at 8-10). These forecasts are complex to perform, and they  
18 are subject to both judgment and error. *Id.* at 8-9. In fact, the potential for error is demonstrated by  
19 APS' testimony, which contained at least two significant errors. *Id.* at 9. For these reasons, the  
20 Commission should adopt Staff's recommended base cost of fuel and purchased power to determine  
21 APS' base rates.

22 **IV. THE COMMISSION SHOULD REJECT APS' PROPOSED PENSION EXPENSE**  
23 **ADJUSTMENT, WHICH WOULD INCREASE TEST YEAR PENSION EXPENSE BY**  
24 **APPROXIMATELY \$44 MILLION.**

25         In her direct testimony, APS witness Rockenberger claims that, as of December 31, 2004, the  
Company's actuaries had calculated a projected benefit obligation of \$1,371 million. (Dittmer Direct

1 at 62). She also states that, as of December 31, 2004, the “market value” of the assets in the external  
2 pension trust was approximately \$982 million. *Id.* According to Ms. Rockenberger, the difference  
3 between these two figures leaves approximately \$389 million of the projected pension obligation  
4 “underfunded.” *Id.* Because Pinnacle West Capital Corporation and other entities are responsible for  
5 approximately 39% of this underfunded amount, APS has proposed recovering from ratepayers the  
6 remaining 61% (approximately \$218 million) over a five year period. *Id.* The \$218 million figure  
7 divided by the five year amortization period results in APS’ requested adjustment of \$44 million. *Id.*  
8 Staff opposes this adjustment.

9 **A. The Commission Should Reject APS’ Proposed Five-Year Amortization Of The**  
10 **Underfunded Projected Benefit Obligation.**

11 ***1. The magnitude of APS’ projected benefit obligation is not highly unusual***  
12 ***and should not be alarming.***

13 Although it is not desirable for the projected benefit obligation to become significantly under  
14 or over funded relative to the current market value of plan assets, APS’ “underfunded” position is not  
15 unusual, nor is it a situation that requires concern. (Dittmer Direct at 64-65). APS’ “underfunded”  
16 position is primarily attributable to 1) the under-performance of returns on plan assets over a short  
17 period and 2) a significant increase in the calculated projected benefit obligation that is directly  
18 linked to the FAS 87 requirement to use a conservative interest rate for purposes of discounting the  
19 future obligation. *Id.* at 71-73, 81. In recent years, interest rates have fallen. A return to more  
20 “normal” interest rate levels would reduce the net present value of the projected benefit obligation  
21 and, in turn, the “underfunded” position. *Id.* at 72, 81. In addition, a short-term rally in the stock  
22 market could result in greater than expected returns on plan assets, which would also serve to narrow  
23 the gap between the market value of plan assets and the projected benefit obligation. *Id.* at 81.

24 The point to emphasize is that the difference between the market value of pension plan assets  
25 and the projected benefit obligation will vary—even significantly—over time. *Id.* These

1 circumstances are not unusual and do not support the drastic and completely unprecedented proposal  
2 requested by APS. *Id.* at 81-82.

3           **2.     *The “underfunded” position of the projected benefit obligation is already***  
4           ***considered within the development of APS’ test year cost of service.***

5           To a large extent, the “underfunded” position of the projected benefit obligation is already  
6 considered within the net periodic pension cost and test year pension expense, which are both  
7 elements used to develop APS’ cost of service. (Dittmer Direct at 65). To add an additional pension  
8 amortization expense, as APS proposes, could lead to a double collection of these expenses. (Dittmer  
9 Direct at 65; Dittmer Surrebuttal at 26-29).

10           When the return on plan assets falls short of expectations or when the current estimate of the  
11 projected benefit obligation exceeds prior projections, FAS 87 requires net periodic pension cost to  
12 include an amortization of significant shortfalls from earlier projections. (Dittmer Direct at 79-80,  
13 82). The 2005 total net periodic pension cost (before allocation to APS’ retail operations) was  
14 \$62,797,000, which includes \$19,801,000 attributable to the amortization of the shortfalls from  
15 earlier projections. *Id.* at 82. Thus, nearly a third of net periodic pension cost for 2005 consisted of  
16 this “catch up” amortization. *Id.* at 80, 82.

17           APS witness Brandt asserts that APS’ pension trust did not “underperform” relative to the  
18 overall stock market. (Dittmer Surrebuttal at 26). While this may be true, it was never a point  
19 suggested by Staff and is completely irrelevant to the resolution of this issue. In his direct testimony,  
20 Staff witness Dittmer stated that APS’ trust balance declined between 2001 and 2003, and he  
21 acknowledged that this decline is not surprising when one considers the *overall performance of the*  
22 *stock market* during this timeframe. *Id.* Contrary to APS’ implications, the basis of Staff’s  
23 opposition to the Company’s pension expense is not that APS should be penalized for the  
24 underperformance of its pension trust. *Id.* Instead, Staff’s testimony simply acknowledges that  
25 projections of pension trust performance are often unachieved in the short run and that significant

1 differences are considered within the “catch-up” provision of FAS-87 determined net periodic  
2 pension costs. *Id.* at 27.

3 In the past, the Commission has developed the retail cost of service for APS by using FAS 87-  
4 determined net periodic pension cost and related net pension expense. (Dittmer Direct at 82).  
5 Whenever retail rates are based upon FAS 87-determined pension expense, such rates will include the  
6 “catch up” amortization designed to “correct” for 1) the impact of returns that are either significantly  
7 below or above previous estimates or 2) the growth or decline in the projected benefit obligation that  
8 is either above or below prior projections. *Id.* at 83. Consequently, APS’ request to recover the  
9 “underfunded” projected benefit obligation over five years duplicates the recovery of such shortfall  
10 that already occurs when retail rates are developed by considering net periodic pension cost, which in  
11 turn includes the “catch-up” amortization. (Dittmer Direct at 83; Dittmer Surrebuttal at 37).

12 **3. *The Company’s proposal is likely to lead to intergenerational inequities***  
13 ***between existing and future ratepayers.***

14 The projected benefit obligation considers future years of employment and future pay raises.  
15 (Dittmer Direct at 67-69, 83; Tr. at 423-24, 427-29). Under APS’ proposal, ratepayers would be  
16 required to pay 1) the FAS-87 determined pension expense (including the “catch up” amortization)  
17 and 2) a five-year amortization of the “underfunded” pension benefit obligation. (Dittmer Direct at  
18 84). Specifically, under the Company’s proposal, retail rates would include not only test year actual  
19 pension expense of \$23,484,000 but also the amortization of the “underfunded” projected benefit  
20 obligation of \$43,695,000. *Id.* at 84, n. 29.

21 The Company’s proposal essentially “front loads” future pension costs to existing ratepayers.  
22 *Id.* at 84. If the Commission were to adopt APS’ proposal, future ratepayers would likely pay little, if  
23 any, pension expenses in rates after completion of the five-year amortization period. *Id.* Because  
24 future ratepayers will benefit from the services yet to be provided by APS employees in future years,  
25 it is inequitable to impose those costs on today’s ratepayers. *Id.*

1                   4.       ***APS' proposal is inconsistent with regulatory precedent.***

2           APS has not identified a single instance in this or any other jurisdiction in which a regulatory  
3 commission has adopted a proposal similar to the one proposed here. (Dittmer Direct at 84-85).  
4 Staff witness Dittmer, who has over thirty years of experience in processing rate cases, stated that he  
5 is not aware of "a single instance where a regulatory commission has adopted the amortization  
6 proposal presented by APS" in this case. *Id.* at 85.

7                   5.       ***It is not clear that funds collected from ratepayers on an accelerated basis  
8 would actually be contributed to the pension fund to reduce the current gap  
9 between the market value of the pension fund assets and the projected  
benefit obligation.***

10           In discovery, Staff asked APS to confirm that it intends to use the funds collected through its  
11 five-year amortization proposal to actually make additional contributions to the pension fund.  
12 (Dittmer Direct at 86). APS' response noted that "[t]he funding decision will depend upon the  
13 minimum pension funding requirements and IRS maximum tax deduction limitations. This may or  
14 may not require the full \$44 million to be contributed to bring the fund to an approximate 100%  
15 funded status." (Dittmer Direct at 74-76, 86 (quoting APS' Resp. to Data Request UTI-2-137)).  
16 Later, APS clarified that it intends to commit to funding \$44 million *more than it would have*  
17 *otherwise contributed* to the pension trust as long as the resulting contribution amount does not  
18 exceed the IRS maximum. *Id.* at 86.

19           APS' statements, however, are not sufficient to satisfy Staff's concerns. First, it will be  
20 impossible in the future to know what APS *might have contributed* to the pension fund absent the  
21 approval of its request for accelerated recovery. *Id.* at 87. In recent years, APS' actual pension fund  
22 contributions have differed significantly from the actuary's calculations of net periodic pension costs,  
23 and APS' contributions were always less than the maximum contribution allowed by the IRS. *Id.* at  
24 75-76, 80, 87. Since APS' last rate case, APS did not fund its pension trust in an amount equal to  
25 what it was permitted to collect for pension costs in rates. *Id.* at 87.

1 In rebuttal, APS witness Brandt states that APS' pension contributions have actually exceeded  
2 net periodic pension costs over the past five years and that Staff witness Dittmer's claims to the  
3 contrary are incorrect. (Dittmer Surrebuttal at 37). In surrebuttal, Mr. Dittmer acknowledged that his  
4 calculations were off by one year and therefore incorrect. *Id.* at 38. This error, however, does not  
5 affect the validity of Mr. Dittmer's underlying premise, *i.e.*, that APS' contributions in recent years  
6 have been less than its net periodic pension cost. *Id.*

7 Notwithstanding the corrections set forth in Mr. Brandt's testimony, the Company's  
8 contributions to the external pension fund were less than its net periodic pension cost for years 2003  
9 and 2004. *Id.* It would be reasonable to expect APS to make contributions to the pension trust that  
10 are at least equivalent to the net periodic pension cost used to establish retail rates before asking  
11 ratepayers to fund an accelerated recovery. (Dittmer Direct at 87; Dittmer Surrebuttal at 38).

12 **6. *Implementation of APS' proposal will lead to other intergenerational equity***  
13 ***issues because some of the "underfunding" is related to payroll dollars being***  
14 ***capitalized as well as expensed.***

14 The level of *net periodic pension cost* that is calculated by the Company's actuaries pertains  
15 to total payroll costs incurred within a given reporting period whether or not such costs are *expensed*  
16 or *capitalized*. (Dittmer Direct at 88). By contrast, the amount of *pension expense* recorded within a  
17 given reporting period relates to costs *expensed* during that same reporting period. *Id.* For  
18 ratemaking purposes, only *pension expense* associated with payroll dollars *expensed* are included  
19 within the test year cost of service. *Id.*

20 APS proposes to collect (in rates over a five-year amortization period) an amount that is  
21 designed to recover a point-in-time calculation of the difference between the projected benefit  
22 obligation and the market value of the pension trust assets. *Id.* However, a portion of such difference  
23 is related to payroll dollars that will be *capitalized* to plant in service. Like other capitalized items  
24 (contractor labor, materials, supplies, interest, etc.), such costs will be included in plant in service and  
25 will be recovered from ratepayers in depreciation expense. Ratepayers who benefit from long-lived

1 plant assets should pay for such facilities over the term of the assets' useful lives. *Id.* The  
2 Company's proposal, however, would charge the underfunded pension amount entirely to existing  
3 ratepayers, thereby ignoring that a portion of those costs should be capitalized. *Id.* This result will  
4 lead to further intergenerational inequity among ratepayers because current ratepayers will pay on an  
5 accelerated basis costs that should instead be capitalized as plant in service. *Id.* at 89. If these costs  
6 were appropriately capitalized to plant in service, future ratepayers would bear these costs by paying  
7 depreciation expense as well as a return. *Id.*

8           7.     ***There is no evidence to suggest that the significant increase in costs that***  
9                   ***APS proposes to pass on to ratepayers at this time will eventually lead to***  
                  ***long-term savings for ratepayers.***

10           If the Company could establish that accelerated recovery of a given expense will provide  
11 subsequent ratepayer savings, that argument might support the Company's proposal. Although Staff  
12 asked the Company to estimate the amount of pension expense savings that could be achieved if its  
13 proposal were adopted, APS was unable to identify any savings. (Dittmer Direct at 89).

14           8.     ***APS' proposal will tend to worsen APS' cash flow position both now and in***  
15                   ***the future.***

16           An examination of the mechanics of APS' proposal shows that it is actually harmful to the  
17 Company's interests. Specifically, APS' proposal will not alleviate APS' current cash flow position  
18 and will very probably exacerbate APS' future cash flow position.

19           APS' proposal will do absolutely nothing to improve APS' cash flow position *in the short*  
20 *term.* APS has stated that it intends to fund the external pension trust with the incremental pension  
21 recovery that it has requested in rates. If the Commission were to grant APS' request, APS would  
22 purportedly contribute to the external pension trust that portion of its rates that is related to pension  
23 expense. In other words, every additional dollar that APS might collect in rates (related to its five-  
24 year accelerated recovery of pension expense) would in turn be used to fund its external pension trust.

25

1 Because every additional dollar collected in rates would be offset by a contribution to the external  
2 trust, APS' current cash flow position would not be improved. (Dittmer Surrebuttal at 32-33, 39).

3 In addition, accelerated recovery of pension expenses will very likely exacerbate APS' *future*  
4 cash flow position. APS has acknowledged that accelerated recovery of its pension expense will  
5 require the creation of a regulatory liability in order to refund to ratepayers the over-recovery of  
6 pension expense collected in years 1-5. *Id.* at 29-30. When the regulatory liability comes due (years  
7 6-15 of APS' proposal), the Company will have to *simultaneously* fund its ongoing construction  
8 program to meet customer growth *and* refund the regulatory liability. *Id.* at 30-33.

9 As Staff witness Dittmer explained, funds that are contributed to an external pension trust  
10 cannot be withdrawn except to meet payment obligations to retirees. Because APS will not be able to  
11 withdraw money from the trust, it will have to refund the regulatory liability with funds from other  
12 sources, such as internally generated funds or borrowed money. *Id.* at 30-33. These circumstances  
13 will only *worsen* APS' cash flow position at a time when it anticipates continued new construction as  
14 a result of continued customer growth.

15 These factors demonstrate that APS' pension expense proposal provides no benefits to either  
16 ratepayers or APS. There is no merit to this proposal, and the Commission should reject it.

17 **B. APS' Proposed Increase To Test Year Pension Expense In Conjunction With Its**  
18 **Payroll Annualization Adjustment**

19 In addition to APS' proposal to amortize the underfunded pension benefit obligation, the  
20 Company has also proposed to increase test year pension expense in connection with its payroll  
21 annualization adjustment. (Dittmer Direct at 63). After annualizing payroll costs to reflect 1) the  
22 number of employees at the end of the test year and 2) wage increases granted through April of 2006,  
23 APS applied a benefits loading rate to the payroll annualization adjustment to reflect claimed  
24 increases in pension expense, post retirement medical benefits, health/medical costs, and payroll  
25 taxes. *Id.*

1 Staff accepted the Company's assumption that increased payroll costs lead to increases in  
2 both payroll taxes and health/medical costs for active employees. *Id.* However, Staff rejects the  
3 assumption that payroll increases also lead to increases in pension expenses and post retirement  
4 medical expenses, and has therefore reversed this adjustment. *Id.* at 63-64.

### 5 C. Summary

6 Staff reversed APS' proposed five-year amortization of the underfunded pension benefit  
7 obligation. (Dittmer Direct at 62, 64). Staff also subtracted the pro forma level of pension expense  
8 that APS had included as part of its payroll annualization adjustment. *Id.* at 63. Finally, Staff  
9 believes that the Commission should set rates in this proceeding based upon the Company's 2006  
10 pension expense as reported in the Company's 2006 actuarial study. *Id.* at 63-64, 89-90. In rebuttal,  
11 APS agreed with this update and proposed an adjustment to reflect 2006 actuarially determined  
12 pension costs. Staff, in turn, incorporated this adjustment in its updated schedules. (*See Ex. S-38*).

## 13 **V. CASH WORKING CAPITAL**

### 14 A. Overview

15 Cash working capital is defined as the amount of cash needed by a utility to pay the day-to-  
16 day expenses incurred in providing service as compared to the timing of the utility's collection of  
17 revenues for those services. (Dittmer Direct at 33). In other words, if the timing of a company's cash  
18 expenditures precedes its cash recovery for those expenditures, investors are providing the cash  
19 working capital. *Id.* at 33, 35, 36. By contrast, if ratepayers' payments for utility service precede the  
20 company's cash disbursements for expenses, ratepayers are providing the cash working capital. *Id.* at  
21 33, 36. Cash working capital is typically included in a utility's rate base in order to recognize these  
22 timing issues related to cash flow. *Id.* at 34. Cash working capital can be either a positive or a  
23 negative value, and a negative result should not be surprising or troublesome. *Id.* at 32, 33, 34. In  
24 fact, both Staff and APS have proposed *negative* allowances for cash working capital in this case.  
25

1 APS has proposed a rate base *deduction* of \$29.1 million for cash working capital based upon  
2 the results of a company-prepared lead lag study<sup>1</sup> for APS' Arizona retail operations. (See Dittmer  
3 Direct at 25, 34, 35). By contrast, Staff increased the amount of APS' proposed deduction thereby  
4 resulting in a larger *negative* cash working capital allowance than that proposed by APS. *Id.* at 25,  
5 31, 32. In quantifying Staff's cash working capital adjustment, Staff did not prepare a stand-alone  
6 lead lag study, but instead analyzed, tested, and proposed corrections to the lead lag study prepared  
7 by APS. *Id.* at 30, 34.

8 **B. APS' Lead Lag Study Fails To Satisfy Applicable Commission Precedent.**

9 APS' proposed lead lag study includes non-cash items—such as depreciation expense,  
10 amortization expense, and deferred income tax expense—and fails to consider interest expense,  
11 thereby significantly overstating the Company's cash working capital requirements. (Dittmer Direct  
12 at 27, 28, 29, 30, . . . ). This approach is inconsistent with longstanding Commission precedent:

13 We have repeatedly rejected the inclusion of deferred taxes and depreciation in  
14 the calculation of current cash working capital requirements. We have also  
15 finally concluded that interest expense should be included in a lead/lag study, and  
we have expressly approved the concept of negative cash working capital.

16 Decision No. 55931 at 66. Curiously, APS recognizes this precedent in its January 31, 2006 rate case  
17 filing, wherein APS Witness Rockenberger included the following statements:

18 I am testifying to all of the data in SFR Schedule B-5, with the exception of the  
19 Working Capital calculation (line 1 of page 1), which Mr. Fred Balluff will address.  
20 My testimony presents the calculation of the allowance for working capital, *which*  
*includes a cash working capital component determined using the lead/lag study*  
*methodology required by Decision No. 55931.*

21 (Rockenberger Direct Test., Ex. APS-56 at 27 (emphasis added); *see also* Dittmer Direct at 28).

22 Despite this assertion, it is undisputed that APS' proposed lead lag study does not comply with the  
23 requirements of Decision No. 55931, *i.e.*, it does not exclude depreciation expense, amortization  
24 expense, and deferred income tax expense, and it fails to include interest expense. (Dittmer Direct at

25 \_\_\_\_\_  
<sup>1</sup> A lead lag study systematically measures the timing of cash flows through the utility. (Dittmer Direct at 35).

1 28-29; Tr. at 2662-64). The rate base impact of APS' failure to prepare its lead lag study in  
2 accordance with Commission precedent overstates cash working capital, and therefore APS' rate  
3 base, by approximately \$43.6 million. (Dittmer Direct at 39).

4 **C. The Commission Should Exclude Non-Cash Items From APS' Lead Lag Study.**

5 In considering this issue, it is helpful to review the definition of cash working capital: cash  
6 working capital is defined as the amount of cash needed by a utility to pay the day-to-day expenses  
7 incurred in providing service as compared to the timing of the utility's collection of revenues for  
8 those services. (Dittmer Direct at 33, 36). Therefore, the particular cash flows that appropriately fall  
9 within the scope of a lead lag study are those transactions that relate to the *day-to-day payment* of  
10 expenses incurred in providing utility service. *Id.* at 36, 37.

11 Neither depreciation expenses nor deferred income tax expenses requires APS to make a cash  
12 outlay in order to meet its day-to-day expenses incurred in providing utility service. Both  
13 depreciation expenses and deferred income tax expenses are non-cash expenses; both represent  
14 accrued expenses; both are recovered through utility rates; the cumulative recoveries of both  
15 expenses are recognized as zero cost capital and used to reduce rate base; neither involves current  
16 period payments to suppliers, vendors, or taxing authorities; and both provide a source of cash (in  
17 other words, positive cash flow) that can be used for investment in plant construction or other  
18 corporate activities. *Id.* at 41-42. As Staff witness Dittmer explained in his direct testimony,

19 [including non-cash expense items in a lead lag study] would be inconsistent with the  
20 widely accepted view of cash working capital as the amount of invested capital  
21 required to bridge the gap between the *payment* of cash expenses and the *collection* of  
22 related revenues. When there is no expense payment, no cash working capital is  
23 required. Depreciation and deferred income tax expenses do not require current  
24 period cash payments. Since investors are not required to provide cash advances for  
25 these expense items prior to the collection of revenues, it would be improper to  
include such items in a study of cash working capital requirements.

1 *Id.* at 42 (emphasis in original). For these reasons, non-cash expenses, such as depreciation,  
2 amortization, and deferred income tax expenses, should be removed from the lead lag study in order  
3 to limit the study results to “cash” expense requirements. *Id.* at 30.

4 In rebuttal, APS witness Balluff claims that a lead lag study should include a lag for the  
5 collection of depreciation expense, because the recorded “accumulated depreciation” as of the end of  
6 the test year has not been fully collected from ratepayers at that point in time. This approach,  
7 however, expands the lead lag study to consider “cash” recovery of plant and depreciation reserve.  
8 (*See* Dittmer Direct at 39-40). Staff opposes this approach.

9 Although not every dollar of recorded depreciation reserve would have been collected from  
10 ratepayers as of the end of the test year, not every dollar of construction recorded as plant in service  
11 would have been “paid for” by the Company as of the end of the test year. (Dittmer Direct at 39-40;  
12 Dittmer Surrebuttal at 46). Further, as Staff witness Dittmer explained, every dollar of the  
13 depreciation reserve recorded at the end of the test year will have been recovered from ratepayers by  
14 the time rates become effective in this case. (Dittmer Direct at 40).

15 APS witness Balluff has not raised new arguments. These arguments have been presented—  
16 and rejected—in previous Commission rate cases. Those outcomes should be reaffirmed in this case.

17 **D. The Commission Should Include Interest Expense In APS’ Lead Lag Study.**

18 Interest expense is a direct result of the Company’s debt obligations. (Dittmer Direct at 43).  
19 Each debt issue requires the periodic cash payment of interest expense in known amounts that  
20 become due at specific points in time, *e.g.*, in quarterly or semi-annual payments. *Id.* The  
21 ratemaking formula provides for the recovery of these periodic payments to debt holders. *Id.*  
22 Because ratepayers pay for service on a monthly basis and because these periodic payments to debt  
23 holders typically occur quarterly or semi-annually, the lead lag study should recognize the  
24 Company’s use of these funds for the extended period between their collection from ratepayers and  
25 the Company’s payout of interest to debt holders. *Id.*

1           **E. Staff Also Incorporated Certain Adjustments To APS' Lead Lag Study That APS**  
2           **Has Conceded.**

3           Staff's proposed adjustments to APS' lead lag study include the following corrections: 1)  
4 Staff revised the purchased power expense level to reflect the elimination of significant unregulated  
5 power marketing activity from the quantification of cash working capital; 2) Staff recalculated the  
6 composite revenue lag using test year revenues, instead of 2004 revenues, thereby adopting a re-  
7 weighting method that is consistent with the preceding purchased power expense adjustment; 3) Staff  
8 restated APS' expense lag calculation regarding the Palo Verde lease to reflect a shift in semi-annual  
9 payment requirements that began in 2005; and 4) Staff revised the payment lag for Arizona state  
10 taxes to be consistent with the statutory payment due dates. (Dittmer Direct at 30-31). Staff believes  
11 that APS has accepted these corrections.

12 **VI. SUNDANCE UNITS' MAJOR OVERHAUL COSTS**

13           APS has included in its cost of service the operations and maintenance ("O&M") expense  
14 associated with its recently acquired Sundance Combustion Turbine Units ("Sundance"). (Dittmer  
15 Direct at 95). Although Staff conceptually agrees that it is appropriate to recognize Sundance O&M  
16 expenses in APS' rates, Staff disagrees with certain specific estimated O&M expenses requested by  
17 APS in this case. *Id.* Specifically, Staff opposes the recovery of certain estimated Sundance O&M  
18 expenses that will not actually be incurred for many years into the future. *Id.*

19           As part of its Sundance O&M proposal, APS includes \$2.75 million for "non-routine"  
20 maintenance expense. *Id.* at 96. These "non-routine" maintenance activities are broken out between  
21 "Hot Gas Paths" and "Major" overhauls. *Id.* The Hot Gas Path overhauls are scheduled to occur at  
22 18,000 usage-hour intervals, and the Major overhauls are scheduled to occur at 36,000 hour intervals.  
23 *Id.* at 96-97. On average, each Sundance combustion turbine is predicted to run approximately 1,500  
24 hours per year. *Id.* at 97. Therefore, assuming average annual hours of usage for each unit, the  
25 average interval between Hot Gas Path overhauls is approximately twelve years, and the average

1 interval between Major overhauls is approximately twenty-four years. *Id.* Initially, APS intends to  
2 unevenly run the Sundance units so that some units will reach the usage intervals for these types of  
3 overhauls earlier than other units, thereby staggering the overhaul cycle and avoiding the need to  
4 overhaul all ten units at the same time. *Id.*

5 Notwithstanding this staggered overhaul cycle, the Company's adjustment will capture the  
6 costs of events that will not occur for many years into the future and that are unlikely to occur during  
7 the time when rates established in this proceeding will be in effect. (Dittmer Direct Confidential  
8 Version, Ex. S-36 at 97). For these reasons, Staff opposes this element of APS' Sundance O&M  
9 adjustment and urges the Commission to reject it. *Id.*

10 Because these non-routine maintenance activities are related to hours of usage, there is some  
11 conceptual support for beginning to accrue for costs that are expected to be incurred in the future but  
12 are related to usage experienced today. *Id.* at 98. The danger associated with such a practice is that  
13 ratepayers could be overcharged, paying for these O&M expenses once today as estimates and then  
14 again in the future when they are actually incurred. *Id.* at 98-99. Unless the cost for future expenses  
15 being recovered in today's rates are specifically accrued on the Company's balance sheet for  
16 consideration in future rate proceedings, there is a high probability that ratepayers will be "double  
17 charged" for such expenses. *Id.* at 98. APS has indicated in discovery that it has no intention of  
18 undertaking a specific accrual for these expenses to ensure that they will be considered in future rate  
19 proceedings. *Id.*

20 This high probability for overcharging such costs is related to the way that APS has typically  
21 normalized maintenance costs for its *mature* generating units. *Id.* In this current case and in previous  
22 cases, APS has proposed to normalize maintenance costs for mature generating units by calculating a  
23 multi-year historical average of maintenance costs, adjusted for inflation over time, to arrive at a  
24 normalized level of maintenance expense. *Id.* This method tends to smooth the somewhat uneven  
25 and significant costs of major planned overhauls and other non-routine events. *Id.* at 98-99. If this

1 method continues to be used in the future, the Sundance costs for non-routine maintenance  
2 activities—once they are actually incurred—presumably will be considered in the multi-year  
3 averaging process described above. *Id.* at 99. At that point in time in a future rate case, it is very  
4 likely that ratepayers will again be charged for costs that they have already paid, unless regulators  
5 have some means to reconsider the issue. *Id.* It is important to note that this issue would not occur  
6 until many years into the future. *Id.* at 97, 99.

7 APS has implied that Staff's approach to maintenance expense for the Sundance units is  
8 inconsistent to its approach to maintenance expense for the PWEC units. (Tr. at 4223). In both its  
9 last rate case and this current rate case, APS proposed to include in its cost of service a multi-year  
10 projection of PWEC's non-fuel and maintenance expense, and Staff has accepted this proposal in  
11 both cases. Staff's acceptance of APS' proposal regarding PWEC is not relevant to determining the  
12 appropriate level of maintenance expense for the Sundance units.

13 Although APS used a forecast to develop its cost of service proposals for both PWEC and  
14 Sundance, there are significant factual distinctions between the PWEC units and the Sundance units.  
15 *Id.* at 4223-24. Staff accepted the non-routine maintenance included in the PWEC forecast because  
16 that maintenance had already occurred. *Id.* By contrast, the Sundance non-routine maintenance is  
17 not scheduled to occur until far into the future—well beyond the time that rates established in this  
18 proceeding will be in effect. *Id.*

19 If the Commission were to grant APS' request to begin recovery of these non-routine  
20 maintenance expenses, the Commission should at least require APS to recognize monies for non-  
21 routine maintenance collected within rates as a current period expense and to concurrently establish a  
22 regulatory liability on its balance sheet. *Id.* at 99. When these costs are eventually incurred, they  
23 could then be charged against the deferred liability account rather than being charged to maintenance  
24 expense, where they could otherwise be considered in developing future rates. *Id.* at 99-100.

25

1 Staff's primary recommendation on this issue is to entirely eliminate the non-routine portion  
2 of Sundance O&M expense from APS' cost of service. If, however, the Commission were to adopt  
3 the Company's request, it should also impose the accounting treatment discussed above. (Dittmer  
4 Direct at 100). This latter alternative is not an especially desirable approach, considering the value of  
5 this issue relative to other issues.

## 6 VII. OTHER MISCELLANEOUS ADJUSTMENTS

### 7 **A. SFAS 112—Other Deferred Credits As A Rate Base Offset**

8 Staff has proposed a rate base deduction of \$3.67 million for the Accumulated Provision of  
9 SFAS 112 costs. (Dittmer Direct at 22). These SFAS 112 costs relate to payments to employees on  
10 long-term disability and are ultimately included in the above-the-line cost of service. *Id.* at 21. For  
11 this reason, it is appropriate to include these cost-free funds as a rate base offset. *Id.* APS has  
12 acknowledged that it is appropriate to include the end-of-test-year balance for the Accumulated  
13 Provision of SFAS 112 as a rate base offset, and APS has also acknowledged that it failed to include  
14 this item in its original case. *Id.*

### 15 **B. Bark Beetle Remediation Costs**

16 In APS' last rate case, the parties reached a settlement agreement, which was in large part  
17 adopted by the Commission. (Dittmer Direct at 22). That settlement agreement provided for APS to  
18 defer bark beetle remediation costs. *Id.* These costs relate to removing trees in northern Arizona that  
19 are located near transmission lines and that have died from bark beetle infestation. *Id.* The  
20 settlement agreement—and the resulting Commission order—do not provide for recovery of bark  
21 beetle remediation costs in rates, but they do authorize APS to defer for later recovery the reasonable  
22 and prudent costs of bark beetle remediation that exceed the prior test year level of tree and brush  
23 control expense. *Id.*

24 In this case, APS has proposed rate base inclusion of two categories of bark beetle  
25 remediation costs: those deferred on its books as of the end of the test year and those estimated to be

1 incurred through the remainder of 2005 and 2006. *Id.* at 23. APS also seeks cost recovery in base  
2 rates of amortization expense designed to recover over a three year period the end-of-test-year-actual  
3 plus estimated-through-end-of-2006 deferred bark beetle remediation costs. *Id.*

4       There are aspects of the Company's treatment of the bark beetle issues that Staff does not  
5 support. First, Staff disagrees with APS' calculation of its bark beetle deferrals. After the  
6 Commission issued the last rate order in April of 2005, APS essentially began deferring bark beetle  
7 remediation expenditures retroactively to January 1, 2005 – three months before the effective date of  
8 that decision. *Id.* Decision No. 67744, which is APS' last rate order, does not give APS the authority  
9 to defer these costs prior to its effective date. *Id.* Therefore, the bark beetle remediation costs that  
10 relate to work undertaken between January 1, 2005 and March 31, 2005, *i.e.*, the period before the  
11 effective date of Decision No. 67744, should be removed from APS' proposed rate base. *Id.* In  
12 addition, a corresponding portion should also be removed from APS' amortization expense proposal.  
13 *Id.* These adjustments are reflected in Schedule B-2 in Staff Exhibit S-35.

14       Staff made two additional adjustments to APS' proposed bark beetle deferral balance, which  
15 APS has accepted. *Id.* at 24. When calculating its proposed pro forma rate base adjustment, APS  
16 started with its projected end-of-2006 deferral balance. *Id.* From that starting point, APS incorrectly  
17 subtracted the November 30, 2005 actual balance of recorded deferred bark beetle costs instead of  
18 correctly subtracting the September 30, 2005 historic test year ending balance. *Id.* In addition, APS  
19 failed to recognize related accumulated deferred income taxes as a reduction to its pro forma rate  
20 base adjustment. *Id.*

21       In summary, Staff's rate base adjustments on Schedule B-2 eliminate retroactive deferrals  
22 related to expenditures incurred prior to April 1, 2005; reflect related accumulated deferred income  
23 taxes; and correct for the problem of subtracting the incorrect balance of deferred bark beetle costs.  
24 *Id.* In addition, Staff's adjustments on Schedule C-14 reduce the amortization expense related to the  
25

1 deferrals of expenditures incurred before April 1, 2005. *Id.* Except for the adjustments related to the  
2 retroactive deferrals, APS has accepted Staff's proposed adjustments to bark beetle remediation costs.

3 In rebuttal, APS argues that Decision No. 67744 intends for the Company to be granted a full  
4 year of recovery. (Dittmer Surrebuttal at 40). APS also claims that the settlement agreement intends  
5 for bark beetle remediation deferrals to include the entire calendar year in which the deferral becomes  
6 effective. *Id.* Staff disagrees with these assertions. First, neither the settlement agreement nor  
7 Commission Decision No. 67744 expressly states this intent. *Id.* at 41. More importantly, the  
8 Company's argument assumes that a Commission order may be applied retroactively without the  
9 Commission expressly stating that it intends retroactive application. *Id.* The Commission should  
10 reject the Company's argument and accept Staff's proposed adjustment.

11 **C. Adjustment For Lost Margins From DSM Programs**

12 This adjustment to operating income reverses an adjustment posted by APS to reflect "lost"  
13 retail margins that it anticipates due to the implementation of various demand-side management  
14 ("DSM") programs. (Dittmer Direct at 58). Specifically, Staff recommends that the Commission  
15 disallow APS' proposed \$4,907,000 pro forma adjustment to account for net lost revenue that the  
16 Company claims will result from DSM programs. (Anderson Direct Test., hereinafter referred to as  
17 "Anderson Direct", Ex. S-16 at 8). This adjustment is addressed in more detail in the Demand-Side  
18 Management section of this brief. (Section XIII).

19 **D. Miscellaneous Adjustments To Other Revenues**

20 Staff's adjustment to Schedule C-2 is a correction of APS' pro forma adjustment for Schedule  
21 1 charges. (Dittmer Direct at 58). The correction is necessary to restate the transaction volumes to  
22 reflect actual test period data. *Id.* In addition, the adjustment removes expenses that APS expected in  
23 connection with its program to eliminate paper bills. *Id.* Specifically, APS never initiated a \$5.00  
24 incentive to attract subscribers to its paperless bill program because enrollment in this program has  
25

1 been strong even without the incentive. *Id.* at 58-59. Thus, Staff eliminated the estimated expense  
2 related to the \$5.00 incentive. *Id.* at 59. APS has accepted these adjustments. *Id.* at 58-59.

3 **E. Normalized Fuel Expense, Purchased Power Expense, And Off-System Sales**  
4 **Margins**

5 The adjustment set forth in Schedule C-3 shows the pro forma level of fuel, purchased power  
6 expense, and off-system sales revenues and related expense that Staff believes should be used to  
7 develop base rates. (Dittmer Direct at 59). The pro forma levels for these items should also be used  
8 as the basis for the PSA factor. *Id.* This adjustment is addressed in more detail in the section of this  
9 brief that discusses Staff's proposed base cost for fuel and purchased power expense. (Section III).

10 **F. Elimination Of Expenses Associated With Unregulated Marketing And Trading**  
11 **Operations**

12 APS operates certain unregulated marketing and trading activities. (Dittmer Direct at 59).  
13 However, APS inadvertently included the revenues and expenses associated with these activities in  
14 the development of its test year cost of service. *Id.* at 60. During the test year, unregulated marketing  
15 and trading operations experienced a net loss of approximately \$15 million. *Id.* Removing this net  
16 loss from test year operating results reduces APS' adjusted test year cost of service, thereby reducing  
17 the requested revenue increase. *Id.*

18 Staff's adjustment on Schedule C-5, which APS accepts, shows the elimination of marketing  
19 and trading operations and maintenance expense other than purchased power. *Id.* at 61. Staff  
20 Schedule C-4 shows a separate but related adjustment to eliminate marketing and trading off-system  
21 sales and revenues and related purchased power expense. *Id.* Thus, the net marketing and trading  
22 loss of \$8,273,000 shown on Schedule C-4 plus the removal of non-purchased power operation and  
23 maintenance expenses shown on Schedule C-5 sum to the total before-tax loss of \$15 million. *Id.*

24 ...

25 ...

1           **G.     Post Retirement Medical Benefits Adjustment**

2           Staff has recommended an adjustment to reflect ongoing post-retirement medical benefits  
3 (“PRMB”) expense based upon the actuarial estimate that APS used to record PRMB expense for  
4 2006. (Dittmer Direct at 90). For consistency as well as to incorporate last known changes for this  
5 significant employee benefit, Staff has proposed a PRMB adjustment calculated identically to Staff’s  
6 adjustment for pension expense. *Id.* at 90-91.

7           **H.     Advertising Expense**

8           APS has proposed to remove \$6.1 million from test year expenses related to advertising costs.  
9 (Dittmer Direct at 91). Specifically, APS purports to remove costs for sports team sponsorships and  
10 media advertising to promote the Company’s brand identity. *Id.* Staff believes that this adjustment is  
11 appropriate because these kinds of expenses are not necessary in order to provide utility service. *Id.*

12           Staff has identified additional advertising expenses that should also be removed from APS’  
13 cost of service. *Id.* at 92. These additional expenses include APS’ Dodge Theatre sponsorship costs,  
14 sports suite costs, and various other Pinnacle West advertising costs that have been allocated to APS.  
15 Like the advertising expenses that APS removed from the test year, these additional items are not  
16 related to providing utility service. *Id.* APS has accepted this adjustment. *Id.*

17           In surrebuttal testimony, Staff witness Dittmer addressed additional advertising adjustments  
18 that were proposed by RUCO and were incremental to Staff’s original advertising adjustment.  
19 (Dittmer Surrebuttal at 24-25). Staff recommends that the Commission adopt these additional APS –  
20 conceded advertising adjustments in its final order.

21           **I.     Non-Recurring Out-Of-Period Shared Services Expenses**

22           Staff removed from the test year two out-of-period accruals recorded as PWEC administrative  
23 and general expense. (Dittmer Direct at 93). Because APS agrees that this adjustment is appropriate,  
24 Staff’s testimony on this issue is not extensive. *Id.* Accordingly, the Commission should adopt this  
25 significant adjustment, which has been conceded by APS.

1           **J.       Legal Costs Incurred in Selling the PWEC Silverhawk Power Plant**

2           Staff removed from the test year the cost of legal expenses incurred by Pinnacle West Energy  
3 Corporation ("PWEC") related to the sale of the Silverhawk Power Plant. (Dittmer Direct at 93).  
4 Although the sale of the Silverhawk plant did not occur until after the end of the test year, many costs  
5 related to that sale were incurred during the test year and were charged to PWEC operation and  
6 maintenance expense. *Id.* The appropriate level of PWEC operation and maintenance expense is  
7 relevant to this case because the Commission authorized APS to rate base a number of the PWEC  
8 units in APS' last rate case. *Id.* The Silverhawk Plant, which is located in Nevada, is not one of the  
9 PWEC facilities acquired by APS in connection with the last rate case. *Id.* at 93-94. Staff believes  
10 that all costs related to the Silverhawk Plant should be removed from APS' cost of service in this  
11 case.

12           APS agrees with this concept. When developing its PWEC O&M adjustment, the Company  
13 estimated the costs that were incurred by the various shared services departments that were related to  
14 owning and operating Silverhawk during the test year. *Id.* at 94. APS then eliminated a number of  
15 these costs from PWEC's test year operation and maintenance expense. *Id.* APS' adjustment,  
16 however, fails to capture all test year costs attributable to Silverhawk. *Id.* Staff's adjustment C-10 is  
17 intended to capture and remove these additional costs. *Id.*

18           Staff adjustment C-10 relates specifically to legal fees. *Id.* at 93-94. In the test year, the  
19 shared services Law Department incurred \$1,394,011 of costs related to PWEC. *Id.* at 94. When  
20 developing its PWEC O&M adjustment, APS estimated that ten percent of these costs (\$139,401)  
21 were related to Silverhawk. *Id.* APS therefore removed \$139,401 of the Law Department's costs  
22 from PWEC's test year O&M expense. *Id.* at 94-95. APS' adjustment, however, fails to include all  
23 legal fees related to the sale of Silverhawk. In discovery, APS identified additional charges totaling  
24 \$289,400 that were specifically related to the Silverhawk sale. *Id.* at 95. Accordingly, Staff  
25

1 eliminated the costs related to the Silverhawk sale that exceed APS' original adjustment, i.e.,  
2 \$139,401. *Id.* APS agrees with Staff's adjustment.

3 **K. Non-Recurring Tax Research Costs**

4 Staff's adjustment to schedule C-12 eliminates total non-recurring expenses of \$2,778,128  
5 related to investment tax credit ("ITC") research. (Dittmer Direct at 103). There are two components  
6 of this adjustment, both of which are related to charges for non-recurring tax research that were  
7 recorded in the test year. *Id.* at 100. Staff's adjustment to schedule B-3 reflects a rate base offset for  
8 ITCs. (Dittmer Direct at 106; Dittmer Surrebuttal at 43-45).

9 **1. Reversal of non-recurring credit to joint facility owners that was recorded**  
10 **during the test year as additional production expense.**

11 APS retained Deloitte and Touche, LLP ("Deloitte"), an independent certified public  
12 accounting firm, to research whether prior federal income tax returns could be amended in order to  
13 claim additional investment tax credits ("ITCs") related to plant that had been constructed in the mid  
14 to late 1980s. (Dittmer Direct at 100). Although the Tax Reform Act of 1986 generally eliminated  
15 ITCs, there exists the ability to claim some amount of ITCs related to plant that was under  
16 construction, but not in service, as of the end of 1986. *Id.* at 100-01. In APS' case, the Palo Verde  
17 units were still under construction at that time. *Id.* at 101.

18 APS retained Deloitte on a contingency basis whereby Deloitte would only be paid out of  
19 actual realized "tax savings" related to the additional ITCs. *Id.* In 2003, APS accrued \$2,385,468 in  
20 anticipation of paying Deloitte as a result of expected ITCs to be claimed as a result of Deloitte's tax  
21 research. *Id.* This accrual occurred after the last APS rate case test year and well before the  
22 beginning of the current rate case test year. *Id.*

23 APS is a joint owner of several generating facilities. *Id.* Pursuant to operating agreements  
24 with the joint owners, APS is permitted to "load" direct production costs incurred at the jointly  
25 owned plants with administrative and general ("A&G") costs incurred by APS. *Id.* at 101-02. In

1 2003, a portion of the A&G costs loaded onto the direct-assigned production costs included the  
2 accrual for the contingency fee expected to be paid to Deloitte for tax research related to ITCs. *Id.* at  
3 102. The joint owners eventually contested the “loading” of A&G costs that included the Deloitte  
4 contingency fee, and APS ultimately conceded that it would be inequitable to charge the joint owners  
5 for tax research from which they would not benefit. *Id.* APS subsequently “credited” the joint  
6 owners for overbillings made in 2003 related to the Deloitte tax research. *Id.* This “credit” resulted  
7 in the recording of incremental APS production expense during the test year in the amount of  
8 \$1,224,795. *Id.* Thus, one part of Staff adjustment C-12 reverses the non-recurring credit to joint  
9 owners that was recorded during the test year as additional APS production expense.

10 **2. Reversal of non-recurring tax research costs recorded during the test**  
11 **year.**

12 Although Deloitte originally undertook the tax research on a contingency basis, these  
13 compensation arrangements were eventually changed to a fee-for-service basis. (Dittmer Direct at  
14 102). As a result, APS recorded \$1,533,333 during the test year for outside services expense for the  
15 tax research undertaken by Deloitte. *Id.* at 102-03. Staff therefore eliminated these non-recurring tax  
16 research costs from the test year. *Id.* at 103. APS has conceded that both portions of Staff’s  
17 adjustment related to tax research are appropriate.

18 **3. Investment Tax Credits as a Rate Base Offset**

19 As a result of the ITC tax research, a tax refund in the amount of \$6,483,389 is expected and  
20 “imminent.” (Dittmer Direct at 103). Thus, for a total outlay of \$3,918,801 in cash (composed of the  
21 contingency fee of \$2,385,468 and a fee-for-service charge of \$1,533,333), APS is expected to  
22 receive \$6,483,389 in tax savings. *Id.* Stated in revenue requirement terms, APS is receiving  
23 approximately \$10 million of before-tax savings in exchange for incurring \$3,918,801 of tax research  
24 expense, thereby resulting in a before-tax gain of approximately \$6.1 million. *Id.*

25

1 In his direct testimony, Staff witness Dittmer recommended sharing the \$6.1 million of  
2 revenue requirement savings on a fifty/fifty basis between ratepayers and shareholders. *Id.* at 103-06.  
3 In rebuttal, however, APS argued that the majority of Staff's proposed rate base adjustment for ITCs  
4 will violate Internal Revenue Code ("IRC") "normalization" requirements. (Dittmer Surrebuttal at  
5 42).

6 In response, Staff has modified its proposed adjustment so that a normalization violation will  
7 not occur. *Id.* at 42-43, 45. APS claims that 62% of Staff's originally proposed rate base adjustment  
8 will result in a normalization violation. *Id.* at 43. Staff therefore reduced its original rate base  
9 adjustment to eliminate 62% of the ITCs related to property that has already been fully depreciated  
10 for tax purposes. *Id.*

11 Of the remaining 38% of ITCs, APS further claims that only the unamortized balance may be  
12 allowed as a rate base offset in order to comply with IRC normalization requirements. *Id.* In  
13 surrebuttal, Staff has proposed that the Commission recognize as a rate base offset all of the  
14 unamortized ITC balance related to plant not fully depreciated. *Id.* For purposes of calculating this  
15 adjustment, Staff assumed that one-half of the ITCs would be amortized as of the end of the test year.  
16 *Id.* This adjustment is reasonable because it is equitable to credit ratepayers with at least some of the  
17 savings realized by APS when it amended its prior years' tax returns. *Id.* Because the majority of  
18 ITC savings cannot be shared with ratepayers, it is only fair that savings from "unrestricted" ITCs be  
19 credited to ratepayers in this proceeding. *Id.* at 43-44. Specifically, Staff's calculation of this  
20 adjustment will allow APS to retain all of the ITC savings that result from the 62% of ITCs that are  
21 fully amortized and one-half of the remaining 38% of ITC savings realized. *Id.* at 44. This treatment  
22 provides some benefits to ratepayers without causing any normalization violations. *Id.*

23 APS witness Froggett agrees that Staff's revised ITC rate base adjustment will not result in a  
24 normalization violation. However, after Staff had addressed Mr. Froggett's only rebuttal argument—  
25 the IRC normalization issue—Mr. Froggett argued for the first time in rejoinder that Staff's revised

1 adjustment is not equitable. For the reasons stated above, Staff's revised ITC rate base adjustment is  
2 not only reasonable for APS' ratepayers but also quite generous for APS' shareholders. (Tr. at 4215).

3 **L. Incentive Compensation**

4 Staff adjustment C-13 represents a partial disallowance of test year incentive compensation  
5 expense. (Dittmer Direct at 106). Staff recommends eliminating costs associated with APS' *stock-*  
6 *based* incentive compensation plans and allowing recovery of test year expenses associated with  
7 APS' *cash-based* incentive compensation plans. *Id.* Staff's adjustment still allows approximately  
8 \$17.8 million of cash incentive compensation expense (before jurisdictional allocation) and disallows  
9 only \$4.8 million of stock-based incentive compensation expense. *Id.* at 107, 110.

10 Staff recommends disallowing APS' stock-based incentive compensation expenses because  
11 the award of these incentives is entirely driven by Pinnacle West earnings objectives that, at best,  
12 *might* indirectly provide benefits to ratepayers. *Id.* at 110-11. It is undeniable that APS' stock-based  
13 incentive compensation plan is aligned with stockholder—and not ratepayer—interests. Specifically,  
14 the stated purpose of APS' stock-based incentive plan is “to promote the success and enhance the  
15 value of Pinnacle West Capital Corporation . . . by linking . . . [the employees' personal interests] to  
16 those of . . . [the] shareholders . . . .” (APS Response to Staff Data Request No. UTI-1-83,  
17 Attachment APS09850 (quoted in Dittmer Direct at 107-08)). APS' stock-based incentive  
18 compensation programs are driven by the financial performance of Pinnacle West, rather than the  
19 operational performance of APS as a public utility. *Id.* at 108. Although corporate earnings also  
20 serve as a precondition to the payout of APS' cash-based incentive compensation, the Company-  
21 proposed level of test year cash-based incentive compensation is tied primarily to performance  
22 measures that benefit APS' customers. *Id.* at 108-10. By contrast, the stock-based incentives are  
23 entirely driven by Pinnacle West earnings objectives. *Id.* at 111.

24 Enhanced earnings levels can sometimes be achieved by short-term management decisions  
25 that may not encourage the development of safe and reliable utility service at the lowest long-term

1 cost. *Id.* For example, some maintenance can be temporarily deferred, thereby boosting earnings.  
2 *Id.* at 112. But delaying maintenance can lead to safety concerns or higher subsequent “catch-up”  
3 costs. *Id.* Rate recovery of stock-based incentive compensation that is exclusively tied to  
4 shareholders’ interests is simply bad regulatory policy. *Id.* The Commission should therefore  
5 disallow APS’ stock-based incentive compensation expenses from the Company’s cost of service.

6 **M. Lobbying Expenses**

7 The Staff adjustment reflected in Schedule C-15 eliminates test year above-the-line charges  
8 for lobbying expense. (*Dittmer Direct* at 113). Lobbying expenses are not generally included within  
9 the development of utility cost of service. *Id.* at 113-14. Pursuant to the FERC Uniform System of  
10 Accounts, lobbying costs are required to be recorded below the line, where there is a presumption of  
11 non-recovery. *Id.* at 114-15.

12 Ratepayers could potentially be harmed by allowing cost recovery of lobbying expenses. *Id.*  
13 at 115. With the unique monopoly status that utilities enjoy, the potential for abuse through the  
14 promotion of unfair or unnecessary legislation is obvious. *Id.* Staff does not mean to suggest that all  
15 utility lobbying efforts are detrimental to ratepayers in particular or the public in general, and it is  
16 possible that, in certain instances, utility-supported legislation has benefited ratepayers. *Id.* at 116.  
17 However, it is virtually impossible to know at what cost the achievement of even pro-consumer  
18 legislation is accomplished. *Id.*

19 What is perceived as “good lobbying” from the utility’s or ratepayers’ point of view may be  
20 considered “bad lobbying” from another constituent’s point of view. For instance, as Staff witness  
21 *Dittmer* discussed, a utility may lobby against—and succeed in defeating—certain expensive  
22 environmental legislation. Although ratepayers may receive an economic benefit from such  
23 lobbying, residents in general may suffer adverse health consequences from the defeat of such  
24 legislation. (*Tr.* at 4269-70). Staff believes that the Commission should refrain from involving itself  
25 in the process of discerning “good lobbying” from “bad lobbying.”

1 During the test year, APS recorded some of its lobbying costs below the line, and those costs  
2 were not included in APS' proposed test year cost of service. (Dittmer Direct at 116). However,  
3 contrary to specific USOA guidelines, APS charged a number of its lobbying costs above the line to  
4 administrative and general expense accounts, and these lobbying costs were included in its proposed  
5 test year cost of service. *Id.* It is these above the line lobbying expenses that Staff has eliminated on  
6 Schedule C-15. *Id.*

7 In addition to adopting this disallowance, the Commission should require APS to record all  
8 lobbying expenses below the line in FERC USOA Account No. 426.4. *Id.* Although the requirement  
9 to record lobbying expenses below the line is not conclusive for ratemaking purposes, it will ensure  
10 that the issue is highlighted for review by auditors. *Id.* at 116-17. APS will be free to request cost-  
11 of-service recognition for lobbying efforts in subsequent rate cases. *Id.* at 117. However, if these  
12 costs are appropriately recorded below the line, APS will be required to propose a specific adjustment  
13 to its operating income in order to recover these costs in rates. *Id.* This will ensure that expenses that  
14 are presumed to fall outside of the Company's cost of service are not "hidden" within inappropriate  
15 accounts, thereby complicating the audit. *Id.*

16 **N. ISFSI Expense**

17 The Independent Spent Fuel Storage Installation ("ISFSI") is Palo Verde's dry storage facility  
18 for spent nuclear fuel. (Dittmer Direct at 117). The storage pools where Palo Verde's spent fuel is  
19 currently stored will soon reach maximum capacity, and Palo Verde will therefore need an interim  
20 storage facility until the United States Department of Energy can site and construct permanent  
21 storage facilities for spent nuclear fuel. *Id.* at 117-18.

22 The need for this interim storage facility has been anticipated for a number of years. *Id.* at  
23 118. In a previous decision, the Commission allowed APS to defer ISFSI costs within a regulatory  
24 asset account for later recovery from ratepayers. *Id.* In Decision No. 67744, issued in 2005, the  
25 Commission allowed APS to recover these previously deferred ISFSI costs. *Id.* That decision also

1 allowed APS to recover ongoing ISFSI costs related to current nuclear fuel burns. *Id.* Both of these  
2 issues—the recovery of previously deferred ISFSI costs and the recovery of ongoing ISFSI  
3 expense—were examined in a study undertaken by TLG Services, Inc. in 2002. *Id.* In the pending  
4 case, APS is again proposing ISFSI adjustments. *Id.*

5 Decision No. 67744 (APS' last rate case) did not become effective until April 1, 2005.  
6 (Dittmer Direct at 118). The test year in this case, which ends September 30, 2005, reflects only one-  
7 half of the annual amortization level of deferred ISFSI costs that were approved in Decision No.  
8 67744. *Id.* Therefore, APS has proposed an adjustment to reflect the annualization of the  
9 amortization expense related to the ISFSI deferrals approved for recovery in Decision No. 67744. *Id.*  
10 Staff has accepted this adjustment.

11 APS also proposes adjustments that reflect incremental "ongoing" ISFSI expense as well as  
12 incremental ISFSI amortization expense resulting from the TLG Services, Inc. study that was updated  
13 in 2004. *Id.* Finally, APS proposes an adjustment to ISFSI amortization expense to consider  
14 additional deferrals following June 30, 2004, the cutoff date used in the last rate case, through  
15 December 31, 2006, the approximate effective date for rates developed in this proceeding. *Id.* at 118-  
16 19.

17 Staff accepts the majority of APS' proposed ISFSI adjustments, but nonetheless proposes  
18 certain minor modifications in its adjustment set forth in Schedule C-16. *Id.* at 121-25. The updated  
19 2004 TLG study predicts an overall increase in ISFSI costs from that projected in the 2002 study. *Id.*  
20 at 124. Furthermore, the 2004 study predicts a significant shift in ISFSI expenditures from post-shut  
21 down activities that have a long amortization period to pre-shut down activities that have only a five-  
22 year amortization period. *Id.* APS' ISFSI adjustments incorporate both the higher overall ISFSI  
23 estimate and the shift of costs to pre-shut down activities that have a shorter amortization period. *Id.*  
24 However, the 2004 TLG study also predicts a reduction in costs related to post-shut down activities,  
25 and APS' ISFSI adjustments fail to capture those reductions. *Id.* at 125. Conceptually, Staff's ISFSI

1 adjustment captures the reduction in costs for post-shut down activities that were ignored by APS.  
2 Staff believes that it would be unfair to reflect in rates the elements of the 2004 TLG study that show  
3 increased costs but to omit the elements of the same study that show declining costs. *Id.*

4 **O. Property Tax Expense**

5 Staff has proposed an adjustment to APS' proposed level of property tax expense. (Dittmer  
6 Direct at 125). In his direct testimony, Staff witness Dittmer recommended eliminating the portion of  
7 APS' pro forma property tax adjustment related to a property tax increase anticipated to occur in  
8 2007. *Id.* APS had designed one element of its proposed property tax adjustment to reflect the  
9 statutory phase-in of property tax increases associated with the former PWEC units. *Id.* Although it  
10 is probable that property taxes related to these facilities will increase, "cherry picking" post test year  
11 changes that occur far beyond the end of the test year will result in a mismatch in cost of service  
12 revenues, expenses, and rate base. For these reasons, Staff eliminated the portion of APS' property  
13 tax adjustment that is related to anticipated 2007 tax increases. *Id.* at 125-26. APS has agreed to  
14 Staff's property tax adjustment.

15 At the hearing, Staff witness Dittmer stated that he supports RUCO's additional property tax  
16 adjustment. (Tr. at 4187-89). Specifically, RUCO identified a known and measurable reduction in  
17 property tax expense that became effective in 2006 as a result of new legislation. In rebuttal, APS  
18 claims that, notwithstanding the reduction in 2006 property tax expense, its 2007 property tax  
19 expense will still be higher than either its test year actual property tax expense or its 2006 adjusted  
20 property tax expense. Staff, however, agrees with RUCO on this issue: to adopt 2007 property tax  
21 levels would create a mismatch in the development of APS' cost of service.

22 Furthermore, APS' position on this issue is inconsistent with its revised production tax credit  
23 proposal. During discovery, APS suggested that it should not reach into 2007 to incorporate a higher  
24 production tax credit rate than would be available to it in 2006. Staff witness Dittmer agreed with  
25 APS and reduced APS' originally proposed cost of service income tax expense to reflect the lower

1 2006 production tax credit rate. It would therefore be both unfair and inconsistent to adopt higher  
2 projected 2007 property tax expense and ignore the reduction in the production tax credit that will  
3 become available to APS in 2007. (Tr. at 4190-92). For these reasons, the Commission should adopt  
4 both Staff's and RUCO's property tax adjustments.

5 **P. Generation Production Income Tax Deduction**

6 APS has proposed an income tax adjustment to reflect additional tax deductions and  
7 accompanying tax savings that will result from the American Jobs Creation Act. (Dittmer Direct at  
8 126). Staff agrees with APS' approach, but nonetheless proposes some adjustments.

9 When APS prepared its original case, the treasury regulations related to the American Jobs  
10 Creation Act were not final. *Id.* at 127-28. APS therefore relied upon *proposed* treasury regulations,  
11 which were subsequently superseded by the final regulations. Staff's adjustment on this issue merely  
12 calculates the additional tax deductions and accompanying tax savings based upon those final  
13 regulations. *Id.* at 126-27. APS has accepted this adjustment. *Id.* at 127. Staff has also proposed  
14 adjustments intended to synchronize this adjustment with other elements of Staff's position in this  
15 case. *Id.* at 127-28.

16 Additionally, Staff recalculated the production tax credit to reflect the three percent credit that  
17 was available in 2006 rather than the six percent credit available in 2007, which APS used to  
18 calculate its original proposal on this issue. Staff believes that it will create a mismatch to selectively  
19 adopt cost of service elements scheduled to occur in 2007 and beyond. (Tr. at 4190-92).

20 **Q. Interest Synchronization**

21 Staff has adjusted APS' pro forma level of income tax expense to synchronize the interest  
22 deduction for consideration in the development of Staff's cost of service income tax expense with the  
23 jurisdictional rate base and weighted cost of debt proposed by Staff. (Dittmer Direct at 129). This  
24 adjustment, which is routinely adopted by regulatory commissions in utility rate cases, is derived by  
25 multiplying Staff's proposed retail jurisdictional rate base times the weighted cost of debt included

1 within Staff's development of the overall cost of capital. If the Commission were to adopt a different  
2 rate base or weighted cost of debt than that proposed by Staff, it would be necessary to revise this  
3 adjustment accordingly. *Id.*

4 **R. Federal And State Income Tax Expense**

5 Staff proposes an adjustment as a correcting calculation to APS' proposed level of cost of  
6 service income tax expense. (Dittmer Direct at 129). Although most accountants can agree  
7 conceptually to the appropriate development of allowable cost-of-service income tax expense, the  
8 mathematical or mechanical computation of such an adjustment can become complicated. *Id.* at 129-  
9 30. This is especially true in this case, which addresses an historic test year that spans two calendar  
10 years, each of which may include unique or non-recurring tax accrual entries. *Id.* at 130.

11 As a result of a series of discussions with APS personnel, Staff witness Dittmer concluded  
12 that an error exists within the Company's development of its proposed test year cost of service  
13 income tax expense, even though the precise error was never precisely identified. *Id.* Staff proposed  
14 a "top down" calculation that uses estimated 2006 permanent book/tax differences and other income  
15 tax credits. *Id.* at 130-31. APS has accepted this adjustment. *Id.* at 131.

16 **S. RUCO's Palo Verde Steam Generator Replacement Depreciation Issues**

17 APS proposed a post test year adjustment to reflect a steam generator replacement at Palo  
18 Verde. No party has objected to this adjustment. RUCO, however, has proposed two corresponding  
19 adjustments, which Staff supports.

20 First, RUCO has proposed an adjustment to reflect a corresponding retirement related to the  
21 post-test year Palo Verde steam generator replacement. APS' failure to reflect the associated  
22 retirement overstates APS' proposed balance of gross plant in service. Second, RUCO proposed an  
23 adjustment to depreciation expense to reflect the impact of the retirement associated with the Palo  
24 Verde steam generator replacement. Because APS had annualized depreciation expense based upon  
25 the overstated balance of gross plant in service, APS' proposed pro forma level of depreciation

1 expense was also overstated. APS agreed with these RUCO adjustments, and the Commission should  
2 adopt them.

3 **T. RUCO's Customer Deposit Interest Annualization Adjustment**

4 RUCO proposed an adjustment to reflect the interest rate that was paid on customer deposits  
5 in 2006, and APS agreed with this adjustment in rebuttal. Staff has reflected this adjustment within  
6 its updated accounting schedules filed with Staff's surrebuttal testimony. (Ex. S-38; Schedule B,  
7 p.1). This adjustment should also be adopted in the Commission's decision in this matter.

8 **VIII. POWER SUPPLY ADJUSTER**

9 Staff believes that it is appropriate for the Commission to continue to approve some type of  
10 Power Supply Adjuster ("PSA") mechanism for APS, because prices for fuel and energy remain  
11 volatile. (Antonuk Direct at 4). That volatility will likely continue for some time, and will  
12 substantially diminish the chance that rate case determinations for fuel and energy expenses will bear  
13 a reasonably close relationship to actual costs for those items during the period that rates are in effect.  
14 *Id.*

15 Staff has proposed several changes to APS' existing PSA:

- 16 1) The use of a forecasted year for setting the PSA rate in the future;
- 17 2) The elimination of the 90/10 sharing mechanism;
- 18 3) The elimination of the \$776 million cap;
- 19 4) The elimination of the 4 mil bandwidth;
- 20 5) The adoption of a new plan of administration, which would replace the  
21 existing plan of administration.

22 (Antonuk Direct at 33, 37; *see generally* Antonuk Supplemental Test., hereinafter referred to as  
23 "Antonuk Supplemental", Ex. S-30 at 2-8).

24 For a number of reasons, the existing PSA mechanism led to the build-up of substantial  
25 undercollections in 2005-06. (*See* Dittmer Surrebuttal at 6; Tr. at 3033). The combination of

1 implementing a new PSA in conjunction with the increase in fuel and purchased power prices in the  
2 wake of Hurricane Katrina led to significant and unanticipated undercollections in APS' fuel and  
3 purchased power costs. This build-up of deferrals attracted unfavorable attention from the ratings  
4 agencies, which threatened to downgrade APS' ratings. (*See* Parcell Direct Test., Ex. S-8 at 14).  
5 Arguably, this build-up of deferrals also prompted APS to file its emergency rate case in early 2006.  
6 (Tr. at 3033).

7 In evaluating APS' rate case, Staff recognized that the public interest would be served by  
8 addressing any aspects of APS' existing PSA that may have contributed to the build-up of significant  
9 deferrals. Staff believes that the changes that it is recommending will lead to more timely recovery  
10 by APS of its costs for fuel and purchased power. Staff also believes that these changes will address  
11 the rating agencies' concerns, as alleged by APS.

12 Staff's proposed Plan of Administration provides a detailed description of the mechanics of  
13 Staff's proposed PSA. (Antonuk Supplemental, Ex. S-30). The "forward component" of Staff's  
14 proposed PSA has some bearing on the issues related to the base cost of fuel and purchased power.  
15 Although Staff recommends that the Commission reject APS' 2007 forecasts as the basis for the base  
16 cost of fuel and purchased power, Staff does not object to using APS' 2007 rejoinder forecast to  
17 determine the "forward component" for 2007. Adoption of this proposal would essentially serve as a  
18 "middle ground" between the competing positions of Staff and APS regarding the appropriate base  
19 cost of fuel and purchased power. (Antonuk Supplemental at 2-3, 5-6).

20 **IX. COST OF CAPITAL**

21 The first step in performing a cost of capital analysis is the development of an appropriate  
22 capital structure. The second step is a determination of the embedded cost rate of long-term debt.  
23 The third step is the estimation of the cost of common equity. Although the first two steps are not  
24 generally controversial, the third step often generates significant dispute.

25

1 For the cost of equity evaluation, Staff applied three recognized methodologies (discounted  
2 case flow, capital asset pricing model, and comparable earnings) to two proxy groups (a group of  
3 comparison electric utilities with similar operating and risk characteristics to APS and PWC, and the  
4 group of proxy electric companies analyzed by Company witness Avera). Based upon these  
5 analyses, Staff has concluded that the cost of common equity for APS falls within a range of 9.5  
6 percent to 10.75 percent, with an approximate midpoint of 10.25 percent. Combining the three steps  
7 of the cost of capital analysis into a weighted cost of capital results in an overall rate of return of 8.05  
8 percent. (*See generally* Parcell Direct; Parcell Surrebuttal Test., Ex. S-9).

9 **A. Economic Principles**

10 Cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be  
11 estimated. There are several useful models that can be employed to assist in estimating the cost of  
12 equity capital, which is the capital structure item that is the most difficult to determine. These  
13 include the discounted cash flow (“DCF”), capital asset pricing model (“CAPM”), comparable  
14 earnings, (“CE”), and risk premium (“RP”) methods. Each of these methods is different, and if  
15 properly employed, can be a useful tool in estimating the cost of common equity for a regulated  
16 utility.

17 Economic and financial conditions are also important in determining the cost of capital. The  
18 level of economic activity, the stage of the business cycle, the level of inflation, and expected  
19 economic conditions all have a direct and significant influence on the cost of capital. Currently,  
20 capital costs are low in comparison to the levels that have prevailed over the past three decades.  
21 Even a moderate increase in interest rates, as well as other capital costs, would still result in capital  
22 costs that are low by historic standards. Therefore, it can reasonably be expected that cost of equity  
23 models, such as the DCF, will currently produce returns that are lower than was the case in prior  
24 years.

25

1           **B. Capital Structure**

2           A utility's capital structure is important since the concept of rate base/rate of return regulation  
3 requires that a utility's capital structure be determined and utilized in estimating the total cost of  
4 capital. The purpose of determining the proper capital structure for a utility is to help ascertain the  
5 capital costs of the company. APS has proposed the following capital structure: long term debt- 45.5  
6 percent, and common equity - 55.5 percent. This capital structure contains a higher equity ratio than  
7 that of the electric utilities in both the general and the specific proxy groups. Therefore, the APS  
8 capital structure reflects a lower degree of financial risk than that exhibited by the proxy groups.  
9 Staff has nonetheless accepted APS' proposed capital structure for purposes of determining APS'  
10 cost of capital in this proceeding.

11           **C. Cost of Long-Term Debt**

12           The Company's filing proposes a long-term debt cost of 5.41 percent, and Staff has  
13 determined that this proposal is reasonable.

14           **D. Cost of Equity**

15           The common equity ratio is the capital structure item that receives the most attention. This is  
16 because common equity usually commands the highest cost rate, generates associated income tax  
17 liabilities, and causes the most controversy since its cost cannot be precisely determined. It is not  
18 possible to conduct direct analyses of the cost of common equity for APS because it is not a publicly  
19 traded company. It is possible to conduct studies of PWC's cost of equity, but due to the diversified  
20 nature of PWC's operations, it is not an adequate proxy for the cost of equity for APS. As a result, it  
21 is useful to analyze groups of comparison or "proxy" companies as a substitute for APS to determine  
22 its cost of common equity. Two groups were examined for comparison to APS: 1) a selected group  
23 of electric utilities similar to APS and PWC, and 2) the proxy group of electric utilities selected by  
24 APS witness Avera.

1                                    *1.      Discounted Cash Flow Analysis*

2                    The discounted cash flow (DCF) model is one of the oldest as well as the most commonly  
3 used models for estimating the cost of common equity for public utilities. The DCF model is based  
4 on the “dividend discount model” of financial theory, which maintains that the value (price) of any  
5 security or commodity is the discounted present value of all future cash flows. The relationship can  
6 be simplified because dividends are assumed to grow at a constant rate of  $g$ . This variant of the  
7 dividend discount model is known as the constant growth or Gordon DCF model. The constant  
8 growth equation can be solved for the cost of capital. When doing so, the return expected or required  
9 by investors is comprised of two factors: the yield (current income) and expected growth (future  
10 income).

11                    There are several methods which can be used for calculating the yield component. These  
12 methods generally differ in the manner in which the dividend rate is employed, such as current versus  
13 future dividends or annual versus quarterly compounding of dividends. However, the most  
14 appropriate yield component is a quarterly compounding variant that recognizes the timing of  
15 dividend payment and dividend increases. The growth rate component of the DCF model is usually  
16 the most crucial and controversial element involved in using this methodology. The objective of  
17 estimating the growth component is to reflect the growth expected by investors which is embodied in  
18 the price of a company’s stock. Also, it is important to recognize that individual investors have  
19 different expectations and consider alternative indicators in deriving their expectations. A wide array  
20 of techniques exists for estimating the growth expectations of investors. No single indicator of  
21 growth is always used by all investors, and it is necessary to consider alternative indicators of growth  
22 in deriving the growth component of the DCF model.

23                    Staff considered five indicators in its DCF analyses: (1) 2001-2005 earnings retention, or  
24 fundamental growth; (2) 5-year average of historic growth in earnings per share (EPS), dividends per  
25 share (DPS), and book value per share (BVPS); (3) 2006-2010 projections of earnings retention

1 growth; (4) 2004-2010 projections of EPS, DPS, and BVPS; and (5) 5-year projections of EPS  
2 growth as reported in First Call. This combination of growth indicators is a representative and  
3 appropriate set with which to estimate investor expectations of growth for the groups of utility  
4 companies. Based on Staff's analyses, a range of 9 percent to 10 percent represents the current DCF  
5 cost of equity for APS. The lower end (9 percent) approximates the upper values for the  
6 average/median results, while the upper end (10 percent) reflects the high value of the constant  
7 growth DCF calculations for the groups examined.

8         Although APS witness Avera performed a DCF analysis, he concluded that its results were  
9 not useful (presumably too low) in estimating a reasonable cost of equity for APS. (Tr. at 1863-65).  
10 By contrast, both Staff and RUCO have appropriately incorporated the results of their respective DCF  
11 analyses into their recommendations, recognizing that the DCF method is commonly relied on by  
12 regulatory commissions – including this Commission – to estimate the cost of equity. *Id.* at 1869-70.

## 13                     2.         *Capital Asset Pricing Model Analysis*

14         The capital asset pricing model (CAPM) is a version of the risk premium method. The  
15 CAPM describes and measures the relationship between a security's investment risk and its market  
16 rate of return. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio  
17 theory (MPT), which studies the relationships among risk, diversification, and expected returns. The  
18 CAPM is generally superior to the simple risk premium method because the CAPM specifically  
19 recognizes the risk of a particular company or industry, whereas the simple risk premium method  
20 does not. Staff performed CAPM analyses for the same groups of electric utilities evaluated in the  
21 DCF analyses.

22         Two types of Treasury securities are often utilized as the risk free rate component: short-term  
23 United States Treasury bills and long-term United States Treasury bonds. The three month average  
24 yield for twenty year United States Treasury bonds was used for Staff's CAPM calculations. Staff  
25 also used the most current Value Line betas for each company in the groups of comparison electric

1 companies in its CAPM calculation. The market risk premium component represents the investor-  
2 expected premium of common stocks over the risk-free rate, or government bonds. For the purpose  
3 of estimating the market risk premium, returns of the S&P 500 and 20-year United States Treasury  
4 bonds were used. A combination of arithmetic and geometric means is appropriate since investors  
5 have access to both types of information, and both types are reflected in investment decisions and  
6 thus stock prices and cost of capital. Staff's CAPM results collectively indicate a cost of about 10.5-  
7 10.75 percent for the two groups of proxy companies.

### 8 **3. Comparable Earnings Analysis**

9 The CE method is designed to measure the returns expected to be earned on the original cost  
10 book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return,  
11 since it translates into practice the competitive principle upon which regulation rests. The CE  
12 methodology is conducted by examining realized returns on equity for several groups of companies  
13 and evaluating the investor acceptance of these returns by reference to the resulting market-to-book  
14 ratios. One objective of a fair cost of equity is the maintenance of stock prices above book value.  
15 Staff considered experienced equity returns of the proxy groups of companies for the historic period  
16 1992-2005 as well as the future period 2006-2010 in its analysis. Historic returns of 9.9-11.7 percent  
17 have been adequate, and projected returns on equity for future periods are within a range of 8.2-10.4  
18 percent for the proxy groups. Therefore, the cost of equity for APS is no greater than 10 percent, and  
19 an earned return of 10 percent or less should result in a market-to-book ratio of at least 100 percent.

### 20 **E. Total Cost Of Capital**

21 The overall conclusion from the three methodologies (DCF, CAPM and CE) is a range of 9.5  
22 percent to 10.75 percent, and Staff's specific recommendation for APS' cost of equity is 10.25  
23 percent, the approximate mid-point of that range. In addition, there is no need to make a flotation  
24 adjustment. A utility should only be allowed to recover from ratepayers its actual quantifiable levels  
25 of issuance costs. Staff's recommended overall weighted cost of capital for APS is 8.05 percent.

1 **X. PALO VERDE ISSUES**

2 **A. Palo Verde Nuclear Outages Resulting From Imprudence Are the Responsibility**  
3 **of the Company.**

4 Beginning in 2005, the Palo Verde Nuclear Generating Station (“Palo Verde”) experienced  
5 unusually low performance. The Nuclear Regulatory Commission (“NRC”) ranked the facility at  
6 next to the lowest possible level for an operating plant. (GDS August 17, 2006 Report, hereinafter  
7 referred to as “GDS Report”, Ex. S-45 8). Further, the Institute of Nuclear Power Operations  
8 purportedly ranked Palo Verde as an INPO-3 which the Company concedes reflects poorly on the  
9 performance of the plant. (Tr. at 5161-62).

10 Because of the high capital investment costs of a nuclear power facility, efficient plant  
11 operation is fundamental to attaining the low operational costs that make nuclear power competitive  
12 with other means of generation. In 2005, Palo Verde experienced eight unplanned outages, thereby  
13 requiring APS to seek replacement power to meet its commitments. These outages, as well as the  
14 low evaluations of Palo Verde, suggested a need to investigate the causes of this poor performance.

15 The results of that investigation reveal a steady deterioration in Palo Verde’s performance,  
16 which culminated in low regulatory marks and accounted for four of the unplanned outages in 2005.  
17 Initially, Staff determined that these four imprudent outages resulted in a \$16.269 million cost for  
18 replacement power, of which 14.944 million was incurred in April-December of 2005 when the PSA  
19 was in effect. However, in surrebuttal, Staff accepted certain changes proposed by Company witness  
20 Ewen. In total, these changes effect a \$1.188 million reduction to Staff’s estimate. Thus, Staff’s  
21 final estimate of the cost of replacement power is approximately \$15.082 million,<sup>2</sup> with \$13.757<sup>3</sup>  
22 million occurring during the effective period of the PSA. The investigation also outlined options that  
23 the Commission could pursue in the form of a Nuclear Performance Standard. Such a mechanism

24 \_\_\_\_\_  
25 <sup>2</sup> \$16.269 million – \$1.188 million = approx \$15.082 million.

<sup>3</sup> \$14.944 million – \$1.188 million = approx \$13.757 million.

1 would contribute to effectively distributing the costs of poor performance between the Company and  
2 ratepayers. Without such a mechanism, the costs of poor performance fall solely on ratepayers, who  
3 cannot influence the efficiency of Palo Verde's operations.

4 **1. The Outages are the result of imprudence on the part of the Company.**

5 During 2005, Palo Verde experienced a total of eleven planned and unplanned outages. Of  
6 these outages, Staff identified four as the result of imprudence. (GDS Report at 2). The approximate  
7 impact of these outages in terms of the cost of replacement power is \$15.082 million, \$13.757 million  
8 of which occurred during the period in which the PSA was effective. *Id.* at 41-53. In addition to  
9 power replacement costs, APS experienced reduced margins on off-system and opportunity sales  
10 used to offset fuel and purchased power costs recovered through the PSA. These items should thus  
11 also be counted as a component of the total cost of the imprudent outages. Factoring in the lost  
12 margins on off-system and opportunity sales results in a total cost of \$16.186 million. The ratepayers  
13 are not responsible for these outages and should not be forced to bear these costs.

14 Four discreet instances give rise to the imprudent outages that will be discussed further below.  
15 Briefly, they are the Emergency Diesel Generator Governor failure (March 18-21, 2005), the  
16 Extended Outage due to an operator-caused Reactor Trip on high steam generator level (August 26-  
17 28, 2005), the Unit 2 Refueling Water Tank inoperability (October 11-20, 2005), and the Unit 3  
18 Refueling Water Tank inoperability (October 11-20, 2005).

19 **a. The Emergency Diesel Generator Governor Failure (March 18-21)**

20 Following maintenance, the Company performed a post-maintenance test of one of the Unit 1  
21 Emergency Diesel Generators ("EDG"), a vital safety device necessary to provide power in the event  
22 of disconnection from offsite power sources. As Company witness Denton testified, in the event of  
23 losing off-site power, EDGs are necessary to ensure the orderly and safe shut down of the plant. (Tr.  
24 at 5040). According to NRC regulations, APS is required to shut down the unit if both EDGs are not  
25 available to operate for an extensive period of time. *Id.* at 5041. In fact, both EDGs are necessary in

1 the event of an actual loss of off-site power. *Id.* During the retest of the equipment on March 17,  
2 2005, one of the two EDGs failed to start. Operators determined that the cause of the failure was a  
3 faulty governor for the EDG. Though the governor was replaced, technical specifications require the  
4 shutdown of the unit during the retest.

5 Examination of the governor failure pointed to rust as the source of failure. Though the  
6 Company cited a number of possible causes for the rust, (*see* Tr. at 5136-5137), all of these possible  
7 causes indicate that APS' inability to detect and prevent the failure was due to imprudence. The  
8 governor was stored in a non-climate controlled warehouse, drained of oil. (GDS Report at 23). Had  
9 the Company stored the governor with oil in it, it could have avoided the governor failure and the  
10 outage. (*Id.* at 24. *See also* Tr. at 5139-5140). Because each unit requires both EDGs to be operable  
11 in the event of a loss of off-site power, and because the loss of an EDG for extended periods requires  
12 shutdown of the affected unit, (Tr. at 5041), it is clear that the Company did not treat the EDGs with  
13 the degree of care appropriate to the significance of this particular piece of equipment.

14 **b. Unit 1 Reactor Trip and Outage Extension Due to Operator Error**  
15 **(August 26-28, 2005).**

16 Operator error exacerbated an otherwise unavoidable outage that began on August 11, 2005  
17 with the failure of Unit 1's second EDG. A faulty diode in the voltage regulator prevented the EDG  
18 from maintaining the proper steady output voltage. A further, unavoidable equipment failure, namely  
19 an oil leak on a reactor coolant pump, likewise delayed the restart of Unit 1.

20 On August 26, 2005, operator error during startup caused an avoidable extension of the  
21 outage. Specifically, the steam generator operator failed to obtain supervisory approval before  
22 switching to manual operation of the digital feedwater control system ("DFWCS") when he perceived  
23 that the automatic settings were not raising the level as high as the operator deemed appropriate.  
24 (GDS Report at 24-26). Failure to communicate operator actions led to increased feedwater flow  
25

1 beyond the level necessary for the steaming rate, thereby resulting in a high steam generator level and  
2 a consequent reactor trip. *Id.*

3 The Company did not provide adequate training and permitted a culture of unsupported and  
4 inaccurate beliefs among DFWCS operators. The Company conceded that, in the post-event  
5 interviews, many operators claimed that the DFWCS was unreliable in maintaining stable feed water  
6 levels at low power levels. (Tr. at 5144). Further, the Company conceded that, with respect to the  
7 narrow issue of the DFWCS, no updated training or procedures had been set in place to deal with this  
8 inaccurate perception. *Id.* at 5144-45.

9 The Company suggests that the problem was not with the equipment but with the operators  
10 who perceived fault with the system. (Levine Rej. Test., Ex. APS-95 at 8). The Company's  
11 contention reinforces, rather than detracts from, Staff's conclusions. The operators' erroneous  
12 perception of the system was the root of the problem. As Staff testified, reactor startups were  
13 unusually frequent during 2005 at Palo Verde, and the Company had many prior experiences with  
14 operator misgivings toward the DFWCS. (Jacobs Surrebuttal Test., hereinafter referred to as "Jacobs  
15 Surrebuttal", Ex. S-48 at 22-23). The Company understood that a common mindset of anticipated  
16 system failure preexisted the event. *Id.* This led to a preemptive and incorrect action by an operator  
17 that caused the reactor trip. In spite of its prior knowledge, the Company did not take steps to alter  
18 training so as to eliminate this mindset. This failure to address a known problem supports the  
19 conclusion that this outage is imprudent.

20 **c. Unit 2 and Unit 3 Refueling Water Tank Inoperability (October 11-**  
21 **20, 2005)**

22 From October 11-20, 2005, Palo Verde Units 2 and 3 were out of operation because the  
23 Refueling Water Tanks ("RWT") for both units were declared inoperable. Two safety systems  
24 depend on the RWT, the Emergency Core Cooling System ("ECCS") and the Containment Spray.  
25

1 The declaration of inoperability of these connected systems followed an NRC inspection in  
2 2005. (GDS Report at 32, 39-40; Jacobs Surrebuttal at 24). During the inspection, the NRC voiced  
3 the concern that, during suction from the RWT under certain conditions, air could be entrained that  
4 could damage and disable the safety pumps on which the Containment Spray and ECCS depend.  
5 (GDS Report at 31-32, 39). The Company could not demonstrate to the NRC that air entrainment  
6 was not occurring and thus the units were shut down pending a full analysis to determine whether air  
7 entrainment threatened safe operations. (Jacobs Surrebuttal at 24).

8 The Company—instead of the NRC—should have identified this issue because of the NRC’s  
9 yellow finding in 2004 on a related issue. (See Jacobs Surrebuttal at 24-25). The yellow finding in  
10 2004 resulted from empty containment sump piping, thereby raising concerns that air entrainment  
11 from the empty sump piping could damage safety related pumps. The Company should have known  
12 that air entrainment damage to pumps is a safety concern. Draining the RWT gives rise to the same  
13 air entrainment concerns as the empty sump piping. A reasonably complete analysis of the issues  
14 related to the 2004 yellow finding would have permitted the Company to identify this largely  
15 identical issue. *Id.* Therefore, this outage was avoidable and imprudent.

16 **2. The Proper Measure of the Impact of the Outages requires examining Palo**  
17 **Verde’s performance, without considering the unconnected performance of**  
18 **the Company’s other operations.**

18 In addition to arguing that the outages were not imprudent, the Company also argues that the  
19 improved performance of its coal generation should offset the loss of generation at Palo Verde. This  
20 argument is not persuasive and should not be adopted. Improved performance in the Company’s coal  
21 generation is external and unrelated to the Palo Verde outages. The Palo Verde outages did not cause  
22 improved operations at the Company’s various coal-fired plants, nor did they produce lower coal  
23 prices.

24 The Company incurred costs for replacement power in spite of the improved efficiency of its  
25 coal facilities. These replacement power costs are unaffected by the superior performance of the coal

1 plants even when evaluating them cumulatively. Allowing the performance of the coal facilities to  
2 mitigate the costs of the Palo Verde outages would clearly double count the influence of coal  
3 generation. The Company's arguments for this type of mitigation should not be accepted.

4 **3. A Nuclear Performance Standard is Appropriate and Reasonable.**

5 The Commission should adopt a performance standard to govern the operation of Palo Verde.  
6 As noted above, the Company will recover its cost of invested capital regardless of the quality of its  
7 performance, and the ratepayers therefore bear the risk of poor performance. This is unfair when one  
8 considers that nuclear plants have exceptionally high capital cost and that only the low cost of fuel  
9 and operations offsets the high capital costs. The lower cost of operations can only be achieved when  
10 the plant operates at a high capacity factor. Adopting a reasonable Nuclear Performance Standard  
11 ("NPS") will alleviate this situation by distributing the cost of inefficient operations on both the  
12 Company and the ratepayers. (See Tr. at 5128, 5225).

13 Staff's proposed NPS has the following features:

- 14 1) Evaluating Palo Verde performance by averaging capacity factor achieved every three  
15 years;
- 16 2) Setting the target capacity factor as three year average capacity factor of U.S. nuclear  
17 plants similar in type to Palo Verde (pressurized water reactors ("PWR") with over  
18 600 MW capacity);
- 19 3) Excluding U.S. PWRs with a three year average capacity factor below 60% from the  
20 target capacity factor calculation;
- 21 4) Allowing no action if Palo Verde exceeds the target value for the relevant period;
- 22 5) Assigning to the Company the cost of replacement power for the difference between  
23 actual system costs and system costs had Palo Verde achieved its target capacity  
24 factor;
- 25 6) Allowing the Commission to determine the treatment of the additional costs; and
- 7) At Commission discretion, performing detailed studies of extended outages or other  
extraordinary events that would significantly impact Palo Verde's capacity factor  
during the three year period.

1 (Jacobs Direct Test., hereinafter referred to as “Jacobs Direct”, Ex. S-47 at 7-8).

2 **a. Regulating Company Operations is a Reasonable Means to**  
3 **encourage APS to Achieve an Appropriate Level of Performance.**

4 APS’ Performance Improvement Plan states that APS intends to make Palo Verde a top  
5 performing nuclear facility. (See GDS Report at 51; see also Tr. at 5127). Staff’s proposed NPS,  
6 which sets the industry average as its target, is not inconsistent with that goal. Likewise, an NPS  
7 would reduce the need to undergo extensive and costly investigations of each outage because the  
8 averaging mechanism would focus attention properly on the bottom line.

9 The Company contends that implementation of the NPS, which does not contain incentives,  
10 will not affect the way it does business. (Tr. at 5126). Instead of providing an incentive, the NPS  
11 reallocates costs associated with poor performance between the Company and ratepayers. Staff’s  
12 recommendation shifts the impact of operational deficiencies that are solely within the Company’s  
13 control and thereby applies appropriate pressure to the Company to improve its performance without  
14 jeopardizing the recovery of the cost of investment. Thus, regardless of whether the Company  
15 pursues operational excellence to avoid the graduated penalties of the NPS, ratepayers will no longer  
16 be subsidizing inefficiency.

17 **b. The Performance Standard should solely Consider Palo Verde.**

18 The Company has tentatively expressed willingness to agree to an NPS that examines  
19 Company performance overall rather than examining the isolated performance of its single most  
20 capital intensive asset, Palo Verde. Evaluating the Company’s performance as a whole would  
21 produce skewed results. Though nuclear and coal power plants are both used for base load  
22 generation, they are fundamentally different. (Jacobs Surrebuttal at 36). They use different  
23 operational and safety processes, are subject to different forms of regulation, and have costs that are  
24 unrelated and not directly comparable. *Id.* In addition, nuclear facilities are more expensive and  
25 should operate with lower variable costs. *Id.* A broad performance standard that includes all of the

1 Company's generation would, in effect, permit the Company to gloss over the performance of its  
2 single most costly asset, Palo Verde.

3 **B. Establishing A Power Supply Adjustor Surcharge To Recover Costs Associated**  
4 **With Nuclear Plant Outages That Have Not Been Identified As Imprudent Or**  
5 **Preventable.**

6 Decision No. 67744 allows APS to recover or refund the amount of increased costs for fuel  
7 and purchased power up to a certain limit based on the annual adjustor rate. The Paragraph 19(d)  
8 Balancing Account includes only those power supply costs falling outside of the \$0.004 bandwidth.  
9 The Commission must approve any surcharges to recover or refund any amounts in the Paragraph  
10 19(d) Balancing Account.

11 Staff's testimony addresses whether the Commission should allow APS to recover through  
12 surcharges the costs in its Paragraph 19(d) Balancing Account related to outages at Palo Verde.  
13 Staff's Palo Verde report identifies certain outages as imprudent, and the costs relating to these  
14 outages should therefore be removed from the Paragraph 19(d) Balancing Account. Staff also  
15 recommends that the Commission allow APS to recover through a surcharge the costs resulting from  
16 the Palo Verde outages that were not imprudent.

17 **XI. PROCUREMENT AUDIT**

18 APS' testimony appears to be in general agreement with the findings of the fuel and  
19 purchased power audit conducted by the Liberty Consulting Group on behalf of Commission Staff.  
20 (Antonuk Surrebuttal at 1). Staff did not observe any significant matter of disagreement that would  
21 affect either the establishment of base rates or the design of the PSA. (Antonuk Surrebuttal at 1).  
22 APS has claimed that a number of changes recommended by the audit have already been undertaken;  
23 nonetheless, there does not appear to be a difference of opinion about what both APS and Staff have  
24 concluded ought to be implemented in order to optimize fuel and energy procurement and  
25 management. *Id.*

1 In these circumstances, a reasonable way to address audit findings is for the Company to  
2 prepare 1) an implementation plan for each recommendation that it accepts and 2) a detailed  
3 explanation of its reasons for concluding that particular recommendations need not be implemented.  
4 *Id.* Staff can then identify the best method for monitoring the Company's implementation plan and  
5 for resolving any issues that may be in dispute. *Id.* Staff therefore recommends that the Commission  
6 require the Company to prepare an implementation plan as outlined above. *Id.*

## 7 **XII. ENVIRONMENTAL IMPROVEMENT CHARGE**

8 Staff's testimony addressed APS' proposed Environmental Improvement Charge ("EIC").  
9 APS wants to implement this additional charge to recover its capital investment in coal plant  
10 environmental controls. Through the EIC, APS intends to collect revenues from ratepayers based on  
11 the estimated capital investment needed to install pollution controls on its coal-fired power plants.  
12 Staff recommends that the Commission reject the proposed EIC.

13 Staff listed the following reasons for rejecting APS' proposed EIC:

- 14 1) The EIC would include costs that will not be incurred for several years beyond the test  
15 year;
- 16 2) The EIC would include funding for projects before they are mandated to be installed  
17 on APS' system;
- 18 3) Regulatory mandates typically build in construction lead times to provide industry  
19 sufficient time to comply with mandated regulatory requirements;
- 20 4) The EIC is derived based upon multiple year revenue requirements that increase the  
21 complexity of auditing the charge in the context of future general rate cases and  
22 annual EIC reset proceedings;
- 23 5) The effect of the EIC on APS' interest expense is unclear;
- 24 6) The annual reset of the EIC could be implemented without Commission approval  
25 under APS' proposal;
- 7) The EIC does not address the fundamental financial challenges that APS has identified  
*i.e.*, customer growth and rising fuel costs;
- 8) The environmental impact of implementing the EIC is unclear.

1 (Rowell Direct Test., Ex. S-19 at 14-15). Staff highlighted two points in recommending that the  
2 Commission reject the proposed EIC: 1) the EIC would collect revenues from ratepayers based  
3 predominately upon estimated rather than incurred costs; and 2) the EIC appears to be unique in that  
4 Staff is not aware of any jurisdiction that employs a mechanism with the same characteristics as the  
5 EIC.

6 Staff does not support collecting funds from ratepayers, including interest, before the costs  
7 have been incurred. This policy is reasonable as applied to APS' proposed EIC in this case. APS has  
8 the option of collecting up-front funds for environmental controls from investors, but the EIC would  
9 collect these funds from ratepayers. Collecting funds before costs have been incurred means that  
10 APS will have to estimate capital expenditures. It is very difficult to accurately compute capital  
11 expenditures because costs are unpredictable, and projected completion dates are often unreliable.  
12 Customers would be caught in the middle of pre-funding projects that potentially have different costs  
13 and later completion dates than expected.

14 APS' proposed EIC financing scheme is actually contrary to industry standards. This is  
15 illustrated by two industry studies: a Cambridge Energy Research Associates' study and a NARUC  
16 study. NARUC's study focused on state level incentives for environmental controls on coal-fired  
17 power plants. None of the fifteen states that responded to the NARUC study have a cost recovery  
18 mechanism similar to APS' proposed EIC. None of the twenty-two states that responded to the  
19 Cambridge survey allow companies to collect funds before the costs are actually incurred. Staff was  
20 unable to identify any other jurisdiction that employs a mechanism with the characteristics of the  
21 proposed EIC.

22 ...  
23 ...  
24 ...  
25 ...

1 **XIII. DEMAND-SIDE MANAGEMENT**

2 **A. How Should APS Be Compensated For Its Effort To Make DSM Programs**  
3 **Available?**

4 APS proposed a \$4,907,000 pro forma adjustment to compensate for net lost revenues  
5 resulting from its efforts to create DSM programs. The Settlement Agreement contained in Decision  
6 No. 67744 requires APS to intensify its DSM efforts and to spend at least \$16 million on DSM per  
7 year. In response, APS recently created a number of new DSM programs as part of its Portfolio Plan.  
8 Staff opposes APS' pro forma adjustment and recommends that the Commission disallow the net lost  
9 revenue adjustments for DSM programs. Staff instead recommends that the Commission reward  
10 APS for DSM savings through a performance incentive.

11 APS should be compensated for its efforts to make DSM programs available and for the  
12 savings achieved by successful DSM programs through a performance incentive. A performance  
13 incentive and an adjustment for net lost revenues are two separate approaches to compensating the  
14 utility. These techniques are mutually exclusive, and the Commission should adopt either approach  
15 individually, but not both. (Anderson Direct Test., hereinafter referred to as "Anderson Direct", Ex.  
16 S-16 at 9). The Settlement Agreement that underlies Decision No. 67744 provides for a performance  
17 incentive, arguably signaling the Commission's preference for that approach.

18 Conceptually, a performance incentive is preferable to an adjustment for net lost revenues  
19 because a performance incentive rewards the Company only when its DSM programs successfully  
20 result in energy or demand savings. In other words, APS would not be compensated through a  
21 performance incentive if its DSM programs fail to result in energy efficiency savings. The amount  
22 collected in performance incentives would represent a portion of the actual energy efficiency savings  
23 that APS' DSM programs achieve.

24 Nor is APS' proposed adjustment for net lost revenues sufficiently known and measurable to  
25 merit inclusion in rates. (Anderson Surrebuttal Test., hereinafter referred to as "Anderson

1 Surrebuttal”, Ex. S-17 at 4; Tr. at 3641). Staff believes that DSM spending for the remainder of the  
2 Portfolio Plan period, 2005-07, is very much in question. The energy savings resulting from that  
3 spending is even more difficult to quantify with certainty. (Anderson Surrebuttal at 4). In addition,  
4 Staff believes that, to date, there has not been a significant amount of lost revenue due to DSM  
5 programs. Thus far, the Company has incurred up-front costs, but significant energy savings and  
6 reduced revenues resulting therefrom have not yet fully materialized. (Tr. at 3648).

7 APS proposed a performance incentive in its Portfolio Plan of DSM programs, and Staff  
8 concurred with that proposal, which sets the performance incentive at 10 percent of the net benefits  
9 achieved and caps it at 10 percent of total DSM spending. Staff recommends that APS include its  
10 request for a performance incentive in each semi-annual DSM report. Staff also recommends that  
11 APS provide Staff with backup workpapers and input data to substantiate the numbers for net benefits  
12 and performance incentives included in its semi-annual DSM reports.

13 Staff recommends that APS use the most recent and regionally similar energy savings data  
14 available instead of the program-filed savings numbers from 2005. In addition, APS should  
15 incorporate results from its baseline study into its calculations. Staff believes that a time limit should  
16 be placed upon energy use measurements from other regions. Staff further recommends that APS use  
17 measured savings obtained from APS customers by the Measurement, Evaluation, and Research  
18 (“MER”) contractor beginning no later than July 1, 2007. (Anderson Surrebuttal at 4). The averages  
19 of actual measured usage, for both standard and upgraded equipment, should be recalculated by the  
20 MER from usage samples for each prescriptive measure based on new measurements from the field  
21 no less frequently than every two years. (Anderson Direct at 11).

22 **B. Whether The Commission Should Allow APS To Accrue Interest On The**  
23 **Demand-Side Management Adjustment Charge (“DSMAC”) Account Balance.**

24 Currently, the DSMAC account does not accrue interest. Staff does not oppose APS’  
25 proposal to allow the accrual of interest earnings on the DSMAC account balance. If interest is

1 allowed to accrue, the applicable interest rate should be the one-year Nominal Treasury Constant  
2 Maturities rate that is contained in Federal Reserve Statistical Release H-15 or its successor  
3 publication.

4 **C. What Action Should Be Taken If APS Fails To Spend The \$30 Million For DSM**  
5 **During The Initial Three Year Period Identified In Decision No. 67744?**

6 In rebuttal, APS witness Orlick addressed how to handle under-spending of DSM dollars in  
7 the 2005-07 period. She recommends that any under-spending should be carried over to and spent in  
8 subsequent years, in addition to the \$16 million required to be spent in each subsequent year.

9 Staff's position is guided by Decision No. 67744, which provides that any unspent amount  
10 should be credited to the balance of the Demand-Side Management Adjustment Clause ("DSMAC")  
11 account if APS does not spend at least \$30 million of the base rate allowance for approved and  
12 eligible DSM-related items during 2005-07. In effect, any "under-spending" is returned to  
13 ratepayers. (Anderson Direct at 7; Anderson Surrebuttal at 2).

14 **XIV. ISSUES RELATED TO RENEWABLES**

15 **A. Increasing The Environmental Portfolio Standard Adjustor Rate To Recover**  
16 **Costs For The EPS Credit Purchase Program.**

17 The Environmental Portfolio Standard ("EPS") requires distribution entities to derive a  
18 portion of their retail energy from environmentally friendly renewable sources. APS is able to meet  
19 some of its EPS requirements through the EPS Credit Purchase Program. The program allows APS  
20 to receive renewable energy credits for partially reimbursing customers who install renewable energy  
21 systems on their properties. APS recovers the costs for the EPS requirements through a Systems  
22 Benefit Charge and through the Environmental Portfolio Surcharge, an adjustment mechanism.

23 Staff recommends that the EPS adjustor rate and caps be increased to allow for more funding  
24 of the EPS Credit Purchase Program. The EPS adjustor rate should be set at \$0.001392 per kWh with  
25 monthly caps per service of \$0.56 for residential customers, \$20.68 for non-residential customers,

1 and \$62.04 for non-residential customers with demands of more than 3,000 kW. This increased  
2 funding will provide an additional \$4.25 million for the EPS Credit Purchase Program.

3 The recommended increase in the EPS adjustor rate and caps is reasonable because it is  
4 consistent with Commission Decision No. 68668. In that decision, the Commission approved the EPS  
5 Credit Purchase Program and ordered APS to allocate an additional \$4.25 million for the EPS Credit  
6 Purchase Program, specifying that these additional funds should be recovered in rates in APS'  
7 ongoing general rate case.

8 **B. Maintaining The Systems Benefit Charge For Renewables At \$6,000,000.**

9 Currently, APS' Systems Benefits Charge contains \$6,000,000 for renewables. As mentioned  
10 before, the Systems Benefit Charge is one way that APS recovers some of the costs related to  
11 meeting its Environmental Portfolio Standard requirements. Staff recommends that the Commission  
12 maintain funding for renewables in the Systems Benefits Charge at \$6,000,000.

13 **C. APS' Proposed New Rate Schedule For Net Metering.**

14 Net metering is a way to incent customers to invest in renewable energy generation by  
15 allowing their generation to offset their consumption over one or multiple billing periods. APS has a  
16 proposed new rate schedule for net metering: EPR-5, Rates for Renewable Resource Facilities of  
17 10kW or Less for Partial Requirements. APS' proposed plan requires a bidirectional meter so that  
18 power flows both ways. With APS' proposed plan, customers that generate more electricity than they  
19 use will receive kWh credits for that excess energy in the subsequent billing period. This means that  
20 the customer will receive full retail value of the energy component of its bundled rate for the excess  
21 power that the customer provides to APS. EPS funding will be used to recover the metering costs,  
22 billing system modification costs, and revenue loss.

23 Staff recommends approving EPR-5 the following with modifications:

- 24 1) Staff would not require a bidirectional meter;  
25 2) Staff recommends that the facility size limit be increased to 100kW;

- 1           3)       Customer participation should not be limited by rate schedule;
- 2           4)       The schedule should be modified to indicate that all changes to the schedule will  
3           require Commission approval;
- 4           5)       APS should be required to clarify the tariff to indicate that ratepayers will be  
            responsible for the cost of the meter.

5 (Keene Direct Test., hereinafter referred to as "Keene Direct", Ex. S-12 at 6-7).

6           In testimony, various parties have criticized Staff for its recommendation concerning the bi-  
7           directional meter. Although Staff believes that the Company should not be allowed to *require* a bi-  
8           directional meter as a condition to subscribing to this tariff, Staff recognizes that there may be  
9           benefits to using bi-directional meters in some circumstances. (Tr. at 3550). If using bi-directional  
10          meters is less expensive, if operational considerations indicate that bi-directional meters are  
11          preferable, or if long-term savings can be achieved by use of bi-directional meters, Staff would not be  
12          opposed to their use. *Id.* Certainly, Staff does not intend for its recommendation to foreclose the use  
13          of bi-directional meters in appropriate circumstances. *Id.* Nonetheless, Staff believes that achieving  
14          the objectives of the tariff at the lowest feasible cost is a reasonable consideration. The evidence  
15          presented in this proceeding demonstrates that two standard meters (one measuring outgoing  
16          electricity and one measuring incoming electricity) would appear to be less expensive than a bi-  
17          directional meter. (Keene Direct at 6).

18          In direct testimony, Staff witness Keene recommended that APS should be permitted to  
19          recover revenue loss associated with its proposed net metering tariff. (Keene Direct at 6; Tr. at  
20          3577). At the hearing, however, she disagreed with APS' proposal for measuring revenue loss. (Tr.  
21          at 3577). Staff believes that the revenue loss is the difference between the retail rate and APS'  
22          avoided cost. (Tr. at 3510-11). Ms. Keene proposed that lost revenue should apply only to excess  
23          generation, not to total capacity; she further stated that actual retail rates should be applied, not an  
24          annual average *Id.* Avoided costs should reflect seasonal on-peak and off-peak rates, as on EPR-2

1 and EPR-4. *Id.* Finally, Staff witness Keene proposed that all metered rate schedules should be  
2 eligible. *Id.*

3 **D. Green Pricing Tariffs.**

4 APS is proposing two new rate schedules, Green Power Block Schedule (GPS-1A) and Green  
5 Power Percent Schedule (GPS-2A). Staff recommends approving the two new green pricing tariffs as  
6 proposed by APS.

7 APS' current Solar Partners Program allows customers to pay \$2.64 per month for a block of  
8 15 kWh of solar energy, which adds .0176 per kWh to the customer's current rate schedule. APS'  
9 proposed new tariff, GPS-1A, will allow customers to purchase 100kWh blocks of electricity  
10 generated by renewable resources and pay an additional \$1.00 per month (\$0.01 per kWh) for each  
11 block. It is reasonable to approve the GPS-1A tariff because APS is offering more energy from  
12 renewable resources at a cheaper price than the current program offers. GPS-2A offers customers the  
13 opportunity to determine the percentage of their electricity that will come from renewable resources.  
14 Customers will pay an additional price, depending on the percentage requested, on top of their current  
15 rate schedule. This tariff should be approved because the prices are reasonable (\$0.01 per kWh for  
16 100%; \$0.005 per kWh for 50%; \$0.0035 per kWh for 35%; \$0.001 per kWh for 10%), and this  
17 program promotes the use of renewable energy.

18 **XV. COST OF SERVICE STUDY**

19 APS prepared a cost of service ("COSS") study 1) to perform jurisdictional allocations to  
20 separate the retail portion of APS' operations from the non-retail portion; and 2) to determine overall  
21 retail revenue requirements and to further allocate costs among customer classes. (Brosch Direct  
22 Test., hereinafter referred to as "Brosch Direct", Ex. S-7 at 5). APS conducted its COSS on a  
23 combined basis, performing jurisdictional and class allocations within a single model. *Id.* Although  
24 Staff generally found APS' COSS model to be reasonable, Staff has proposed one modification: Staff  
25

1 employed a Four Coincident Peak and Average (“4CP & Average”) allocation in place of the  
2 Company’s Four Coincident Peak (“4CP”) method. *Id* at 7-8.

3 Staff’s modification centers around the proper method for allocating production demand  
4 costs, which are the costs associated with the Company’s nuclear, coal, and gas-fired generation  
5 facilities. *Id.* at 8, 10-11. Staff believes that the Company’s COSS should use an energy-weighted  
6 allocation approach, instead of the Company’s proposed 4CP method, which allocates production  
7 demand costs based solely upon relative class demands registered during the four peak hours of the  
8 year. *Id.* at 8. Staff therefore modified the Company’s COSS to use a 4CP & Average allocation for  
9 production plant investment and expenses. *Id.*

10 Coincident peak demands are the measured maximum combined loads of all customers on the  
11 system in the single hour (or four hours under the Company’s proposal) when overall system demand  
12 is the highest during the year. *Id.* The Company’s proposed 4CP allocation factor would use these  
13 hourly demands registered by each customer class during the four highest peak system demand hours  
14 in the test year to allocate responsibility for *all* power generation production resources among  
15 customer classes. *Id.* Customer use during the remaining 8,756 hours of the year has no impact upon  
16 the allocation of costs for APS power plants under the 4CP approach. *Id.* The theory assumes that  
17 meeting hourly peak demand is the sole planning criteria used by APS to determine whether to incur  
18 generation fixed costs. *Id.* at 8-9.

19 Staff does not accept this premise. *Id.* at 9. Costs of APS’ power production facilities are not  
20 incurred solely to meet peak hour demands, but are instead incurred to efficiently produce electricity  
21 throughout the entire year. *Id.* Although APS is a summer peaking utility, its generation facilities are  
22 also required to serve customers during all of the non-peak hours of the year. *Id.* at 11. Many of the  
23 costs incurred by APS to own, operate, and maintain its power plants could be much lower if the  
24 Company were concerned only with meeting demands during the four peak hours of the year. *Id.* at  
25 11-12.

1 Generally, the effect of using an energy-weighted 4CP & Average approach (as recommended  
2 by Staff) is to recognize that demands throughout the year contribute to cost causation and to attribute  
3 some generating capacity costs to the lighting classes and to attribute more production costs to higher  
4 load factor customers that use more energy relative to their peak demands. *Id.* at 10. In APS' case,  
5 the 4CP allocation of production demand costs results in Street Lighting and Dusk to Dawn lighting  
6 classes paying nothing toward the fixed costs of APS' production facilities. *Id.* at 12. While it is  
7 obvious that APS must use its generation facilities to serve these customers, the 4CP method fails to  
8 allocate any production demand costs to them simply because their loads do not occur coincident  
9 with the four hours when the 4CP method measures customer demand. *Id.* at 12-13.

10 An energy-weighted allocation factor considers the fact that electric production facilities are  
11 designed and operated to meet both peak and non-peak demands. *Id.* at 13. The 4CP & Average  
12 approach involves a weighted combination of the peak demand allocation factor used by APS along  
13 with an average demand (or energy-based) allocation factor. *Id.* Although Staff proposes to apply  
14 weight to customer demands throughout the year, Staff nonetheless proposes to heavily weight hourly  
15 peak demands when determining production demand allocation factors. *Id.* at 9.

16 Staff witness Brosch explained that, in the last APS rate case, Staff and RUCO opposed the  
17 Company's use of a 4CP production demand cost allocation method and also noted that other Arizona  
18 utilities with summer peaking characteristics, such as Tucson Electric Power, have employed a 4CP  
19 & Average approach in proceedings before the Commission. *Id.* at 16-19.

20 Staff anticipated that APS would argue that Staff's 4CP & Average method would shift costs  
21 away from retail customers and inappropriately place them upon non-jurisdictional, FERC-regulated  
22 services. *Id.* at 22. Therefore, Staff elected to not disturb the jurisdictional allocation of production  
23 plant, so that no jurisdictional shifting of costs could occur. *Id.* The 4CP & Average calculation  
24 performed by Staff was limited to revision of the retail class allocation factors so that the percentage  
25

1 of production demand related costs allocated to FERC jurisdictional customers is unchanged and is  
2 still based upon the Company's proposed 4CP method. *Id.*

3 Finally, transmission costs in the COSS are treated as entirely non-jurisdictional.  
4 APS' retail customers are charged for transmission services for native load at the FERC Open Access  
5 Transmission Tariff rate. *Id.* at 23. This treatment is consistent with the resolution of APS' last rate  
6 case. *Id.*

## 7 **XVI. RATE DESIGN**

### 8 **A. Interclass Returns For Residential Service Category Recommendations.**

9 In general, Staff favors a rate spread that is informed by the results of the cost of service study  
10 as opposed to an across-the-board increase, as recommended by RUCO witness Diaz-Cortez. Staff  
11 recommends a total increase of 9.69 percent for the residential class as a whole, which is greater than  
12 the system average. Staff also recommends that residential rates EC-1, ET-1, and ECT-1 receive  
13 greater than average increases because these rate classes are underperforming relative to the rest of  
14 the residential class as well as the system average rate of return. Staff also recommends that E-12  
15 receive an increase that is less than the system average because this rate class is earning slightly more  
16 than the system average.

17 Staff considered two scenarios in determining the proper rate spread for the interclass  
18 residential cost-of-service categories. The first scenario takes into account the elimination of frozen  
19 rate schedules E-10 and EC-1, consistent with Commission Decision No. 67744. In the second  
20 scenario, Staff evaluated an interclass residential rate spread where E-10 and EC-1 would not be  
21 cancelled in this proceeding. Staff recommends the first scenario and included the second scenario  
22 for information purposes only. A chart providing interclass residential rate spreads can be found in  
23 Staff witness Andreasen's testimony. (Andreasen Direct Test., hereinafter referred to as "Andreasen  
24 Direct", Ex. S-22 at 6).

1           **B. Interclass Returns For General Service Category.**

2           Staff's testimony addresses the rate increase percentage to apply to the general service  
3 category. Staff recommends a total increase of 9.52% for the general service class as a whole, which  
4 is less than the system average increase.

5           Staff recommends a smaller than average increase for E-20, which is reasonable because E-  
6 20's rate of return is greater than the system average and exceeds that of any other general service  
7 rate category, according to the cost-of-service review presented by Staff witness Brosch. Staff  
8 further recommends that the cost of service category E-32 (1,000 kW or greater) receive a greater  
9 increase than all other E-32 cost-of-service categories because this category is underperforming  
10 relative to the other E-32 cost-of-service categories. Staff also recommends a higher than average  
11 increase for both E-34 and E-35 because both of these rates have significantly lower average rates of  
12 return compared to the rest of the general service category and the system average rate of return. A  
13 chart providing an interclass general service rate spread can be found in Staff witness Andreasen's  
14 testimony. (Andreasen Direct at 7).

15           **C. Customer Transition Plan For Residential Customers On E-10 And EC-1.**

16           Staff's testimony addresses the elimination of frozen rate schedules E-10 and EC-1. The  
17 Commission provided for the cancellation of E-10 and EC-1 in Decision No. 67744 in April, 2005.  
18 APS proposes that residential customers subscribing to these rate schedules be given six months to  
19 review and choose a new rate schedule after this case concludes. By contrast, Staff recommends that  
20 residential customers on these rate schedules be given one year instead of six months to choose a new  
21 rate schedule, that APS continue to educate these customers on their rate options during the one-year  
22 period, and that APS wait until the end of the one-year transition period to cancel E-10 and EC-1. A  
23 one-year transition period is reasonable because the increase is fairly significant, and customers may  
24 need a longer period to evaluate all other available rate options, including time-of-use and demand  
25 options. For the evaluation period to be effective, APS should continue to educate its customers. In

1 the rebuttal testimony of APS witness Rumolo, APS accepted Staff's proposal for the one-year  
2 transition period for residential customers on E-10 and EC-1. (Rumolo Rebuttal Test., Ex. APS-70 at  
3 7).

4 Under APS' proposal, E-10 and EC-1 customers will be moved to default rates if they fail to  
5 elect a new rate during the transition period. E-10 and EC-1 customers who consume less than 1,000  
6 kWh would be moved to E-12, E-10 customers who consume more than 1,000 kWh would be moved  
7 to ET-1, and EC-1 customers who consume more than 1,000 kWh would be moved to ECT-1. Staff  
8 finds this proposal to be reasonable.

9 **D. Customer Transition Plan For General Service Customers On The Experimental**  
10 **Time-Of-Use Rates E-21, E-22, E-23, and E-24.**

11 Staff's testimony addresses whether APS should be permitted to automatically switch general  
12 service customers on the experimental time-of-use rates E-21, E-22, E-23, and E-24 to a default rate  
13 at the conclusion of the rate case. Under APS' proposal, the default rate would be E-32 TOU. APS  
14 would then provide each customer with a comparison of his/her bill on E-32 and E-32 TOU. If a  
15 customer were to find that E-32 is a more advantageous rate than E-32 TOU, the customer could  
16 switch to E-32 as soon as a meter change out could be provided by APS.

17 Staff recommends that APS first give customers a six-month transition period to evaluate and  
18 choose among the various rate options. APS shall then cancel E-21, E-22, E-23, and E-24 at the end  
19 of the six-month interim period. This recommendation is reasonable because a six-month interim  
20 period provides customers the opportunity to consider all of their rate options before APS places  
21 them on a default rate, and it gives APS time to make the required meter change outs. Additionally,  
22 an interim period will mitigate unintended rate impacts by giving each customer the opportunity to  
23 choose the most economic rate option based on factors specific to his/her individual load pattern. In  
24 the rebuttal testimony of APS witness Rumolo, APS accepted Staff's proposal for the six-month  
25 transition period for general service customers on experimental rates E-21, E-22, E-23, and E-24. *Id.*

1           **E.     Rate Design For ET-2 & ECT-2.**

2           Staff recommends that rate designs for ET-2 and ECT-2 remain revenue neutral compared to  
3 ET-1's and ECT-2's respective adopted rates. Regarding ET-2, Staff also recommends that the  
4 Commission incorporate off-peak kilowatt-hour winter rates that are less than off-peak summer rates.  
5 This approach is appropriate because a utility's generation or purchased power costs are typically  
6 lower in the winter than they are in the summer. This approach is also consistent with other APS off-  
7 peak rate designs.

8           **F.     Demand Rates And Structure Of E-32.**

9           APS has proposed applying an increase of about 21% to rate schedule E-32, which is the  
10 proposed system average increase. Staff recommends that demand rates not be raised significantly  
11 over levels proposed by APS. Staff's hesitation to raise demand rates significantly is supported by  
12 two factors: 1) the last rate case significantly raised the demand charge for customers above 20 kw,  
13 such that some lower load factor customers received increases significantly greater than the average  
14 increase; and 2) this adoption of a higher demand rate is fairly new in that current rates have only  
15 been in effect for a year and a half.

16           AECC witness Higgins has recommended various demand rate alternatives that would recover  
17 additional revenue requirements through demand rates as opposed to energy rates. Increasing  
18 demand rates favors higher load factor customers. Staff believes that the Commission should be  
19 cautious about adopting higher demand rates for E-32 that would adversely impact low load factor  
20 customers, who have recently experienced greater than average increases as a result of APS' last rate  
21 case.

22           In addition to restricting the proposed demand rates, Staff also recommends that the  
23 Commission require APS to propose in its next rate case a replacement for E-32 with three separate  
24 tariffs for small, medium, and large general service categories or other appropriate divisions.  
25 Replacing E-32 with three separate tariffs is a reasonable modification because the current structure

1 complicates the rate design process for E-32, making it difficult to tailor rate structures to different  
2 size customers with similar usage characteristics. Dividing E-32, which currently serves about 96%  
3 of APS' general service customer base, into size-based categories would mitigate this problem.

4 Staff witness Andreasen noted that creating multiple size-based categories for general service  
5 customers is common in the industry. Utilities often opt to have multiple rates for general service  
6 customers designed by different categories of size, rather than one rate structure that applies to  
7 customers of varying sizes. Staff believes that APS and its general service ratepayers could both  
8 benefit from rate schedules that are designed for groups of customers of similar sizes. In rebuttal  
9 testimony, APS witness Rumolo and DEAA witness Murphy both accepted Staff's proposal to divide  
10 E-32 into size-based categories.

11 **G. Rate Structure of E-32 TOU**

12 Staff agrees with DEAA witness Murphy that E-32 TOU should also be replaced with size  
13 sensitive rates. (Murphy Rebuttal Test., Ex. DEAA-2 at 2). Consistent with Staff's recommendation  
14 for E-32, Staff therefore recommends that APS file three separate tariffs for small, medium, and large  
15 general service categories (or other appropriate divisions) in its next rate case. Staff believes that the  
16 E-32 TOU rate structure should correspond to the E-32 rate structure; therefore, APS' future  
17 proposals for replacement tariffs for E-32 and E-32 TOU should be consistent.

18 Staff also agrees with AECC witness Higgins that the same rate increase applied to E-32  
19 should also be applied to E-32 TOU in order to maintain the same relationship between the two  
20 schedules that was established in the last rate case. (Higgins Direct Test., Ex. PDMC/ARCC-5 at 17).  
21 Staff finds no evidence to support an increase for E-32 TOU that is significantly higher than the  
22 increase assigned to E-32.

23 **H. System Benefits Charge.**

24 Staff recommends that the System Benefits Charge be \$49,191,690. Staff recommends the  
25 same amounts for demand-side management, renewables, and Palo Verde Power Plant

1 Decommissioning that APS has proposed. Staff recommends a higher amount than APS proposes for  
2 the E-3/E-4 Low Income Programs to take into account the \$150,000 administrative and marketing  
3 expenses that APS identified in discovery. APS recommended including \$10,177,404 for ISFI, but  
4 Staff recommends reducing that amount to \$9,917,657. This proposed reduction of \$259,747 is  
5 addressed in the Direct Testimony of Staff witness Dittmer. Staff recommends that the System  
6 Benefit Charge for all applicable APS rate schedules be set at \$.001850 per kWh.

7 **I. Schedule 1 Recommendations**

8 Schedule 1 is a rate schedule that sets forth APS' terms and conditions of service. APS has  
9 proposed making certain clarifying changes as well as changing the way the after-hours charge for  
10 other services is collected from customers. APS' proposal would change the way in which the after-  
11 hours charge for other services is assessed to customers and would result in a charge of \$75.00 per  
12 crew person per hour.

13 Staff believes that APS' proposal has the potential to create customer confusion and that  
14 customers will not be able to know ahead of time what they will be charged. Therefore, Staff  
15 recommends that the after-hours charge on Schedule 1 for other services remain at \$75.00 per trip.

16 Staff recommends that the wording for sections 4.3.2.3.4, 5.4, and 6.4 on Schedule 1 included  
17 on APS document number 10679 be adopted, which can be found in Staff witness Andreasen's  
18 Surrebuttal testimony as Exhibit A. Additionally, Staff recommends that APS should include a  
19 definition for "Multi-Unit Residential High-Rise Developments" to avoid confusion.

20 **J. Schedule 3 Recommendations**

21 Schedule 3 is a service schedule that sets forth APS' line extension policy. Schedule 3 allows  
22 APS to collect the costs of installing distribution-related facilities that are associated with the  
23 development of new homes and businesses within APS' service territory. APS is proposing to move  
24 from a free-footage-based allowance to a dollar-based allowance. This proposal would improve  
25 APS' ability to recover its distribution costs associated with new growth. (Andreasen Direct at 22).

1 APS has reorganized Schedule 3 by specific type of end-use development: (1) Residential  
2 Homebuilder Subdivisions, (2) Residential Customer Home "Lot Sale" Developments, (3) Master  
3 Planned Community Developments, and (4) Residential Multi-Family Developments. For the  
4 Residential Custom "Lot Sale" Developments, Staff recommends that APS add clarifying language to  
5 Schedule 3 to specify that the "construction cost" refers to the "backbone infrastructure cost." Under  
6 sections titled "Master Planned Community Developments" and "Residential Multi-Family  
7 Developments," Staff recommends that APS clarify the allowances that will be credited to the  
8 applicant. With respect to the definition section of Schedule 3, Staff recommends that APS amend its  
9 definition for "Residential Homebuilder Subdivision" on Schedule 3 to be consistent with R14-2-  
10 201(34). Staff also recommends that APS add language to each section of Schedule 3 clarifying the  
11 applicable timeframes for field audits and refundable advances.

12 In rebuttal, APS witness Rumolo provided a redlined exhibit DJR-3RB, which adopts Staff's  
13 recommendations for Schedule 3. Staff finds this acceptable subject to the following three  
14 recommendations: (1) clarify that under section 1.1.1 of Schedule 3, "group" would be defined as "4  
15 or less homes" instead of "less than 4 homes"; (2) clarify that under section 1.3.1, the allowance  
16 would be credited against the "total construction costs"; and (3) clarify that under section 1.3.2.,  
17 advances would be subject to refund as specified in "section 4.1" instead of "section 4.2." In the  
18 rejoinder testimony of APS witness Rumolo, APS agreed that these recommendations are acceptable.

## 19 **XVII. MISCELLANEOUS ISSUES**

### 20 **X. Hook-Up Fees.**

21 Staff surveyed and researched the feasibility of establishing a hook-up fee for APS. There are  
22 many unanswered questions that should be addressed before the Commission decides this question.  
23 Therefore, Staff does not recommend the adoption of hook-up fees for APS at this time.

24 If the Commission chooses to pursue hook-up fees for electric and gas utilities, Staff  
25 recommends that the Commission open a generic docket where parties can provide feedback, and the

1 Commission can evaluate the adoption of hook-up fees for the energy industry. If the Commission  
2 were to adopt a hook-up fee for APS in this proceeding, Staff believes that the structure of Schedule 3  
3 should be changed 1) to remove the free allowance and 2) to account for specialized distribution  
4 related costs in excess of those included in the hook-up fee.

5 **B. Demand Response And Load Management.**

6 Demand response programs are mechanisms designed to provide incentives for customers to  
7 reduce their load in response to prices, market conditions, or threats to system reliability. Demand  
8 response can result in savings of variable supply costs during times when wholesale prices and  
9 demand are high. This would displace the need to build additional capacity-related infrastructure,  
10 such as generation, transmission, and distribution. This would also improve system reliability by  
11 reducing demand when facilities, such as a generator or transmission line, fail. Load management  
12 refers to deliberate actions initiated by a utility to reduce peak demands or to improve system  
13 operating efficiency.

14 Staff recommends that APS conduct a study to identify the types of demand response and load  
15 management programs that would be most beneficial to APS' system. In the study, APS should  
16 demonstrate why certain programs are more beneficial than others, and it should also identify the  
17 customer segments that are most likely to respond to such programs. The study should rely on a cost-  
18 benefit analysis based on the Societal Cost Test and should be filed with the Commission within eight  
19 months of a Commission decision in this matter. If APS needs more than eight months to complete  
20 its study, Staff would not object to extending the deadline.

21 In addition, APS should be required to file for Commission approval one or more cost  
22 effective demand response or load management programs that APS believes would be most beneficial  
23 to its system and its ratepayers. APS should file its proposed program concurrently with the study  
24 referred to above.

25

1           **C.     Rate Stabilization Fund**

2           The Commissioners asked the parties to address whether APS should establish a rate  
3 stabilization fund. Although a rate stabilization fund is a novel idea with potential benefits, Staff  
4 does not support the adoption of such a mechanism for APS at this time. (Rowell Rate Stabilization  
5 Response to Comm'rs., Ex. S-21).

6           A rate stabilization fund would require up-front funding from ratepayers, thereby front-  
7 loading the necessary costs. Furthermore, given the size of recent actual and requested APS rate  
8 increases, any hypothetical rate stabilization fund would have had to have been very large (and thus  
9 very expensive) to achieve any meaningful rate impact. With respect to SRP's rate stabilization fund,  
10 Staff notes that SRP is a fundamentally different entity than APS; thus, policies that are appropriate  
11 for SRP may not be appropriate for APS.

12           **D.     Depreciation**

13           Staff concluded that the depreciation rates presented in APS witness White's Attachments  
14 REW-1 and REW-2 should be adopted for use in this case. (Smith Direct Test., Ex. S-18 at 34).  
15 These depreciation rates were developed in a manner that is consistent with the Commission's rules  
16 for depreciation rates. *Id.* at 35. These rates are also consistent with a "technical update" approach to  
17 the depreciation rates approved by the Commission in Decision No. 67744. *Id.* The net change in  
18 percentage terms is fairly small, resulting in an increase of .06 percentage points for APS plant and a  
19 decrease of .2 percentage points for plant that APS acquired from PWEC. *Id.*

20           The Commission should require APS to clearly break out each of the new depreciation rates  
21 between 1) a service life rate and 2) a net salvage rate, similar to the rates shown in Appendix A to  
22 Decision No. 67744. By doing this, the depreciation expense related to including the estimated future  
23 cost of removal can be tracked and accounted for by plant account. *Id.* Finally, Staff also  
24 recommends that the Commission consider amending A.A.C. R14-2-102, the Commission's rule  
25 addressing depreciation, to allow alternative treatment for the cost of removal. *Id.* at 34.

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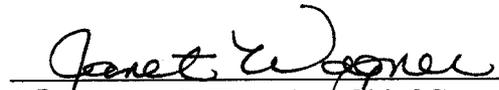
**E. Staff Engineering Report**

Staff conducted an engineering inspection to determine whether APS' 2005 capital improvements were used and useful and to evaluate APS' plant for quality of service purposes. (J. Smith Direct Test., Ex. S-2 at 6-7). Staff concluded that the utility plant improvements constructed by APS in 2005 were appropriate and necessary to maintain reliable, efficient, and cost effective service to its retail customers and the wholesale market. *Id.* Staff therefore concluded that all utility plant contained in APS' rate application is "used and useful" in meeting customers' needs. *Id.*

**XVIII. CONCLUSION**

For the reasons set forth above, Staff requests that the Commission adopt Staff's recommendations in this matter.

RESPECTFULLY SUBMITTED this 22<sup>nd</sup> day of January, 2007.

  
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